VALUATION AND STRESS ANALYSIS OF EXPLORATION AND PRODUCTION (E&P) SHALE ASSETS

A Thesis

by

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ABSTRACT

Shale oil and gas exploration and production (E&P) projects differ in many aspects from the projects with traditional reservoirs. These differences are reflected in the key aspects of the project, ranging from technical analysis of the drilling location and schedule, equipment selection and site logistics operations, as well as production decline including reserve analysis, to more financial analysis such as payback periods, discounted cash flow model, including net present value analysis, production growth versus investment, debt service coverage ratio and financial stress analysis (using RiskAMP Excel-Add-in).

This study provides with a holistic valuation model especially for exploration and production (E&P) shale assets which takes into account the risks associated with differences between conventional and unconventional reservoirs and their resulting financial impacts. The risks due to differences between the conventional and unconventional reservoirs is accounted for by including different production decline models i.e. hyperbolic, harmonic, exponential, and stretched exponential. Their financial impacts are accounted for through cash flow analysis and revenue growth per investment analysis. The net present value of these cash flows is also tested for delayed drilling, and variable interest rates. In order to determine the borrowing base amount in case of a reserve based lending, debt service ratios have been determined. A stress analysis has been performed using the RiskAMP Excel add-in with variable oil and gas prices, cost of drilling and completion, initial production, initial decline rates, and correlation between

oil and gas prices and cost of drilling and completion, and that between initial production and initial decline rates. In addition to this it also accounts for the risks associated with low production growths, early declines and late paybacks of shale oil and gas reserves.

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DEDICATION

I would like to dedicate this thesis to my parents and friends.

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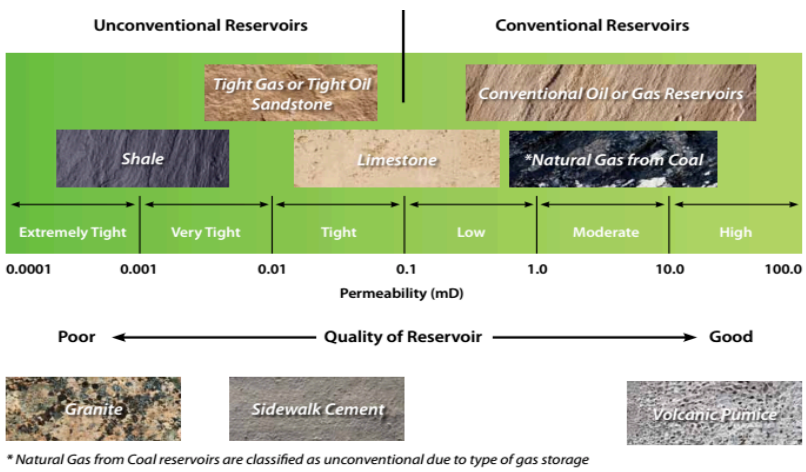
1. INTRODUCTION & LITERATURE REVIEW

1.1 INTRODUCTION

The shale oil revolution led to the sudden increase in the shale oil production in the mid-2000s, as a result of which the decline in the U.S. crude oil production was reversed. This revolution was fueled by the high conventional crude oil prices around 2003, which made the shale oil extraction technology cost competitive during that time (Kilian, 2016). Since 2010 through 2013, the U.S. shale oil and Canadian heavy oil production have increased drastically but were balanced by the reduction in the supply from Libya, Iran, Syria, Sudan and Yemen due to political events. Additionally, there was depletion from the North Sea and West Africa. However, in 2014, the increases in the North American oil productions could not be matched by theses politically influenced reductions in oil productions. Thus, major price collapse occurred in 2014 and continues today due to sustained surplus oil production majorly form the U.S. shale oil production increases (Berman, 2015). However, this over production of unconventional oil, mainly shale oil is being funded by debt. Therefore, the increase in production from the OPEC is a part of its strategy to prevent capital providers from funding the “non-commercial” shale projects and increase its market share lost due to increase in U.S. shale oil production. According to Art Burman, the rig productivity, drilling efficiency and re-fracking are simply distractions indented to mask the truth that the unconventional oil companies are losing money. And therefore, future oil prices will inevitably be higher as a result of deferred investment, growing oil demand and geo-political risks like from the OPEC.

Until the mid 1990s the world produced its hydrocarbons from porous and permeable rocks like sandstones and limestones, individually sealed by the geological traps of shale or salts. These reserves are known as conventional reserves and a very large portion of the world reserves comes from the conventional reserves.



Reprinted from: Shale gas and tight oil, unconventional fossil fuels. Petroleum & Coal, 56(3), 206-221.

Figure 1:Differences in Permeability between Unconventional and Conventional reservoirs

Unconventional reserves on the other hand differ from the conventional ones, however the underlying hydrocarbons i.e. the oil and gas remain the same. Most of the unconventional hydrocarbons are found in the same basin as the conventional ones, forming the source rock and a potential seal for the conventional hydrocarbons. The fact that unconventional hydrocarbons are trapped within a complete reservoir unit due to its inherently almost negligible permeability, as seen in **Figure 1** makes them very different from the conventional ones (Scotchman, 2016).

Generally, the term 'unconventional hydrocarbons' represents the shale resources i.e. the shale oil and gas reserves, both characterized by very low permeability and natural fractures. Therefore, hydrocarbons from shale reservoirs are extracted by artificially creating permeable reservoirs within almost impermeable shale with the help of hydraulic fracturing (Scotchman, 2016). Whereas drilling a conventional well involves a reservoir having pressure as a result of which oil flows out. Therefore, the technologies used to extract unconventional hydrocarbons especially horizontal drilling and hydraulic fracturing, are not only different but also expensive than that used for the conventional ones (Plummer, 2015).

As far as the differences in the production of conventional and unconventional oil and gas are concerned, ultimate recovery for shale gas reserves is about 28-40%, whereas, that for conventional gas is almost double, about 60-80%. Additionally, the well life span for unconventional wells is about 5 years (without re-fracking), whereas the same for conventional wells is about 25-30 years (Infographic: Conventional vs. Unconventional Gas Exploration, 2016). Another major issue related to unconventional oil and gas production is that the production from unconventional wells decline by 60-80% in the first year itself, whereas that from conventional wells declines relatively at lower rates, i.e. by 25-40% in the first year.

These differences between conventional and unconventional reservoirs in terms extraction technologies, well characteristics and production efficiencies generate a need to further understand and analyze the different technical as well as economic aspects of shale reservoirs.

Figure 2 demonstrates how it is more expensive to produce oil and gas from shale reservoirs than from conventional.

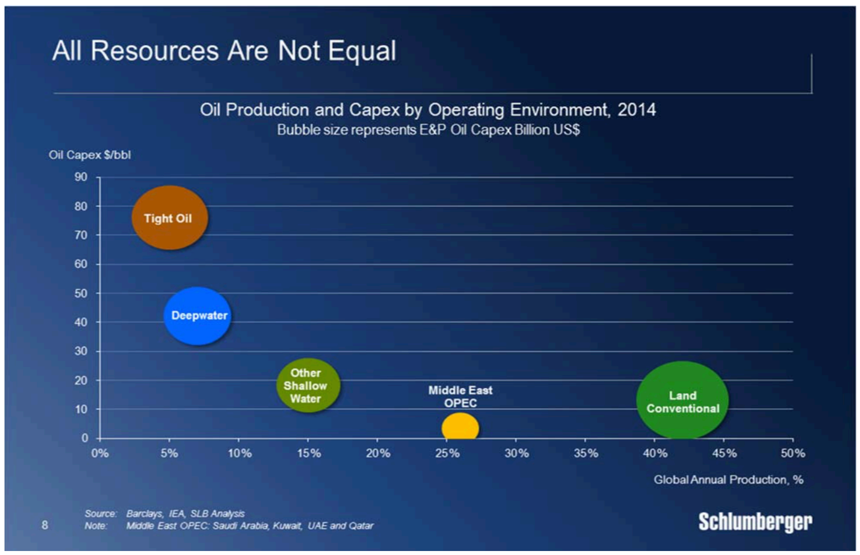


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Figure 2: Oil Production and Capex by Operating Environment 2014

The Marginal cost to produce tight oil is $75 per barrel whereas it is less than $25 per barrel for land conventional production. Also, the marginal cost to OPEC countries is $10 per barrel.

From the **Figure 3**, we can interpret that it required almost hundred times more wells for U.S. tight oil reserves to produce approximately the same amount of oil as Saudi Arabia.

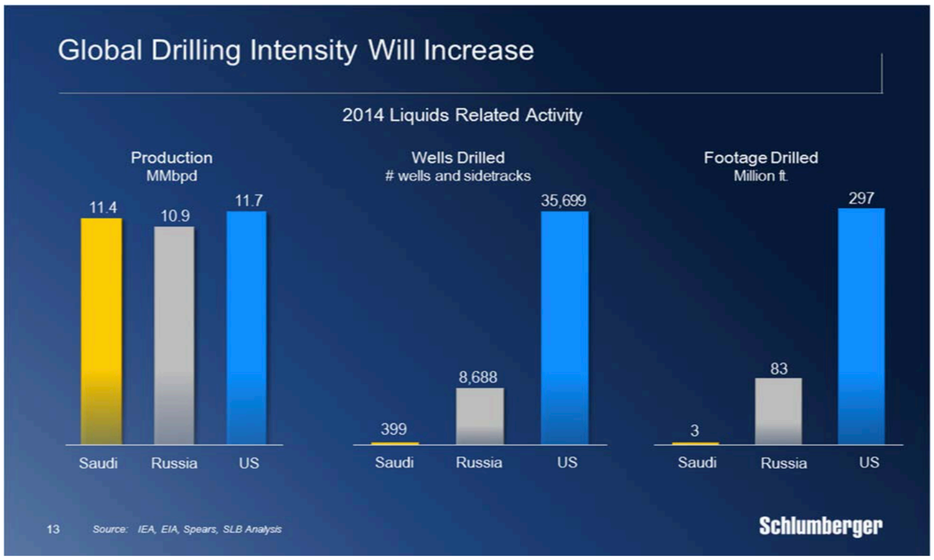

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Figure 3: Drilling and Production activities related Oil

Therefore, the cost to produce oil from shale reserves was hundred times as much (Berman, 2015). This is because, the productivity of shale wells is lower than the conventional ones, having high decline rates of production in the first couple of years itself. This resulted in drilling of more wells, therefore increasing costs of extraction. Additionally, the extraction methods such as horizontal drilling and hydraulic fracturing are more expensive than conventional extraction techniques (Chatterjee, 2011).

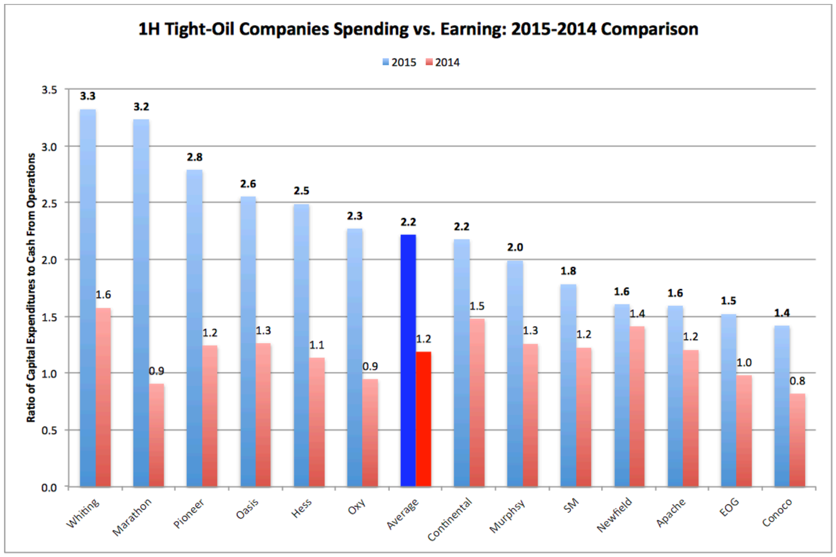

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Figure 4: Tight Oil Companies Spending vs. Earnings

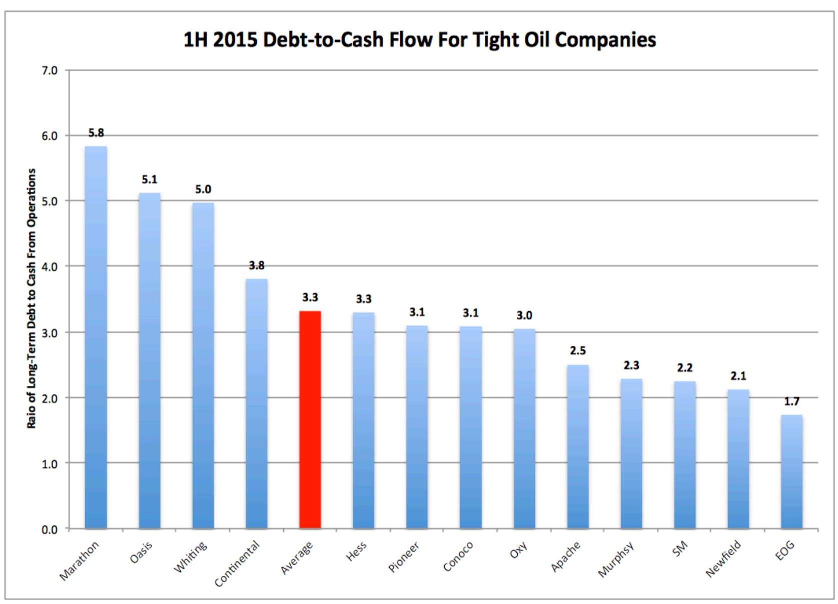

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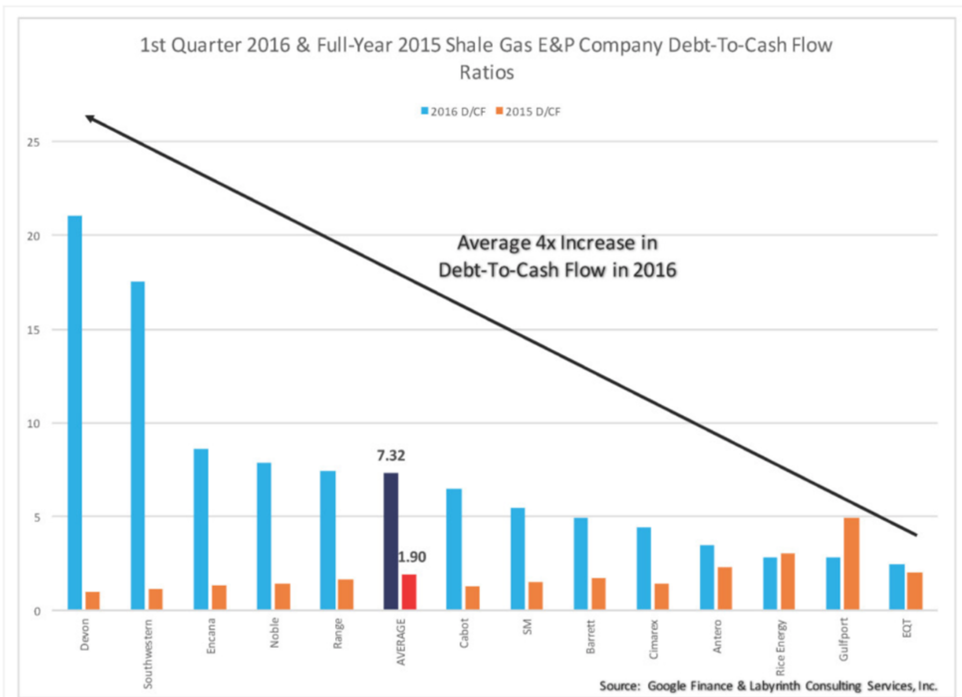
Figure 5: Tight Oil Companies Debt-to-Cash Flow

Figure 4 and **Figure 5** illustrate how the tight oil and shale gas plays are not profitable for most of the companies.

On an average, the tight oil companies outspend their cash flows by 120%, i.e. for every dollar earned from operating activities, they spent $2.2 on an average. Also, the average of debt-to-cash from operating activities ratio is about 3.3. This means that it would take more than three years to repay the debt if all the cash flow was used. The average for the E&P companies from 1992 to 2012 was 1.59 and usually a ratio of 2 serves as a threshold to trigger loan agreements. However, the shale revolution has been funded by debt, public offerings and bond sales, made attractive by zero interest rate policies (Berman,2015).

Similarly, **Figure 6** shows how average debt-to-cash flow ratio for shale gas companies increases by four times from 2015 to 2016. The debt-to-cash flow ratio for Devon was more than 21 and that for Southwestern was above 17 as seen in the graph below. And the average for the first quarter of 2016 and full year of 2015 is about 7. Which means that it would take the shale gas E&P companies 7 years to repay their debt if they were to use all the cash from operating activities. Even though the threshold ratio of 2 has increased to 4, a ratio of 7 is clearly beyond the bank's normal exposure to risk.



Reprinted from: Berman, A.E. (2015) The North American Unconventional Revolution and the 2014-15 Oil Price Collapse.

Figure 6: Debt-to-cash flow ratio for first quarter 2016 and full year 2015, for Shale Gas E&P Companies

1.2 PROBLEM DESCRIPTION

The Diagram below provides a brief understanding of the cash flows and how they interconnect both, the technical as well as the financial activities of a Shale E&P firm.

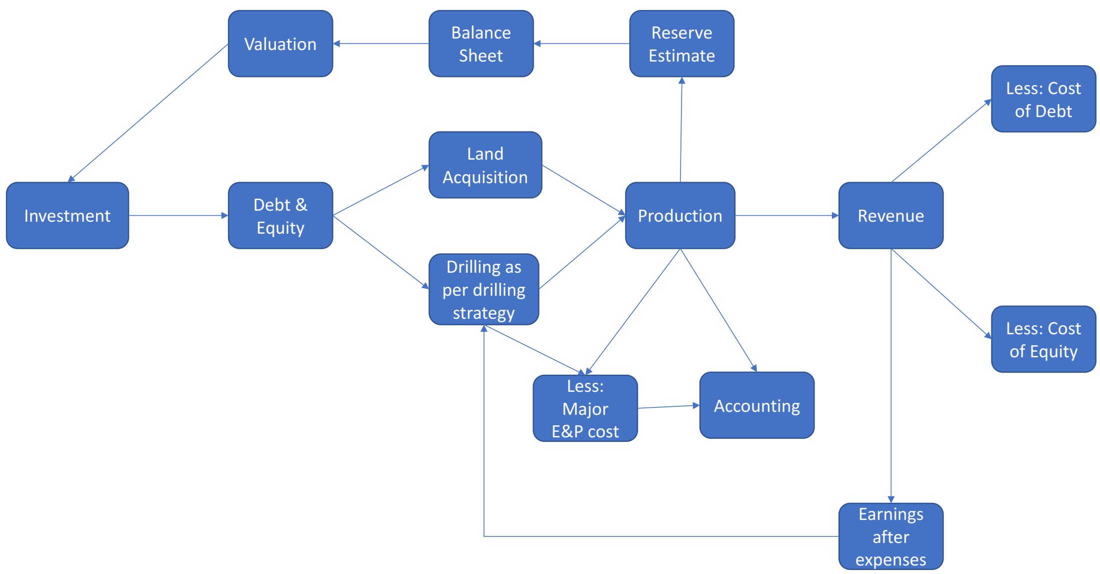


Figure 7: A flow Diagram representing interconnections between technical and financial activities of a Shale E&P firm

In general, the Shale E&P firms obtain investment in terms of Debt and Equity. These forms of investments are majorly utilized for Land Acquisition and Drilling of wells. For a Shale E&P company, the drilling and completion costs largely contribute towards the operating expenses. These activities eventually lead towards production of oil and gas, which in turn generates revenue. The revenue generated is used up to pay dividends to the equity holders, pay up the debt taken from money lenders and the remaining earning are invested back majorly to carry out drilling as per the drilling strategy of a company. Additionally, the production of the Shale E&P company determines the reserve estimates of that company which is reflected on the Balance Sheet of the company, and in turn used to value the company itself. The value of a company or majorly the value of the reserves of a Shale E&P company are used as securities to obtain investment.

The Shale E&P projects are majorly funded by debt. Out of the various loan structures used by the shale E&P companies to finance their E&P projects, the Reserve Based Loan (RBL) is most commonly used (Comptroller's Handbook, A. C. O. C. 2011). An RBL is a revolving facility, secured by developed oil and gas reserves of the company. The borrowing base i.e. the amount of loan facility available to the borrower is determined by a valuation of those reserves.

The borrowing base therefore depends on the value of the reserves (proved and maybe unproved), the expected price of oil and gas, and projected operating and capital expenditure (Reserve Based Lending, 2016). However, reserves are classified based on the probability of being produced i.e. they can proved (90% probability), probable (50% probability) and possible reserves (10% probability). The proved reserves are further classified as proved developed producing, proved developed non-producing and proved undeveloped. It is important to note that the proved developed reserves are currently or in future contributing to the earnings of the E&P company. However similar contributions from the proved undeveloped are highly uncertain.

Since the borrowing base available to the borrowers is driven by the value of reserves, it is critical to not just accurately, but also correctly obtain a best estimate of the value of the reserves. Also, considering that unconventional oil and gas is more expensive than conventional one, leading to low profitability of the unconventional oil and gas companies and high average debt to cash flow ratios, the real value of the shale reserves may not be reflected during due diligence and shale project appraisals. Therefore, the following major questions need to be answered while valuing the shale reserves, also termed as "Shale Assets":

a) How do the projected volumes of oil and gas production differ from the historical production? If, significantly different, which might be the case, then how to account for the uncertainty?

b) What is the level of concentration of the production by well, field and region? This is because if a significant amount of the projected cash flow is represented by just one or two wells, i.e. high concentration of production by well, the risk would be very high.

c) What commodity price forecast was used to value the reserves? Was the effect of variable commodity prices accounted for?

d) Do traditional reserve accounting methods used for conventional reserves reflect the actual value of the unconventional reserves?

Answers to the above questions will not only help one determine the actual value of the shale assets, but also be conducive towards assessing various risks associated with shale oil and gas development, given the production decline rates, plummeting oil and gas prices, oversupply issues combined with low growth in oil and gas demand and high technology related costs.

Accurately assessing the risks with shale development projects will help in correctly determining the borrowing base in case of reserve based lending (RBL) in order to be able to make informed investment decisions for the shale oil and gas development projects.

1.3 LITERATURE REVIEW

The U.S. oil and gas productions have reversed due to its recent ability to produce oil and gas from unconventional shale reserves. Technological advancements such as Hydraulic Fracturing and Horizontal Drilling have made production of unconventional oil and gas technologically feasible. However, there are concerns related to the economic feasibility of the unconventional shale oil and gas production. In the industry and academia, there are some who conclude that the production of unconventional oil and gas is economically feasible, whereas the other argue that it is the opposite. Some examples of the related work have been discussed below.

An Economic Viability of Shale Gas production in the Marcellus Shale; indicated by Production rates, Costs and current Natural gas prices (Duman, 2012) focused on determining the profitability of an average shale gas well through economic analysis with the help of representative data of natural gas production from 2009 to 2011 in the Marcellus shale. The economic analysis included using various production and cost components to project cash flow statements for Marcellus Shale. These cash flow statements were in turn used to calculate various profitability metrics such as internal rate of return (IRR) of the simulated well, the Net Present Value (NPV) of the projected cash flows, and the breakeven price required by the company in order to obtain a minimum set return on investment. The results of this analysis say that the shale gas well in the Marcellus shale is profitable currently, and in years to come based on the values obtained for NPV, IRR and breakeven price.

However, this paper looks at the economic viability of an average well at the Marcellus shale specifically. Therefore, the results relating to the economic viability of an average gas well at Marcellus Shale, may not be representative of an average well at any shale play. Also, it looks at a single well and not a shale play as a whole. Thus, this study does not provide an economic feasibility of shale gas production from a shale play.

A Primer on the Economics of the shale Gas Production: Just How Cheap is Shale Gas? (Lake, Martin, Ramsey & Titman, 2013) focused on solving three major problems faced by the Shale Gas Industry namely, overestimation of recoverable Shale gas reserves using traditional methods, uncertainties attached to the economic viability of the Shale gas production, and environmental concerns related to Shale gas production. According to this study, these three problems ultimately affect the economics of Shale gas production. Therefore, a base case model was development to evaluate the economic viability of producing natural gas from shale reserves. This was performed by valuing the predicted natural gas productions from the wells with the help of estimated production costs for a given region and estimated natural gas prices. The financial model has been generalized to a certain extent using sensitivity analysis and simulation analysis of key value drivers. As per the analysis carried out in this study, most of the shale gas wells are profitable (60% likelihood) under the assumed conditions of their model data. However, the NPV calculated is most sensitive to the natural gas price, which at the time of the calculation was very close to the breakeven levels. Thus, if the prices drop just by 17% from the assumed prices in the study, the NPV would drop to zero. According to the authors, the major questions still remain with respect to the economic viability of shale gas production. This study also deals with the economics of a single shale gas well, which does not provide the economic feasibility of an entire shale play.

A review of Technical and Economic Evaluation Techniques for Shale Gas Development (Yuan, Luo, & Feng, 2015) is concerned with solving the issue of accurately evaluating the economic viability of Shale Gas development in order to lower the risks related to investment in Shale Gas development thus increasing investment opportunities. This paper aims at providing an overview of the current status of various technical and economics evaluation techniques for Shale Gas Development through their systematic review and examination. These techniques need further improvement to more accurately assess the economic viability for Shale Gas Development especially to assist investment decisions more accurately. Therefore, various useful ideas and approaches are presented in order to propose few potential improvements in the evaluation techniques for Shale Gas development. These improvements are divided into three categories namely, Input-output parameter prediction techniques, modelling technical-economic evaluation, assessing models of technical-economic decisions.

Possible focuses and trends of the technical–economic evaluation techniques for shale gas development have been proposed for each category which have been summarized in the **Figure 8** below:

Subjects		Possible focuses and trends
Input-output parameter prediction techniques	Input	Deterministic forecast methods based on more key drivers More reliable probabilistic methods
	Output	Revenues: production, identifying suitable production decline curves to predict which consider the consumption demand constraint; price, incorporating suitable price change factor More reliable probabilistic methods
Modeling technical–economic evaluation		Deterministic evaluation highlighting uncertainty and risk analysis Deterministic evaluations combined with probabilistic evaluation Integrated assessment of exploration and development
Assessing models of typical technical–economic decisions		Combination of both technical and economic factors Reflecting the corresponding economic boundaries through their technical indicators

Reprinted from: United States Environmental Protection Agency (EPA), 2015

Figure 8: Possible focuses and trends of the technical–economic evaluation techniques for shale gas development

This study has dealt with the various technical and economic evaluation techniques for production of Shale gas.

Economic Appraisal of Shale Gas plays in Continental Europe (Weijermars, 2013) has focused on the five emergent shale gas plays in the European Continent with an aim to evaluate their economic feasibility. The assessment of each play is performed by creating a constant field development plan where 100 wells are drilled at the rate of 10 wells per year in the first decade. In order to evaluate the economics of five potential shale plays namely, Austria, Germany, Poland, Sweden and Turkey, the well productivity type curves are developed for each play. These curves are based on an earlier review of estimated ultimate recovery (EUR) for the plays. Based on the Decline Curve Analysis of the wells, the Net Present Value (NPV) and the Internal Rate of Return (IRR) were calculated for each shale play by applying the Discounted Cash Flow Analysis using the gas prices, production costs, taxes, depreciation and discount rate. A sensitivity analysis is performed with varying EUR values for each play, which therefore provided with the minimum EUR at which the wells are economic which is a directive for 'sweet spot targeting'. According to the authors, the NPV and IRR analysis indicate the Polish and Austrian shale plays are profitable when the wells have a 90% certainty (P90) with respect to their productivity. On the other hand, for the same level of certainty, the Posidonia (Germany), Alum (Sweden) and a Turkish shale play have shown negative values for discounted cumulative cash flows, placing them below the hurdle rate. The estimated value for IRR of the three wells in question, is about 5%. Therefore, the author suggests that a 10% improvement in the IRR value obtained by sweet spot targeting may overcome the hurdle rate. In conclusion, this paper has provided a model where a range of the NPV and IRR values are obtained based on the productivity uncertainty i.e. P90, P50 and P10 (90%, 50% and 10% productivity certainty) reflecting the level of risk and serves as screening criterion while selecting the best field for future development. The author has accounted for the different types of reserves in the economic analysis, however has not considered the sub-categories of proven reserves, i.e. the proven developed (PD) reserves and the proven undeveloped reserves (PUD) which affect the actual value of reserves and hence the economic viability of the shale play.

The recent studies reviewed are majorly targeted towards evaluating the economic feasibility of Shale gas production. However, the very valuable shale oil production has been neglected. Since a well would produce both, Shale oil and gas, it is critical to account for Shale Oil production in the evaluation of the economic feasibility for a Shale play Development.

2. METHODOLOGY AND ANALYSIS

The research is carried out in three phases, where the first phase deals with understanding of major upstream activities and various costs associated with them. The second phase deals with financial modelling and determination of the economic value of shale oil and gas reserves. Lastly, the third phase deals with the stress analysis of the financial model using Monte Carlo simulation.

2.1 PHASE 1: UNDERSTANDING SHALE UPSTREAM ACTIVITIES AND COSTS

This process involves site selection and construction of an exploratory well before drilling and production can take place. Site Selection: A geologically favorable site is identified by delineating the subsurface features with other geologic information from rock core samples. This method requires integration of data from geophysical surveys including seismic surveys and drilling exploratory wells or test holes to obtain cores (EPA, 2015). The characteristics of the oil and gas bearing formation, like the porosity, permeability and the qualities and quantities of the hydrocarbon resource.

The strata being drilled can be identified with the help of drilling rates and drill cuttings and also help confirm and correlate the stratigraphy and formation depths, like the depths of water bearing formation (EPA, 2015). Additionally, the properties of the formation can be best understood with the help of well logging in combination with core analysis.

Various logistical factors are considered while assessing a site, which include topography, access roads, routes for pipelines and resources, availability of water resources, environmental factors such as wetlands and sensitive wildlife habitat, proximity to populated areas (schools or residences), well spacing considerations, potential for site erosion, etc (EPA, 2015).

Before the Oil and Gas Company initiates the site development and well drilling, it is required to obtain a mineral rights lease, negotiate with the landowners, and apply for drilling permits from the relevant local and state authorities. Additionally, leases and permissions are also required for other activities to be carried out such as seismic surveys and drilling exploratory holes (EPA, 2015).

An important aspect of site selection is an integrated evaluation of the site to answer the following questions:

a) How much oil or gas is there?
b) How producible are they?
c) What would be the level of difficulty to complete the reservoir?
d) What would be the estimated ultimate recovery potential?

We look at some of the most important parameters of the shale reservoir, in order to evaluate shale reservoirs. For example, the total organic carbon (TOC) for a source rock should be 2% in weight, effective porosity should be more than 4% for a shale gas reservoir, higher is better; water saturation should be less than 45%, the lower the better

(EPA). This is because higher the water saturation more will be the water, and wet pores within the inorganic minerals, which may not contain producible hydrocarbons. Therefore, it is important to analyze the quality of the reservoir as well as that of completion for successfully developing an unconventional well.

Parameter	Critical or Desired Values	Data Sources
TOC	>2% (Weight)	Leco TOC, Rock-Eval
Thermal maturity	Oil window: 0.5 < Ro < 1.3 Gas window: 1.3 < Ro < 2.6	Vitrinite reflectance, Rock-Eval
Mineralogy	Clay <40%, quartz or carbonate >40%	X-ray diffraction, Spectroscopy, log-based
Average porosity	>4%	Core, logs
Average water saturation	<45%	Core, Capillary pressure, log-based
Average permeability	>100 nanoDarcy	Mercury injection capillary pressure, nuclear magnetic resonance, gas expansion
Oil or gas-in-place	Gas: free and adsorbed gas > 100 Bcf/section	Log-based, integrated evaluation
Natural fracture	Moderate to dense, and contained in the target zone	Seismic, image log
Wettability	Oil-prone wetting of kerogen	Special core analysis
Formation lateral continuity	Continuous	Sequence stratigraphy with core, logs, and regional data
Hydrocarbon type	Oil or thermogenic gas	Geochemistry, Rock-Eval
Pressure	Overpressure is preferable	Log-based, seismic
Reservoir temperature	>230 °F	Drill stem test
Stress	<2000 psia net lateral stress	Logs, image log, seismic
Young's modulus	>3.0 MM psia	Acoustic logs, cores
Poisson ratio	<0.25	Acoustic logs, cores

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Figure 9: Most important parameters considered while evaluating a shale reservoir

After obtaining values for the above parameters listed in **Figure 9**, we may assign favorability scores to each of the reservoir and completion quality parameters, and then compares the reservoir to analog reservoir. These parameters obtained cannot be linearly combined, since we cannot directly derive a composite score of quality. For example, a reservoir having 10% porosity and 1% weight TOC (Total Organic Carbon) may not be as good as the one having 5% porosity and 2% weight TOC. Therefore, radar plots may be used to help us analyze the qualities visually and compare them with analog reservoirs.

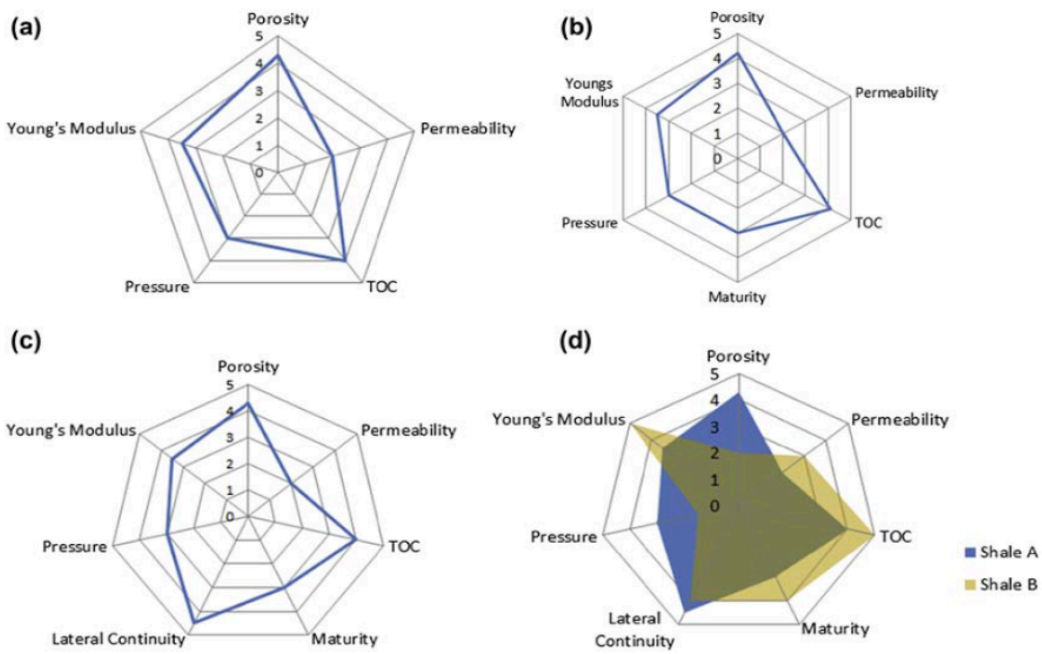

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Figure 10: Radar Plots used for ranking reservoir and completion qualities of Shale reservoirs with 6- level scores (0-low to 5-high).

Figure 10 is an example of how radar plots are used to analyze the reservoir and completion qualities based on the availability of the data where, (a) is 5- parameter ranking, (b) is 6- parameter ranking, (c) is 7- parameter ranking, (d) is 7- parameter ranking with analog comparison. The ranking becomes more complex as the quality parameters increase, but it helps in making more informed decisions.

However, an operator typically takes one of the four strategies to acquire an acreage position which may largely influence the overall cost of operation. One of them is called **Aggressive entrant** strategy, where an operator is able to acquire a large portion of land, about 100,000 acres within a play only based on the initial geologic assessment and before the play is de-risked or any pilot programs have been initiated (EPA, 2015). Therefore, land acquired through this strategy is usually in speculative plays, having a very high risk which are never converted into economic investments, despite of costs being as low as $200-$400 per acre (EPA, 2015).

The second strategy is called the **Legacy owner**, wherein the operator inherits an acreage position in the play since they have been involved in conventional production. Therefore, these plays are mature basins with historic conventional production. Even though this might lead to substantial cost savings, it is not necessary that the legacy owners have acquired the "sweet spots" or better areas of the play (EPA, 2015).

The third strategy is that of the **Fast Followers**, who do not have the financial capacity to lease land and therefore enter into a Joint Venture with a company who has an acreage position. This usually occurs when the play has been de-risked and proved to be economically viable. At this stage however, the 'sweet spots' may not be exactly delineated and the operators may end up acquiring sub-standard positions. The costs associated with this strategy may be 10 to 20 times higher than initial entry (EPA, 2015). Also depending on the number of acres required per well, an additional of $1-$2 MM maybe incurred per well (EPA, 2015).

The fourth strategy is that of a **Late entrant.** They usually enter the play when the 'sweet spots' have been delineated and the plays have been de-risked. They pay a premium 3 to 4 times that of the fast follower, which include potential drilling location as well as currently producing wells (EPA, 2015).

Site Development and Well Pad Preparation: Site development is important to improve the accessibility of the well area. Based on an initial site survey access roads may be required to accommodate truck traffic. The permit area will be fenced. Site leveling and grading is performed to help drainage management and placing of the equipment on the site. For storage of fluids, pits and steel tanks may be placed near the well pads. The pits usually hold drilling fluids, used drilling mud and drill cuttings, or flow back and produced water post fracturing (EPA, 2015).

Therefore, pit construction is regulated by local and or federal governments (EPA, 2015). For example, in some areas the pit needs to be lined to avoid fluid seepage into the shallow subsurface whereas in other areas they are prohibited. Few sites use pipelines to transport the water required for hydraulic fracturing, remove the flow back and produced water, or transport the produced oil and gas (EPA, 2015).

Altogether the site will be prepared to provide for support facilities, production, processing, and shipping facilities as seen in **Figure 11** below.

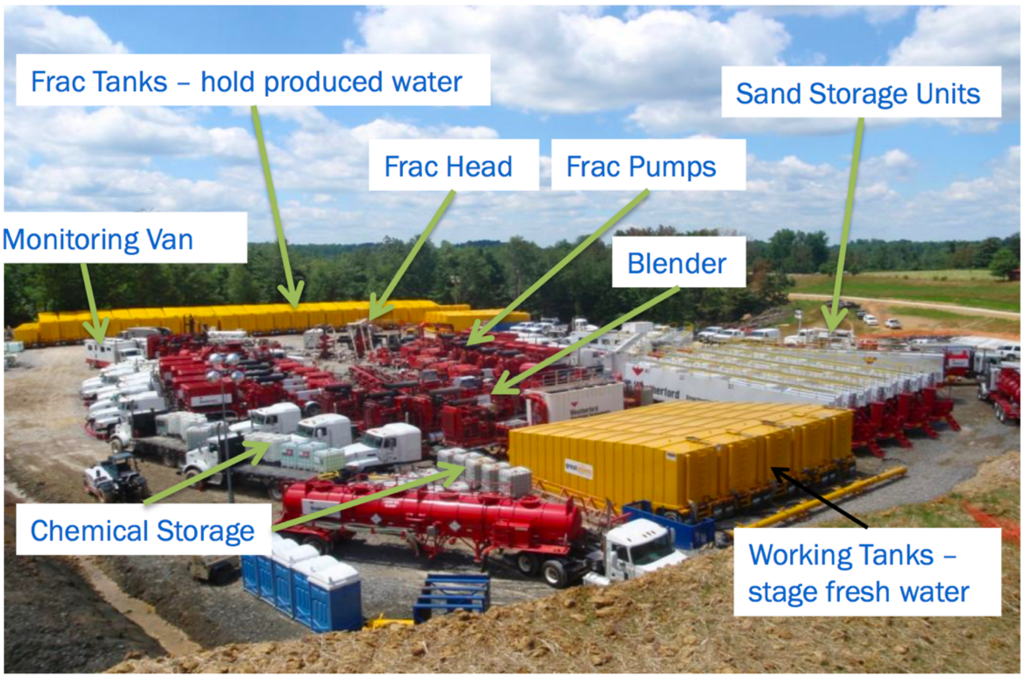

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Figure 11: Typical Shale Development Site Layout

During well drilling and completion drill rigs and associated equipment may be moved on and off the well pad and size of the well pads may range from less than an acre to several acres, based on the scope of the operations.

There are various costs associated with the site development and well pad preparation. These costs are called facilities construction costs, which comprises 7-8% of the total well cost (EPA, 2015). These costs are majorly incurred due to road construction and site preparation, surface equipment, such as storage tanks separators, dehydrators, evaporation pits, batteries, pumps or compressors to push products to gathering lines, and artificial lift installations. The facilities construction costs are approximately several hundred thousand dollars (EPA, 2015).

In order to benefit from the economies of scale, the several wells maybe drilled consecutively on the same pad as more wells will be able to use the same facilities (EPA, 2015).

Well Drilling and Construction: Production well is constructed by drilling a wellbore. A series of casing strips are installed and cemented which support the wellbore and isolate and protect both the hydrocarbon being produced and any water bearing zones through which the well passes (EPA, 2015).

A drill string consisting of a drill bit, drill pipe and drill collars is lowered and rotated to vertically drill a wellbore. The drill pipe attaches to the drill bit, rotating and advancing the bit. In order to drill deeper, new sections of pipe are added to the surface as drilling proceeds further (EPA, 2015). While drilling a water-based or oil based drilling fluid is circulated. It is pumped down the drill bit in order to cool and lubricate the drill bit, counterbalance the down hole pressures and lift the drill cuttings to the surface.

In order to optimize production, wells are initially drilled vertically and completed with a suitable orientation such as vertical, deviated or horizontal. The well orientation is decided based on the best access provided to the intended zones within the formation, and the alignment of the wells with existing fractures and other geological structures. 'S' shaped or continuously slanted wells are called deviated wells (EPA, 2015). Horizontal wells have lateral sections almost perpendicular to the vertical portion of the well. The lengths of the lateral sections of the horizontally completed wells can range from 2000 to 5000 feet or more.

Well drilling and construction proceeds with repeated steps i.e. lowering, rotating and drilling the drill string to a certain depth, pulling it out, and lowering the casing into the hole and cementing it. As the hole is drilled deeper, casing with smaller diameter is used. The casing strings isolate hydrocarbon reservoirs from nearby aquifers, isolate over pressurized zones and transport hydrocarbons to the surface (EPA, 2015). Therefore, the selection and installation of casing strings is very important.

Casing strings, which are newly installed, are cemented in place before drilling continues or before well completion in case of production casing. The purpose of the cement is to protect the casing from corrosion by the formation fluids, stabilize the casing and the wellbore, and prevent fluid movement along the well between the outside of the casing and the wellbore (EPA, 2015). The well can be cemented continuously right from the surface to the production zone as seen in **Figure 12.**

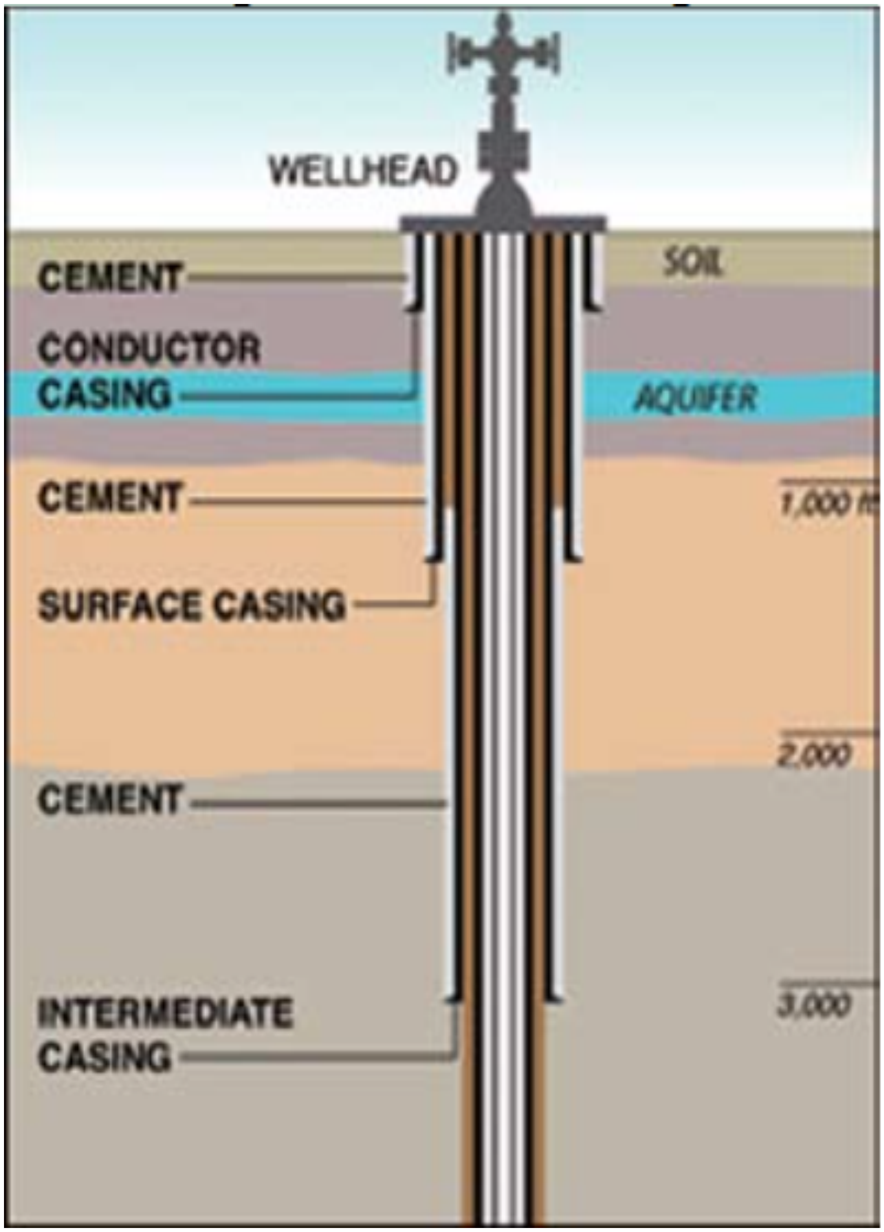

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Figure 12: Well Casing

After drilling, casing and cementing, the well completion can take place in the production zone in several ways. Like cementing the production casing all through the production zone and perforating before hydraulic fracturing in desired locations. An open hole completion method may also be used wherein the casing is only set into the production zone and cemented. The remaining part of the wellbore is left open without any cementing (EPA, 2015). After the completion of well construction, the drilling rig is removed, wellhead is installed, and the well is prepared for hydraulic fracturing followed by production.

The well drilling and construction costs contributes to about 30-40% of total well cost (EIA U., 2016). These costs mainly comprise of activities associated with utilizing a rig to drill the well to total depth and include:

i. Tangible Costs such as well casing and liner, which have to be capitalized and depreciated over time, and

ii. Intangibile Costs which can be expensed and include drill bits, rig hire fees, logging and other services, cement, mud and drilling fluids, and fuel costs.

Average horizontal well drilling costs range from $1.8 MM to $2.6 MM.

Well Completion and Stimulation (Hydraulic Fracturing): This process is carried out by hydraulic fracturing. It is a stimulation technique mainly used to increase the production of oil and gas (EPA, 2015). It is carried out by injecting fluids at pressure high enough to fracture the oil and gas formation. The hydraulic fracturing fluid transfers the pressure generated at the surface to the subsurface, which in turn creates fractures in the target formation (EPA, 2015). The fracturing fluids also carry the proppant and place into the fractures allowing the fractures to remain open even after the injection pressure is released. Thus, hydraulic fracturing is a short but repetitive and intense process, which uses large amounts of water, chemicals, proppant, and specialized equipment usually for high volume horizontal wells (EPA, 2015). All the required machinery and equipment are transported to the site on trucks, and remain mounted on trucks during their use. Additionally, various storage tanks, totes and other storage vessels for water and chemicals are also brought to the site and installed (EPA, 2015).

Injection process is the first step towards Hydraulic fracturing. Initially the hydraulic fracturing fluids are prepared through mixing with the help of feeding and mixing equipment (EPA, 2015). Mixing takes place mechanically by a truck mounted blender, which is electronically controlled by operators in another van (EPA, 2015). Ultimately a large number of pipes and hoses are required to transport fracturing fluid components from storage vessels to the mixing equipment and finally to the wellhead (EPA, 2015).

A proppant laden-fluid of high pressures and volume is injected into the well during the fracturing treatment. A temporarily installed wellhead assembly on the well head allows for this injection process at such high pressures and volumes. Factors such as depth, pressure inside the formation and the type of rock, dominate the pressure requirements during the fracturing treatment. Reported pressures during fracture treatment range from 4,000 psi to 12,000 psi (EPA, 2015). These are usually measured using pressure gauges installed at the surface and or downhole (EPA,2015).

The length of the well in the production zone is isolated, segmented and then fractured in stages instead of fracturing the whole length of the well at once. Also, each segment is injected using a phased injection process, where every phase consists of different fluids made of varying chemicals and additives. Each type of fluid mixture serves different purpose. For example, a) Acid based fluid used to remove excess drilling fluid or cement from the formation, b) Pad fluid (without proppant), used to initiate fractures in the formations, c) fluid used to carry away the proppant from the wellbore, d) Fluid used to completely flush the wellbore off the proppant-laden fluid in order to ensure all of it reaches the fractures (EPA, 2015). For every phase requires millions of gallons of fluids are transported across the site through pipelines and hoses, its own set of blending fluids are required which are injected down the well at high pressures (EPA, 2015).

The properties of the formation and the lengths and orientation of the wells determine the number of stages of a well. The number of stages per well has been reported to range between 1 to 59 stages per well (EPA, 2015).

The main aim of the fractures induced is to optimally drain the hydrocarbons from the reservoir formations. Modeling software is used to design the fracture systems with the help of formation data like permeability, porosity, mineralogy, in situ stress, location, geography, etc. Characterization of the vertical and horizontal fractures, which have been created, can be carried out through micro seismic monitoring during the fracturing process. This in turn can also be helpful in designing future fracturing systems. The pressures or tracers monitored post fracturing can also help in characterizing the results of a fracturing job (EPA, 2015).

Fracturing Fluids: The fracturing fluids, a mixture various chemicals and additives serve a variety of purposes when injected into the well. Therefore, every fracturing fluid system serves a unique purpose. A fracturing fluid system is selected based on the geology of the location, geochemistry of the reservoir, type of production, proppant size, etc. The most common type of fracturing fluids is the water based fluids, other types include the foams based or emulsions prepared from nitrogen, carbon dioxide or selected hydrocarbons and acid based fracturing fluids (EPA, 2015). For low permeability reservoirs, the slick water based fluid mixtures are commonly used. Whereas for high permeability reservoirs gel based fracturing fluids are mostly used.

With the improvements and refinements in the fracturing processes, the types of chemicals being used are continually changing. These changes in the fluid formulations are majorly driven by economics, technological advancements, and impacts on the health of the people and the environment as a whole (EPA, 2015).

Typically, the major component of a fracturing fluid system is water. The water used as the based fluid for hydraulic fracturing fluid can be obtained from various water sources like ground water, surface water, reused produced or flow back water, treated waste water, etc (EPA, 2015). The water can be transported to the production well site with the help of trucks or pipelines, when the water sources are located far away. When water is sourced locally like local rivers or wells, it can be pumped from the rivers or diverting the local ground water lines. Therefore, the types of water sources selected depend on their availability, locations, cost in obtaining the source majorly due to the logistics involved in transporting it to the site, and the quality of water obtained (EPA, 2015).

The second most major component by volume of the fracturing fluid mixture is the proppant. Silicate minerals, mainly quartz sand is commonly used as proppant (EPA, 2015). Increasingly, resins are being used to coat the silicate proppants in order to avoid any development and flow back of particles or even fragments of particles. Few ceramic materials like calcined bauxite or calcined kaolin, because of their high strength and ability to resist deformations are being use as proppants (EPA, 2015).

Usually additives contribute a small fraction to the hydraulic fracturing fluid systems, generally < 2.0% of the fluid. In case of high volume hydraulic fracturing system even these small fractions of additives can sum up to tens of thousands of gallons of chemical additives (EPA, 2015). These additives may be a single chemical or a mixture of chemicals. The types of chemicals used in additives mix is largely governed by the characteristics of the formation, the quantity and characteristics of proppant required, operator's preference, potential chemical compatibility with each other and its availability in the local or regional areas (EPA, 2015).

There are various costs associated with the completion of a well which contribute 55-70% to the total well costs (EIA, U., 2016). These costs mainly comprise of the costs dues to well perforations, fracking, water supply and disposal. Usually this work is carried out with the help of specialized frac crews and a workover rig or coiled tubing, which incurs: tangible Costs such as liners, tubing, Christmas trees and packers and intangible costs include frack-proppants of various types and grades, frac fluids which may contain chemicals and gels along with large amounts of water, fees pertaining to use of several large frac pumping units and frac crews, perforating crews and equipment and water disposal (EIA, U., 2016)

Average completion costs generally fall in the range of \$2.9 MM to \$5.6 MM per well (EIA, U., 2016). However, in the last decade, the completion costs in North America have increased sharply due to horizontal drilling, especially since lateral lengths are becoming longer and completions are becoming larger and more complex (EIA, U., 2016).

Oil and Gas Production: Post Hydraulic fracturing, if there are no plans of drilling of additional wells or laterals, then the equipment may be removed and partial site reclamation may be carried out. The pits that may no longer be required, will be dewatered, filled and regarded. The pads maybe partially reseeded and reduced in size during the production. For example, if the size of the well pad ranged from 3 to 5 acres during drilling and fracturing, then it may be reduced to 1 to 3 acres during the production process (EPA, 2015).

After well completion, if the market conditions are not favorable, the wells are shut-in. Prior to actual production, usually production tests are run, in order to optimize the equipment setting by determining the maximum flow rates the well can sustain (EPA, 2015). Monitoring process throughout the production is carried out. For example, mechanical integrity tests, corrosion monitoring, and any compliance with the state monitoring requirements maybe performed, to ensure that the well is operated as desired (EPA, 2015).

In case, of gas wells, the produced gas flows to a separator, where the gas is separated from water and liquid hydrocarbons if any. The finished gas is then compressed at a compressor station, to pipeline pressure and then transported through the pipeline to the market (EPA, 2015). In case, of an oil well, the production process is almost similar to that of gas. However, the separation process takes place at the well pad and no compression is required. The oil can be transported via trucks or tankers or maybe piped directly from the well pad. This process is demonstrated in **Figure 13.**

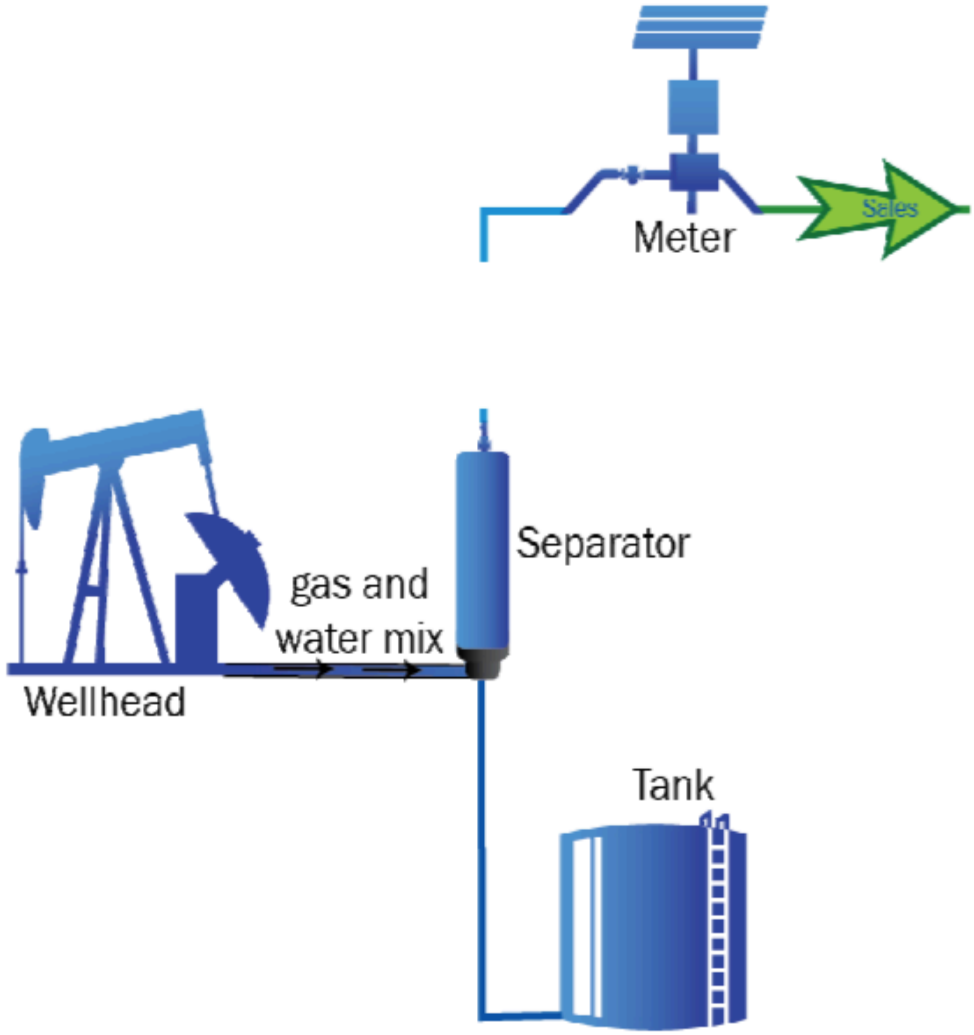

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Figure 13: Shale gas onsite production to market

Maintaining the well is also an important part of well development process. Required workovers are performed to maintain or repair portions or components of the well. It includes ceasing production, removal of the well head, cleaning away sand or deposits from the well, repairing the casing, replacement of the worn well components, and lift equipment to pump hydrocarbons to the surface. In some cases, recompletion of the well after initial construction, with re-fracturing due to decrease n production can also take place (EPA, 2015). Recompletion may also include perforation at different location that a previous one, extending the wellbore, or drilling new laterals from the existing wellbore (EPA, 2015).

Oil and gas production incurs **operating costs**. These costs are primarily the lease operating expenses. They may vary based on the product, location, well size and well productivity.

Typically, these costs include (EIA, U., 2016):

Fixed lease costs including artificial lift, well maintenance and minor workover activities. They accrue over time, and are reported on a $/boe basis.

Lease operating expenses range between $2.00 per Boe to $14.50 per Boe, including water disposal costs. More the production from the well, higher is the cost it incurs over its lifetime. And deeper the wells, higher is the cost than the shallower ones.

Variable operating costs to deliver oil and natural gas products to a purchase point or pricing hub. The upstream company pays a fee for these services provided by the midstream companies based on the volume of oil and natural gas. These costs are measured by $/Mcf or MMbtu or $/bbl and include gathering, processing, transport, and gas compression. These fees vary from contract to contract which the upstream companies have with the third-party midstream companies. Operators with large production end up with better negotiations. The associated costs for every product differs due to different requirements:

Dry Gas incurs the lowest cost since it does not require any processing. It costs about \$0.35/Mcf to gather and transport to a regional sales point and the differential of Henry hub price ranges from \$0.02 to \$1.4.

Wet gas includes NGLs and the associated gas within the oil play. They incur processing, fractionation and transportation. The gathering and processing fee range from \$0.65 to \$1.3 per Mcf. The fractionation fee ranges from \$2.00 to \$4.00 per bbl of NGL recovered. The NGL transportation fee range from \$2.20 to \$9.78 per bbl.

Oil and condensate can be transported through gathering lines at costs ranging between \$0.25 and \$1.5 per bbl. Transportation through truck is more expensive with costs about \$2.00 to \$3.5 per bbl. Oil wil also need to be transported to refineries at longer distances, either by pipeline or rail, which would create a price differential to the play, ranging between \$2.2 to \$13 per bbl.

In addition, there are General and Administrative (G&A) costs which form a part of the operating expenses and range between \$1.0 to \$4.0 per bbl.

2.2 PHASE 2: FINANCIAL MODELLING

This phase will help us in the valuation of the shale oil and gas reserves. Firstly, shale oil and gas production forecasts is carried out using decline curve models. This will be followed by development of a cash flow model. The cash flow model will be used to perform financial analysis in terms of Net Present Value (NPV) analysis, payback period, break even analysis, and Debt Service Coverage Ratio (DSCR). Additionally, this model will also be used to perform financial stress analysis.

2.2.1 SHALE OIL AND GAS PRODUCTION FORECASTING

Decline Curve models have been used to forecast the shale oil and gas production. Shale oil and gas reserves, like any other hydrocarbon resources are produced on geological time scales which require millions of years to produce, whereas its man-made extraction takes few years or decades. (Guo, Zhang, Aleklett, HÖÖk, 2016). When extraction occurs faster than the it can be produced by nature, depletion of these resources occur.

Arp's decline curve models and an extended exponential curve has been used to forecast the shale oil and gas production. Arp's models are empirical decline models that include the following: 1. Exponential decline 2. Harmonic decline 3. Hyperbolic decline.

These decline curves are expressed in general form (Lund, 2014), by Equation 1:

$$\lambda_t = \frac{-dq/dt}{q} = C_q^{\beta}$$

where, λ is the rate of decline, q is the rate of production, t is the time, C is the constant and β is an exponent, which is the rate of change in decline rate with respect to time. The decline rate may be constant (β = 0, exponential decline), directly proportional to the production rate (β = 1, harmonic decline), or directly proportional to the fraction of the production rate (0 < β < 1, hyperbolic decline) (Lund, 2014). Equations for Arps decline models (Arps, 1945) are presented in **Table 1.**

	Exponential Decline	Harmonic Decline	Hyperbolic Decline
β	$\beta = 0$	$\beta = 1$	$0 < \beta < 1$
q(t)	$q_o e^{-\lambda t}$	$\frac{q_o}{1 + \lambda t}$	$\frac{q_o}{(1 + \lambda \beta t)^{\frac{1}{\beta}}}$
Q(t)	$\frac{q_o - q}{\lambda}$	$\frac{q_o(\ln q_o - \ln q)}{\lambda}$	$\frac{q_o^{\beta}(q_o^{1-\beta} - q_t^{1-\beta})}{(1-\beta)\lambda}$

Table 1: Arps Decline Curve Models

In the above table, $q(t)$ is the production rate at time t, which is a function of the initial rate of production q_o, the decline parameters λ and β, and the initial time t_o, i.e. the time which the production starts. $Q(t)$ is the cumulative production at time t. It is the sum of the cumulative production until the decline starts, Q_o, and the cumulative production of the decline phase.

Initially shale oil and gas production forecast was carried out for a single well using Arps decline curve models. Calibrated values for decline parameters have been assumed to be true for shale oil and gas wells. An initial decline rate (λ_o) of 8% per month has been assumed for production forecast (Baihly, Altman, Malpani and Schlumberger, 2010). For a hyperbolic decline curve model, a β value of 0.84 has been assumed to be true for a single shale oil and gas well (Lund, 2014). An average initial oil production of 225 bbl/day has been used to forecast future oil production per month (EIA DPR, 2015). In case of gas production forecast, an average gas to oil ratio of 6 Mcf/bbl (EIA DPR, 2015) has been used to calculate an average initial gas production of 1350 Mcf/day.

Figure 14 and **Figure 15** below represent the hyperbolic decline curve for oil production and for gas production respectively from one well, forecasted for 1000 months.

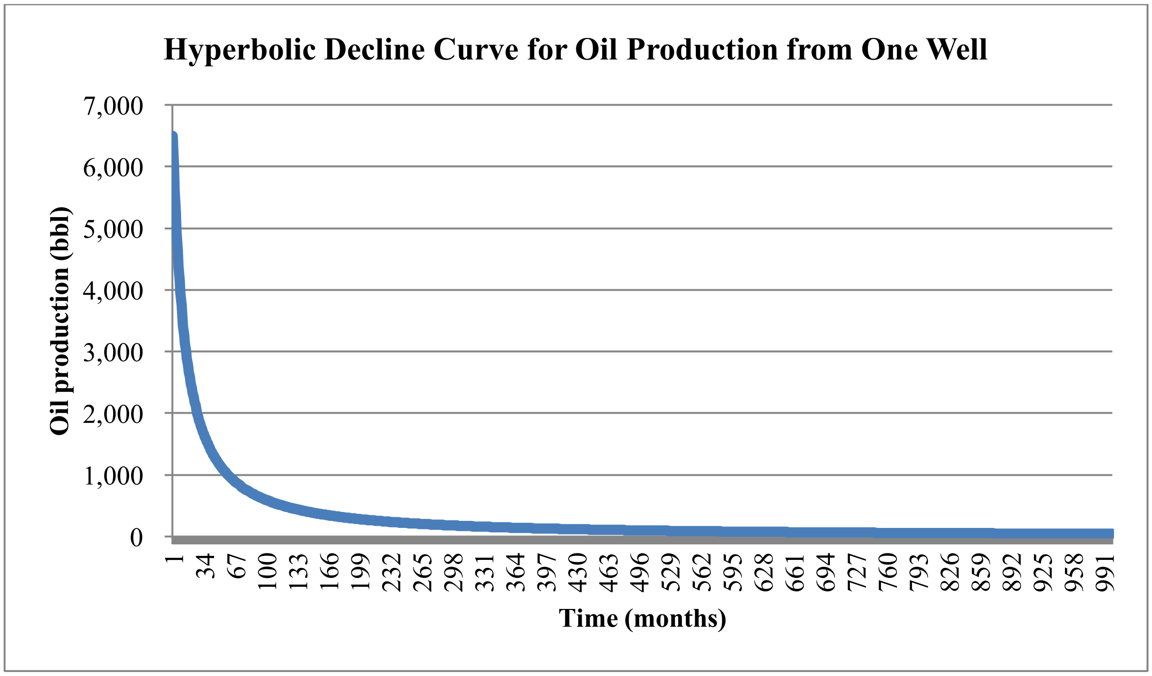

Figure 14: Hyperbolic Decline Curve for Oil Production from One Well

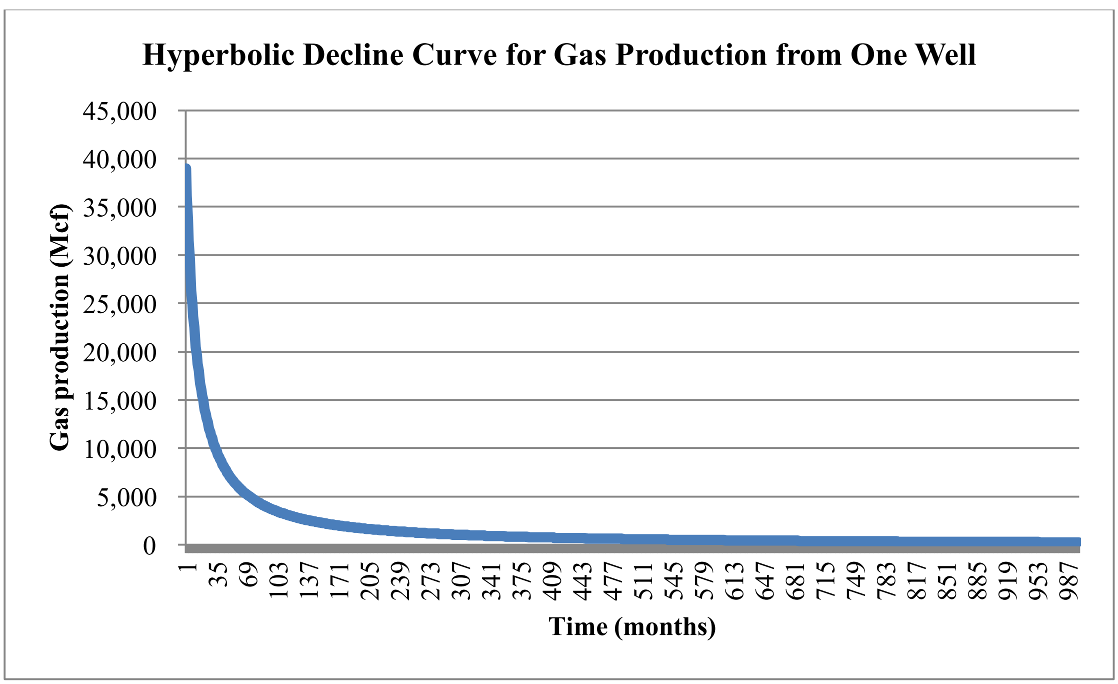

Figure 15: Hyperbolic Decline Curve for Gas Production from One Well

Similarly, shale oil and gas production has been forecasted using the harmonic and exponential decline curve models. **Figure 16** and **Figure 17** represent the harmonic decline curve for oil production and for gas production respectively from one well, forecasted for 500 months. Additionally, **Figure 18** and **Figure 19** represent the exponential decline curve for oil production and for gas production respectively from one well, forecasted for 500 months.

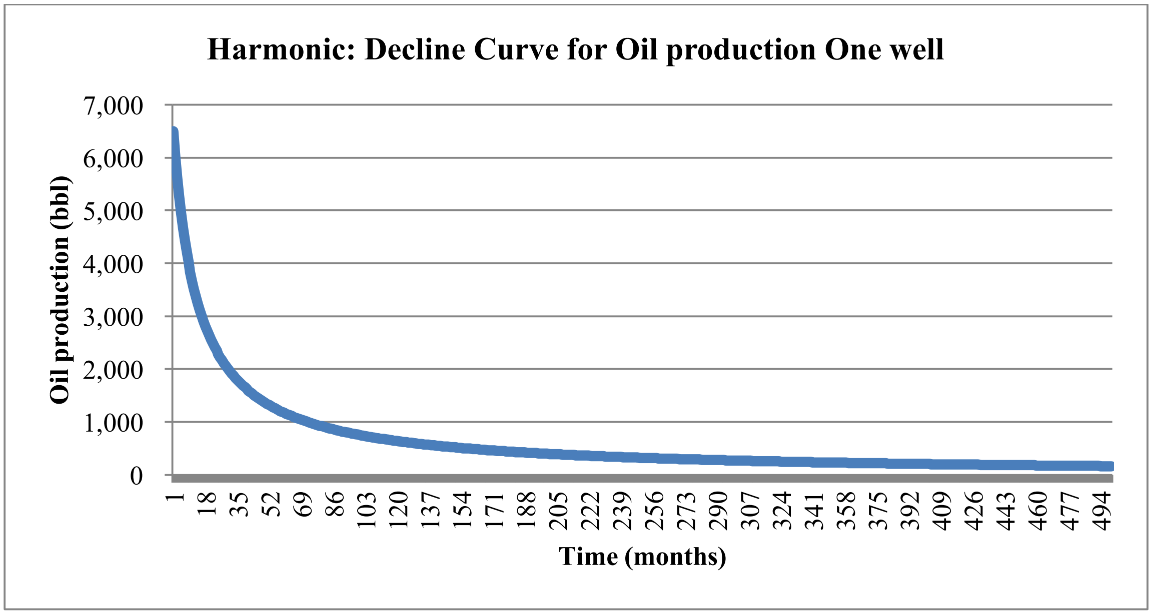

Figure 16: Harmonic Decline Curve for Oil Production from One Well

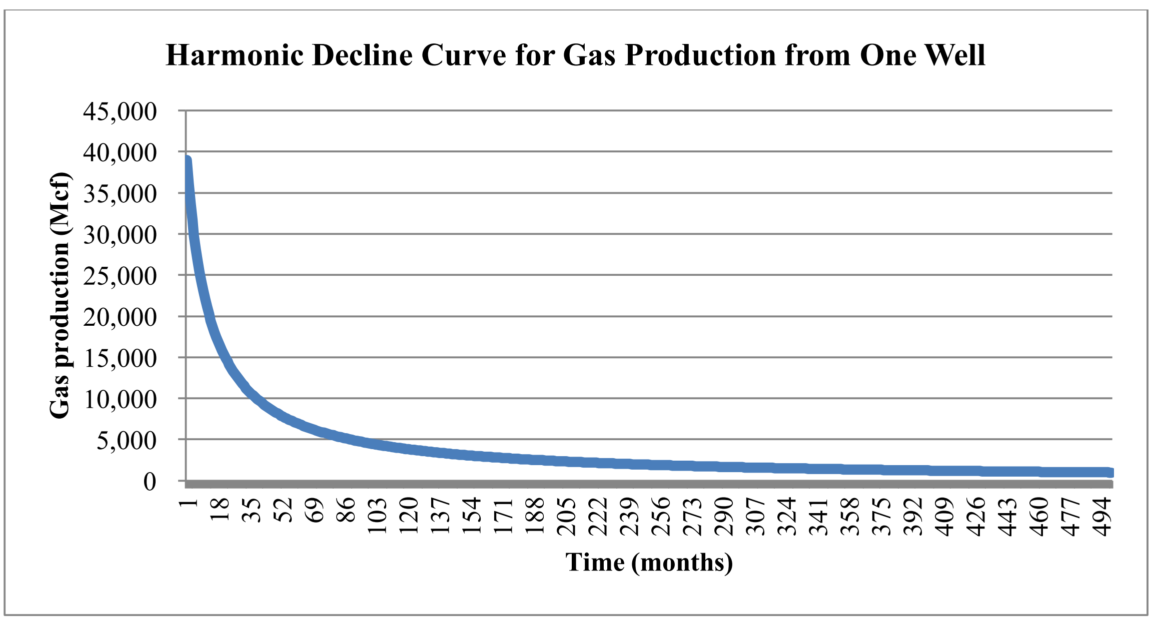

Figure 17: Harmonic Decline Curve for Gas Production from One Well

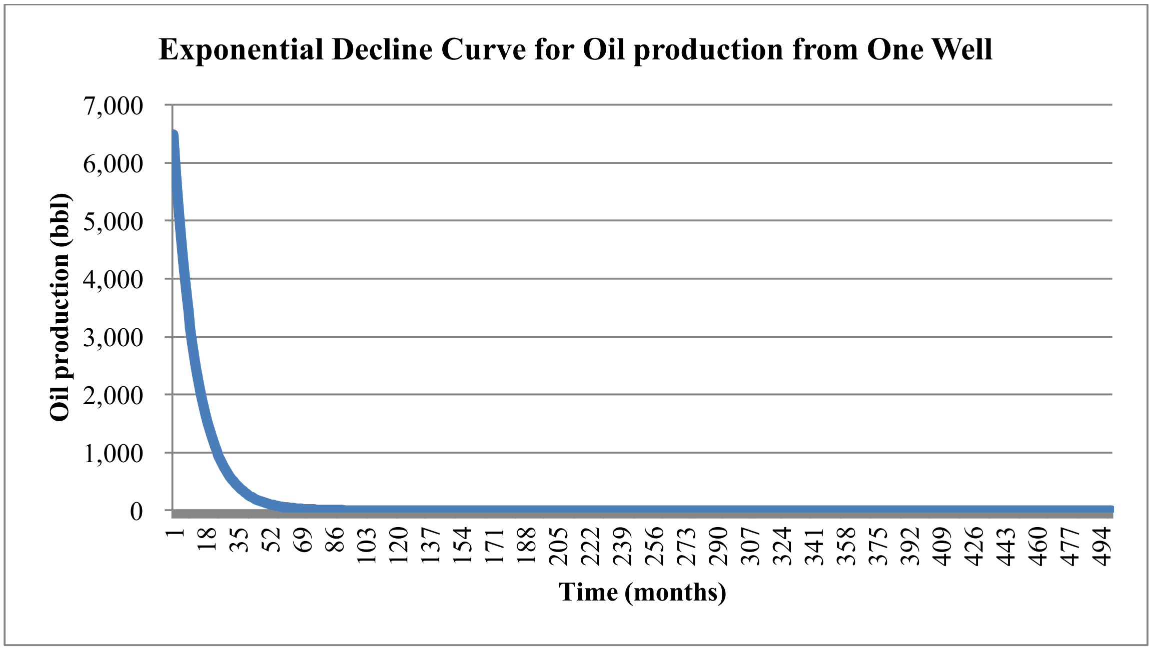

Figure 18: Exponential Decline Curve for Oil production from One Well

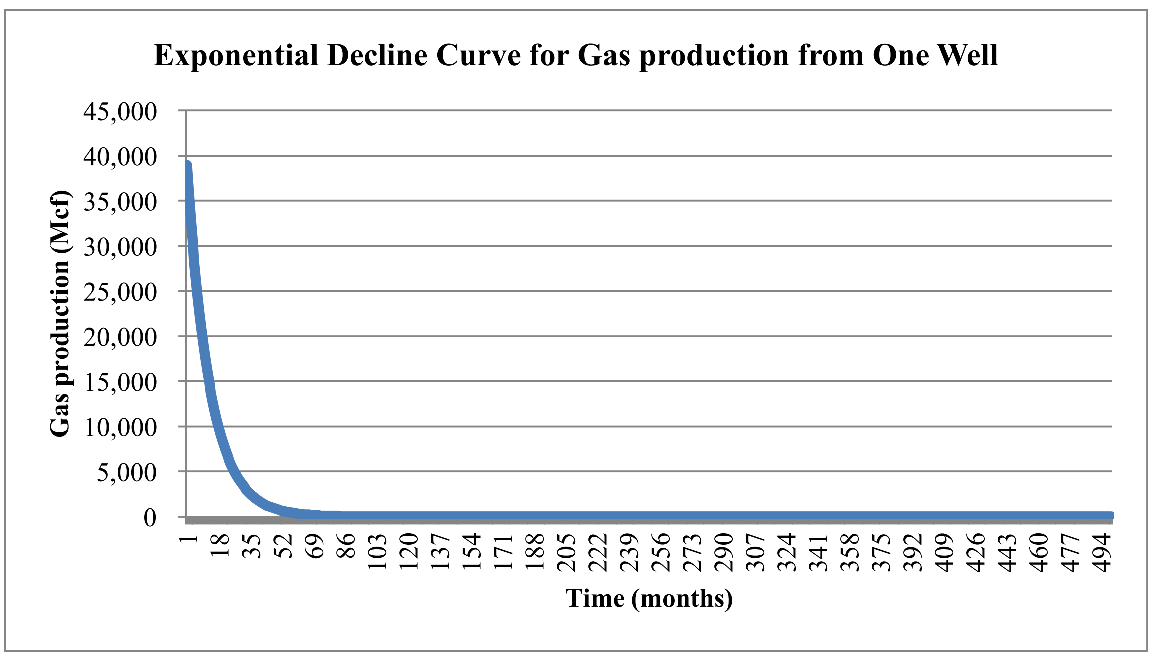

Figure 19: Exponential Decline Curve for Gas production from One Well

It is important to note that as the value of the decline parameter β increases, the value of the decline parameter λ decreases and hence the decline curve becomes more flat. This means that the exponential decline curve (β =0), leads to faster decline in production followed by hyperbolic decline curve ($0 < \beta <1$), and harmonic decline curve (β =1).

A shale play consists of more than one well. Therefore, shale oil and gas production forecast has been performed for a shale play of 500 wells. A drilling rate of one well per month, and same initial production for all 500 wells has been assumed. The shale oil and gas production forecast has been carried using the three decline curve models for 500 wells. Additionally, a decline in production from the second month onwards has been assumed. **Figure 20** and **Figure 21** represent the hyperbolic decline curve models for oil and gas production from 500 wells respectively.

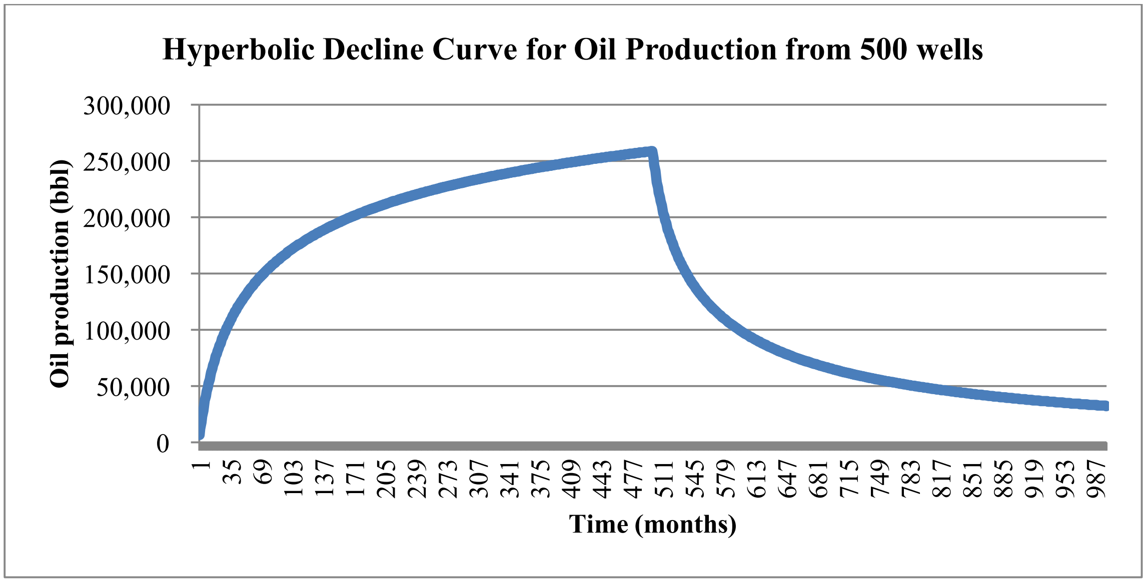

Figure 20: Hyperbolic Decline Curve for Oil Production from 500 wells

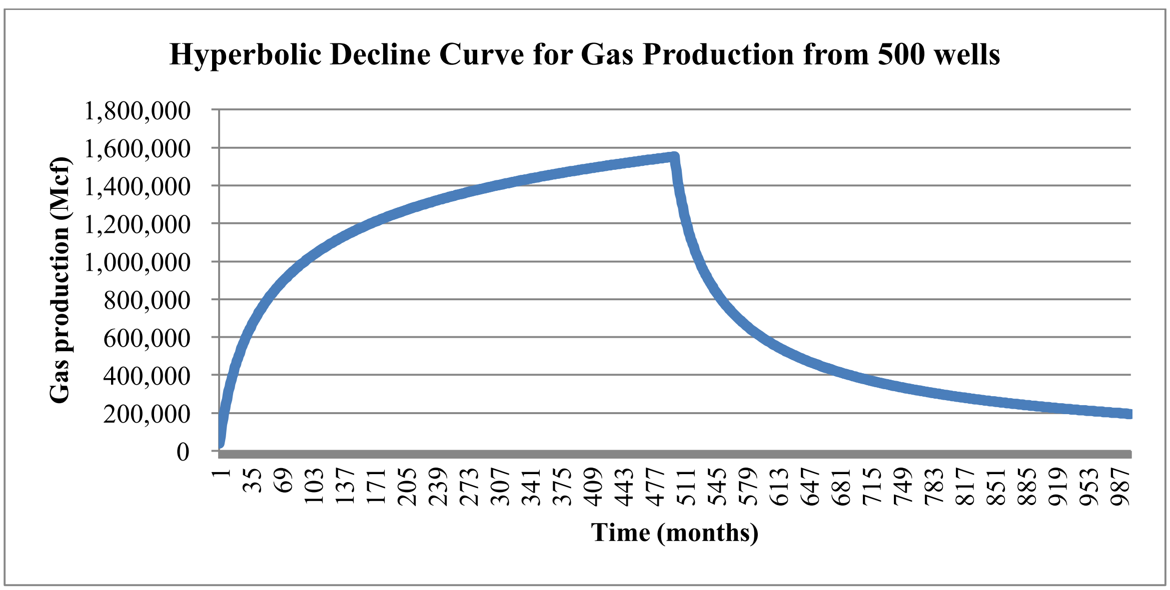

Figure 21: Hyperbolic Decline Curve for Gas Production from 500 wells

The Hyperbolic decline curve model for oil and gas production from 500 wells is projected over a period of 1000 months. From **Figure 20** and **Figure 21** we can see that the oil and gas production increases gradually with the increase in the number of wells, followed by a decrease in in production growth until 500 wells are drilled. When drilling is stopped at 500 wells, the oil and gas production of the shale play starts to decline.

Similarly, harmonic decline curve model for oil and gas production from 500 wells is projected over a period of 1000 months. These have been represented in **Figure 22** and **Figure 23.**

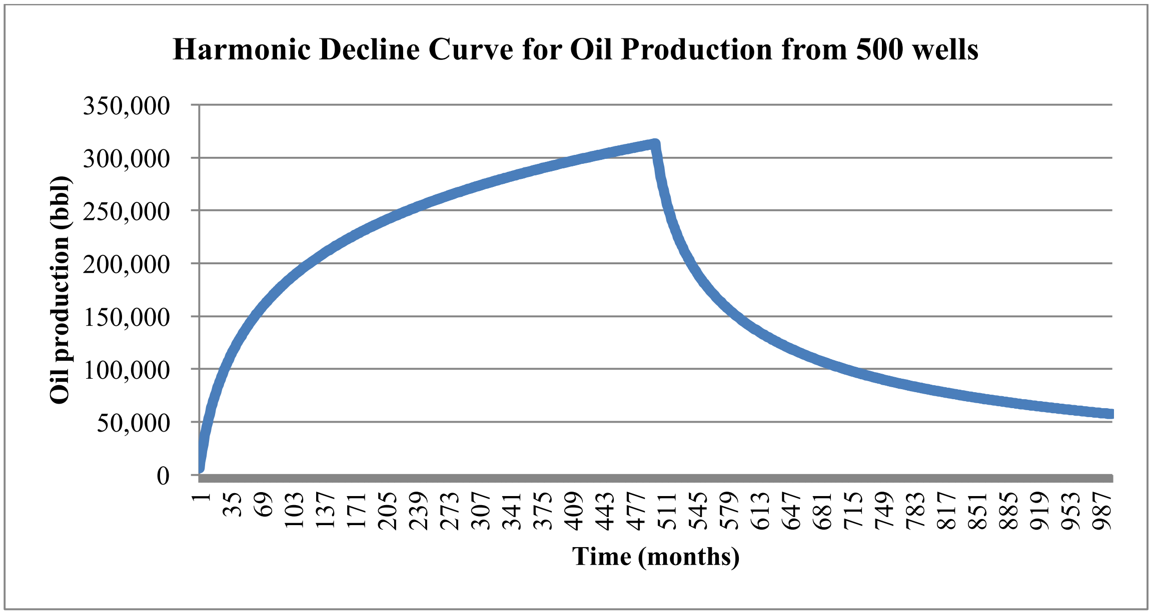

Figure 22: Harmonic Decline Curve for Oil Production from 500 wells

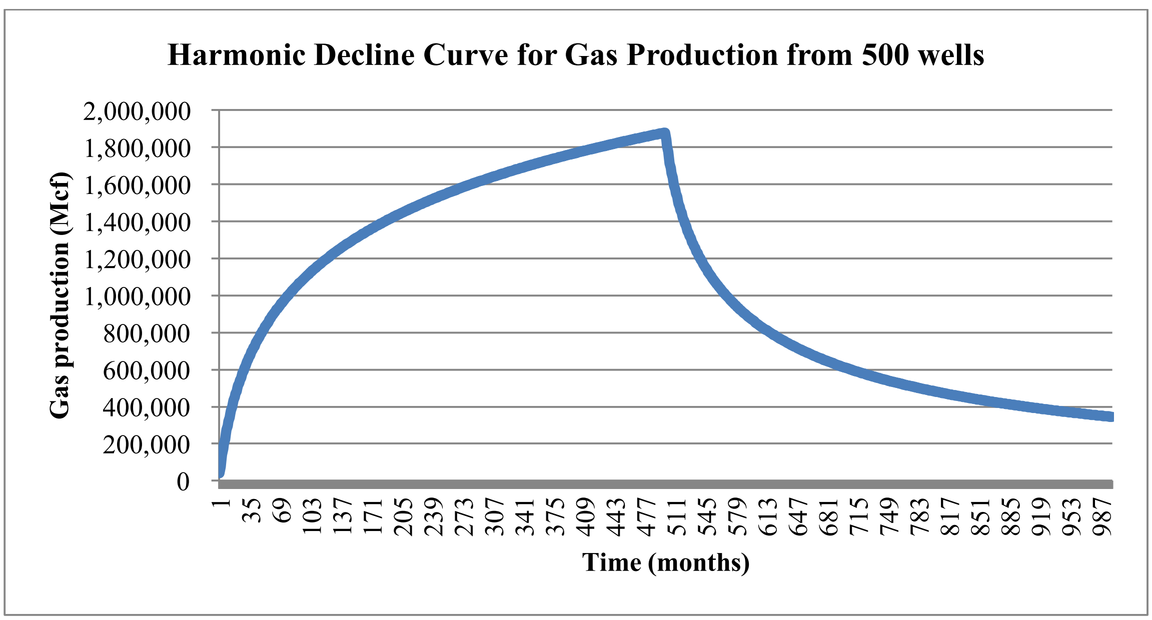

Figure 23: Harmonic Decline Curve for Gas Production from 500 wells

From **Figure 22** and **Figure 23** we can see that, the oil and gas production increases with the increase in number of wells, followed by a decrease in the growth of oil and gas production until all 500 wells are drilled. However, this decrease in the growth of oil and gas production is less as compared to that for a hyperbolic decline curve model for oil and gas production from 500 wells. This is because the β value for harmonic decline curve model is greater than that for hyperbolic decline curve model. Therefore, the decline rate for a harmonic decline curve model is less than that of a hyperbolic decline curve model, leading to a lower decrease in growth of shale oil and gas production. When drilling is stopped at 500 wells, the oil and gas production of the shale play starts to decline, with a relatively lower decline rate than hyperbolic decline curve model.

Exponential decline curve models for shale oil and gas production have been represented in **Figure 24** and **Figure 25** respectively. Here we can see that the shale oil and gas production increases for a relatively short period of time as compared to the two decline curve models discusses earlier. This is followed by an almost zero increase in production in oil and gas production until all 500 wells are drilled. When drilling is stopped at 500 wells, there is a sudden drop in shale oil and gas production. This is because decline rate for an exponential decline curve model is the highest out of all three decline curve models discussed so far.

The three decline curve models and their different decline parameters lead to varied oil and gas production profiles. This in turn affects the revenues generated due to the oil and gas production from a shale play. Therefore, it is very important to understand the decline curve models and the resulting oil and gas production profiles.

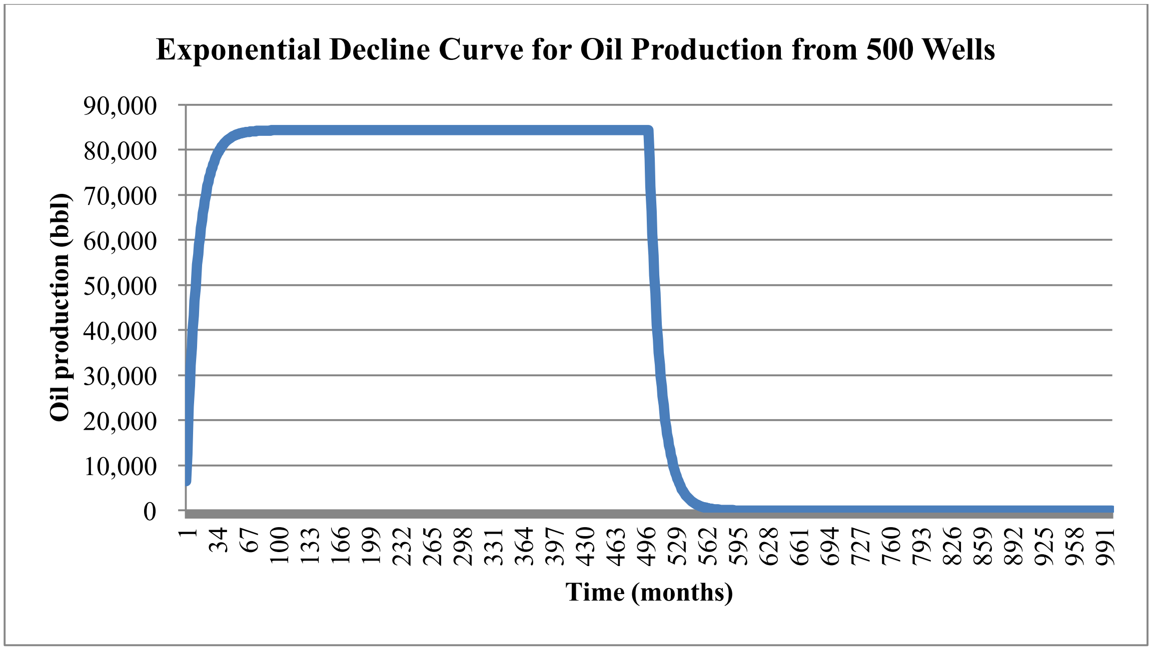

Figure 24: Exponential Decline Curve for Oil Production from 500 Wells

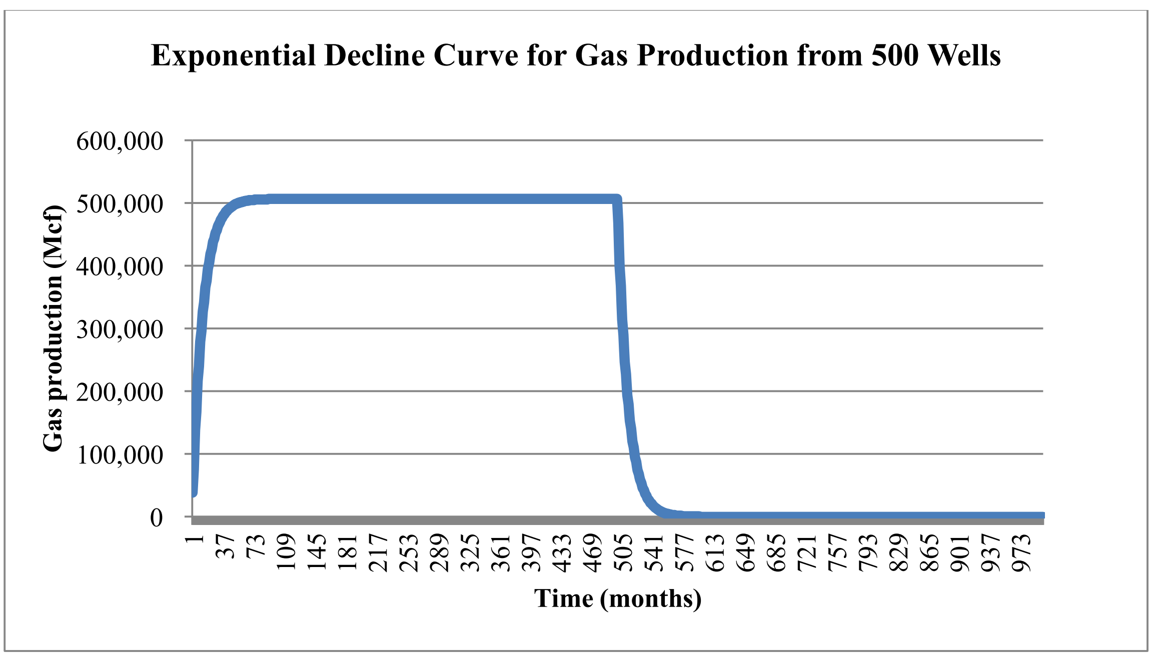

Figure 25: Exponential Decline Curve for Gas Production from 500 Wells

In addition to the Arps decline curve model, shale oil and gas production has been forecasted using a stretched exponential decline curve. Stretched exponential can be expressed an infinite sum of exponentials. A fractured reservoir is expected to have different pressure gradients. One is the original pressure gradient from the reservoir itself and the other is induced pressure created due to the fracturing fluids. An exponential decline curve model discussed earlier accounts only for the original pressure gradient of the reservoir. Therefore, a stretched exponential decline curve model can be used which accounts for different pressure gradients leading to different production profiles. A stretched exponential decline curve is the sum of different exponential declines caused due to various pressure gradients (Wachtmeister, Lund, Aleklett, and Höök, 2016).

The stretched exponential decline curve model is expressed (Can and Kabir, 2011) in **Table 2.**

	Stretched Exponential Decline
q(t)	$q_o e^{-\left(\frac{t}{\tau}\right)^n}$
Q(t)	$\frac{q_o \tau}{n}\left\{\Gamma\left[\frac{1}{n}\right] - \Gamma\left[\frac{1}{n}, \left(\frac{t}{\tau}\right)^n\right]\right\}$

Table 2: Stretched Exponential Decline Curve Model

The stretched exponential decline curve model is similar to the Arps decline curve model where n is equivalent to the β parameter in Arps model (Can and Kabir, 2011).

Similarly, τ is another decline parameters which is a constant. For forecasting the shale oil and gas production, n value is assumed to be 0.247, and a τ value is assumed to be 0.776 per month, for a horizontal well (Valkó and Lee, 2010). The q_o value is assumed to be 225 bbl/day, is the same value used for Arps decline curve models initially. Also, it must be noted that the corresponding β value is 1.6 (Valkó and Lee, 2010).

The stretched exponential decline curve model is used to forecast shale oil and gas production from a well over a period of 500 months. **Figure 26** and **Figure 27** represent the shale oil and gas production as per the stretched exponential decline curve model from one well.

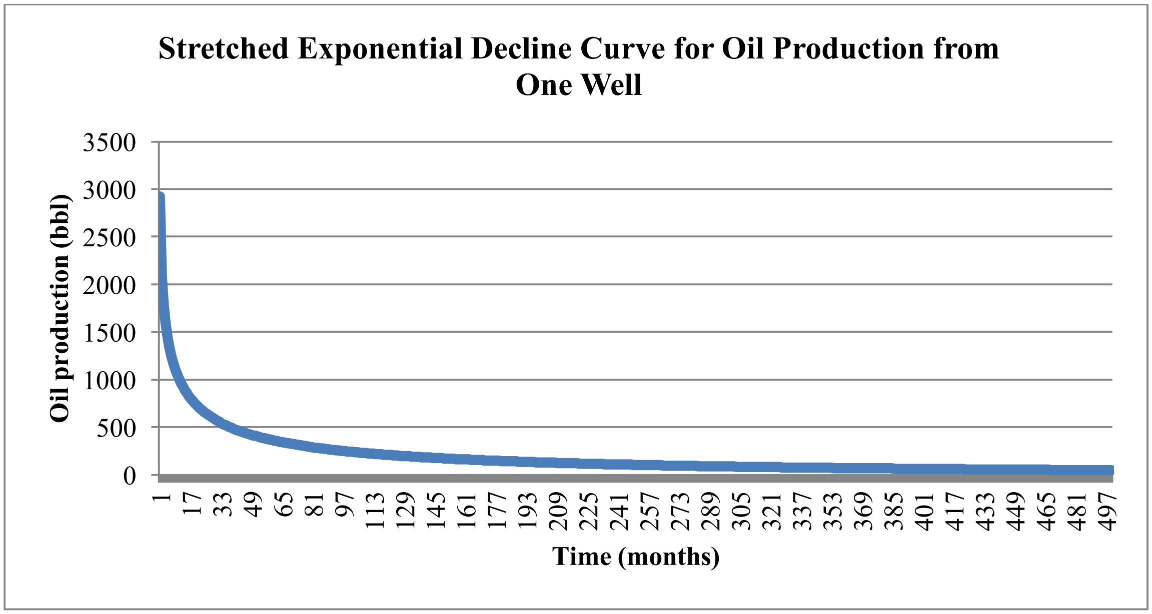

Figure 26: Stretched Exponential Decline Curve for Oil Production from One Well

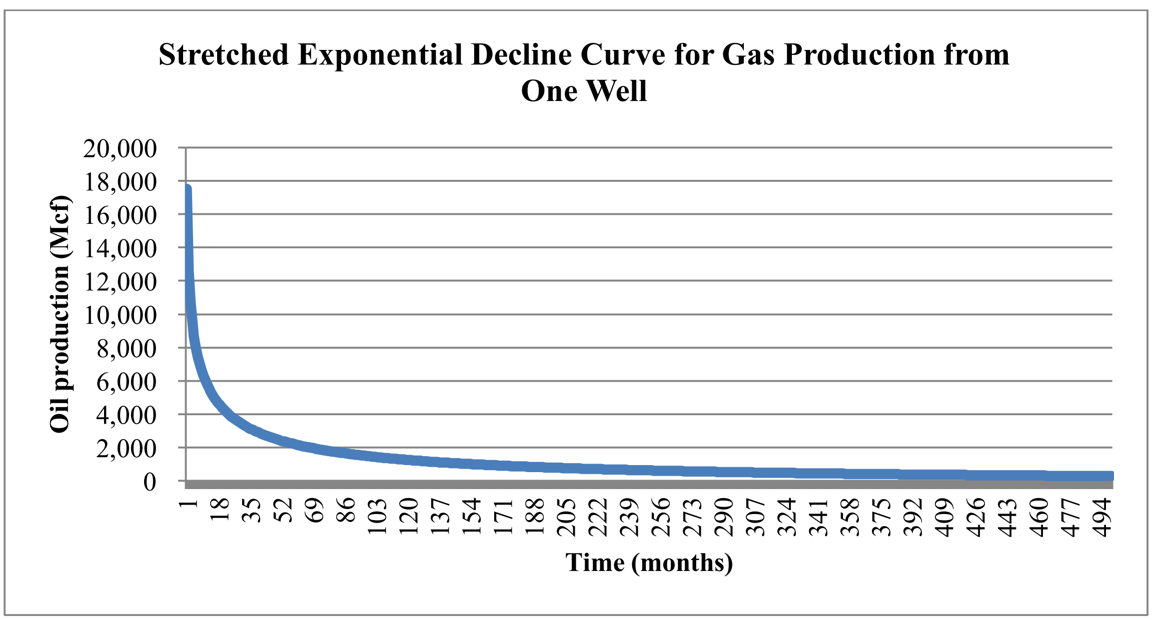

Figure 27: Stretched Exponential Decline Curve for Gas Production from One Well

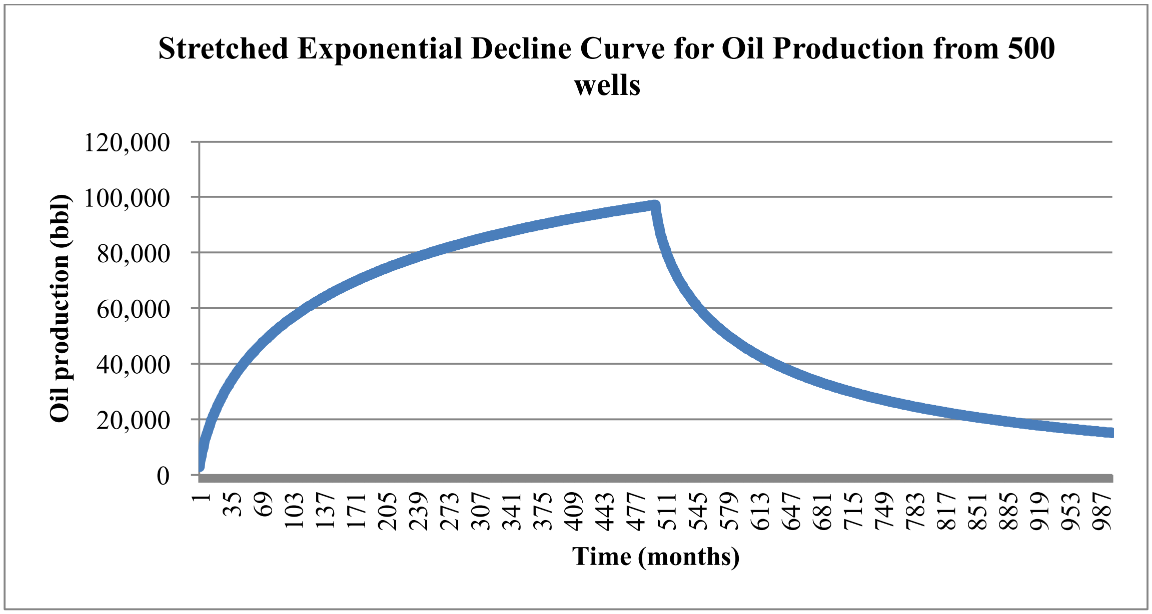

Figure 28: Stretched Exponential Decline Curve for Oil Production from 500 wells

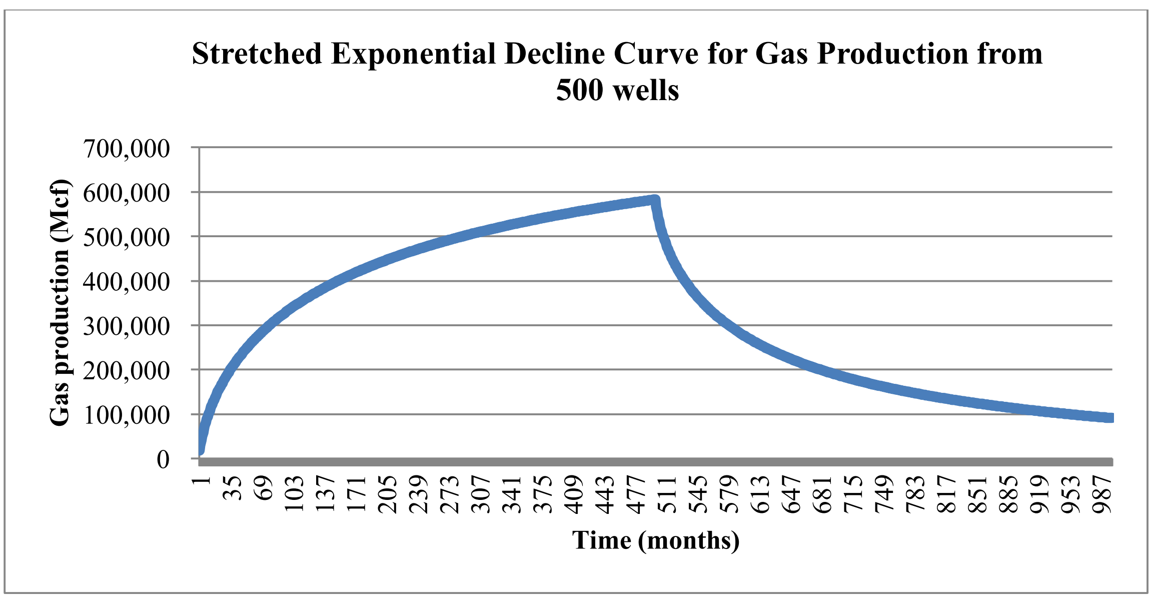

Figure 29: Stretched Exponential Decline Curve for Gas Production from 500 wells

Similarly, stretched exponential decline curve model has been used to forecast production of a shale play with 500 wells. A drilling rate of one well per month, and same initial production for all 500 wells has been assumed. Additionally, a decline in production from the second month onwards has been assumed. **Figure 28** and **Figure 29** represent the stretched exponential decline curve models for oil and gas production from 500 wells respectively.

As discussed earlier, the Arps exponential decline curve has a β value of zero, therefore having the steepest decline rate. As β value increases, the decline rate decreases. However, as β value increases beyond 1, the estimated ultimate recovery (EUR) becomes infinitely large. EUR is the expected amount of economically recoverable oil and gas from a reservoir or field by the end of its producing life. This drawback of the Arps decline curve models is overcome by the bounded nature of the stretched exponential decline curve, the parameter n lies between zero and one for all decline rates. As the decline rate decreases, parameter n assumes lower values (Can and Kabir, 2011). However, when the decline rate is lower, the Arps decline curve models yield an infinite cumulative production. In contrast to that, as seen in **Figure 28** and **Figure 29,** even though the stretched exponential decline curve behaves similar to Arps hyperbolic decline curve in the beginning, its bounded nature is revealed in the later stages (Can and Kabir, 2011).

2.2.2 CASH FLOW ANALYSIS

In order to determine the economic value of the shale oil and gas reserves, it is very important to determine the amount of cash flow it generates. This can be carried out by determining the cash inflow due to sale of oil and gas produced from the reserves and cash outflow due to various exploration and production (E&P) activities.

As discussed in phase 1, the E&P activities across the supply chain of shale oil and gas are associated with certain costs. Out of all the costs associated with the E&P activities, the drilling and completion costs account for 31% and 63% respectively, of the total well cost (IHS Oil and Gas Upstream Cost Study, 2016). Since the drilling and completion costs have a contribution of about 94% to the total cost of a well, the cash flow analysis has been carried out assuming the drilling and completion costs as total well cost.

Initially, cash flow analysis for a single well has been performed. As per the IHS Oil and Gas Upstream Cost Study in 2016, average cost of drilling a horizontal well ranges from about \$1.8 MM to \$2.6 MM. Similarly, average cost of completion ranges from \$2.9MM to \$5.6MM per well. Therefore, an average of \$6.45 MM for drilling and completion of a well has been assumed as the cash outflow throughout the cash flow analysis in this study.

The shale oil and gas production forecasted in the earlier section is used to determine the cash inflow generated by the shale oil and gas reserves. The cash inflow considered in this study is the revenue generated from the forecasted shale oil and gas production. Cash inflow can be expressed as below:

Cash inflow (t) = [Oil and gas production (t)] * [Price of oil and gas (t)]

In the above expression, cash inflow is in U.S. Dollars (USD), oil production is in barrel (bbls) and gas production is in and million cubic feet (Mcf), price of oil is in USD per barrel and price of gas is in USD per Million British thermal unit (Btu), and all are a function of time t. A West Texas Intermediate (WTI) price of $50 per barrel of oil and a Henry Hub price of $ 2.75 per Mcf of natural gas has been considered for this study. These are the average prices from January 2015 to December 2017 (forecasted price) (Short-term Energy Outlook, 2016). The oil and gas prices have been assumed to be constant throughout the cash flow analysis. The changes in the oil and gas prices and its effect on the cash flows will be accounted for in the stress analysis of the financial model in the later section of this study.

Cash flow analysis for a single well with different production decline curves, i.e. hyperbolic, harmonic and exponential decline curves, has been carried out. Cash flow from a single well with a hyperbolic decline in production is represented in **Figure 30**.

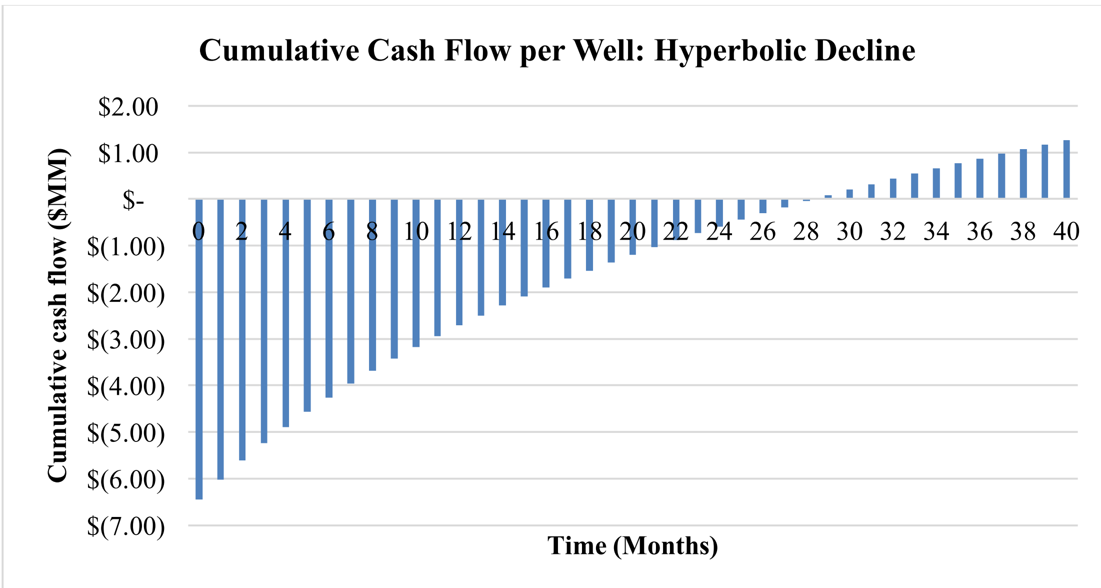

Figure 30: Cumulative Cash Flow per Well: Hyperbolic Decline

The above figure represents a cumulative cash flow per month from a single well with a hyperbolic decline in production. The cumulative cash flow turns positive in the 29th month of production, i.e. approximately 2.42 years of payback period. This indicates that a shale oil and gas well with a hyperbolic decline curve, pays back the investment of $6.45 MM, i.e. the cost of drilling and completion of a well, after a period of 2.42 years.

Similarly, cumulative cash flow of a well with harmonic decline in oil and gas production is represented in **Figure 31**.

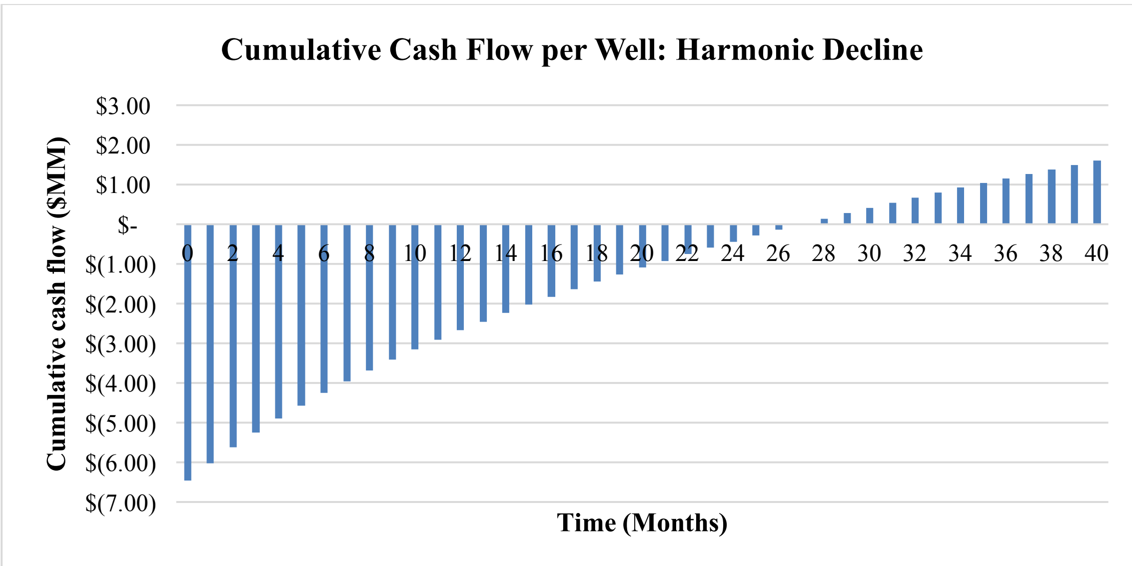

Figure 31: Cumulative Cash Flow per well: Harmonic Decline

The above figure represents a cumulative cash flow per month from a single well with a harmonic decline in production. The cumulative cash flow turns positive in the 27^{th} month of production, i.e. approximately 2.25 years of payback period. This indicates that a shale oil and gas well with a harmonic decline curve, pays back the investment of $6.45 MM, i.e. the cost of drilling and completion of a well, after a period of 2.25 years.

As discussed in section 2.2.1 the production decline rate is slower when the β value higher. In case of harmonic decline curve, the β value is greater than that for hyperbolic decline. Therefore, the shale oil and gas production with a harmonic decline will decline at a slower rate. The slower decline rate of harmonic decline curve results in higher production as compared to the hyperbolic decline and therefore pays back relatively faster than the production with hyperbolic decline.

Similarly, cumulative cash flow of a well with exponential decline in oil and gas production is represented in **Figure 32**.

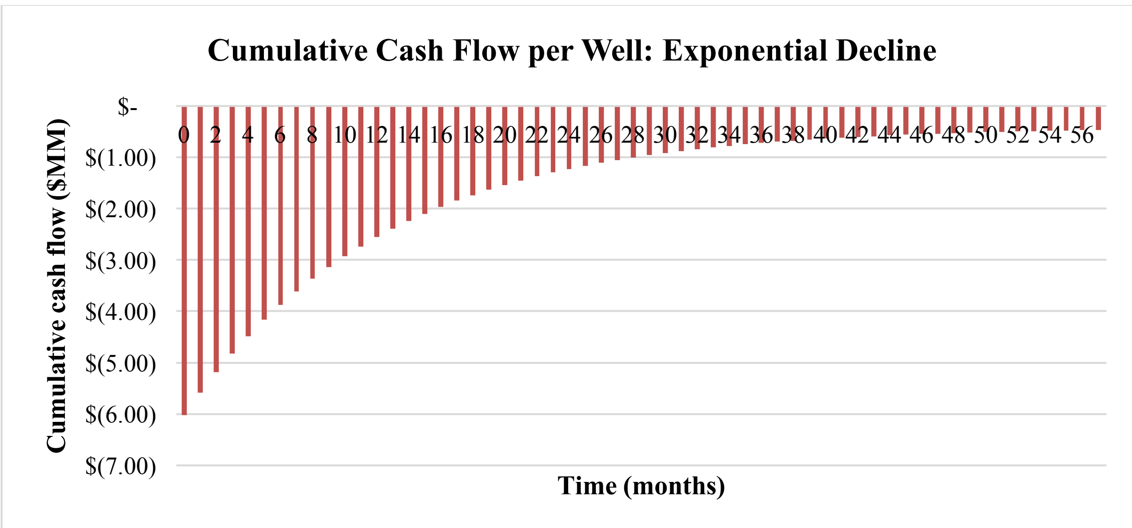

Figure 32: Cumulative Cash Flow per Well: Exponential Decline

The above figure represents a cumulative cash flow per month from a single well with an exponential decline in production over a period of 57 months (Life of the well with exponential decline in production). The cumulative cash flow for an exponential decline is negative throughout its lifetime. This indicates that a shale oil and gas well with an exponential decline curve, does not pay back the investment of $6.45 MM, i.e. the cost of drilling and completion of a well throughout its lifetime, with a payback period of zero years. This is because an exponential decline curve model has a β value of zero, and the highest decline rate as compared to the other two decline curve models discussed so far (i.e. Hyperbolic and harmonic decline curve models).

Similarly, cumulative cash flow of a well with stretched exponential decline in oil and gas production is represented in **Figure 33**.

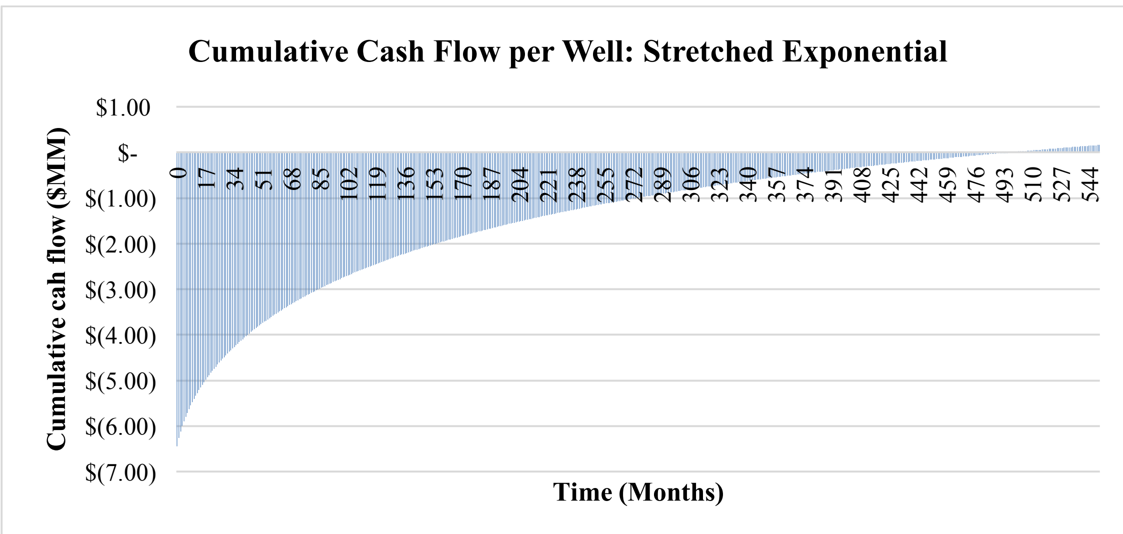

Figure 33: Cumulative Cash Flow per Well: Stretched Exponential

The above figure represents a cumulative cash flow per month from a single well with a stretched exponential decline in production. The cumulative cash flow turns positive 496 months onwards, i.e. approximately 41.33 years of payback period. This indicates that a shale oil and gas well with a stretched exponential decline curve, pays back the investment of $6.45 MM, i.e. the cost of drilling and completion of a well, after a period of 41.33 years.

Understanding payback periods per well for respective production decline curve models plays a major role in valuation of the shale exploration and production assets. However, a shale play consists of multiple wells, drilled as per the drilling strategy of a company. Therefore, cash flow analysis for 2 wells, 5 wells and 500 wells has been carried out. A constant drilling rate of one well per month has been assumed for simplicity of the analysis. Additionally, the oil and gas prices are assumed to be constant (same oil and gas prices as assumed for one well, earlier in this section). The cost of drilling and completion of one well is considered to be $6.45 MM.

Figure 34 below represents the cumulative cash flow for 2 wells with hyperbolic decline in oil and gas production.

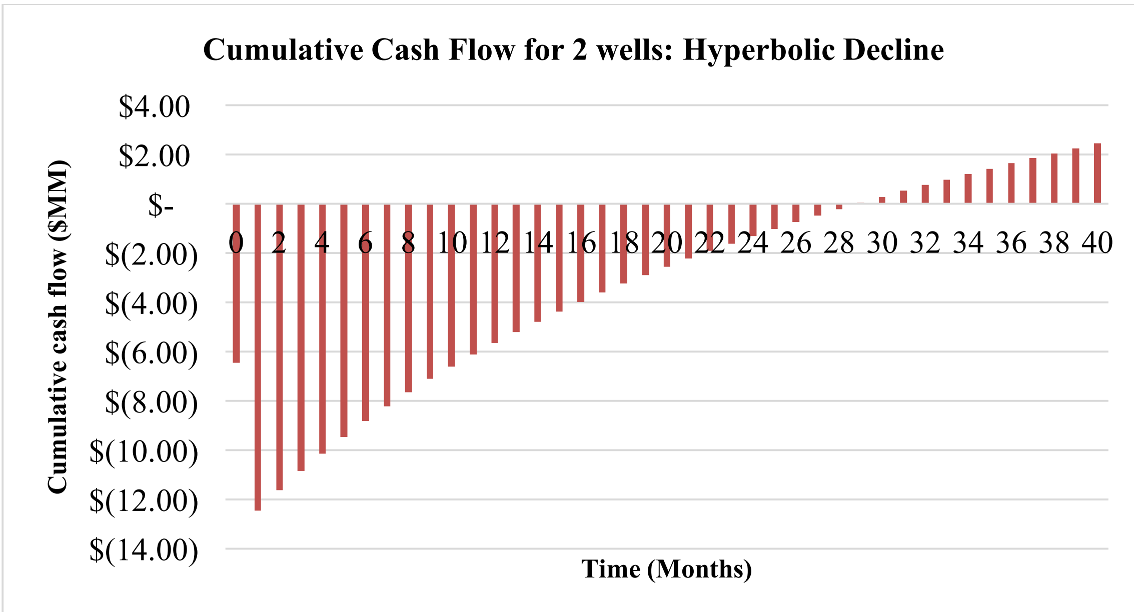

Figure 34: Cumulative Cash Flow for 2 wells: Hyperbolic Decline

The above figure represents a cumulative cash flow per month from two wells with a hyperbolic decline in production. The cumulative cash flow turns positive 29 months onwards, i.e. approximately 2.42 years of payback period. This indicates that 2 shale oil and gas wells with hyperbolic decline curves, pay back the investment of $6.45 MM per well, i.e. the cost of drilling and completion per well, after a period of 2.42 years. It is important to note that the payback period from a single well with a hyperbolic decline and that from two wells are equal, i.e. 2.42 years, given constant drilling rate, price of oil and gas and cost of drilling and completion of a well.

Similarly, cumulative cash flow of 5 wells with hyperbolic decline in oil and gas production is represented in **Figure 35**.

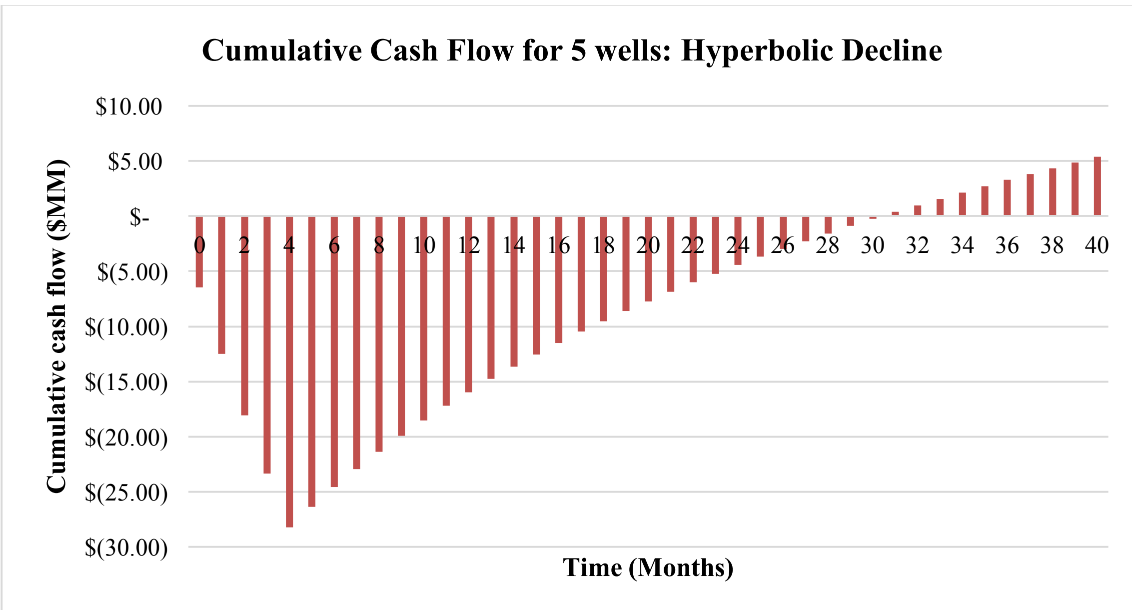

Figure 35: Cumulative Cash Flow for 5 wells: Hyperbolic Decline

The above figure represents a cumulative cash flow per month from 5 wells with a hyperbolic decline in production. The cumulative cash flow turns positive 31 months onwards, i.e. approximately 2.6 years of payback period. This indicates that five shale oil and gas wells with hyperbolic decline curves, pay back the investment of $6.45 MM per well, i.e. the cost of drilling and completion of a well, after a period of 2.6 years. It is important to note that as the number of wells increases, the oil and gas production increases, however the cumulative cash flows are relatively lower as compared to those for lesser number of wells. The cumulative cash flows become greater as compared to those for lower number of wells post the payback period. This is because even though the oil and gas production is higher from 5 wells as compared to that from one or two wells, it is not large enough to compensate for the cost of drilling and completion for five wells. However, post payback period for 5 wells the oil and gas production is larger than that from one or two wells.

In case of 500 wells drilled at the rate of one well per month, cash flow per month with hyperbolic decline in oil and gas production has been represented in **Figure 36**.

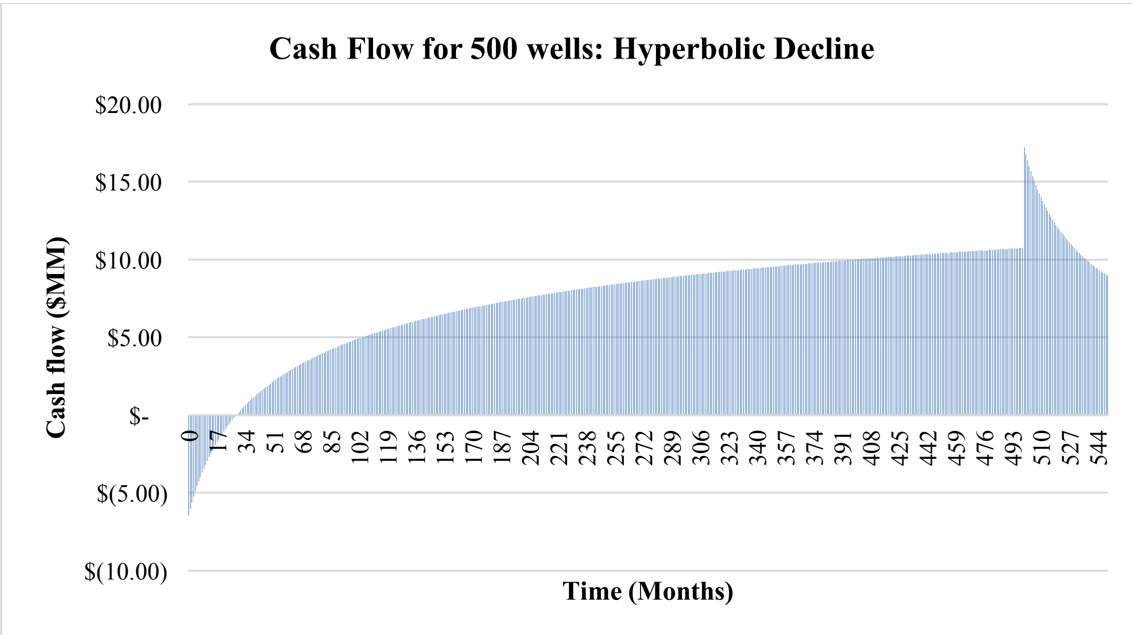

Figure 36: Cash Flow for 500 wells: Hyperbolic Decline

In the above figure, the cash flow per month turns positive 29 months onwards, which coincides with the payback period of one well (refer **Figure 30**). As a new well is drilled every month, the revenue from the oil and gas production per month is greater than the cost of drilling and completion per month, post 29 months of production. In this case, the cash flow per month increases with time till drilling is stopped at the 500th month. At the 500th month, the oil and gas production and the cash flow reaches its peak (i.e.

$17.21MM in **Figure 36**). This is because no well is drilled 500 months onwards therefore the cost of drilling and completion is zero 500 months onwards. Additionally, the oil and gas production per month from 500 wells starts to decline from the 501th month onwards (as seen in **Figure 36**). As a result of which the cash flow per month also starts declining from the 501th month onwards (as seen in **Figure 36**). This indicates that the oil and gas production and the cash flow per month increase with time only when new wells are being drilling with time. However, when drilling is stopped the oil and gas production and the cash flow per month start to decline from the next month itself.

Therefore, it is important to understand at what point one should stop drilling given a drilling rate, so that the oil and gas production and the cash flow per month can be can be maintained at a desired level without having to drill further with time. This will be further discussed in detail in the next **section 2.2.3**.

Figure 37 below represents cumulative cash flow per month for 500 wells with hyperbolic decline in oil and gas production.

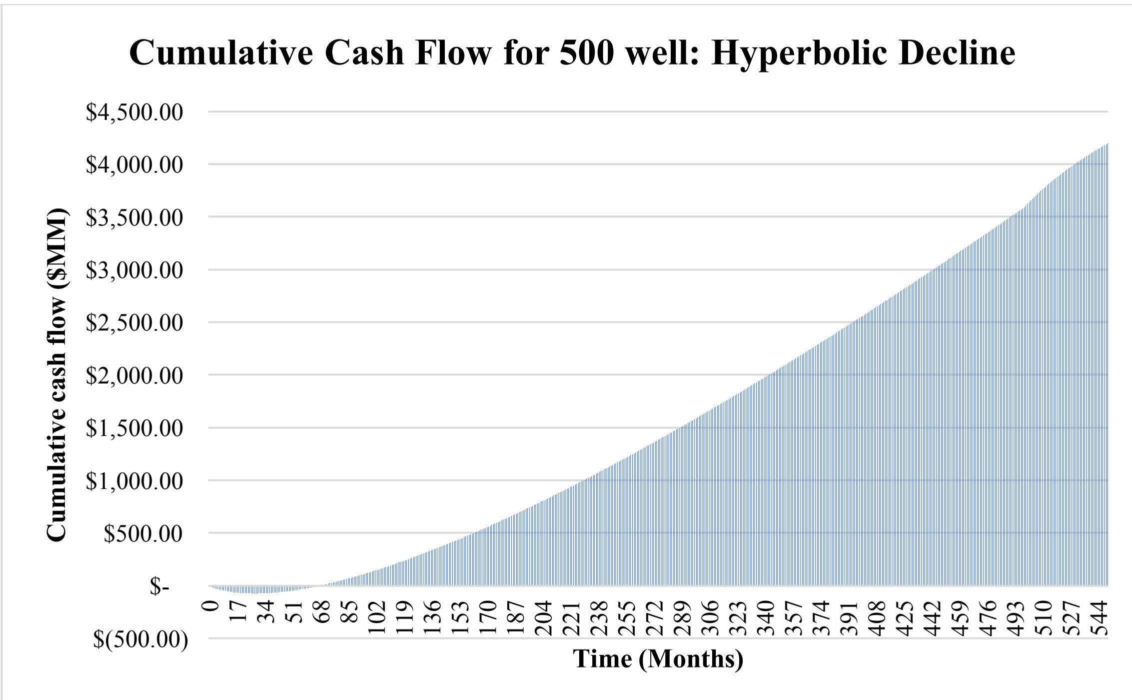

Figure 37: Cumulative Cash Flow for 500 well: Hyperbolic Decline

The above figure represents a cumulative cash flow per month from 500 wells with a hyperbolic decline in production. The cumulative cash flow turns positive 68 months onwards, i.e. approximately 5.67 years of payback period. This indicates that 500 shale oil and gas wells with hyperbolic decline curves, pay back the investment of $6.45 MM per well, i.e. the cost of drilling and completion per well, after a period of 5.67 years. It is important to note that as the number of wells increases, the oil and gas production increases, however the cumulative cash flows are relatively lower as compared to those for lesser number of wells. The cumulative cash flows become greater as compared to those for lower number of wells post the payback period. This is because even though the oil and gas production is higher from 500 wells as compared to that from 1, 2 or 5 wells, it is not large enough to compensate for the cost of drilling and completion for 500 wells. However, post payback period for 500 wells the oil and gas production is larger than that from 1, 2 or 5 wells.

Figure 38 below represents cumulative cash flow per month for 2 wells with harmonic decline in oil and gas production.

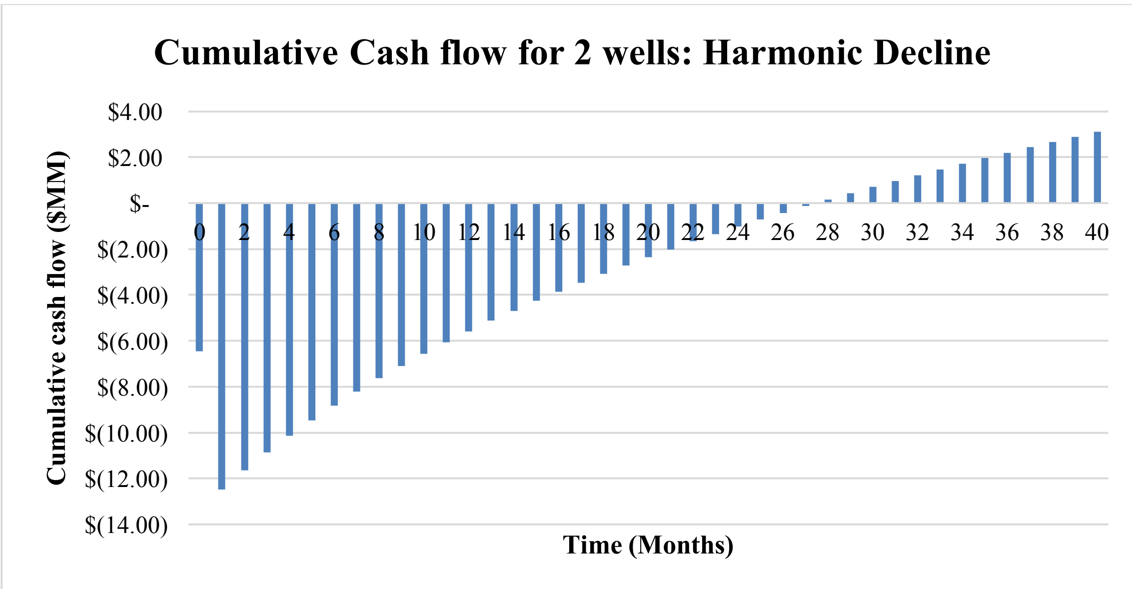

Figure 38: Cumulative Cash flow for 2 wells: Harmonic Decline

The above figure represents a cumulative cash flow per month from two wells with a harmonic decline in production. The cumulative cash flow turns positive 28 months onwards, i.e. approximately 2.33 years of payback period. This indicates that 2 shale oil and gas wells with a harmonic decline curves, pay back the investment of $6.45 MM per well, i.e. the cost of drilling and completion of a well, after a period of 2.33 years. It is important to note that the payback period (i.e. 2.33 years) from two wells with a harmonic decline in production is less than that (i.e. 2.42 years) from two wells with hyperbolic decline in production. This is because the harmonic decline rate is lower than the hyperbolic decline rate due to a higher β value (i.e. $\beta = 1$) than that (i.e. $0 < \beta < 1$) for hyperbolic decline. Additionally, the payback period (i.e. 2.33 years) from two wells with harmonic decline in production is also less than that (i.e. 2.42 years) from one well with harmonic decline in production.

Similarly, cumulative cash flow from 5 wells with harmonic decline in oil and gas production is represented in **Figure 39**.

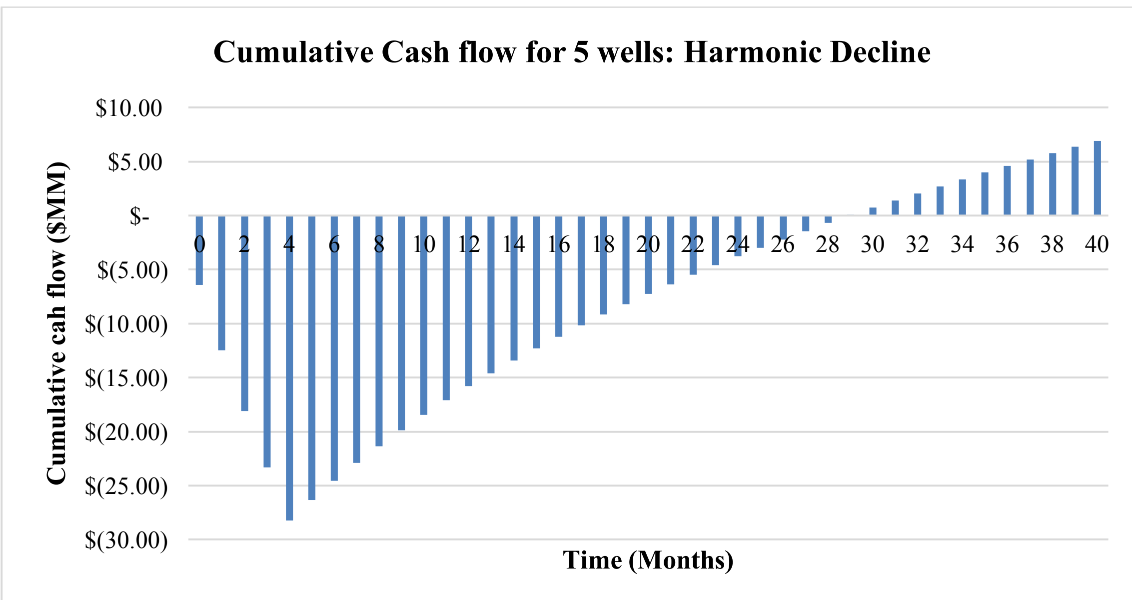

Figure 39: Cumulative Cash flow for 5 wells: Harmonic Decline

The above figure represents a cumulative cash flow per month from 5 wells with a harmonic decline in production. The cumulative cash flow turns positive 29 months onwards, i.e. approximately 2.42 years of payback period. This indicates that 5 shale oil and gas wells with harmonic decline curves, pay back the investment of $6.45 MM per well, i.e. the cost of drilling and completion of a well, after a period of 2.42 years. Similar to the payback period for hyperbolic decline in production, the payback period for harmonic decline in production also increases with an increase in the number of wells. Additionally, it is important to note that the payback period (i.e. 2.42 years) from 5 wells with harmonic decline in production is same as that for one well and two wells with hyperbolic decline in production, given the constant drilling rate, oil and gas prices and cost of drilling and completion.

In case of 500 wells drilled at the rate of one well per month, cash flow per month with harmonic decline in oil and gas production has been represented in **Figure 40**.

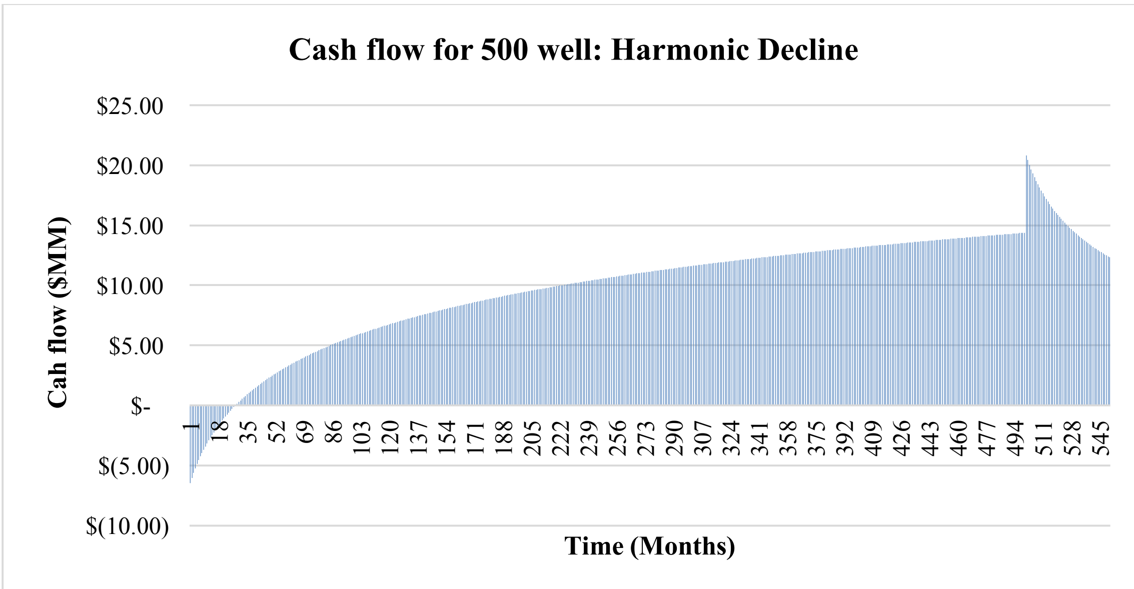

Figure 40: Cash flow for 500 well: Harmonic Decline

In the above figure, the cash flow per month turns positive 27 months onwards, which coincides with the payback period of one well with harmonic decline in production (refer **Figure 31**). Similar to cash flow per month for 500 wells with hyperbolic decline in production, the cash flow per month with harmonic decline in production turns positive from 27 months onwards and increases with time till drilling is stopped at the 500th month. At the 500th month, the oil and gas production and the cash flow reaches its peak (i.e. $20.84MM in **Figure 40**). This peak in cash flow is higher than the peak cash flow from

500 wells with hyperbolic decline in production, due to lower harmonic decline rate. Additionally, the oil and gas production per month from 500 wells starts to decline from the 501st month onwards (as seen in **Figure 40**). As a result of which the cash flow per month also starts declining from the 501st month onwards (as seen in **Figure 40**).

Figure 41 below represents the cumulative cash flow for 500 wells with harmonic decline in oil and gas production.

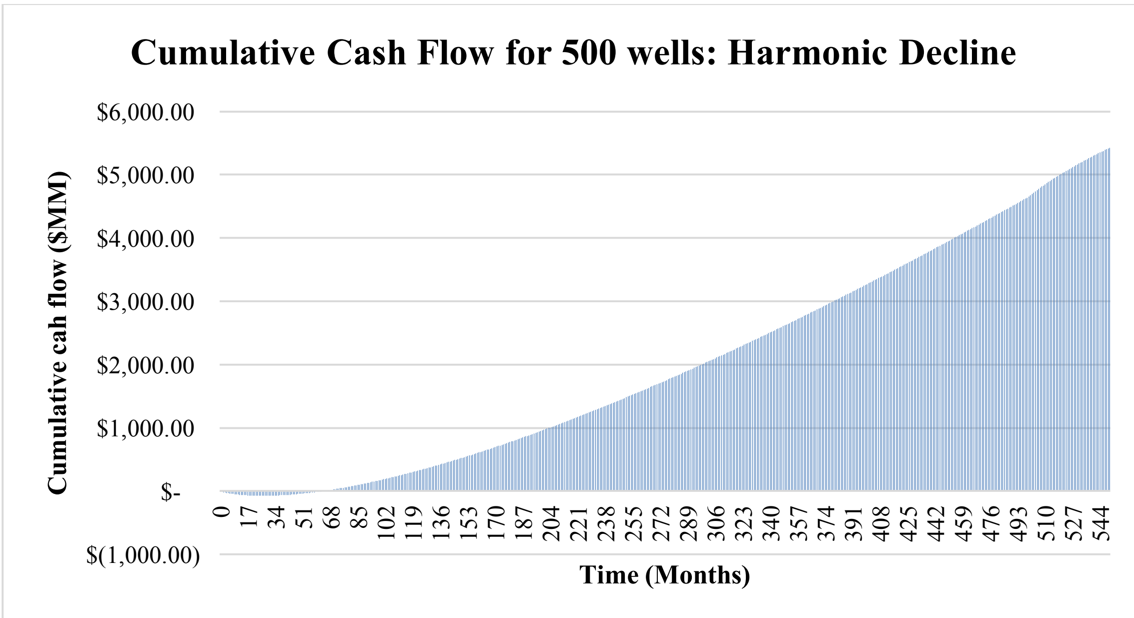

Figure 41: Cumulative Cash Flow for 500 wells: Harmonic Decline

The above figure represents a cumulative cash flow per month from 500 wells with a harmonic decline in production. The cumulative cash flow turns positive 63 months onwards, i.e. approximately 5.25 years of payback period. This indicates that 500 shale oil and gas wells with harmonic decline curves, pay back the investment of $6.45 MM per well, i.e. the cost of drilling and completion per well, after a period of 5.25 years. The payback period of 5.25 years is lower as compared to that (i.e. 5.67 years) for 500 wells with hyperbolic decline in production. This is because the harmonic decline rate is lower than the hyperbolic decline rate due to a higher β value (i.e. $\beta = 1$) than that (i.e. $0 < \beta < 1$) for hyperbolic decline.

Similar to wells with hyperbolic decline in production, as the number of wells increases, the oil and gas production increases, however the cumulative cash flows are relatively lower as compared to those for lesser number of wells. The cumulative cash flows become greater as compared to those for lower number of wells post the payback period. However, post payback period for 500 wells the oil and gas production is larger than that from 1, 2 or 5 wells.

In case of cumulative cash flow with exponential decline in production, as seen in **Figure 32** the well does not payback. Additionally, as we increase the number of wells to 2, 5 and 500, they do not payback during their lifetimes.

Figure 42 below represents the cumulative cash flow for 500 wells with stretched exponential decline in oil and gas production.

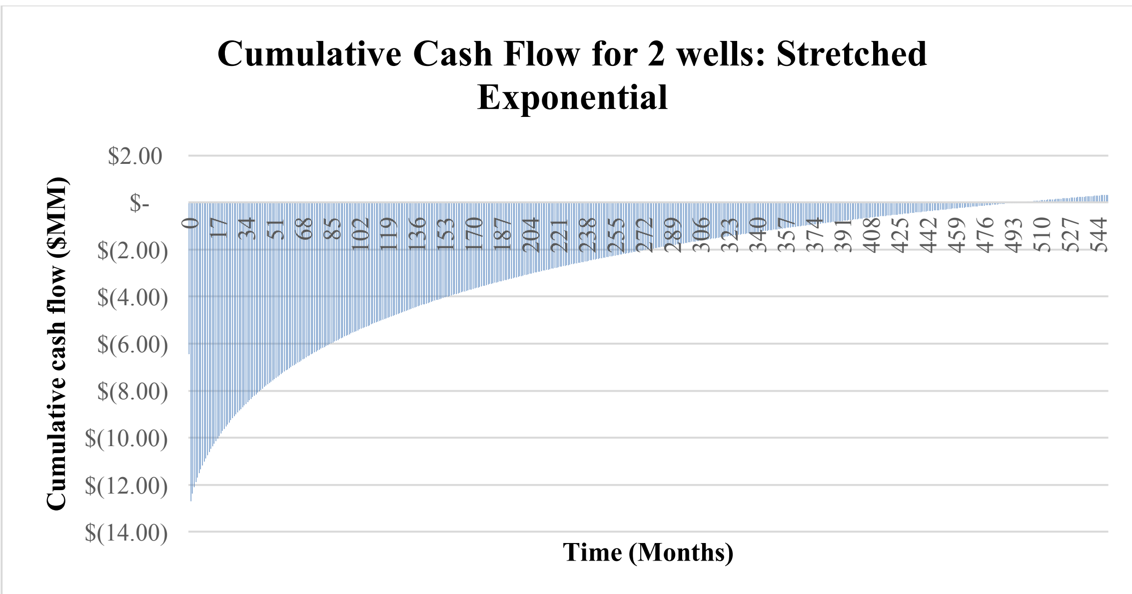

Figure 42: Cumulative Cash Flow for 2 wells: Stretched Exponential

The above figure represents a cumulative cash flow per month from two wells with a stretched exponential decline in production. The cumulative cash flow per month turns positive 496 months onwards, i.e. approximately 41.33 years of payback period. This indicates that two shale oil and gas wells with stretched exponential decline curves, pay back the investment of \$6.45 MM per well, i.e. the cost of drilling and completion of a well, after a period of 41.33 years. The payback period from one and two wells with stretched exponential decline in production are equal at 41.33 years. It is important to note that the two wells with stretched exponential decline in production take the highest amount of time to payback (i.e. 41.33 years) as compared to that from two wells with hyperbolic decline in production (i.e. 2.42 years) and harmonic decline in production (i.e. 2.33 years). This is because the stretched exponential decline rate is the highest as compared to the hyperbolic, harmonic and exponential decline rates. As mentioned explained in **section 2.2.1.** the β value for stretched exponential decline curve model is always greater than 1 and is directly related to the decline rate, unlike the Arp's decline curve models, where the β ranges between zero and one, and is inversely related to the decline rate. Since $\beta = 1.6$ for the given stretched exponential decline curve model, the decline is greater than that for exponential decline ($\beta = 1$, and highest decline as compared to the other two Arp's decline curve model).

Similarly, cumulative cash flow from 5 wells with stretched exponential decline in oil and gas production is represented in **Figure 43**.

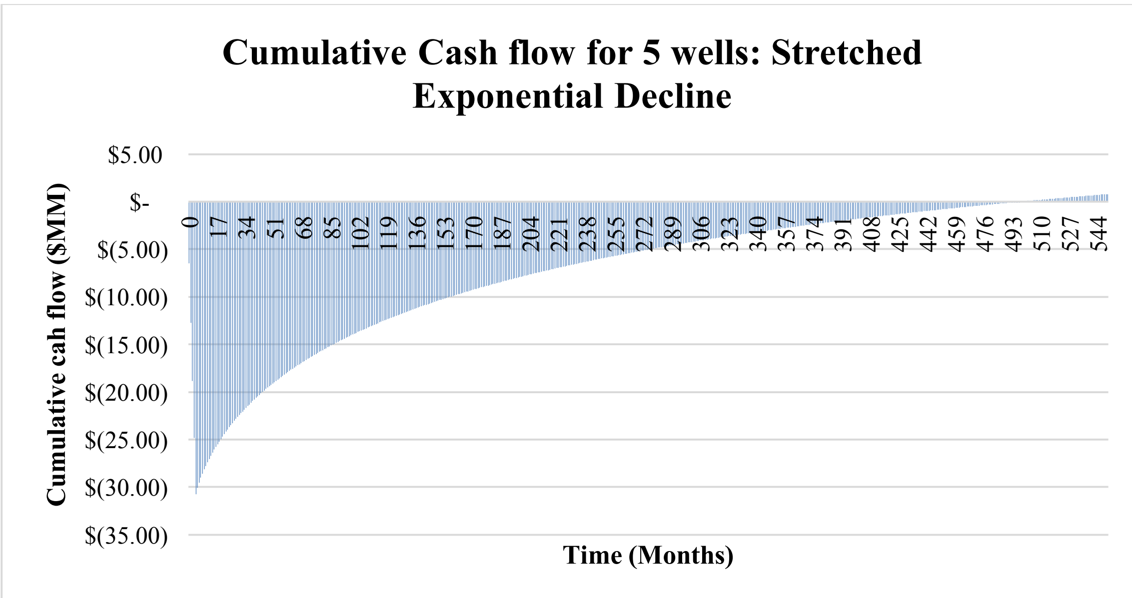

Figure 43: Cumulative Cash flow for 5 wells: Stretched Exponential Decline

The above figure represents a cumulative cash flow per month from 5 wells with a stretched exponential decline in production. The cumulative cash flow turns positive from 498th month onwards, i.e. approximately 41.5 years of payback period. This indicates that 5 shale oil and gas wells with stretched exponential decline curves, pay back the investment of $6.45 MM per well, i.e. the cost of drilling and completion of a well, after a period of 41.5 years. Similar to the payback periods for the three Arps decline curve models, the payback period for stretched exponential decline in production also increases with an increase in the number of wells. Additionally, it is important to note that the payback period (i.e. 41.5 years) from 5 wells with stretched exponential decline in production is significantly greater than those from 5 wells with hyperbolic and harmonic declines in production. This is because the decline rate for stretched exponential decline model is greater than those for hyperbolic and harmonic decline curve models, given the constant drilling rate, oil and gas prices and cost of drilling and completion per well.

In case of 500 wells drilled at the rate of one well per month, cash flow per month with harmonic decline in oil and gas production has been represented in **Figure 44**.

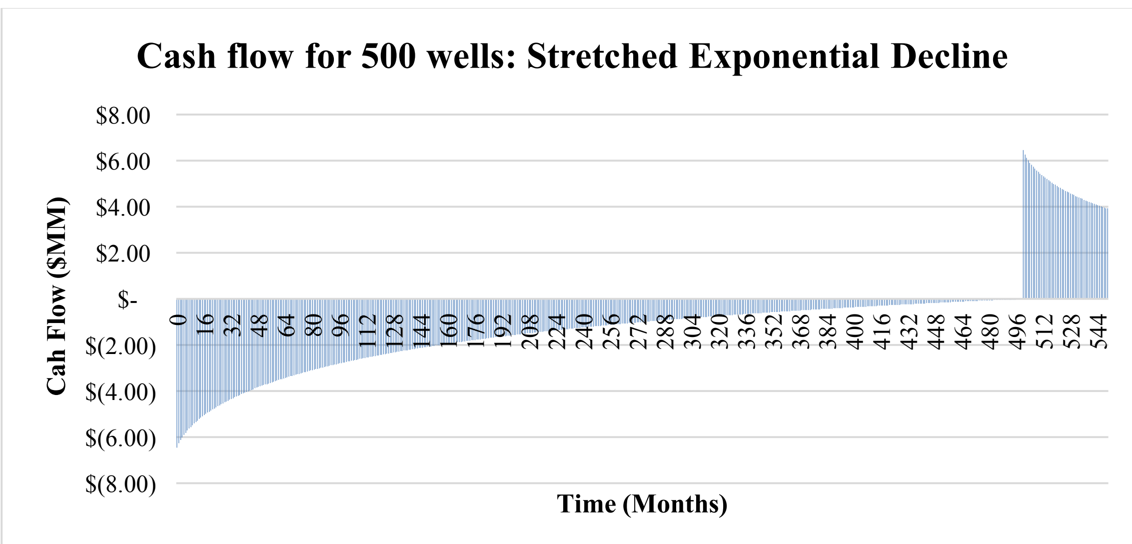

Figure 44: Cash flow for 500 wells: Stretched Exponential Decline

In the above figure, the cash flow per month turns positive 496 months onwards, which coincides with the payback period of one well with stretched exponential decline in production (refer **Figure 33**). Similar to cash flow per month for 500 wells with hyperbolic and harmonic decline in production, the cash flow per month with stretched exponential decline in production increases with time till drilling is stopped at the 500th month. At the 500th month, the oil and gas production and the cash flow reaches its peak (i.e. $6.46MM in **Figure 40**). This peak in cash flow is lower than the peak cash flows from 500 wells with hyperbolic and harmonic decline in production, due to higher stretched exponential decline rate. Additionally, the oil and gas production per month from 500 wells starts to decline from the 501st month onwards (as seen in **Figure 44**). As a result of which the cash flow per month also starts declining from the 501st month onwards (as seen in **Figure 44**).

Figure 45 below represents the cumulative cash flow for 500 wells with stretched exponential decline in oil and gas production.

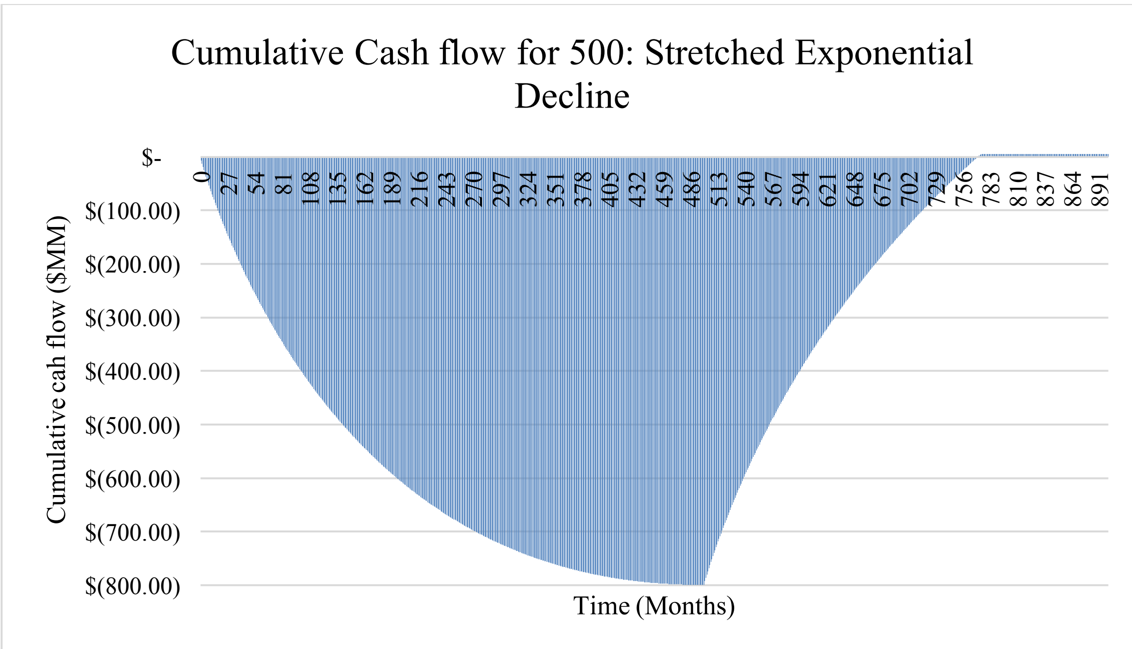

Figure 45: Cumulative Cash flow for 500: Stretched Exponential Decline

From the above figure, we can see that the as the number of wells increase with time the cumulative cash flow is decreasing with time and becomes more negative. However, the cumulative cash flow starts to increase from 500 months onwards when the drilling is stopped. The cumulative cash flow turns positive 771 months onwards, i.e. approximately 64.25 years of payback period. This indicates that 500 shale oil and gas wells with stretched decline curves, pay back the investment of $6.45 MM per well, i.e.

the cost of drilling and completion per well, after a period of 64.25 years. The payback period of 64.25 years is higher as compared to that (i.e. 5.67 years) for 500 wells with hyperbolic decline in production and that (i.e. 5.25 years) for 500 wells with harmonic decline in production. This is because the decline rate for stretched exponential decline model is greater than those for hyperbolic and harmonic decline curve models, given the constant drilling rate, oil and gas prices and cost of drilling and completion per well.

Similar to wells with hyperbolic and harmonic decline in production, as the number of wells increases, the oil and gas production increases, however the cumulative cash flows are relatively lower as compared to those for lesser number of wells. The cumulative cash flows become greater as compared to those for lower number of wells post the payback period. However, post payback period for 500 wells the oil and gas production is larger than that from 1, 2 or 5 wells.

The results of cash flow analysis in this section are summarized in **Table 3 and Table 4**. In case of more than one wells, the drilling rate is assumed to be one well per month. The prices of oil and gas and the cost of drilling and completion of a well is assumed to be constant throughout.

Type of Decline Curve Model	**1 well Payback Period**	**2 wells Payback Period**	**5 wells Payback Period**
Hyperbolic Decline	29 months	29 months	31 months
Harmonic Decline	27 months	28 months	29 months
Exponential Decline	Does not payback	Does not payback	Does not payback
Stretched Exponential Decline	496 months	496 months	498 months

Table 3: Payback Periods as per Decline Curve Models and Number of Wells

The above table summarizes the payback periods for different decline curve models and for increasing number of wells from 1 to 5 wells.

The **Table 4** below represents the time in months when the cash flow per month turns positive for the first time and the payback period, both for N wells.

Type of Decline Curve	First Time Cash Flow Turns Positive	N Wells Payback Period
Hyperbolic Decline	29 months	68 months
Harmonic Decline	27 months	63 months
Exponential Decline	Never	Does not payback
Stretched Exponential Decline	496 months	771 months

Table 4: Cash flow and Payback Period for each Decline Curve and N Wells

In the above figure, N is equal to 500 wells and the rate of drilling is one well per month throughout. Additionally, the oil and gas prices and the cost of drilling and completion of a well is assumed to be constant throughout.

2.2.3 IDENTIFICATION OF STAGES

In the previous section, cash flow analysis for 1, 2, 5 and 500 wells were performed, with a drilling rate of one well per month. However, it is important to identify when to stop drilling before the cash flows from those wells start to drop. An answer to this question will allow the lenders of the shale projects to value the reserves accurately in terms of the actual production economically feasible from the same reserves. Since at any of these stages, drilling may be stopped by the borrower, therefore identification of these stages and the level of risk associated with each stage is crucial during the valuation of the shale reserves.

In this section, we will identify stages at which the percentage change in shale oil and gas production and corresponding revenue per month is less than +1% and when the change is negative. Additionally, we will also identify stages at which the percentage change in the shale oil and gas production and the corresponding revenue per annum is less than +5% and when the change in the same is negative. The percentage change values of +1% and +5% have been assumed out of experience. A percentage change of less than +1% per month and +5% per annum has been assumed to be the minimum amount of growth required in shale oil and gas production and the corresponding revenues. A negative percentage change is the decrease in shale oil and gas production and corresponding revenue.

The shale oil and gas production forecast model and the cash flow model discussed in the previous sections have been used for the identification of stages in this section. Percentage change in shale oil and gas production and revenue for the Arps decline in production models and stretched exponential decline in production model has been presented in this section. The shale oil and gas production forecast model assumes a constant drilling rate of one well per month and the cash flow model assumes constant oil and gas prices and cost of drilling and completion. Therefore, the percentage change in shale oil and gas production and the percentage change in revenue are equal for a given decline in production model.

Figure 46 represents the percentage change in shale oil and gas production and revenue per month for hyperbolic decline in production from 500 wells.

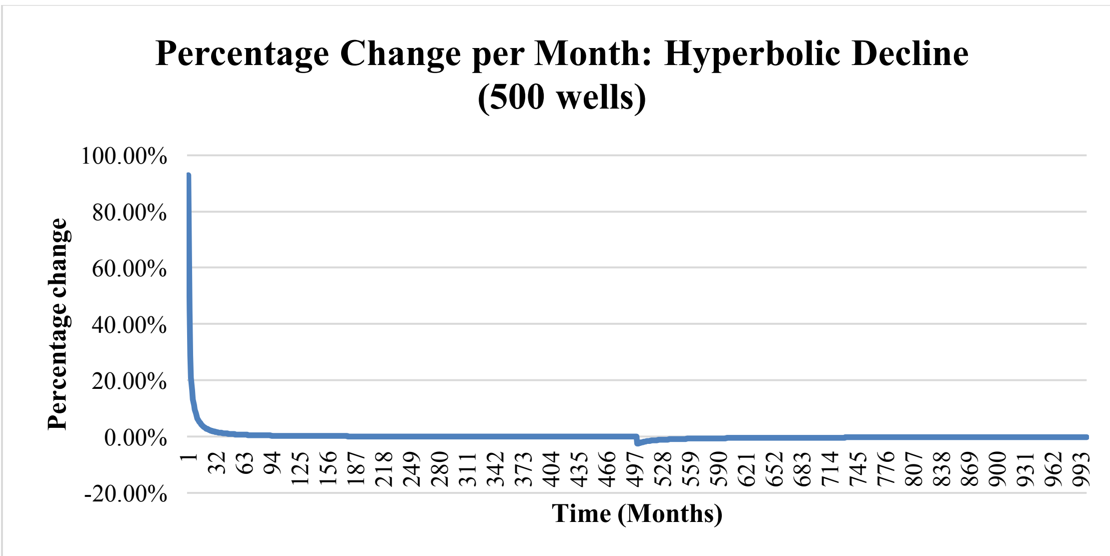

Figure 46: Percentage Change per Month for 500 wells: Hyperbolic Decline

The above figure represents percentage change per month in shale oil and gas production and revenue per month for 500 wells with hyperbolic decline in production.

The percentage change decreases as more wells are drilled with time and turns negative post 500 months when drilling is stopped. This is due to the decline in production of shale oil and gas per well per month. The production from the new well, first compensates for the decline in production from the previous well/wells and then adds onto to the production from previous well/wells. This leads to a decrease in the percentage growth of shale oil and gas production and the corresponding revenue per month. However, the percentage change turns negative i.e. the shale oil and gas production and the corresponding revenues start declining as a whole. This is because when drilling is stopped, there is no new shale oil and gas production to compensate for the decline in shale oil and gas production per well per month.

Figure 47 below, represents the percentage change per month for a hyperbolic decline in production for 500 wells on a logarithmic scale to better understand the relationship between them.

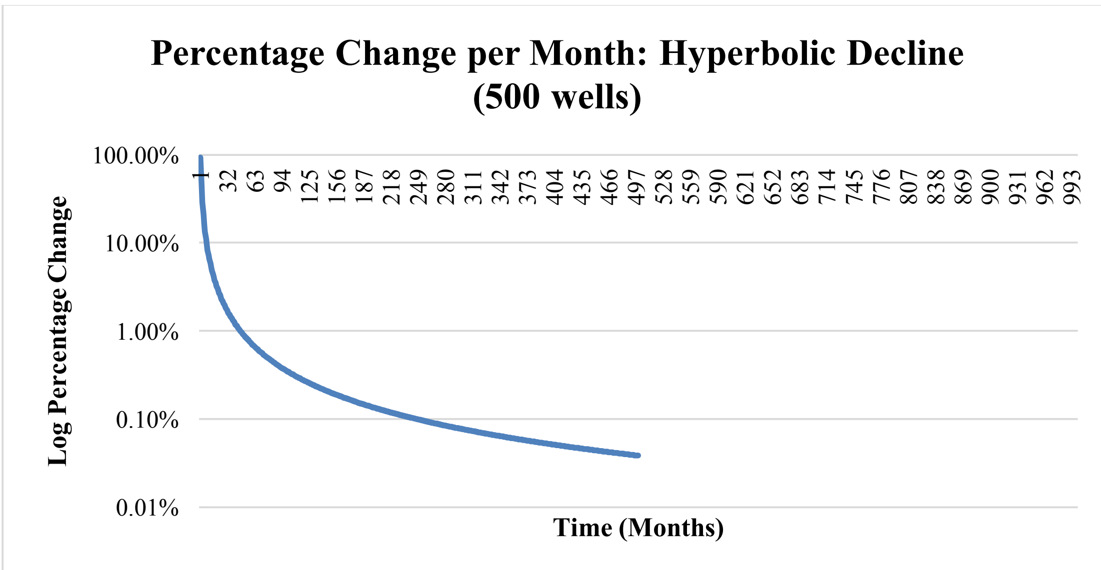

Figure 47: Log Percentage Change per Month for 500 Wells: Hyperbolic Decline

From **Figure 47** above we can see that the percentage change in shale oil and gas production and revenue per month turns less than +1% from 48 months onwards and turns negative post 500 months, given a drilling rate of one well per month (negative values cannot be represented in the logarithmic graph).

Figure 48 represents the percentage change in shale oil and gas production and revenue per annum for hyperbolic decline in production from 500 wells.

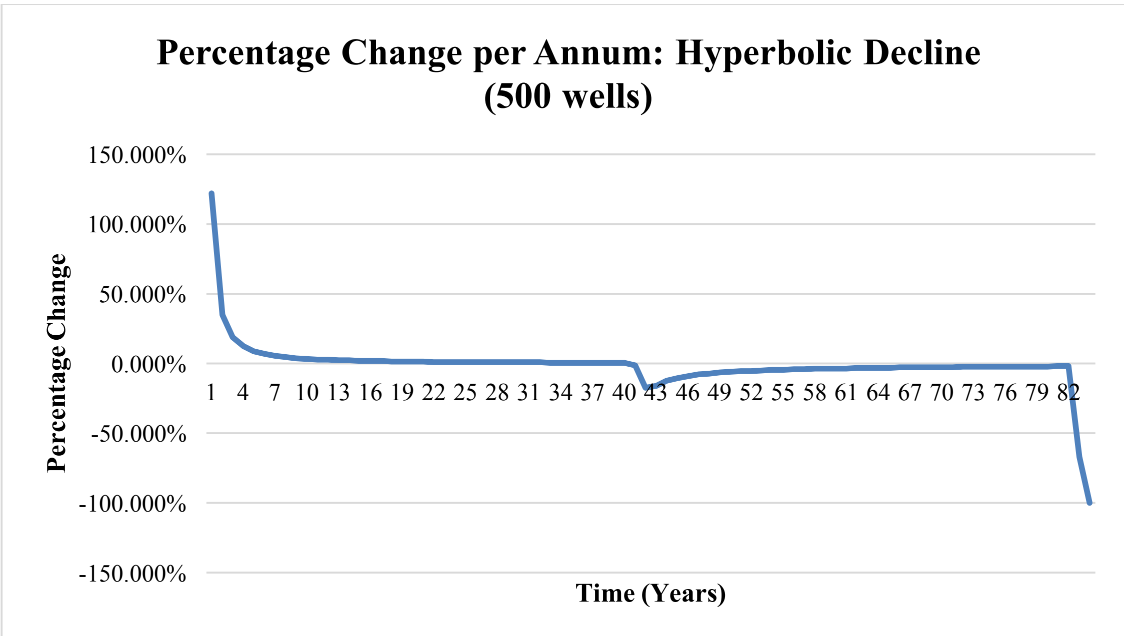

Figure 48: Percentage Change per Annum for 500 Wells: Hyperbolic Decline

From the above figure, we can see that the percentage change per annum in shale oil and gas production and revenue is decreasing as more number of wells are drilled with time. The same percentage change turns negative when drilling is stopped at 500 wells i.e. 500 months or 41.66 years.

Figure 49 below, represents the percentage change per annum for a hyperbolic decline in production for 500 wells on a logarithmic scale to better understand the relationship between them.

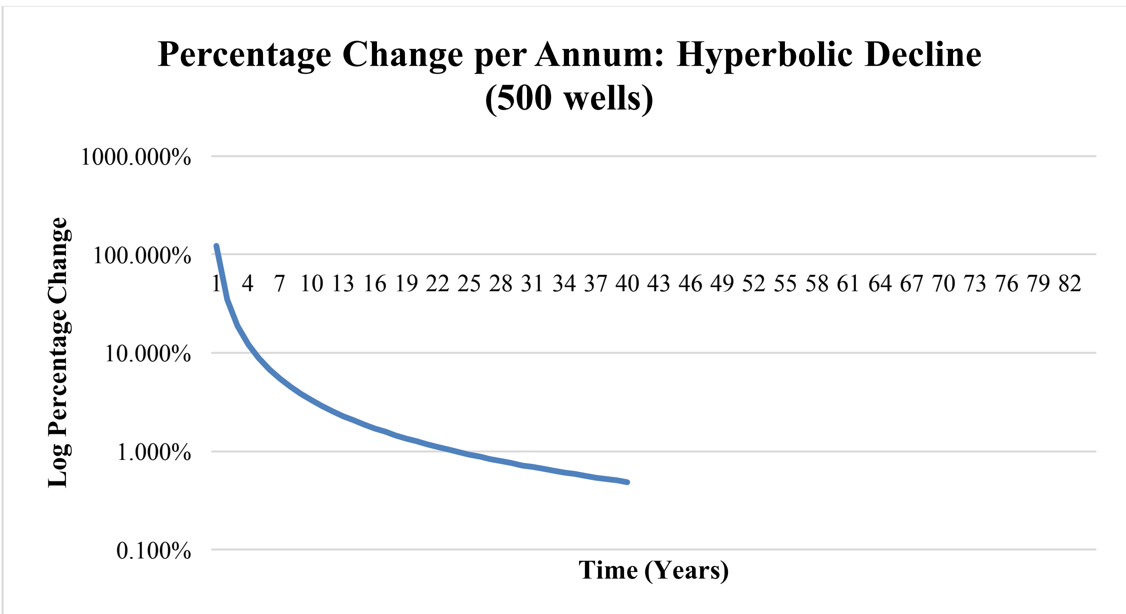

Figure 49: Log Percentage Change per Annum for 500 Wells: Hyperbolic Decline

From **Figure 49** above, we can see that the percentage change in shale oil and gas production and revenue per annum is less than +5% from 9 years onwards and turns negative from 41.66 years onwards (i.e. when drilling is stopped), given a drilling rate of one well per month (negative values cannot be represented in a logarithmic graph).

Similarly, **Figure 50** represents the percentage change in shale oil and gas production and revenue per month for harmonic decline in production from 500 wells.

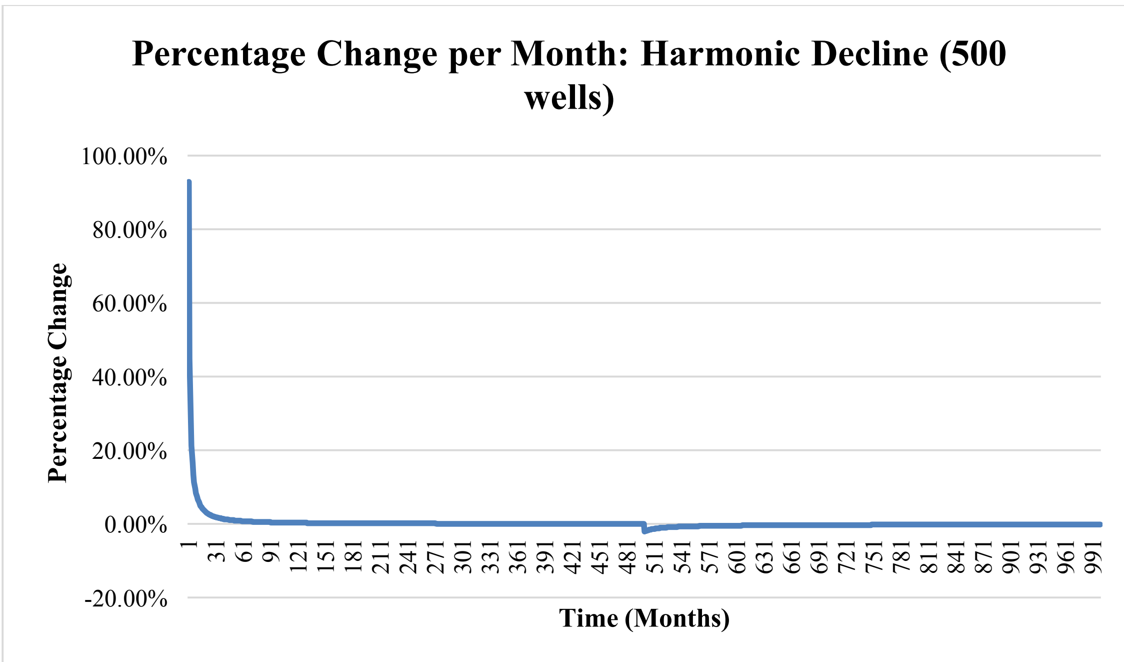

Figure 50: Percentage Change per Month for 500 Wells: Harmonic Decline

The above figure represents percentage change per month in shale oil and gas production and revenue per month for 500 wells with harmonic decline in production. Similar to hyperbolic decline in production, the percentage change decreases as more wells are drilled with time and turns negative post 500 months when drilling is stopped.

Figure 51 below, represents the percentage change per month for a harmonic decline in production for 500 wells on a logarithmic scale to better understand the relationship between them.

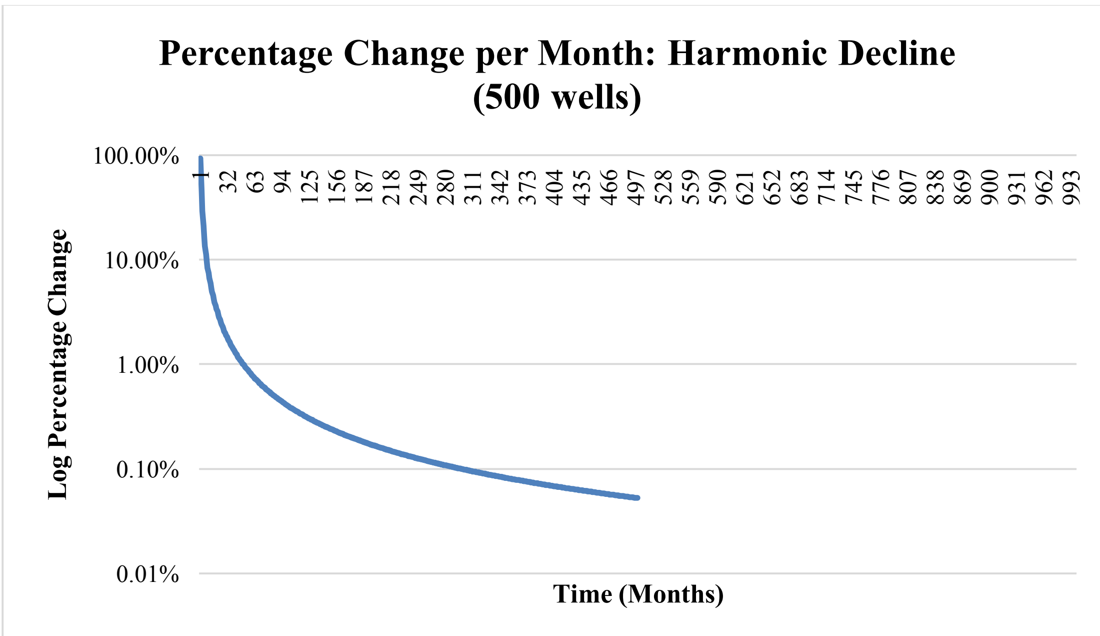

Figure 51: Log Percentage Change per Month for 500 Wells: Harmonic Decline

From **Figure 51** above we can see that the percentage change in shale oil and gas production and revenue per month becomes less than +1% from 51 months onwards and turns negative post 500 months, given a drilling rate of one well per month (negative values cannot be represented in the logarithmic graph). It is important to note that the percentage change in shale oil and gas production and revenue per month for harmonic decline in production becomes less than +1% later (51 months) than the same percentage change die to hyperbolic (48 months) decline in production. This is due to a lower harmonic decline rate as compared to the hyperbolic decline rate.

Figure 52 represents the percentage change in shale oil and gas production and revenue per annum for harmonic decline in production from 500 wells.

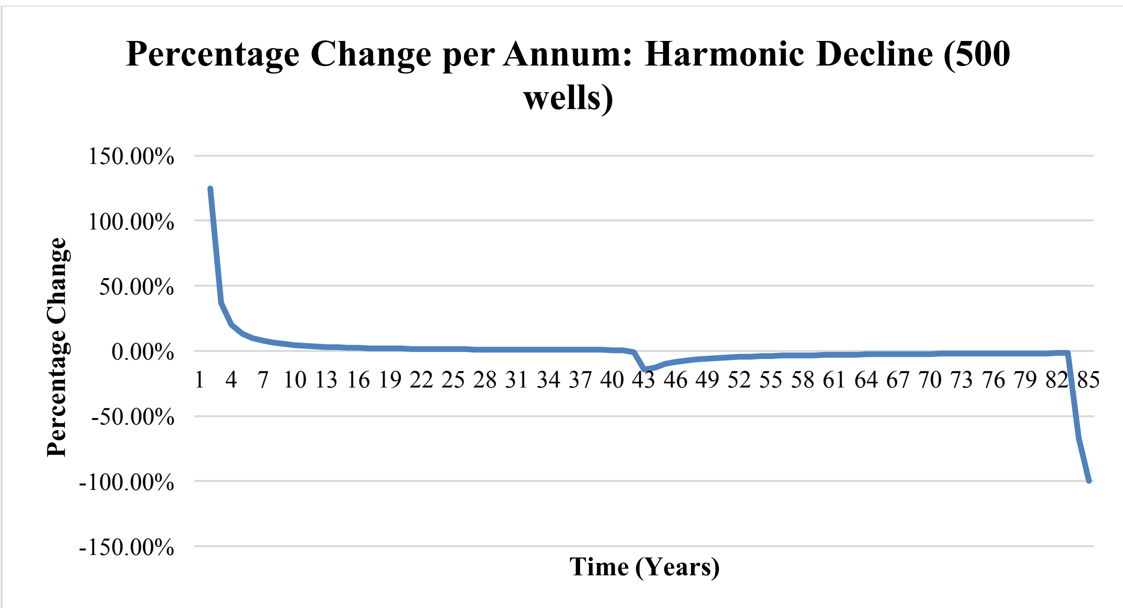

Figure 52: Percentage Change per Annum for 500 Wells: Harmonic Decline

From the above figure, we can see that the percentage change per annum in shale oil and gas production and revenue is decreasing as more number of wells are drilled with time. The same percentage change turns negative when drilling is stopped at 500 wells i.e. 500 months or 41.66 years.

Figure 53 below, represents the percentage change per annum for a harmonic decline in production for 500 wells on a logarithmic scale to better understand the relationship between them.

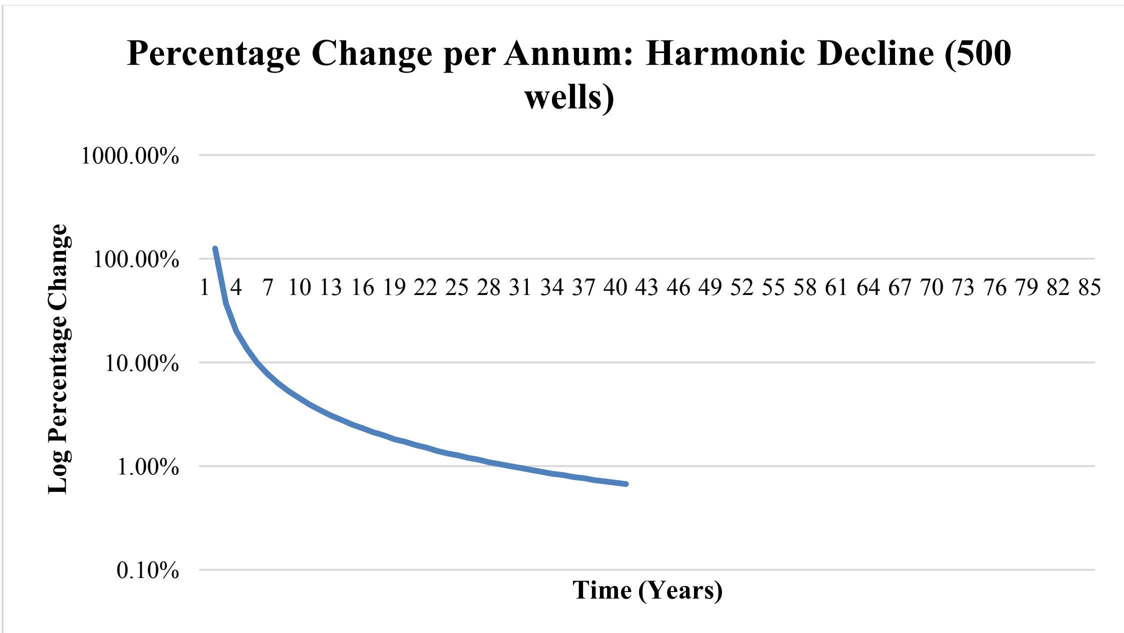

Figure 53: Log Percentage Change per Annum for 500 Wells: Harmonic Decline

From **Figure 53** above, we can see that the percentage change in shale oil and gas production and revenue per annum is less than +5% from 10 years onwards and turns negative from 41.66 years onwards (i.e. when drilling is stopped), given a drilling rate of one well per month (negative values cannot be represented in a logarithmic graph).

Similarly, **Figure 54** represents the percentage change in shale oil and gas production and revenue per month for stretched exponential decline in production from 500 wells.

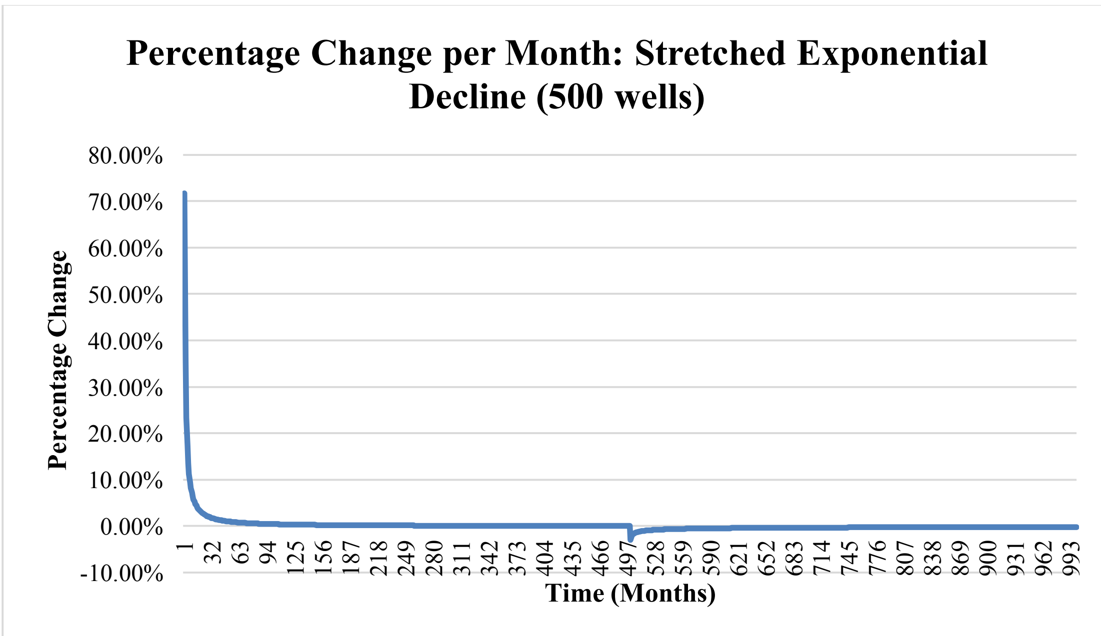

Figure 54: Percentage Change per Month for 500 Wells: Stretched Exponential Decline

The above figure represents percentage change per month in shale oil and gas production and revenue per month for 500 wells with stretched exponential decline in production. Similar to hyperbolic and harmonic decline in production, the percentage change decreases as more wells are drilled with time and turns negative post 500 months when drilling is stopped.

Figure 55 below, represents the percentage change per month for a stretched exponential decline in production for 500 wells on a logarithmic scale to better understand the relationship between them.

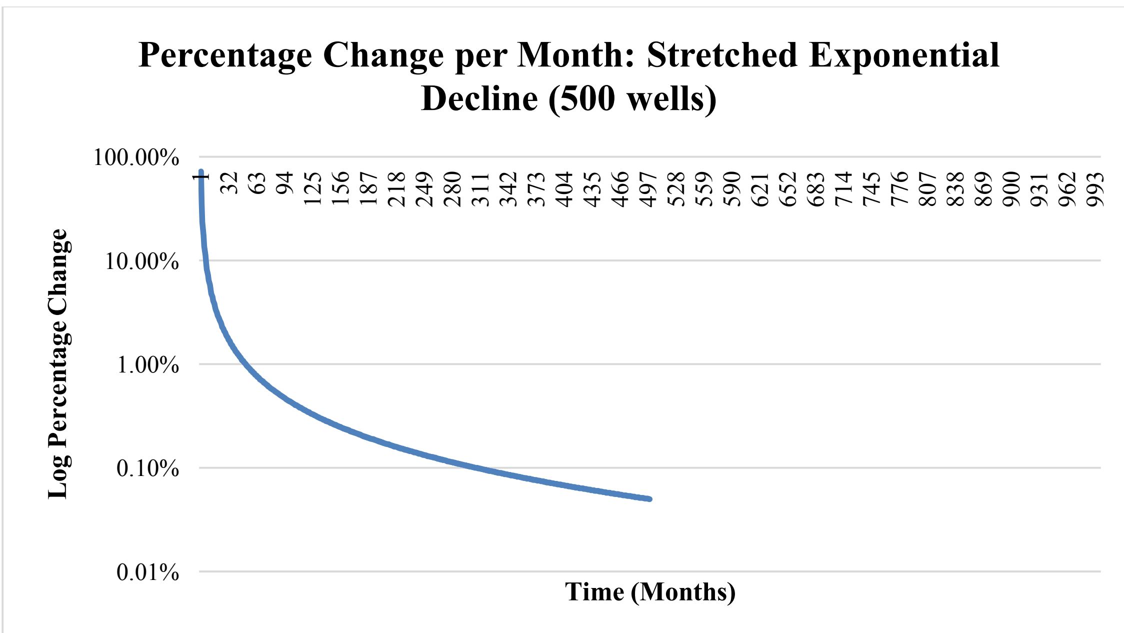

Figure 55: Log Percentage Change per Month for 500 Wells: Stretched Exponential Decline

From **Figure 55** above we can see that the percentage change in shale oil and gas production and revenue per month becomes less than +1% from 52 months onwards and turns negative post 500 months, given a drilling rate of one well per month (negative values cannot be represented in the logarithmic graph). It is important to note that the percentage change in shale oil and gas production and revenue per month for stretched exponential decline in production becomes less than +1% later (52 months) than the same percentage change due to hyperbolic (48 months) and harmonic (51 months) decline in production.

Figure 56 represents the percentage change in shale oil and gas production and revenue per annum for stretched exponential decline in production from 500 wells.

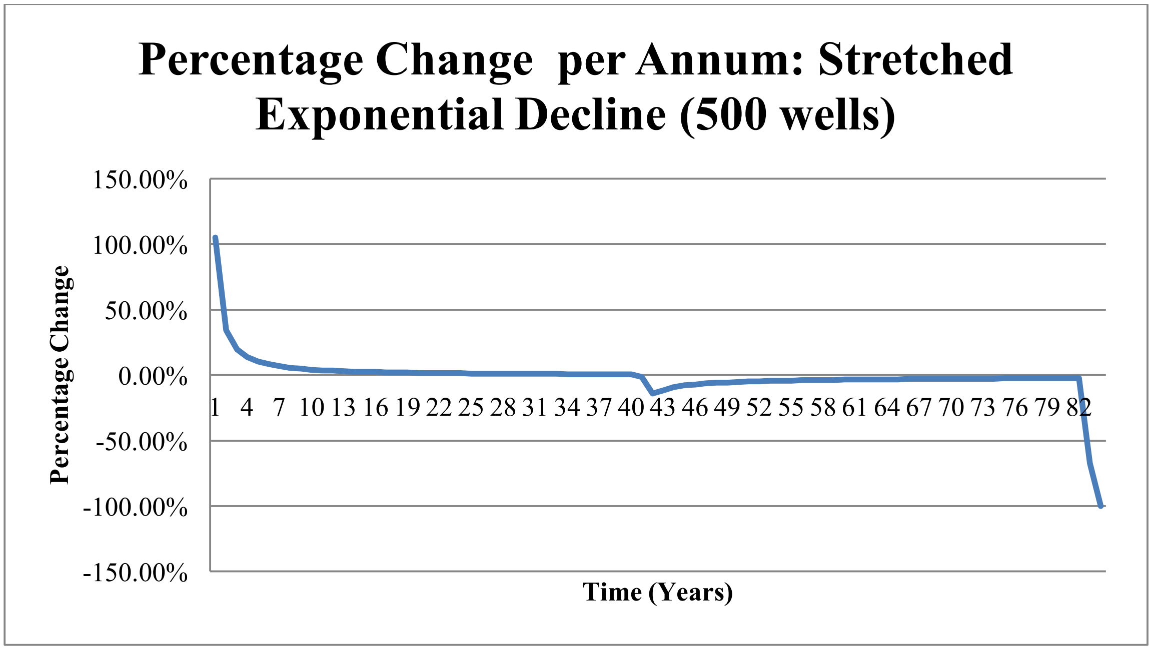

Figure 56: Percentage Change per Annum for 500 Wells: Stretched Exponential Decline

From the above figure, we can see that the percentage change per annum in shale oil and gas production and revenue is decreasing as more number of wells are drilled with time. The same percentage change turns negative when drilling is stopped at 500 wells i.e. 500 months or 41.66 years, similar to the percentage changes for hyperbolic and harmonic decline in production.

Figure 57 below, represents the percentage change per annum for a stretched exponential decline in production for 500 wells on a logarithmic scale to better understand the relationship between them.

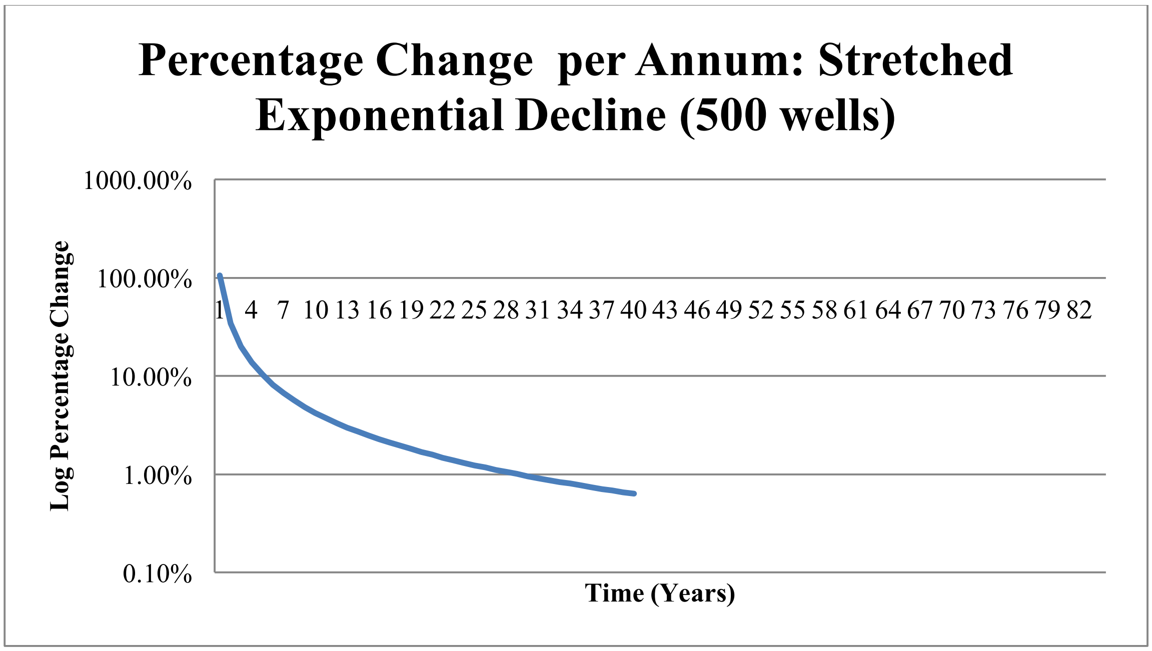

Figure 57: Log Percentage Change per Annum for 500 Wells: Stretched Exponential Decline

From **Figure 57** above, we can see that the percentage change in shale oil and gas production and revenue per annum is less than +5% from 10 years onwards and turns negative from 41.66 years onwards (i.e. when drilling is stopped), given a drilling rate of one well per month (negative values cannot be represented in a logarithmic graph).

The percentage changes in shale oil and gas production and revenue per month and per annum have been summarized in **Table 5** and **Table 6.**

Percentage Change per Month in Oil and Gas Production and Revenue		
Type of Decline Model	**%Change: < +1%**	**% Change: Negative**
Hyperbolic Decline	48 months onwards	500 months onwards
Harmonic Decline	51 months onwards	500 months onwards
Stretched Exponential Decline	52 months onwards	500 months onwards

Table 5: Percentage Change per Month in Oil and Gas Production and Revenue

The above table summarizes two stages for every decline in production model when the percentage change in shale oil and gas production and revenue per month becomes less than +1% and when it turns negative.

Table 6 below summarizes two stages for every decline in production model when the percentage change in shale oil and gas production and revenue per annum becomes less than +5% and when it turns negative.

Percentage Change per Annum in Oil and Gas Production and Revenue		
Type of Decline Model	**%Change: < +5%**	**% Change: Negative**
Hyperbolic Decline	9 years onwards	41.66 years onwards
Harmonic Decline	10 years onwards	41.66 years onwards
Stretched Exponential Decline	10 years onwards	41.66 years onwards

Table 6: Percentage Change per Annum in Oil and Gas Production and Revenue

The percentage changes in shale oil and gas production and their corresponding revenues presented in this section have helped in identifying stages at which the percentage growth is not significant enough to continue drilling at the rate of one well per month for different production decline models namely, hyperbolic, harmonic and stretched exponential decline models. In addition to the results in the above table indicate that the shale oil and gas production and the corresponding revenues per month and per annum start declining from the very next month/year when drilling is stopped. Therefore, in order to maintain a certain level of shale oil and gas production and revenue, it is important to determine “when to stop drilling?”. The answer to this question not only depends on the stages identified earlier in this section, but also depends on the percentage growth in revenue per the amount of investment. The next section provides a detailed revenue growth per investment analysis for drilling shale oil and gas wells.

2.2.4 REVENUE GROWTH PER INVESTMENT ANALYSIS

In the previous section, we discussed how the stages identified based on the percentage growth in the shale oil and gas production and revenue affects the decision of when to stop drilling. This section looks into the other factor that affects this decision, i.e. the revenue growth per investment. The revenue growth per investment analysis will include the following:

a) Revenue growth per investment per month for 500 wells (drill one well per month)
b) Cumulative revenue over N months per cumulative investment over N months.
c) Revenue growth per investment per year for 500 wells (drill 12 wells per year).
d) Cumulative revenue growth over N years per cumulative investment over N years.

This section will present revenue growth analysis as stated above, for three types of production decline models namely, hyperbolic, harmonic, and stretched exponential decline.

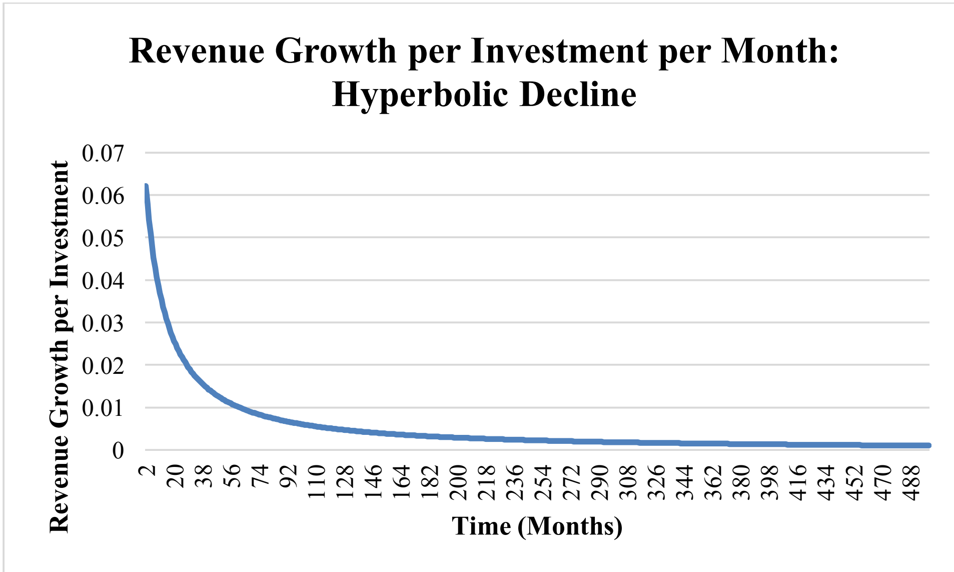

Figure 58: Revenue Growth per Investment per Month: Hyperbolic Decline

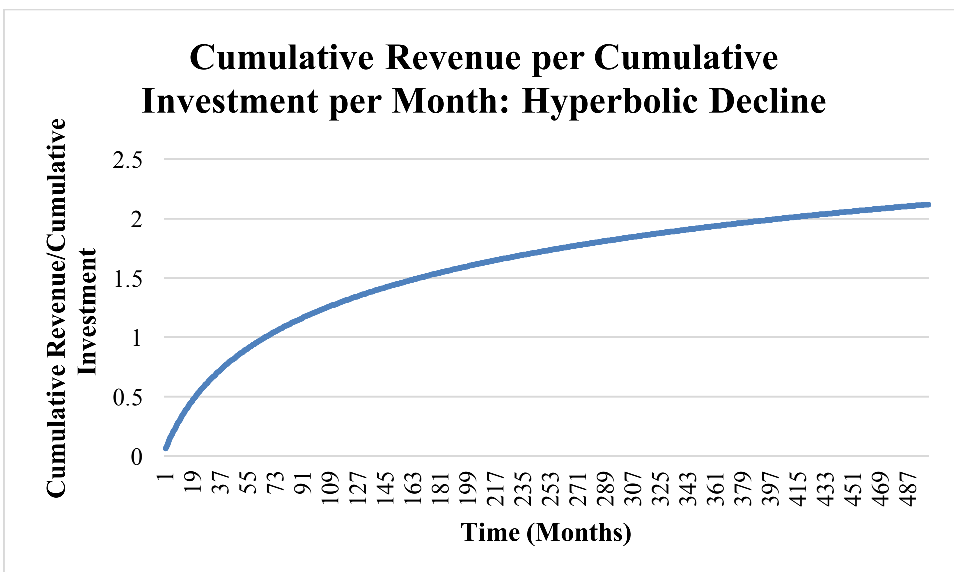

Figure 59: Cumulative Revenue per Cumulative Investment per Month: Hyperbolic Decline

In **Figure 58,** the ratio of revenue growth to investment per month is never greater than or equal to one. This indicates that the capital invested to produce growth in revenue, is not fully compensated by the revenue growth due to the decline in production from the previous wells. The ratio of revenue growth per month to investment per month never turns greater than 1 (highest value of the ratio is 0.06), given 500 wells are drilled at the rate of one well per month with a hyperbolic decline in production. Therefore, there is no economic value addition due to drilling of 1 additional per month with hyperbolic decline in production.

In **Figure 59,** the ratio of the cumulative revenue per month to the cumulative investment per month increases with time and is more than 1, from 66 months onwards. Post 66 months, the ratio of cumulative revenue per month to the cumulative investment per month is greater than 1 and is increasing, given 500 wells are drilled at the rate of one well per month with a hyperbolic decline in production. This indicates that it takes 66 months of cumulative revenue to compensate for the investment of first 66 wells drilled at the rate of 1 well per month with hyperbolic decline in production.

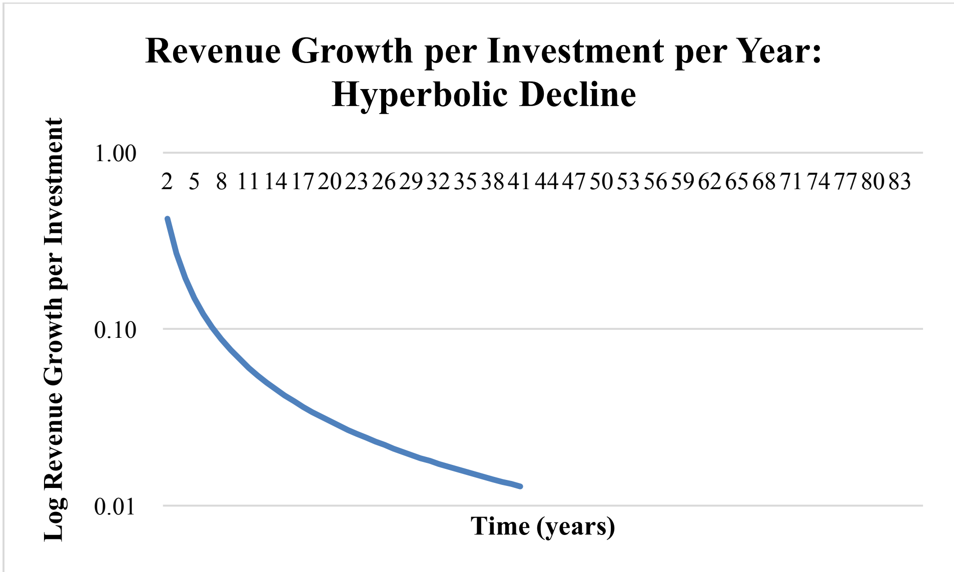

Figure 60: Revenue Growth per Investment per Year: Hyperbolic Decline

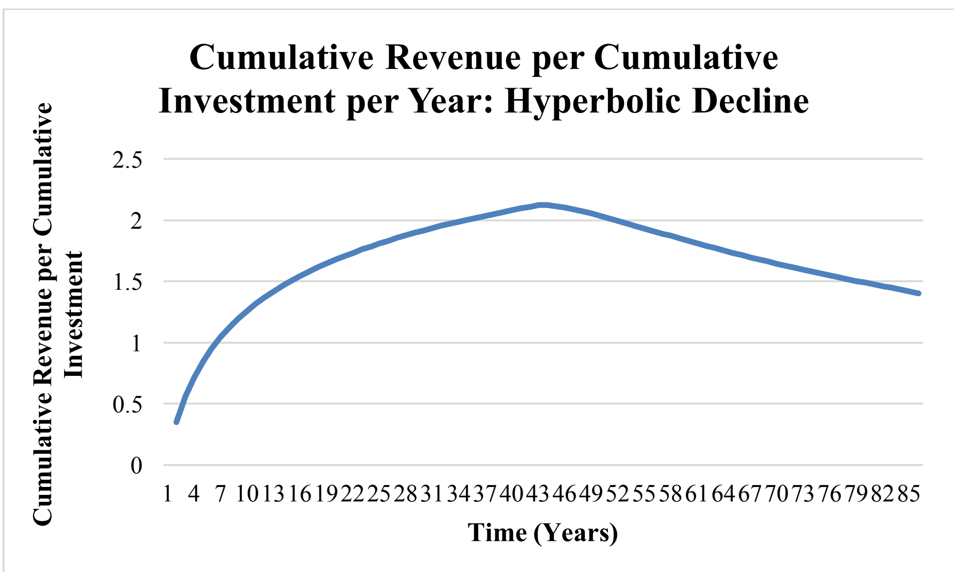

Figure 61: Cumulative Revenue per Cumulative Investment per Year: Hyperbolic Decline

In **Figure 60,** the ratio of revenue growth per year to the investment per year is never greater than 1 and is declining with time. This indicates that the capital invested to produce growth in revenue, is not fully compensated by the revenue growth due to the decline in production from the previous wells. The ratio of revenue growth per year to investment per year never turns greater than 1 (highest value of the ratio is 0.42), given 500 wells are drilled at the rate of one well per month with a hyperbolic decline in production. Therefore, there is no economic value addition due to drilling of additional 12 wells per year with hyperbolic decline in production.

In **Figure 61,** the ratio of the cumulative revenue per year to the cumulative investment per year increases with time and is more than 1, from 6 years onwards. Post 6 years, the ratio of cumulative revenue per year to the cumulative investment per year is greater than 1 and starts to decline post 43 years, given 500 wells are drilled at the rate of 12 wells per year with a hyperbolic decline in production. This indicates that it takes 6 years of cumulative revenue to compensate for the investment of first 72 wells drilled at the rate of 12 wells per year with hyperbolic decline in production.

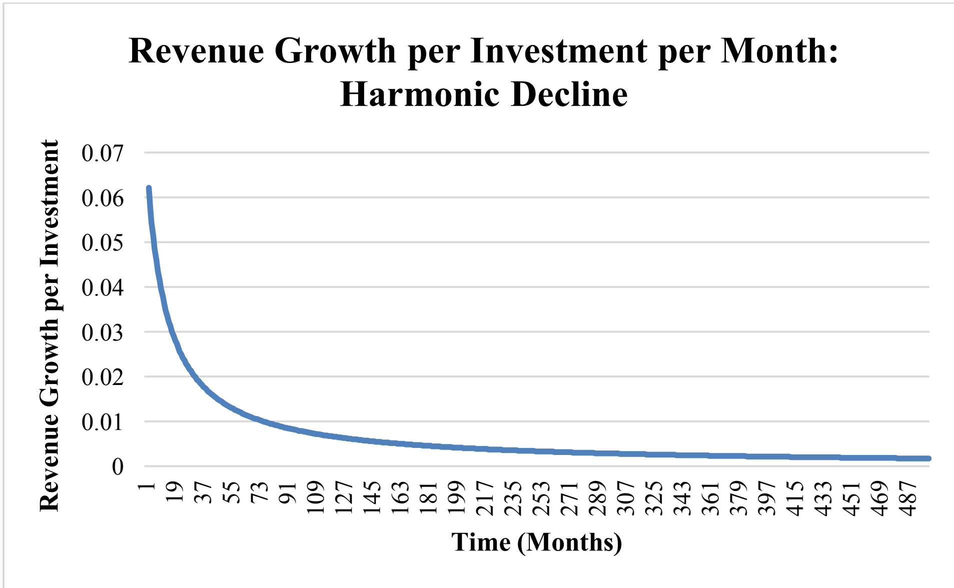

Figure 62: Revenue Growth per Investment per Month: Harmonic Decline

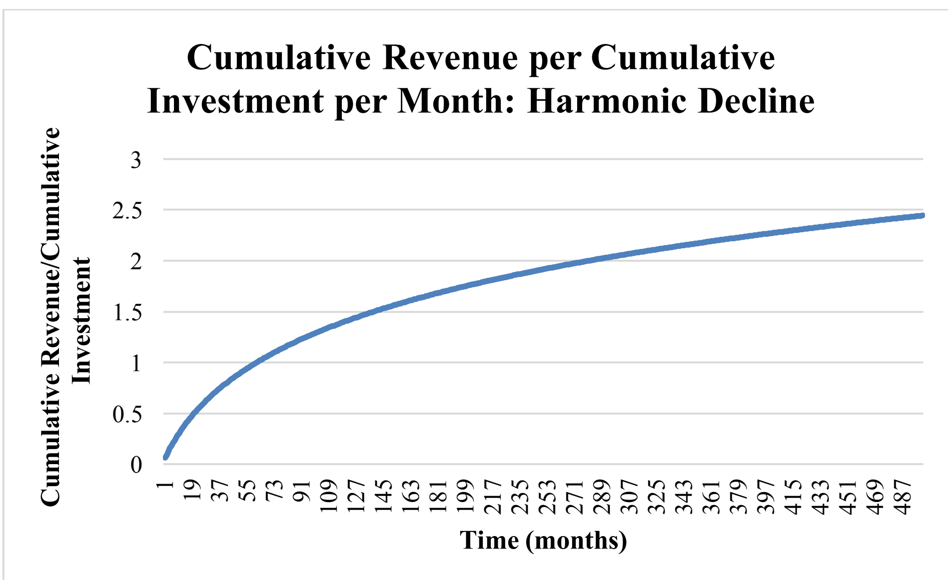

Figure 63: Cumulative Revenue per Cumulative Investment per Month: Harmonic Decline

In **Figure 62,** the ratio of revenue growth to investment per month is never greater than or equal to one. This indicates that the capital invested to produce growth in revenue, is not fully compensated by the revenue growth due to the decline in production from the previous wells. The ratio of revenue growth per month to investment per month never turns greater than 1 (highest value of the ratio is 0.062), given 500 wells are drilled at the rate of one well per month with a harmonic decline in production. Therefore, there is no economic value addition due to drilling of 1 additional per month with harmonic decline in production.

In **Figure 63,** the ratio of the cumulative revenue per month to the cumulative investment per month increases with time and is more than 1, from 62 months onwards. Post 62 months, the ratio of cumulative revenue per month to the cumulative investment per month is greater than 1 and is increasing, given 500 wells are drilled at the rate of one well per month with a harmonic decline in production. This indicates that it takes 62 months of cumulative revenue to compensate for the investment of first 62 wells drilled at the rate of 1 well per month with harmonic decline in production.

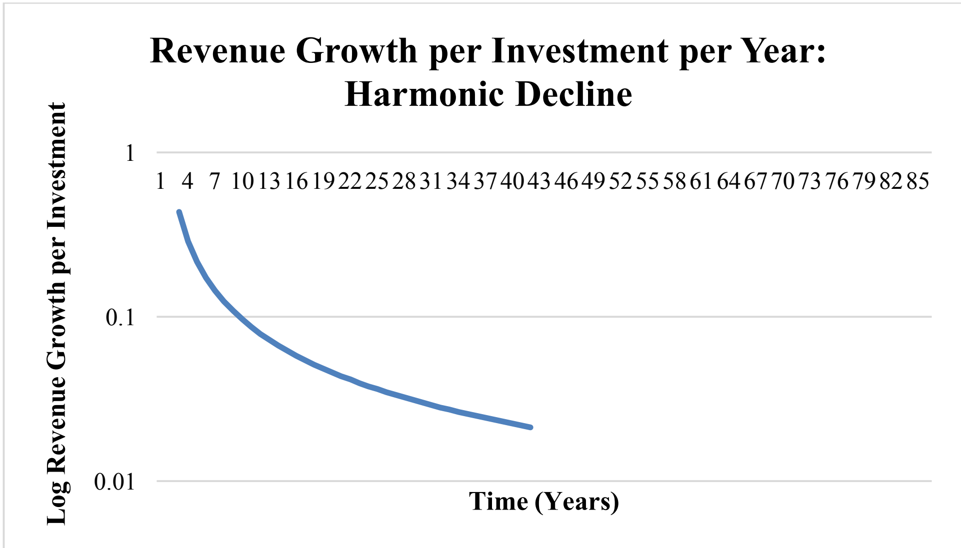

Figure 64: Revenue Growth per Investment per Year: Harmonic Decline

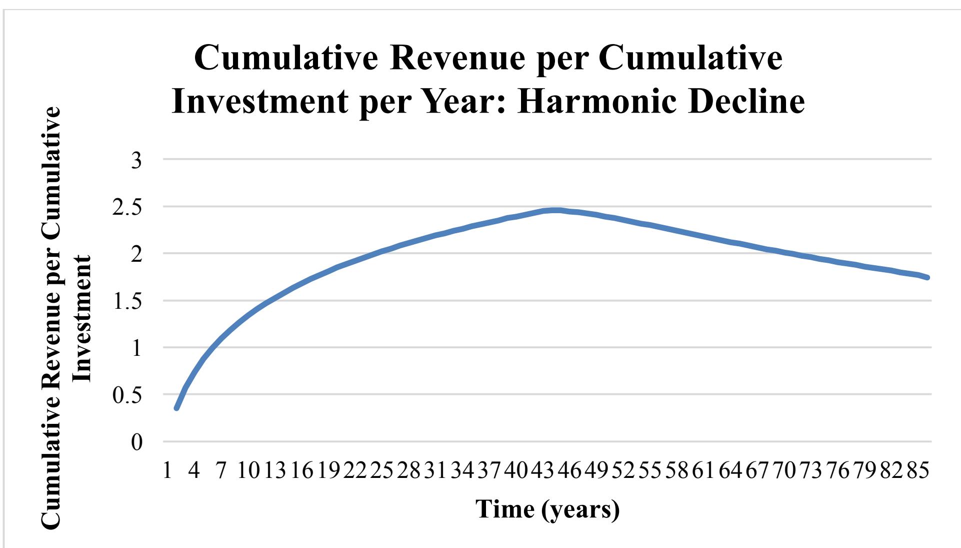

Figure 65: Cumulative Revenue per Cumulative Investment per Year: Harmonic Decline

In **Figure 64,** the ratio of revenue growth per year to the investment per year is never greater than 1 and is declining with time. This indicates that the capital invested to produce growth in revenue, is not fully compensated by the revenue growth due to the decline in production from the previous wells. The ratio of revenue growth per year to investment per year never turns greater than 1 (highest value of the ratio is 0.44), given 500 wells are drilled at the rate of one well per month with a harmonic decline in production. Therefore, there is no economic value addition due to drilling of additional 12 wells per year with harmonic decline in production.

In **Figure 65,** the ratio of the cumulative revenue per year to the cumulative investment per year increases with time and is more than 1, from 6 years onwards. Post 6 years, the ratio of cumulative revenue per year to the cumulative investment per year is greater than 1 and starts to decline post 43 years, given 500 wells are drilled at the rate of 12 wells per year with a harmonic decline in production. This indicates that it takes 6 years of cumulative revenue to compensate for the investment of first 72 wells drilled at the rate of 12 wells per year with harmonic decline in production.

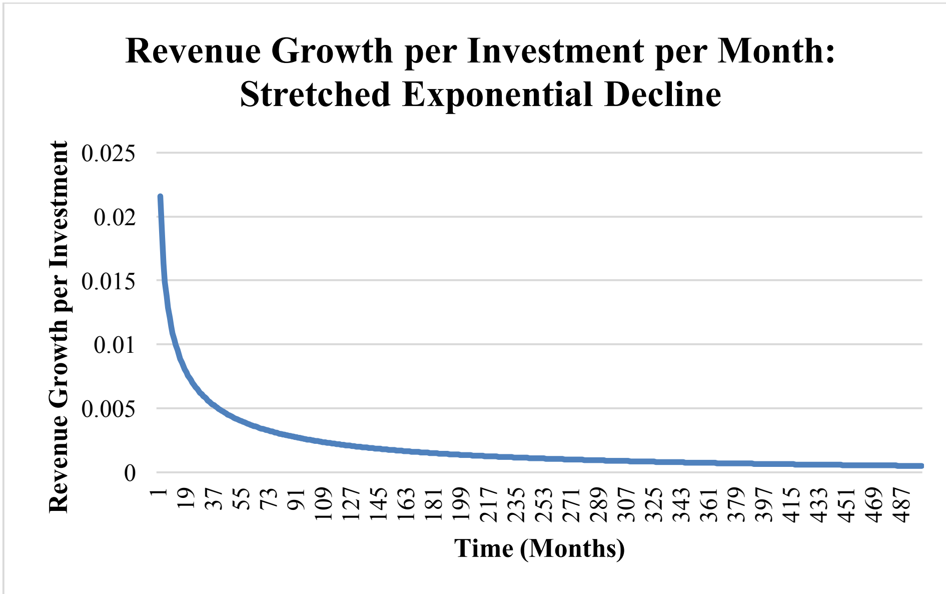

Figure 66: Revenue Growth per Investment per Month: Stretched Exponential Decline

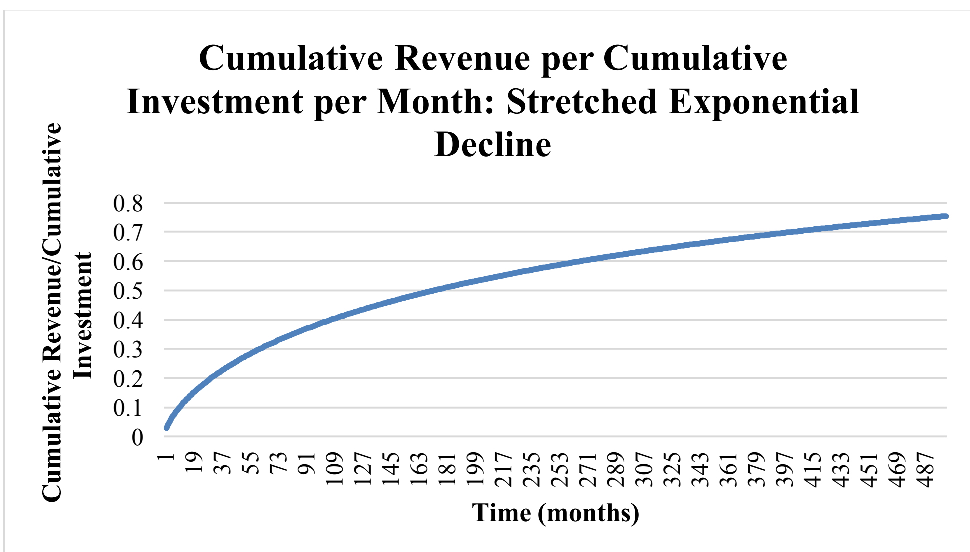

Figure 67: Cumulative Revenue per Cumulative Investment per Year: Stretched Exponential Decline

In **Figure 66,** the ratio of revenue growth to investment per month is never greater than or equal to one. This indicates that the capital invested to produce growth in revenue, is not fully compensated by the revenue growth due to the decline in production from the previous wells. The ratio of revenue growth per month to investment per month never turns greater than 1 (highest value of the ratio is 0.0215), given 500 wells are drilled at the rate of one well per month with a stretched exponential decline in production. Therefore, there is no economic value addition due to drilling of 1 additional per month with stretched exponential decline in production.

In **Figure 67,** the ratio of the cumulative revenue per month to the cumulative investment per month increases with time but is never more than 1. (highest value of the ratio is 0.0754). This indicates that cumulative revenue never compensates for the cumulative investment of 500 wells drilled at the rate of 1 well per month with stretched exponential decline in production.

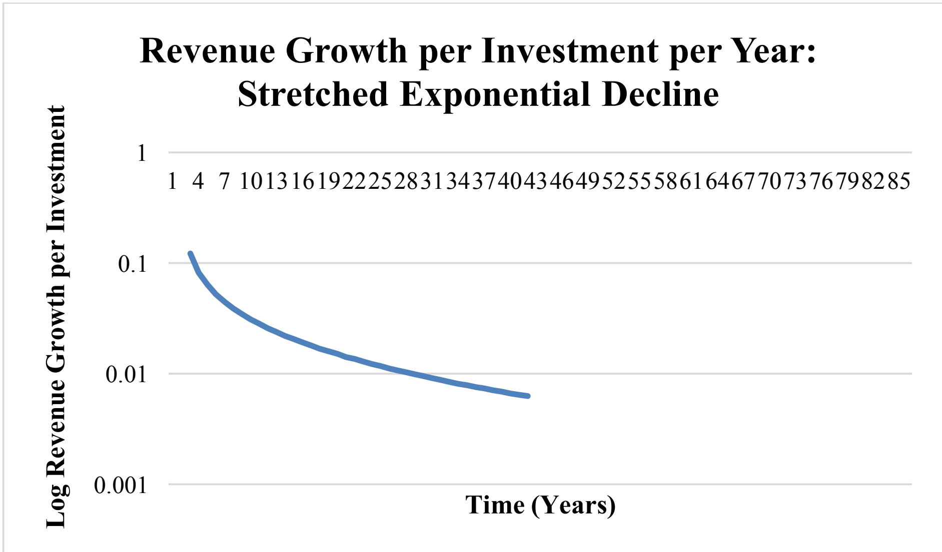

Figure 68: Revenue Growth per Investment per Year: Stretched Exponential Decline

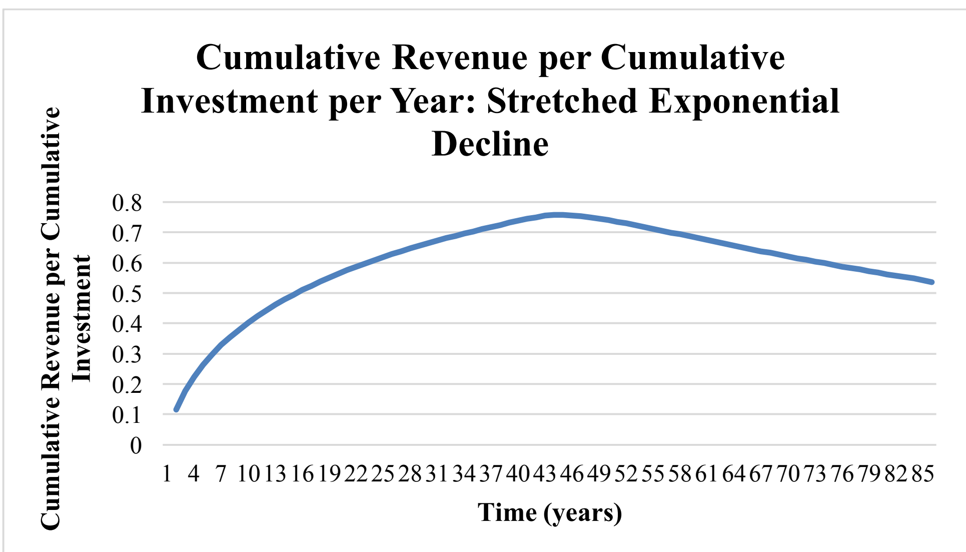

Figure 69: Cumulative Revenue per Cumulative Investment per Year: Stretched Exponential Decline

In **Figure 68,** the ratio of revenue growth per year to the investment per year is never greater than 1 and is declining with time. This indicates that the capital invested to produce growth in revenue, is not fully compensated by the revenue growth due to the decline in production from the previous wells. The ratio of revenue growth per year to investment per year never turns greater than 1 (highest value of the ratio is 0.12), given 500 wells are drilled at the rate of one well per month with a stretched exponential decline in production. Therefore, there is no economic value addition due to drilling of additional 12 wells per year with stretched exponential decline in production.

In **Figure 69,** the ratio of the cumulative revenue per year to the cumulative investment per year increases with time peaks at the value of 0.757 and then starts to decline. However, this ratio is never more than 1. This indicates that cumulative revenue never compensates for the cumulative investment of 500 wells drilled at the rate of 1 well per year with stretched exponential decline in production.

The results of the revenue growth per investment analysis for three decline curve models are summarized in **Table 7, Table 8, Table 9 and Table 10.**

Revenue Growth per Investment per Month		**Formula**
Type of Curve	**Ratio less than 1**	(Prod.$_{(n+1)}$ - Prod.$_{(n)}$)*Price/Cost of Drilling and completion per well n = number of months
Hyperbolic Decline	Always	
Harmonic Decline	Always	
Stretched Exponential Decline	Always	

Table 7: Revenue Growth per Investment per Month

Cumulative Revenue per Cumulative Investment per Month		**Formula**
Type of Curve	**Ratio greater than 1**	∑ (Prod.$_{(n)}$*Price)/ ∑Cost of Drilling and completion over n months n = number of months
Hyperbolic Decline	66 months onwards	
Harmonic Decline	62 months onwards	
Stretched Exponential Decline	106 months onwards	

Table 8: Cumulative Revenue per Cumulative Investment per Month

Revenue Growth per Investment per Year		Formula
Type of Curve	**Ratio Less than 1**	(Prod.$_{(n+1)}$ - Prod.$_{(n)}$)*Price/Cost of Drilling and completion per annum n = number of years
Hyperbolic Decline	Always	
Harmonic Decline	Always	
Stretched Exponential Decline	Always	

Table 9: Revenue Growth per Investment per Year

Cumulative Revenue per Cumulative Investment per Year		Formula
Type of Curve	**Ratio greater than 1**	∑ (Prod.$_{(n)}$*Price)/ ∑Cost of Drilling and completion over n years n = number of years
Hyperbolic Decline	6 years onwards, peak at 43 years, then declining with time	
Harmonic Decline	6 years onwards, peak at 43 years, then declining with time	
Stretched Exponential Decline	Never, highest is 0.0754	

Table 10: Cumulative Revenue per Cumulative Investment per Year

2.2.5 DELAYED NET PRSENT VALUE (NPV) ANALYSIS

In this section, we will be looking at the delayed net present value (NPV) of a single well over five years. Calculating net present value of the well will help in comparing the amount invested for drilling and completion of the well to the present value of the future cash flows generated due to production from the same well. Since drilling starts, there can be delay in production of oi and gas ranging from one-month delay to a delay of 12 months. Therefore, it is essential to account for the effect of delay in production on the net present value of a well net present value (NPV) is expressed as below:

$$\boldsymbol{NPV = \sum_{t=1}^{t=n} (Present\ value\ of\ future\ cash\ inflow)_{t=n} - \sum (Present\ value\ of cash\ outflow)_{t=0}}$$

Where, present value of cash outflow i.e. time (t) equal to zero is the investment made for the drilling and completion of the well. The present value of cash inflow for the n^{th} month is expressed as below:

$$\boldsymbol{Present\ value\ of\ future\ cash\ inflow_{\ t=n} = \frac{(Future\ cash\ inflow)_{t=n}}{(1 + discount\ rate)^{n}}}$$

Where, the cash inflow is the revenue from the oil and gas production of the well drilled. The discount rate is the rate of return required from the investment made for well drilling.

A positive net present value will indicate that the present value of the future cash flows is greater than the amount invested for drilling and completion of the well. However, a negative value will indicate that the present value of the future cash flows is less than the amount invested for drilling and completion of the well.

In order to calculate the delayed net present value (NPV), the cash inflows are delayed by a month, every month until 12 months. Additionally, delayed net present value (NPV) is calculated using variable discount rates ranging from 5% per annum (0.4% per month) to 30% per annum (2.2% per month).

The delayed net present value (NPV) analysis with variable discount rates has been performed for the three production decline models, i.e. hyperbolic, harmonic and stretched exponential decline.

Figure 70 represents the delayed net present values (NPV) for one well with hyperbolic decline in production and delay time ranging from 0 months to 12 months (0 months indicates no delay). Additionally, NPV is calculated at variable discount rates ranging from 5% per annum (pa) or 0.4% per month (pm) to 30% per annum (pa) 2.2% (pm).

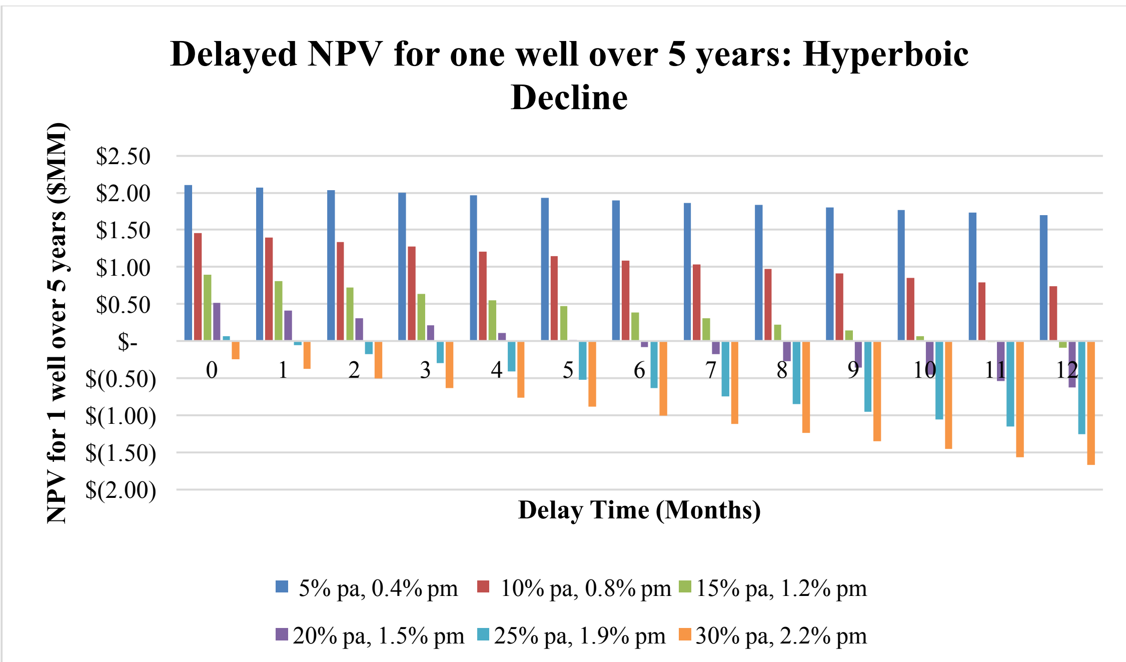

Figure 70: Delayed NPV for 1 well over 5 years and variable discount rates: Hyperbolic Decline

The above figure indicates that the NPV for one well over 5 years with hyperbolic decline in production decreases with the increase in delay time from 0 months to 12 months. Delay time refers to the delay in shale oil and gas production and hence revenues post investments are made for drilling and completion of a well. Additionally, no delay means that complete investment for drilling and completion is made in the 0^{th} month and revenue is generated from the 1^{st} month itself. In **Figure 65**, as the discount rate increases, the net present value is decreasing and also turning negative with increase in delay time. It is also important to note that NPV is always negative at a discount rate of 30% for a single well with hyperbolic decline in production. A negative NPV indicates that drilling a well is not economically feasible. Therefore, in this case at 30% discount rate it is never economically feasible to drill a well.

Figure 71 represents the percentage change in NPV due to delay in production ranging from 1-month delay to a delay of 12 months at variable discount rates.

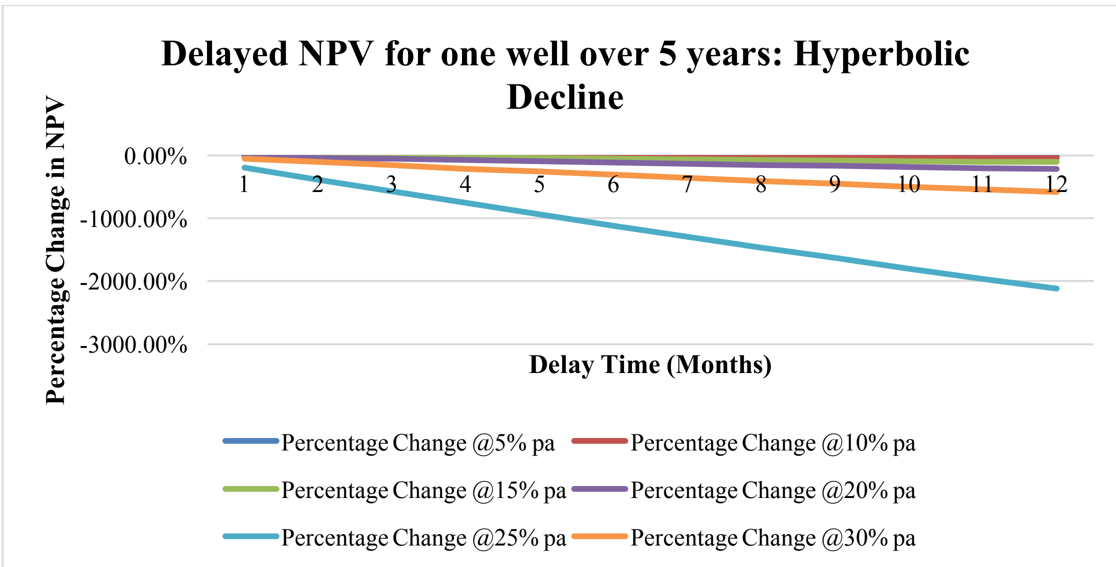

Figure 71: Delayed NPV for one well over 5 years and variable decline rates: Hyperbolic Decline

The above figure indicates that as the delay in oil and gas production and hence revenues increases, the NPV decreases. Additionally, with an increase in the discount rate, the percentage decrease in NPV increases. This means that the percentage decrease in NPV is less at the discount rate of 5% per annum than that at the discount rate of 30% per annum or any discount rate greater than 5% per annum.

Figure 72 represents the delayed net present values (NPV) for one well with harmonic decline in production and delay time ranging from 0 months to 12 months (0 months indicates no delay). Additionally, NPV is calculated at variable discount rates ranging from 5% per annum (pa) or 0.4% per month (pm) to 30% per annum (pa) 2.2% (pm).

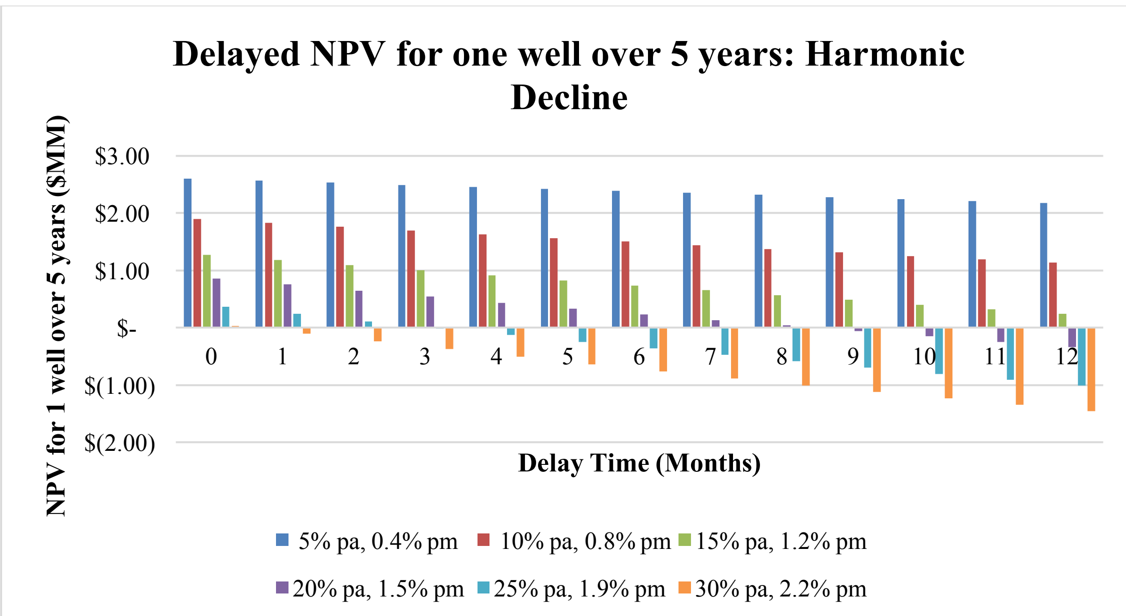

Figure 72: Delayed NPV for 1 well over 5 years and variable discount rates: Harmonic Decline

The above figure indicates that the NPV for one well over 5 years with harmonic decline in production decreases with the increase in delay time from 0 months to 12 months. In **Figure 72,** as the discount rate increases, the net present value is decreasing and turning negative with increase in delay time. It is also important to note that NPV is negative at a discount rate of 30% per annum from 1month delay to 12 months delay for a single well with harmonic decline in production. Similarly, the NPV at a given discount rate for a well with hyperbolic decline in production turns negative faster than that with a harmonic decline in production. This is due to the fact that hyperbolic decline rate is greater than the harmonic decline rate. A negative NPV indicates that drilling a well is not economically feasible. Therefore, in this case at 30% discount rate it is not economically feasible to drill a well post 1 month delay.

Figure 73 represents the percentage change in NPV due to delay in production ranging from 1-month delay to a delay of 12 months at variable discount rates.

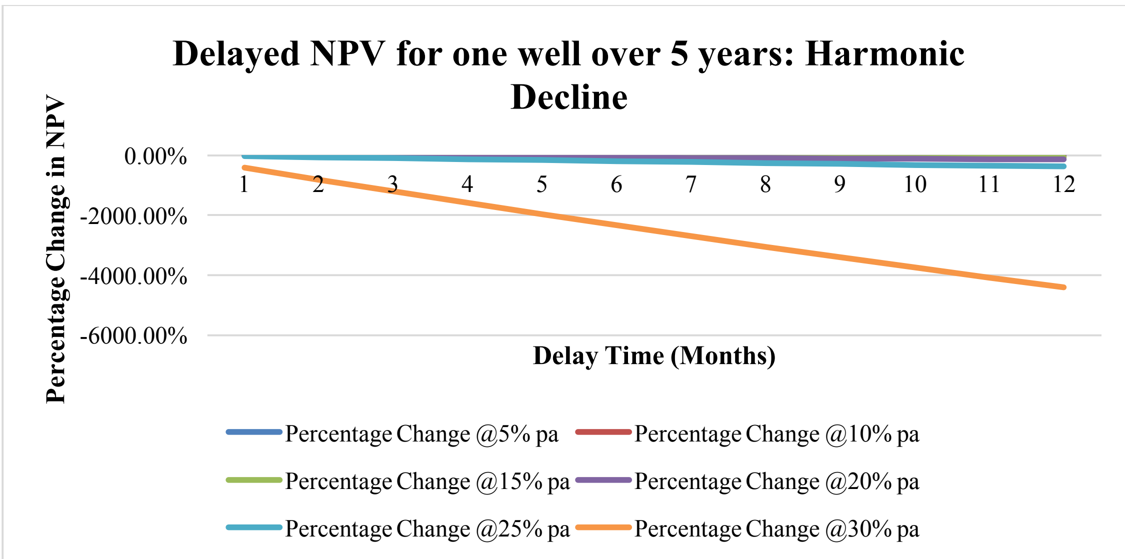

Figure 73: Delayed NPV for one well over 5 years and variable decline rates: Hyperbolic Decline

The above figure indicates that as the delay in oil and gas production and hence revenues increases, the NPV decreases. Additionally, with an increase in the discount rate, the percentage decrease in NPV increases. This means that the percentage decrease in NPV is less at the discount rate of 5% per annum than that at the discount rate of 30% per annum or any discount rate greater than 5% per annum. However, the percentage decrease in NPV is less as compared to that for a well with hyperbolic decline in production.

Figure 74 represents the delayed net present values (NPV) for one well with harmonic decline in production and delay time ranging from 0 months to 12 months (0 months indicates no delay). Additionally, NPV is calculated at variable discount rates ranging from 5% per annum (pa) or 0.4% per month (pm) to 30% per annum (pa) 2.2% (pm).

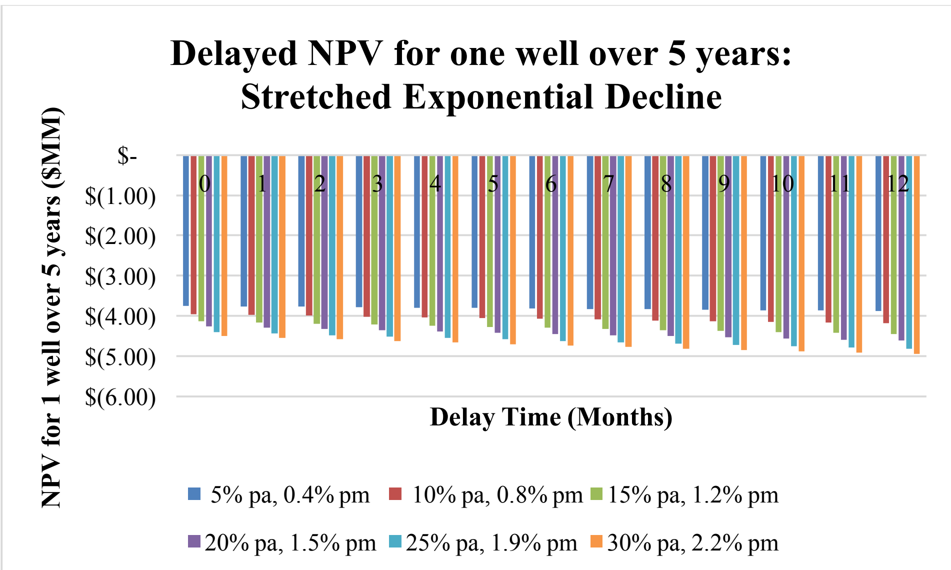

Figure 74: Delayed NPV for one well over 5 years and variable decline rates: Stretched Exponential Decline

The above figure indicates that the NPV for one well over 5 years with harmonic decline in production decreases with the increase in delay time from 0 months to 12 months. In **Figure 74**, the net present value is negative for all discount rates mentioned, and at any given delay time from 1 to 12 months. The NPV in **Figure 74** is also negative at no delay in time. In this case, it indicates that it is economically infeasible to drill a well with stretched exponential decline in production. This is because stretched exponential decline rate is greater than the harmonic and hyperbolic decline rate.

Figure 75 represents the percentage change in NPV due to delay in production ranging from 1-month delay to a delay of 12 months at variable discount rates.

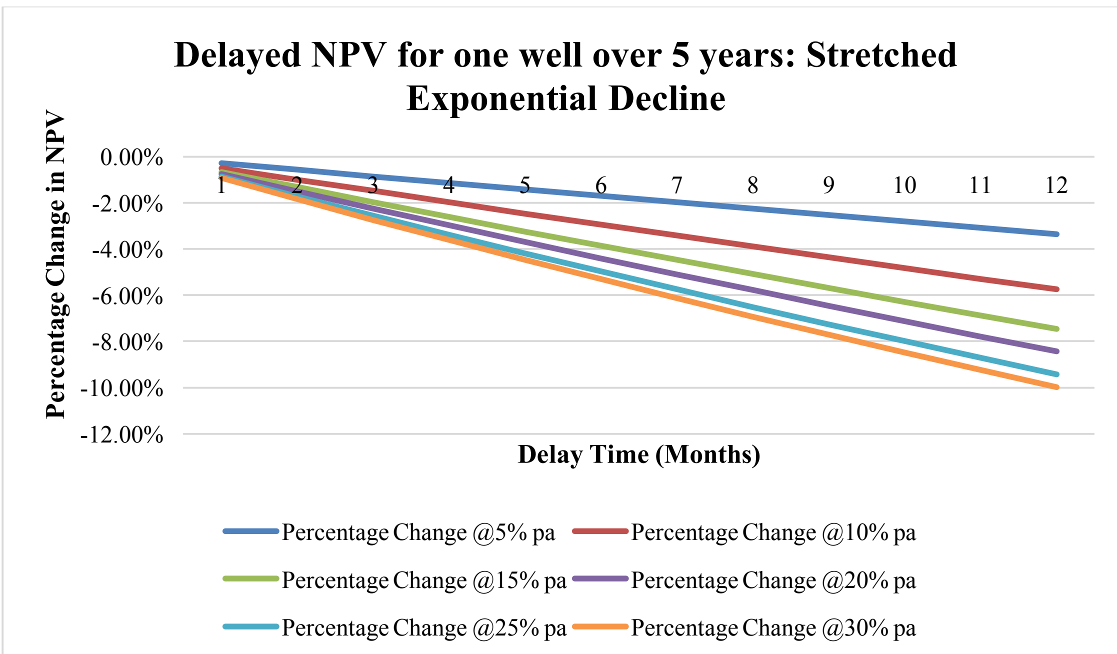

Figure 75: Percentage Change in Delayed NPV for one well over 5 years and variable decline rates: Stretched Exponential Decline

The above figure indicates that as the delay in oil and gas production and hence revenues increases, the NPV decreases. Additionally, with an increase in the discount rate, the percentage decrease in NPV increases. This means that the percentage decrease in

NPV is less at the discount rate of 5% per annum than that at the discount rate of 30% per annum or any discount rate greater than 5% per annum. However, the percentage decrease in NPV is greater than that for a well with hyperbolic and harmonic decline in production.

2.2.6 DEBT SERVICE COVERAGE RATIO

The borrowing base amount (BBA) in case of a reserve based lending (RBL) depends on the net present value of the cash flows generated from the assets included in the transaction, known as the borrowing base assets (Fairnie, 2016). Out of the total cash flows, it is important to understand the amount of cash flows available for debt service. This is calculated using the debt service coverage ratio which is expressed as below:

$$DSCR_n = \frac{(Revenue - Cost\ of\ drilling\ and\ completion)_n}{Interest_n + Principal_n}$$

Where, principal is based on the initial loan amount and interest is calculated on the same amount at a certain interest rate. And n is the number of months. Therefore, interest and principal together form equated monthly payments or installments. DSCR calculation may change based on the different costs associated to the project.

The cash flows available for debt service are calculated throughout the life of the loan. In this case monthly DSCR has been calculated for a loan having a life of 4 years and 5 years. Equated monthly installments (EMI) for a principal amount P over a period of n months at an interest rate r is expressed as below:

$$EMI = \frac{(P * r) * (1 + r)^{n}}{(1 + r)^{n-1}}$$

As explained above, DSCR has been calculated for a loan life of 4 years i.e. 48 months. It has been assumed that the total investment required for the upstream shale project is equal to the cost of drilling and completion of 24 wells drilled at the rate of one well per month. The debt to equity ratio for this case has been set such that the DSCR is at least 1 for the first 12 months of production and at least 1.5 post that. A DSCR of 1 would mean that the cash flows from the assets are equal to the debt i.e. interest and principal and a DSCR greater than 1 would mean that they are more than debt. Since borrowers usually are hedged against oil price declines at least for the first 12 months, for this study the DSCR is maintained at 1during at time. For the above case, debt contributes 30% to the total investment for drilling and completion of 24 wells and the contribution of equity is 70%. Therefore, the debt to equity ratio is 0.42 for this case.

Monthly DSCR for 24 wells and a loan life of 4 years at an interest rate of 7% has been represented in **Figure 76.**

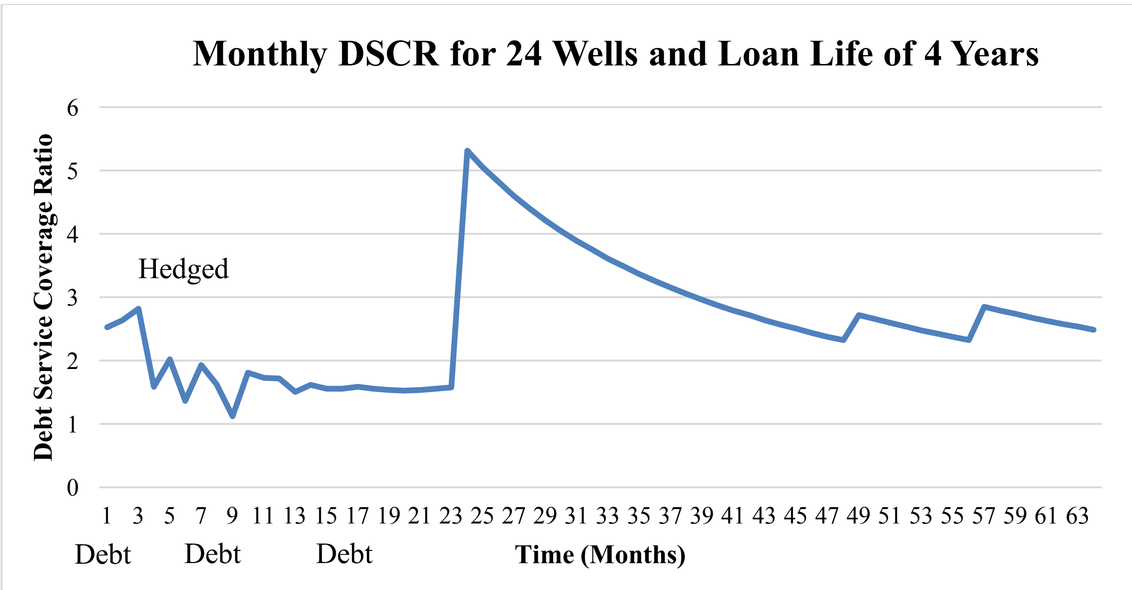

Figure 76: Monthly DSCR for 24 Wells and Loan Life of 4 Years

In the above figure, the total debt required has been obtained in three parts, i.e. debt 1 = debt 2 = 1/6th of total debt, and debt 3 = 2/3rd of the total debt. Additionally, the equity has been spread across the first 23 months. Debt 1 has been obtained at the 0th month, debt 2 at the 8th month and debt 3 at the 16th month of production. These conditions have been fixed so that the DSCR is at least 1 for the first 12 months of production and at least 1.5 post that.

Similarly, **Figure 77** represents monthly DSCR for 24 wells and a loan life of 5 years at an interest rate of 7% per annum.

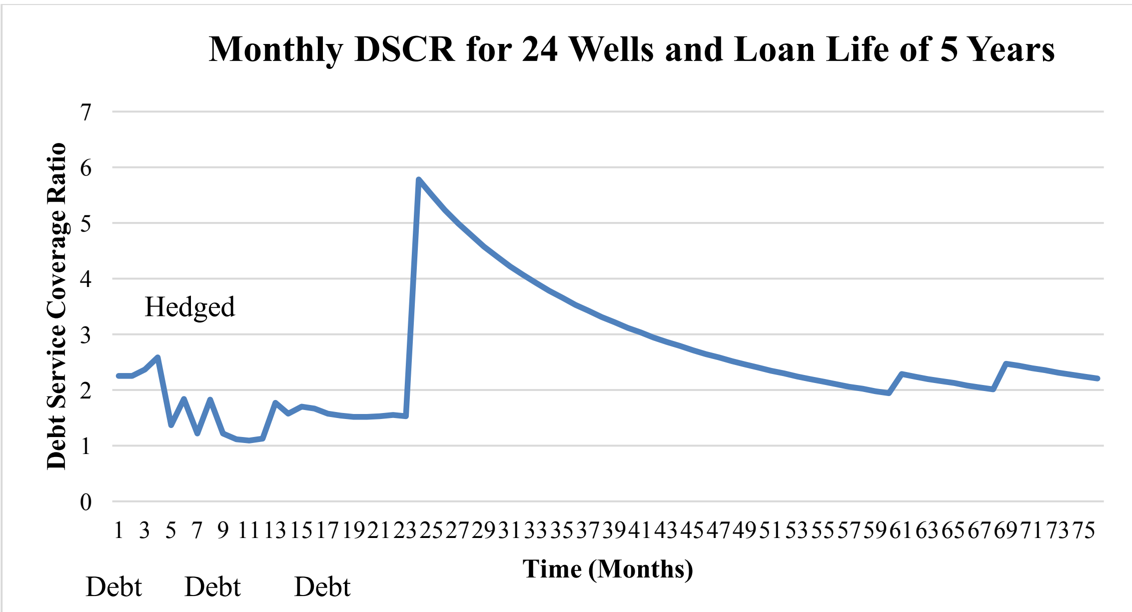

Figure 77: Monthly DSCR for 24 Wells and Loan Life of 5 Years

In the above figure, the total debt required has been obtained in three parts, i.e. debt 1 = debt 2 = 1/6th of total debt, and debt 3 = 2/3rd of the total debt. Additionally, the equity has been spread across the first 23 months. Debt 1 has been obtained at the 0th month, debt 2 at the 8th month and debt 3 at the 16th month of production. These conditions have been fixed so that the DSCR is at least 1 for the first 12 months of production and at least 1.5 post that. Since the loan life is more in this case at 5 years, the debt to equity ratio is also higher at 0.67. Debt contributes 30% to the total investment for drilling and completion of 24 wells and the contribution of equity is 70%.

The debt service ratio calculation in this section has assumed the following to be constant:

1. The prices of oil and gas
2. Cost of drilling and completion
3. Initial production from a well
4. Decline parameters

In real life, the above-mentioned parameters are variable and therefore affect the value of DSCR followed by the borrowing base amount. In order to accommodate for the effect these variables on the DSCR, a financial stress analysis has been performed.

2.3 PHASE 3: FINANCIAL STRESS ANALYSIS

In this study so far, the shale oil and gas production forecast model and the cash flow model have been developed using certain assumptions. However, the investment banks as lenders are exposed to various risks. Therefore, risk assessment plays a very crucial role in investment decision making for the lenders. Financial stress analysis of the developed model will help in assessing those risks. This has been performed using the Monte Carlo Simulation method through the RiskAMP add-in with Microsoft Excel.

Simulation has been performed in two phases: Phase 1 - Assuming all four variables, i.e. price of oil and gas, cost of drilling and completion, initial production from a well and decline parameters are independent of each other. Phase 2 – Assuming price of oil and cost of drilling and completion are correlated, and initial production and initial decline rates are correlated. The effect of simulation on the on the shale oil and gas production forecast model and the cash flow model ultimately reflects on the debt service coverage ratio (DSCR) for drilling 24 wells.

Figure 78 represents the average monthly DSCR post simulation for 24 wells and a loan life of 4 years.

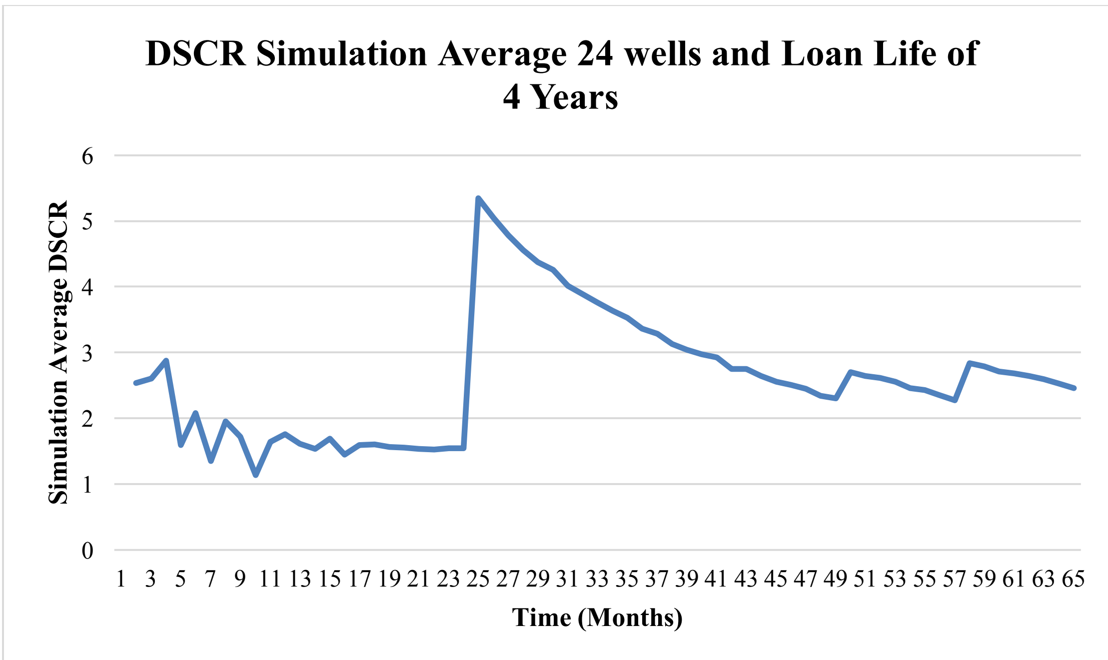

Figure 78: DSCR Simulation Average 24 wells and Loan Life of 4 Years, variable oil and gas prices

In the above figure, the DSCR simulation average results have been obtained for variable oil and gas prices, sampled independently at an average of \$50 per barrel (bbl) and standard deviation of \$10/barrel for oil, and \$2.75 per million cubic feet (Mcf) and standard deviation of \$1 per million cubic feet. Including variable oil and gas prices in the model helps in assessing the commodity price risk (such as decline in oil and gas prices) that a lender would face especially in case of reserve based lending (RBL).

Figure 79 represents the probability that the monthly DSCR post simulation for 24 wells will be at least 1 for the first 12 months and at least 1.5 for the rest 36 months of the loan life.

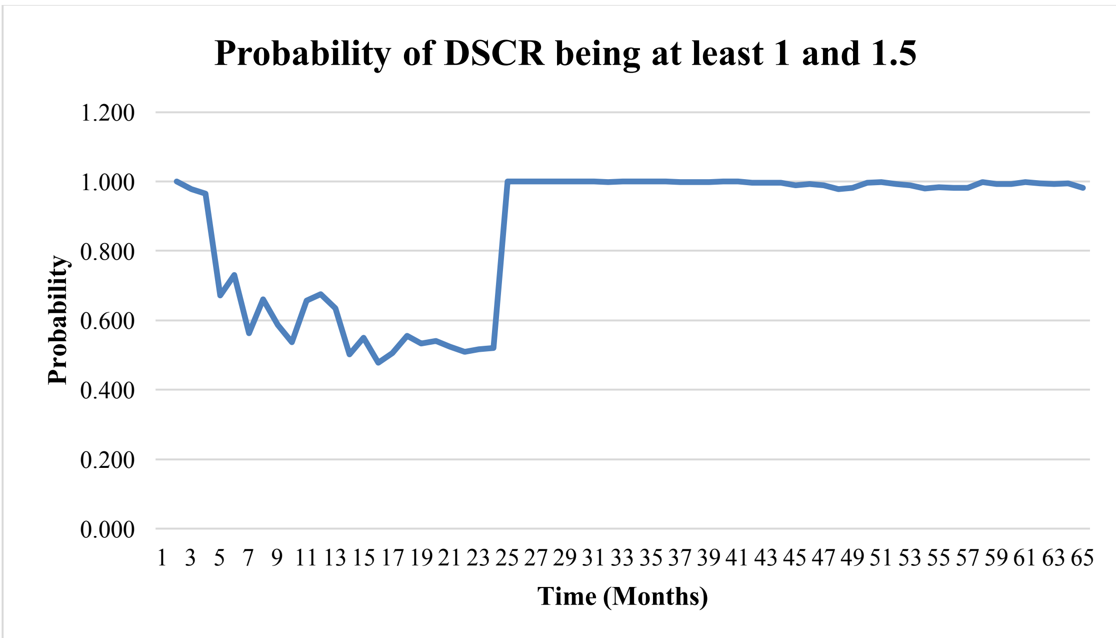

Figure 79: Probability of DSCR being at least 1 and 1.5 over 4 years, variable oil and gas prices

The above figure helps in assessing the commodity price risk due to variable oil and gas prices. It indicates that the probability of DSCR being at least 1 in the first 12 months and at least 1.5 for the next 36 months is between 1 and 0.478 for the first 23 months. From 24 months onwards, the same probability is 1 since drilling is stopped at the 23rd month.

Similarly, simulation with variable oil and gas prices has been carried out for 24 wells with a loan life of 5 years and is represented in **Figure 80.**

Figure 81 represents the probability that the monthly DSCR post simulation for 24 wells will be at least 1 for the first 12 months and at least 1.5 for the rest 48 months of the loan life. It indicates that the probability of DSCR being at least 1 in the first 12 months and at least 1.5 for the next 48 months is between 1 and 0.478 for the first 23 months. From 24 months onwards, the same probability ranges between 1 and 0.6.

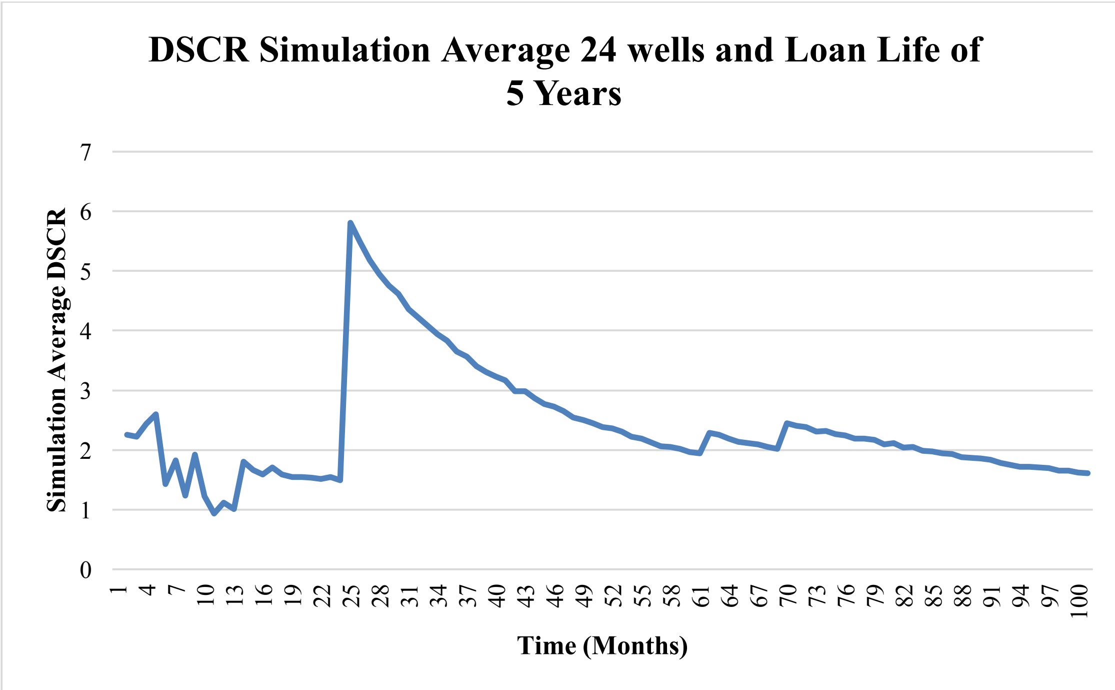

Figure 80: DSCR Simulation Average 24 wells and Loan Life of 5 Years, variable oil and gas prices

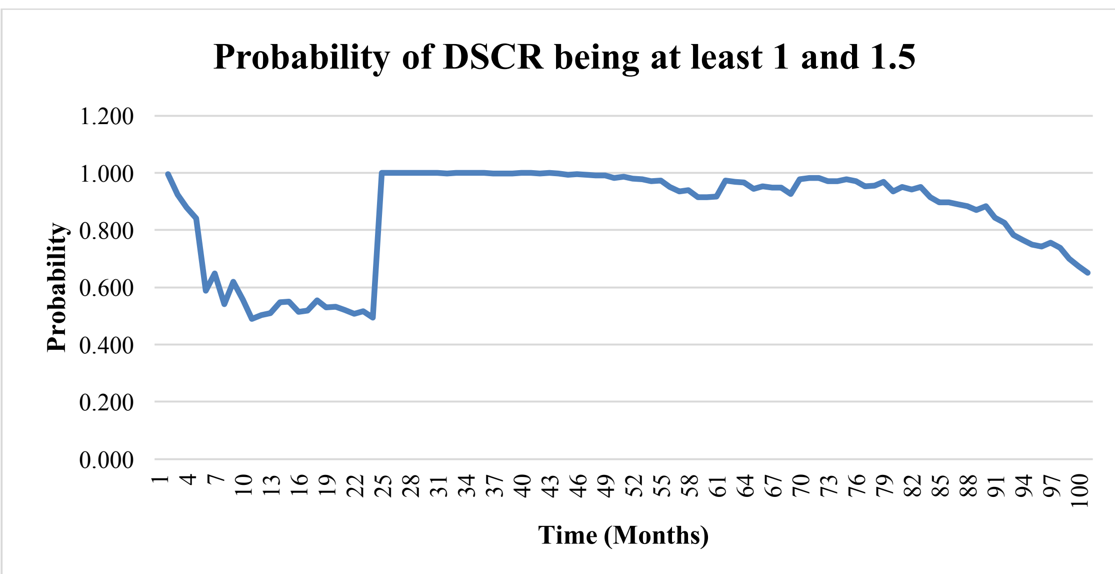

Figure 81: Probability of DSCR being at least 1 and 1.5 over 5 years, variable oil and gas prices

Figure 82 represents the average monthly DSCR post simulation for 24 wells and a loan life of 4 years.

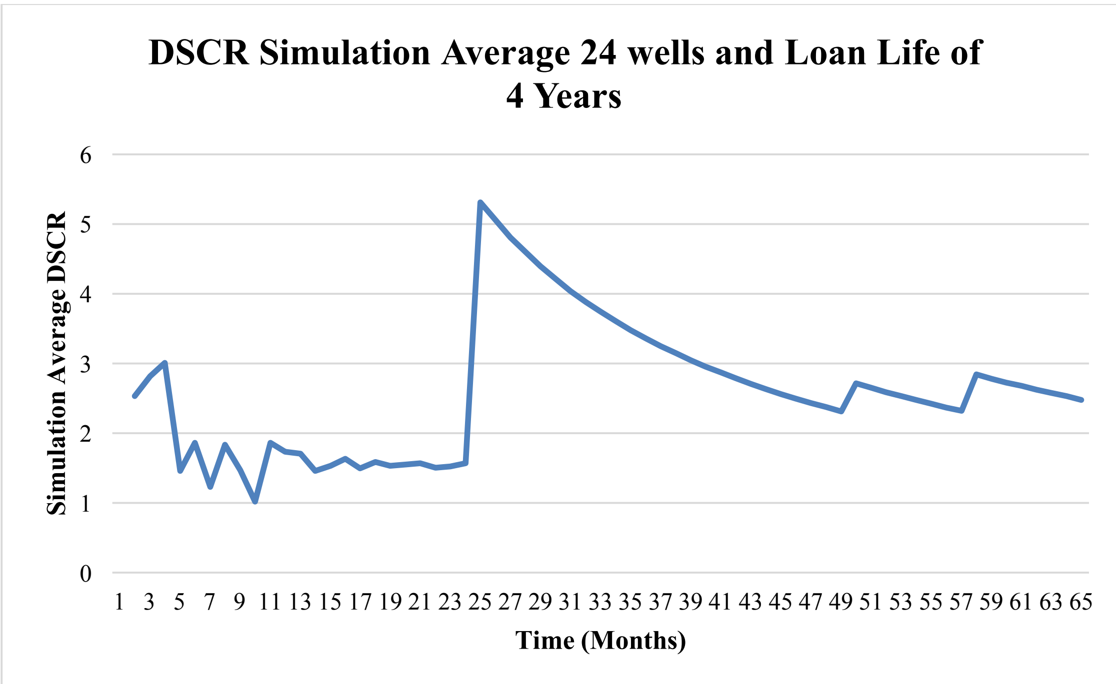

Figure 82: DSCR Simulation Average 24 wells and Loan Life of 4 Years, variable cost of drilling and completion

In the above figure, the DSCR simulation average results have been obtained for variable cost of drilling and completion of a well, sampled independently at an average of \$6.45 million and standard deviation of \$0.5 million. Including variable cost of drilling and completion in the model helps in assessing the risk due to changes in the goods and services prices (such as increase in cost of drilling and completion due to changes in oil and gas prices) that a lender would face especially in case of reserve based lending (RBL).

Figure 83 represents the probability that the monthly DSCR post simulation for 24 wells will be at least 1 for the first 12 months and at least 1.5 for the rest 36 months of the loan life.

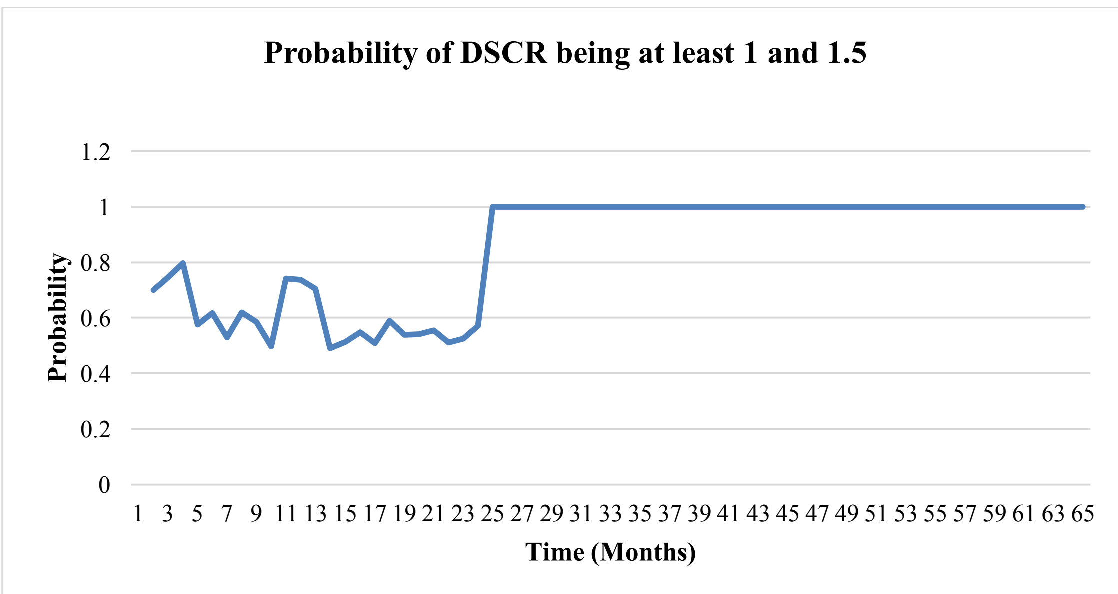

Figure 83: Probability of DSCR being at least 1 and 1.5 over 4 years, variable cost of drilling and completion

The above figure helps in assessing the risk due to changes in cost of drilling and completion of a well. It indicates that the probability of DSCR being at least 1 in the first 12 months and at least 1.5 for the next 36 months is between 0.65 and 0.49 for the first

23 months. From 24 months onwards, the same probability is 1 since drilling is stopped at the 23rd month.

Similarly, simulation with variable cost of drilling and completion has been carried out for 24 wells with a loan life of 5 years and is represented in **Figure 84.**

Figure 85 represents the probability that the monthly DSCR post simulation for 24 wells will be at least 1 for the first 12 months and at least 1.5 for the rest 48 months of the loan life. It indicates that the probability of DSCR being at least 1 in the first 12 months and at least 1.5 for the next 48 months is between 0.65 and 0.49 for the first 23 months. From 24 months onwards, the same probability is 1 since drilling is stopped at the 23rd month.

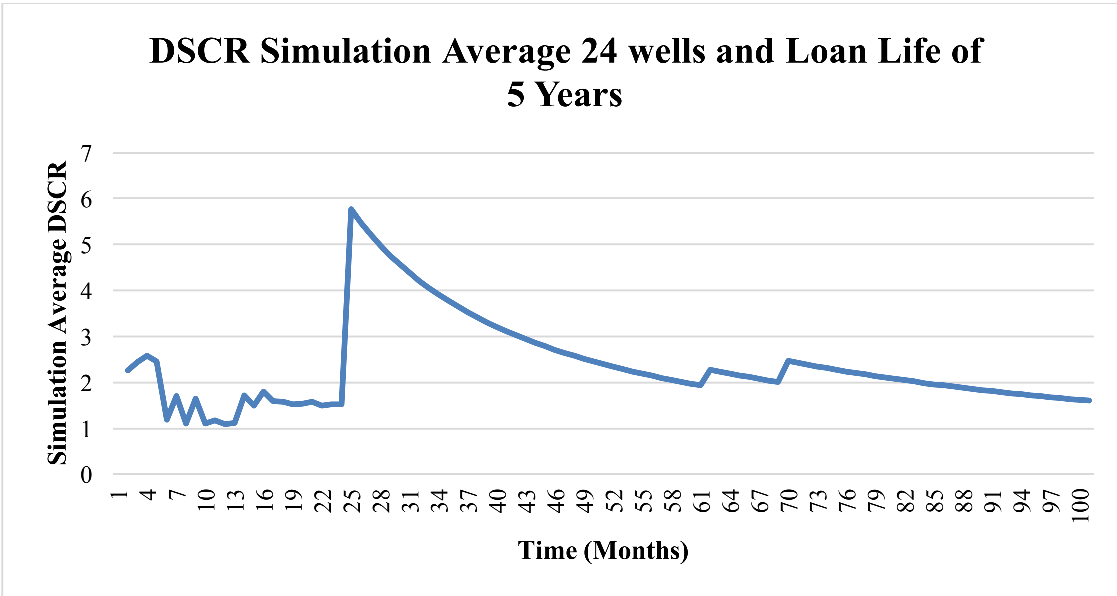

Figure 84: DSCR Simulation Average 24 wells and Loan Life of 5 Years, variable cost of drilling and completion

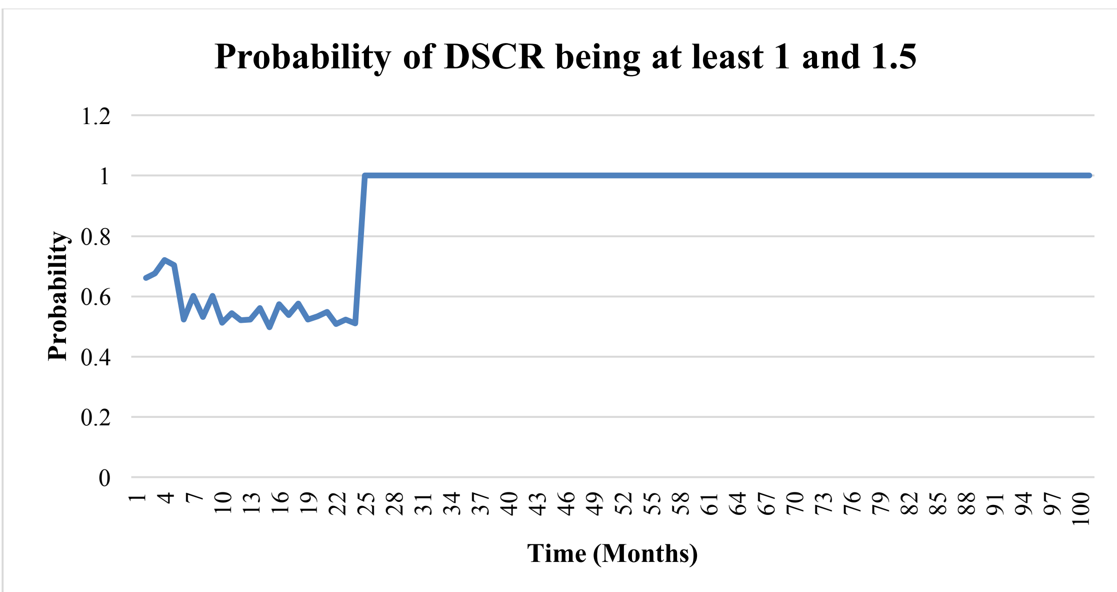

Figure 85: Probability of DSCR being at least 1 and 1.5, variable cost of drilling and completion

Figure 86 represents the average monthly DSCR post simulation for 24 wells and a loan life of 4 years.

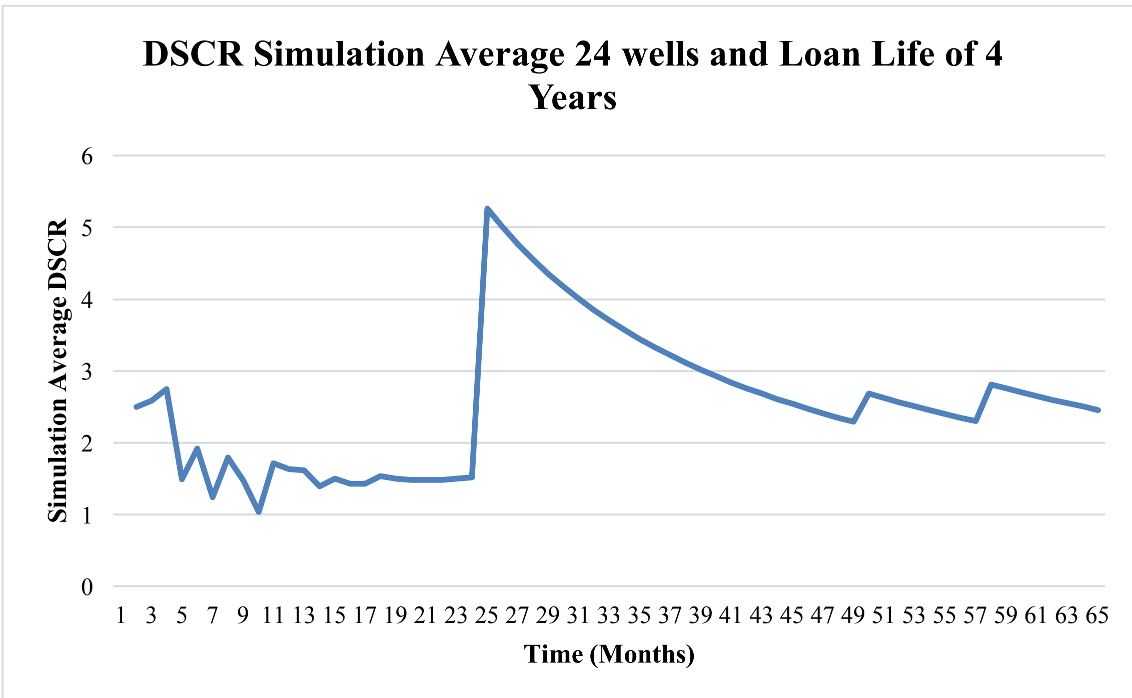

Figure 86: DSCR Simulation Average 24 wells and Loan Life of 4 Years, variable initial oil production

In the above figure, the DSCR simulation average results have been obtained for variable initial production of oil, sampled independently at an average of 225 barrels per day and standard deviation of 65 barrels per day. Including variable initial production in the model helps in assessing the risk associated with the oil production forecasting model (such as lower actual production than forecasted) that a lender would face especially in case of reserve based lending (RBL).

Figure 87 represents the probability that the monthly DSCR post simulation for 24 wells will be at least 1 for the first 12 months and at least 1.5 for the rest 36 months of the loan life.

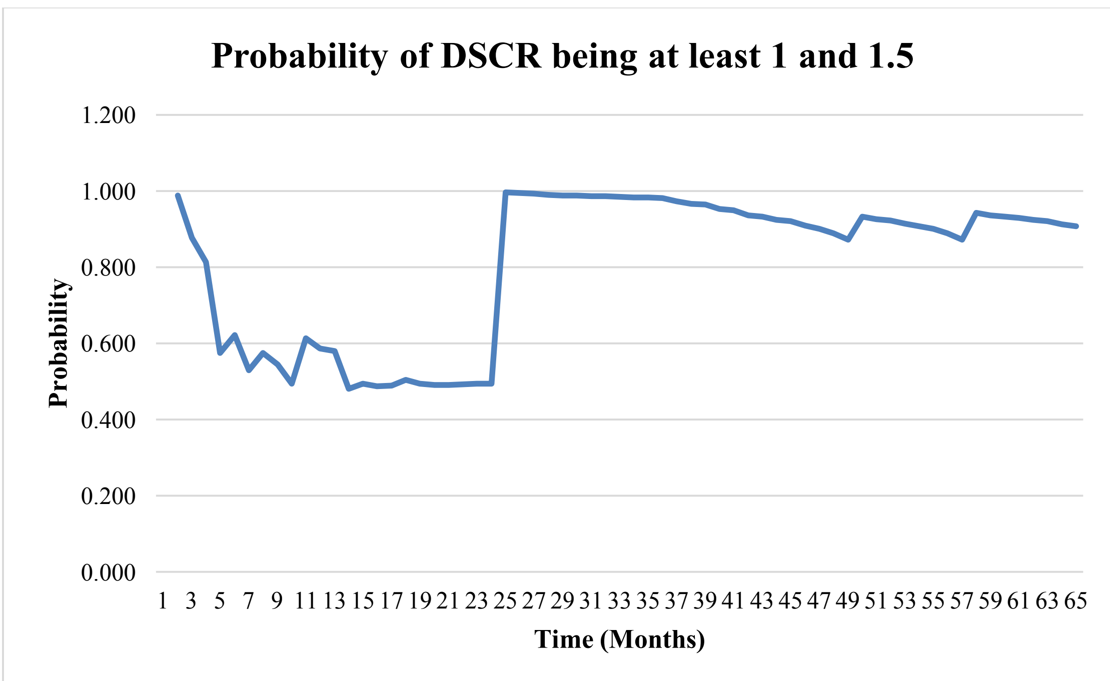

Figure 87: Probability of DSCR being at least 1 and 1.5, variable initial production

The above figure helps in assessing the risk due to changes in initial oil production from a well. It indicates that the probability of DSCR being at least 1 in the first 12 months and at least 1.5 for the next 36 months is between 1 and 0.48 for the first

23 months. From 24 months onwards, the same probability lies between 0.9 to 1 since drilling is stopped at the 23rd month.

Similarly, simulation with variable initial oil production has been carried out for 24 wells with a loan life of 5 years and is represented in **Figure 88.**

Figure 89 represents the probability that the monthly DSCR post simulation for 24 wells will be at least 1 for the first 12 months and at least 1.5 for the rest 48 months of the loan life. It indicates that the probability of DSCR being at least 1 in the first 12 months and at least 1.5 for the next 48 months is between 1 and 0.486 for the first 23 months. From 24 months onwards, the same probability is 1 since drilling is stopped at the 23rd month.

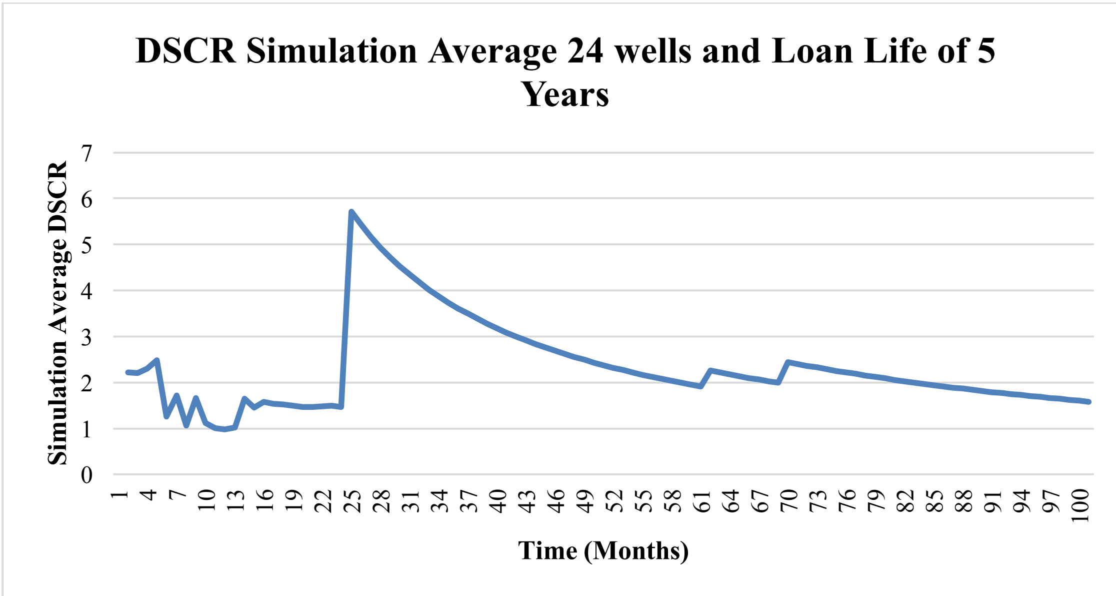

Figure 88: DSCR Simulation Average 24 wells and Loan Life of 5 Years, variable initial oil production

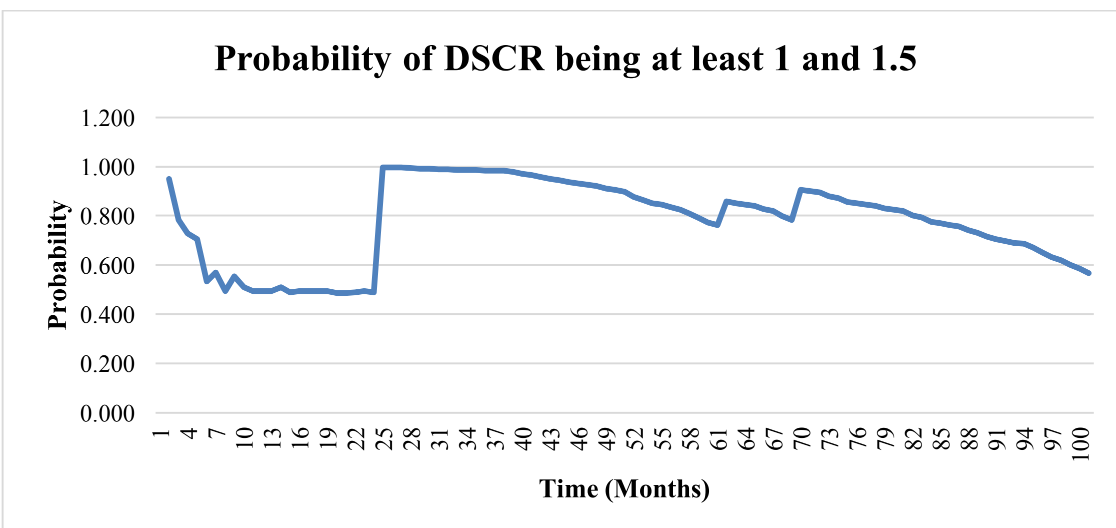

Figure 89: Probability of DSCR being at least 1 and 1.5, variable initial oil production

Figure 90 represents the average monthly DSCR post simulation for 24 wells and a loan life of 4 years.

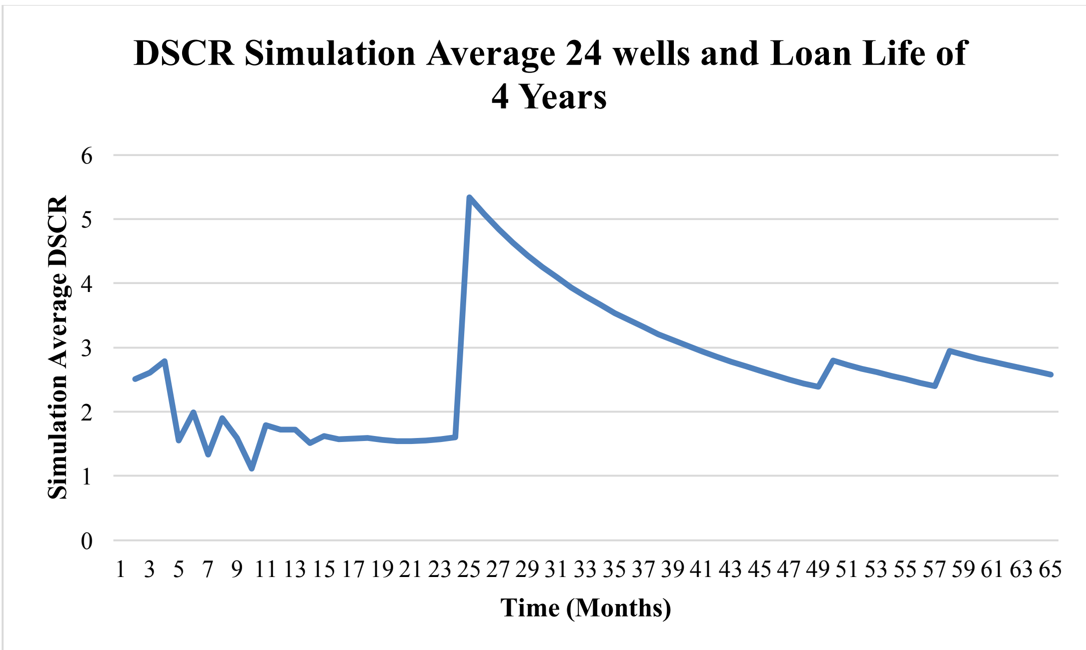

Figure 90: DSCR Simulation Average 24 wells and Loan Life of 4 Years, variable decline parameters

In the above figure, the DSCR simulation average results have been obtained for variable decline parameters (β and initial decline rate), sampled independently at an average β of 0.84 and standard deviation of 0.075, and an average initial decline rate of 0.08 per month and standard deviation of 0.02 per month. Including variable decline parameters in the model helps in assessing the risk associated with the shale oil and gas production forecast (such as faster decline in shale oil and gas production as calculated) that a lender would face especially in case of reserve based lending (RBL).

Figure 91 represents the probability that the monthly DSCR post simulation for 24 wells will be at least 1 for the first 12 months and at least 1.5 for the rest 36 months of the loan life.

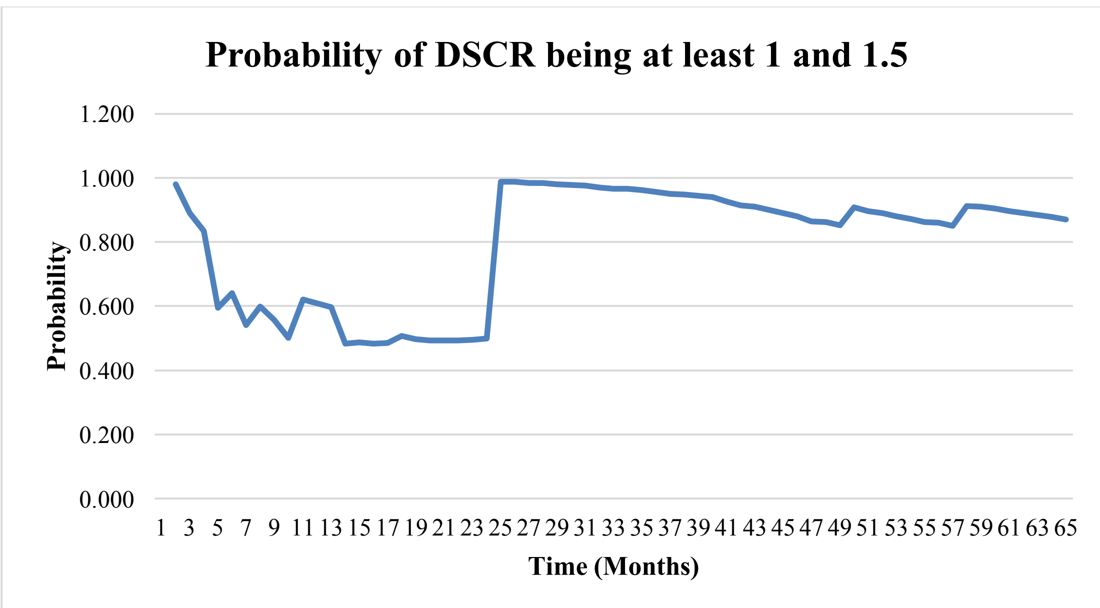

Figure 91: Probability of DSCR being at least 1 and 1.5, variable decline parameters

The above figure helps in assessing the risk due to changes in decline parameters of a well. It indicates that the probability of DSCR being at least 1 in the first 12 months and at least 1.5 for the next 36 months is between 1 and 0.484 for the first 23 months. From 24 months onwards, the same probability lies between 0.85 and 1.

Similarly, simulation with variable decline parameters has been carried out for 24 wells with a loan life of 5 years and is represented in **Figure 92.**

Figure 93 represents the probability that the monthly DSCR post simulation for 24 wells will be at least 1 for the first 12 months and at least 1.5 for the rest 48 months of the loan life. It indicates that the probability of DSCR being at least 1 in the first 12 months and at least 1.5 for the next 48 months is between 1 and 0.488 for the first 23 months. From 24 months onwards, the same probability lies between 0.55 and 1.

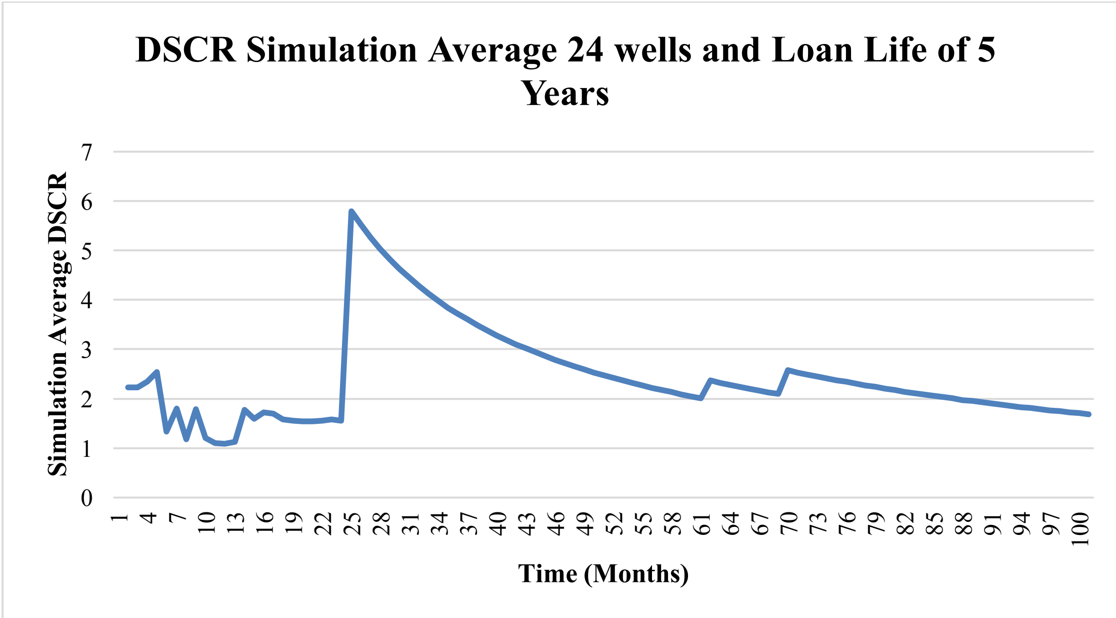

Figure 92: DSCR Simulation Average 24 wells and Loan Life of 5 Years, variable decline parameters

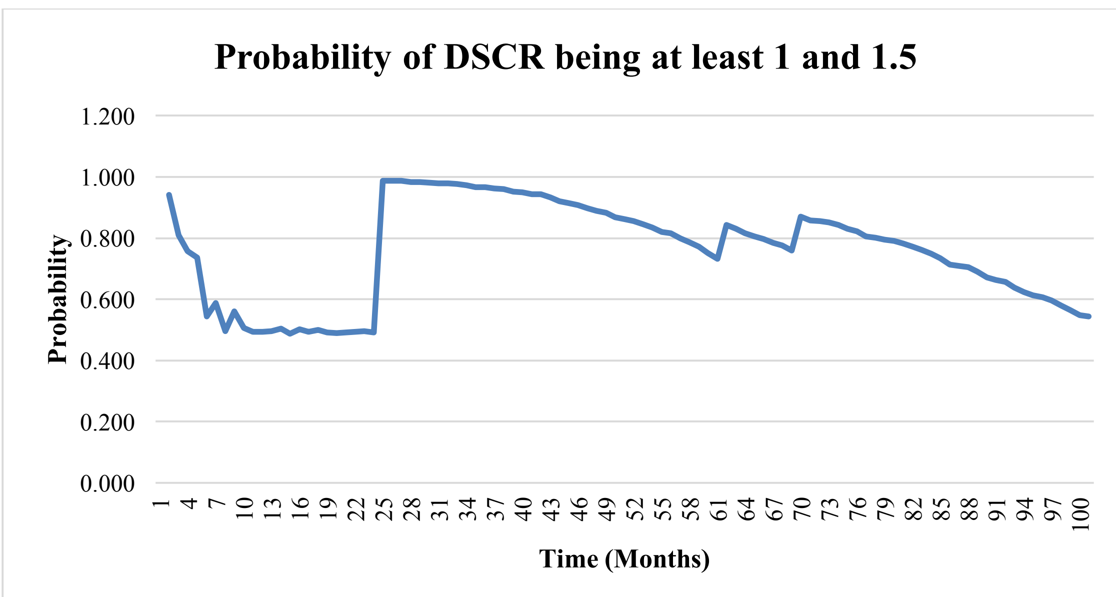

Figure 93: Probability of DSCR being at least 1 and 1.5, variable decline parameters

As mentioned earlier in this section, simulation has also been carried out by sampling correlated values of and initial production and initial decline rates together, and oil prices and cost of drilling and completion together. Initially correlation coefficients have been determined between these variables in Microsoft Excel using the Data Analysis Add-in for Excel.

The correlation coefficient between the initial production and the initial monthly decline rate was calculated to be 0.2424. This indicates that initial production and initial monthly decline rates are positively correlated i.e. if one increases the other also increases and vice versa.

The correlation coefficient between oil prices and cost of drilling and completion of a well was calculated to be 0.4221. This indicates that oil prices and cost of drilling and completion of a well are positively correlated i.e. if one increases the other also increases and vice versa.

Figure 94 represents the average monthly DSCR post simulation for 24 wells and a loan life of 4 years.

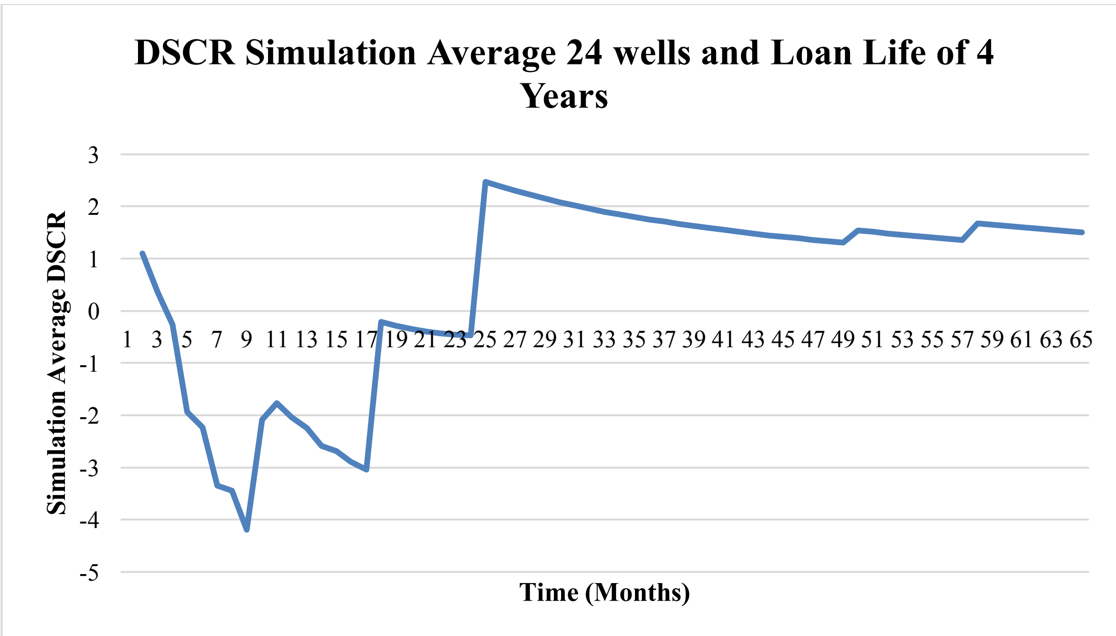

Figure 94: DSCR Simulation Average 24 wells and Loan Life of 4 Years, variable correlated values of initial decline and initial production

In the above figure, the DSCR simulation average results have been obtained for variable initial production and variable initial decline rates. They have been sampled together as correlated at an average initial production of 79 barrels per day and standard deviation of 98.88 barrels per day, and an average initial decline rate of 0.053 per month and standard deviation of 0.012 per month. Including variable correlated values for initial production and initial decline rates in the model helps in assessing the combined risk due to complementary variables associated with the shale oil and gas production forecast model. For example, when initial production is high it will result in faster decline in shale oil and gas production which will lead to lower production as forecasted and hence lower revenues. Therefore, in **Figure 94** the average DSCR is negative or less than zero from the 4^{th} month till 23^{rd} month (time when drilling is stopped). As wells are drilling until the 23^{rd} month at the rate of one well per month leading to high investment and due faster decline, the average DSCR is negative.

Figure 95 represents the probability that the monthly DSCR post simulation for 24 wells will be at least 1 for the first 12 months and at least 1.5 for the rest 36 months of the loan life.

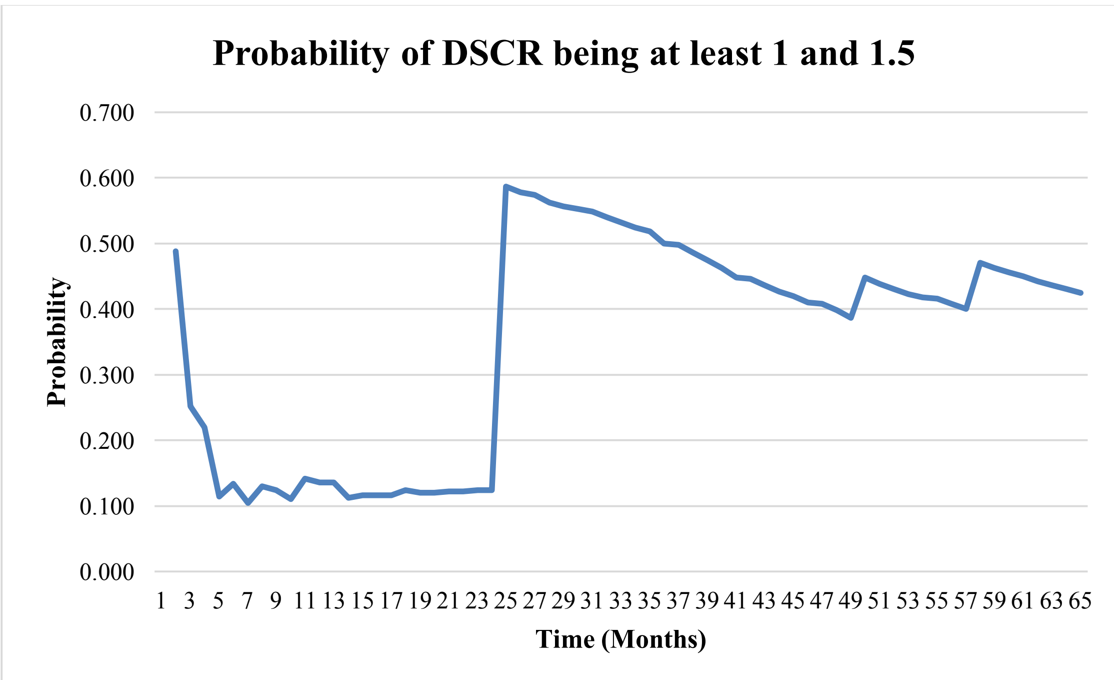

Figure 95: Probability of DSCR being at least 1 and 1.5 over 4 years, variable correlated values of initial decline and initial production

The above figure helps in assessing the risk due to changes in the correlated initial production and initial decline. It indicates that the probability of DSCR being at least 1 in the first 12 months and at least 1.5 for the next 36 months is between 0.6 and

0.1. This indicates that the disk due to correlation between the initial production and initial decline in production is very high.

Similarly, simulation with variable initial production and initial decline rates has been carried out for 24 wells with a loan life of 5 years and is represented in **Figure 96.**

Figure 97 represents the probability that the monthly DSCR post simulation for 24 wells will be at least 1 for the first 12 months and at least 1.5 for the rest 48 months of the loan life. It indicates that the probability of DSCR being at least 1 in the first 12 months and at least 1.5 for the next 48 months is between 1 and 0.098 for the first 23 months.

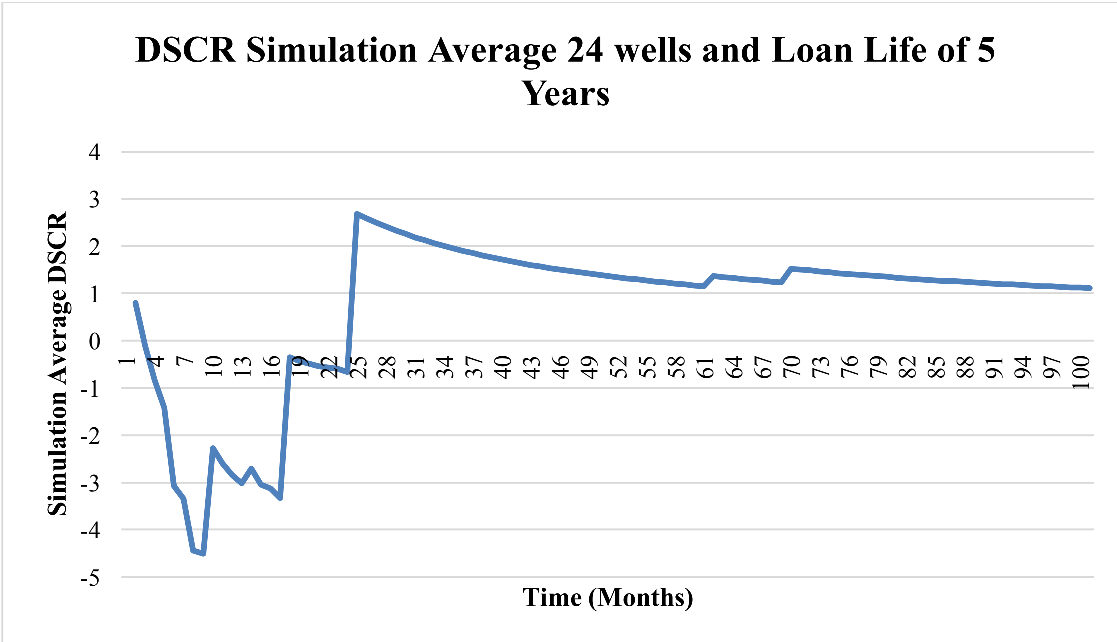

Figure 96: DSCR Simulation Average 24 wells and Loan Life of 5 Years, variable correlated values of initial decline and initial production

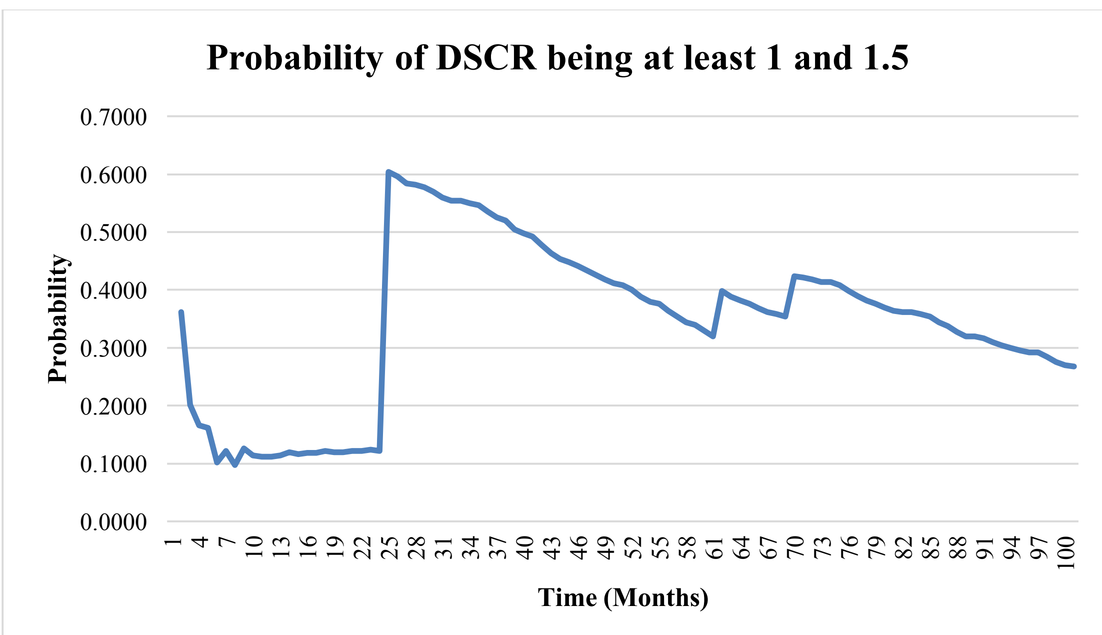

Figure 97: Probability of DSCR being at least 1 and 1.5 over 5 years, variable correlated values of initial decline and initial production

Figure 98 represents the average monthly DSCR post simulation for 24 wells and a loan life of 4 years.

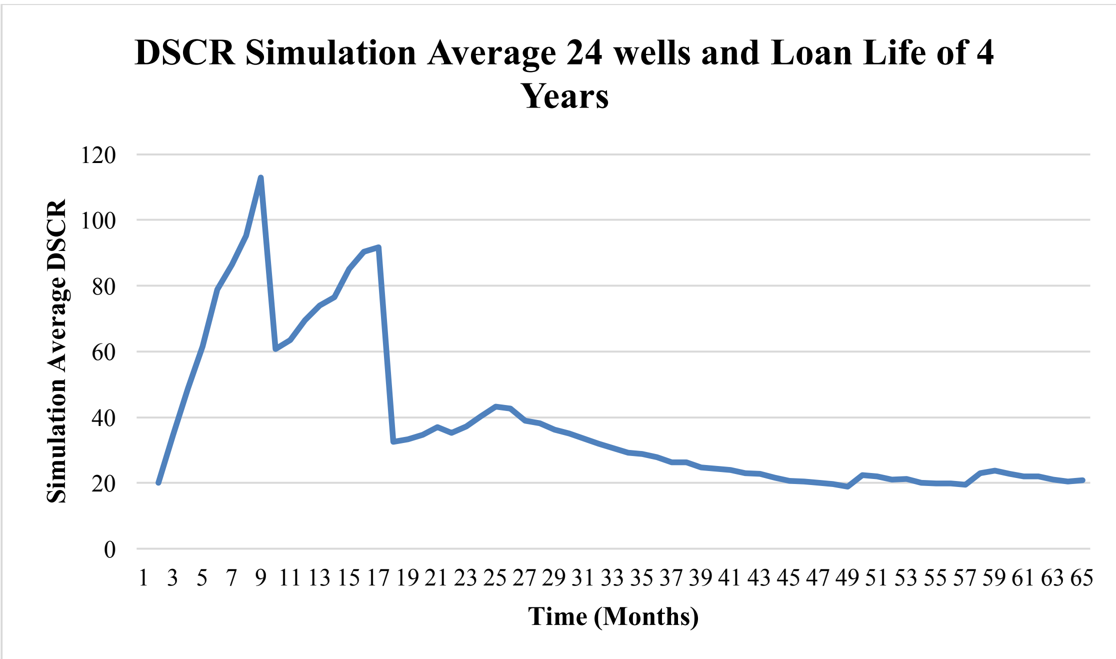

Figure 98: DSCR Simulation Average 24 wells and Loan Life of 4 Years, variable correlated oil prices and cost of drilling and completion

In the above figure, the DSCR simulation average results have been obtained for variable initial production and variable initial decline rates. They have been sampled together as correlated at an average oil price of $37.06 per barrel and standard deviation of $20 per barrel, and an average cost of drilling and completion $645690 per well and standard deviation $539467 per well. Including variable correlated values for oil prices and cost of drilling and completion in the model helps in assessing the combined risk due to complementary variables associated with the shale oil and gas financial model. For example, when the oil prices rise, the cost of drilling and completion will most probably rise and bring down the DSCR value. It is also important to note that the average DSCR values in **Figure 98** are very high as compared to those in the previous scenarios. This is because the average cost of drilling and completion in this case is ten times smaller than the average cost of drilling and completion used in other cases. However, the high average DSCR values in **Figure 98** also reflect that they are highly dependent upon the cost of drilling and completion.

Figure 99 represents the probability that the monthly DSCR post simulation for 24 wells will be at least 1 for the first 12 months and at least 1.5 for the rest 36 months of the loan life.

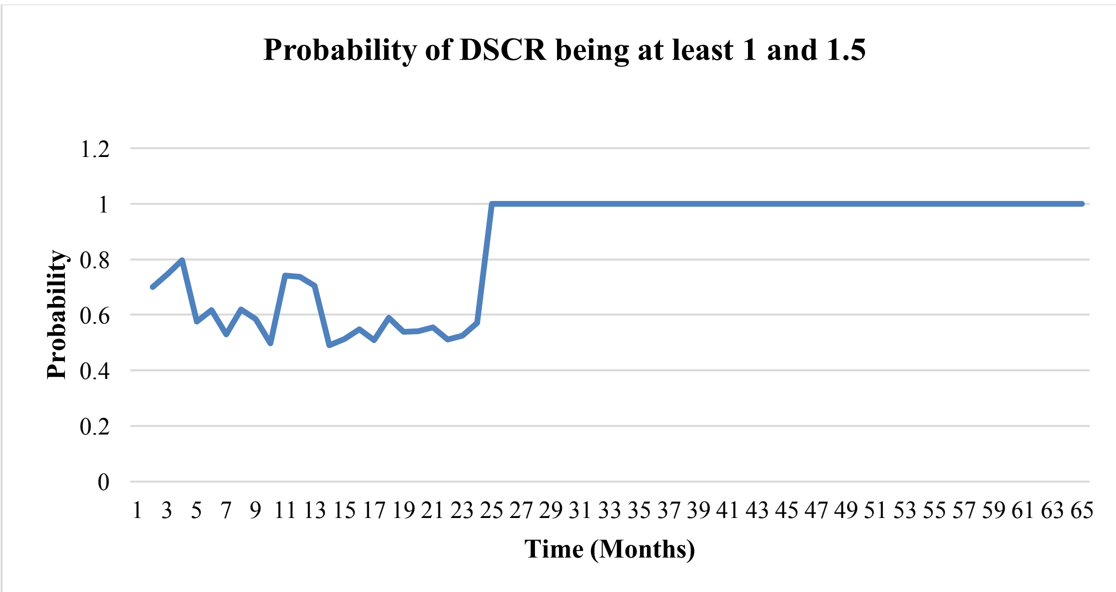

Figure 99: Probability of DSCR being at least 1 and 1.5 over 4 years, variable correlated oil prices and cost of drilling and completion

The above figure helps in assessing the risk due to changes in initial production and variable initial decline rates together. It indicates that the probability of DSCR being at least 1 in the first 12 months and at least 1.5 for the next 36 months is between 1 and 0.7. From 24 months onwards, the same probability is 1 since drilling is stopped at the 23rd month. The probabilities are higher due to the fact that the average cost of drilling and completion is ten times less than the average value considered in the previous cases in this section.

Similarly, simulation with variable initial production and initial decline rates has been carried out for 24 wells with a loan life of 5 years and is represented in **Figure 100.**

Figure 101 represents the probability that the monthly DSCR post simulation for 24 wells will be at least 1 for the first 12 months and at least 1.5 for the rest 48 months of the loan life. It indicates that the probability of DSCR being at least 1 in the first 12 months and at least 1.5 for the next 48 months is between 1 and 0.8.

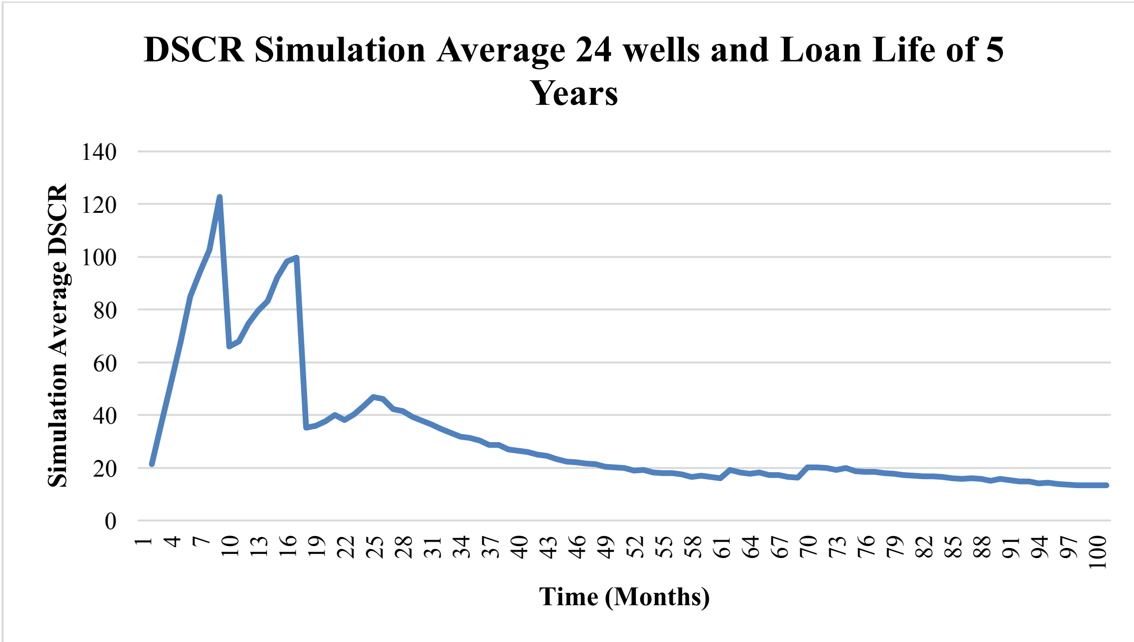

Figure 100: DSCR Simulation Average 24 wells and Loan Life of 5 Years, variable correlated oil prices and cost of drilling and completion

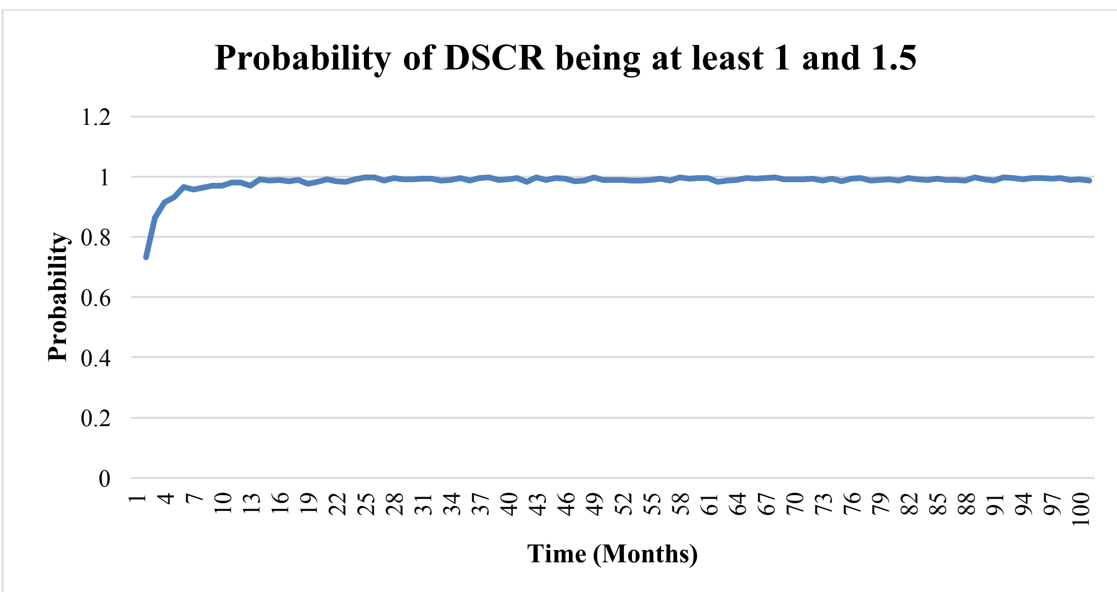

Figure 101: Probability of DSCR being at least 1 and 1.5 over 5 years, variable correlated oil prices and cost of drilling and completion

3. CONCLUSION

From the cash flow analysis performed in the previous section we can conclude that the payback periods are highly dependent on the type of decline model the shale oil and gas production follows. Additionally, a single well with a stretched exponential decline in production paybacks after 496 months, which is almost equivalent to a well which never pays back. A single well with an exponential decline in production does not pay back at all. However, in case of hyperbolic and harmonic decline models, single well paybacks are 29 months and 27 months respectively. A single shale play might have wells different decline parameters. Therefore, valuation of the shale E&P assets must include the possibility of production declines as per all four decline models. Additionally, shale oil and gas production forecast should not be completely dependent on the historical data for production. Therefore, in case of unconventional projects, the type of decline model the shale oil and gas production follows is extremely important as the payback periods from a single well can range from 29 months to 496 months or no economically feasible payback period.

With respect to the analysis carried out for the identification of stages, i.e. in terms of percentage change in production and percentage change in revenue per investment, it is very crucial when valuing the shale reserves. Considering the results from the analysis for percentage change in production, the percentage growth in shale oil and gas production becomes less than 1% per month post 48-51 months and less than 5% per annum post 9-10 years depending on the type of production decline model. Additionally, when drilling is stopped, the percentage growth in production turns negative. Therefore, it is very important to identify stages at which production growth is not significant enough and when drilling is stopped, since post drilling there is no growth in production. This calls for high risk due to decline in oil and gas production and hence revenues.

Considering low growth in production, it is very important for the lenders to understand the ratio of revenue growth to investment. As per the revenue growth to investment ratio analysis performed earlier in this study, the ratio per month and also per year is always less than 1. Therefore, the revenue growth does not compensate for the investment made in drilling additional wells. In addition to that, the ratio of cumulative revenue to cumulative investment per month turns greater than 1 post 66-106 months and depending on the production decline model. In case of the ratio for cumulative revenue to cumulative investment per year, it turns greater than 1, 6 years onwards, peaks at 43 years and then declines, for hyperbolic and harmonic production decline models. In case of stretched exponential decline model, this ratio is never greater than 1. Due to low production growths, early declines and late paybacks, it is very important to analyze the ratio of revenue growth to investment and cumulative revenues to investment, especially while valuing the shale reserves in order to determine a borrowing base.

In order to determine the borrowing base, it is very important that the net present value (NPV) of the future cash flows is determined. In addition to that NPV model was tested for variable interest rates and delayed drilling. Together they have an impact on the NPV of a well over five years such that the percentage change in NPV ranges from 0% to -400%. With declining NPV of a well with time, it is important to assess the risk associated with changing interest rates and delayed drilling.

Finally, while determining the borrowing base in case of reserve based lending, the amount of cash flow available for debt service was calculated. The DSCR model was assessed for risks associated with the variable oil and gas prices, cost of drilling and completion, initial production, and initial decline rates. Additionally, the DSCR model was also assessed for risks associated with correlation between the oil and gas prices and cost of drilling and completion, and initial production and initial decline rates. The probability that DSCR will be more than 1 in the first 12 months and 1.5 for the rest of the loan life ranged from 0.1 to 1 considering the above-mentioned variables. With this broad range of probability for DSCR to be greater than 1 and 1.5, the level of risk exposure of the lender is extremely high and therefore it is important to incorporate the effects of these variables in this valuation model.

This study provides with a holistic valuation model especially for exploration and production (E&P) shale assets which takes into account the risks associated with differences between conventional and unconventional reservoirs and their resulting financial impacts. The risks due to differences between the conventional and unconventional reservoirs is accounted for by including different production decline models i.e. hyperbolic, harmonic, exponential, and stretched exponential. Their financial impacts are accounted for through cash flow analysis and revenue growth per investment analysis. The net present value of these cash flows is also tested for delayed drilling, and variable interest rates. In order to determine the borrowing base amount in case of a reserve based lending, debt service ratios have been determined. A stress analysis has been performed using the RiskAMP Excel add-in with variable oil and gas prices, cost of drilling and completion, initial production, initial decline rates, and correlation between oil and gas prices and cost of drilling and completion, and that between initial production and initial decline rates. In addition to this it also accounts for the risks associated with low production growths, early declines and late paybacks of shale oil and gas reserves.

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