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**Trade-offs and Implications of Two-stage versus One-stage
Unconventional Oil and Gas Exploration and Production Investment
Strategies: A Case Study of the Barnett Play**

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Strategies: A Case Study of the Barnett Play**

by

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Dedication

I dedicate this thesis to my beloved parents.

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Abstract

Trade-offs and Implications of Two-stage versus One-stage Unconventional Oil and Gas Exploration and Production Investment Strategies: A Case Study of the Barnett Play

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The University of Texas at Austin, 2017

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This study considers, first conceptually and then empirically using actual completion and production data, which unconventional investment strategy has superior profitability. In particular, it compares two-stage investment (single with infill drilling technologies) with one-stage investment (cluster drilling technology).

The conceptual model uses Net Present Value (NPV) analysis to discuss the plausible outcome and, also, lays the foundation for the empirical analyses. The empirical analyses comprise two parts – the first part examines a particular acreage to test whether incremental knowledge of geology results in reduced production uncertainty. The second part looks at various candidates across the Barnett play to compare the superiority between the strategies in terms of Expected Ultimate Recovery (EUR) and NPV.

The importance of the learning curve in assessing the production uncertainty is often overlooked in the economic evaluation of unconventional investments. As unconventional resources are extremely heterogeneous in their geological attributes, special attention must be paid to the individual acreage when addressing risks and corresponding economic values. The empirical analyses reveal that the risks do not necessarily decrease with time due to technological changes and/or lack of effort to develop a better understanding of the geology. As a part of the trade-off discussion, recovery profile, profit over time and information profile between the two investment strategies are emphasized. Other important factors that can affect the profitability of an investment include price and extent of cost savings.

Relatively little attention has been paid by academics on the economics of unconventional resource investment strategies. The present research strengthens the collective understanding of unconventional resource economics by suggesting some insights for unconventional resource producers to better assess their investment strategies.

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Chapter 1. Introduction

1.1. NATURAL GAS OVERVIEW

The Barnett is one of the oldest shale plays developed in the U.S., producing primarily natural gas, but also some liquids such as condensate and oil, especially in the western half of the play. Because the technological breakthrough of horizontal drilling and hydraulic fracturing in the early 2000s coincided with increasing natural gas price, the play was rapidly developed. The success in the Barnett play spread to other shale gas and tight oil plays, driving the dramatic growth of domestic U.S. oil and natural gas production (Figure 1).

<Figure 1> U.S. dry natural gas production by type (EIA 2017a)

The positive changes related to lifting the ban on crude oil export are characterized by the U.S. Congress as “domestic economic benefits, enhanced energy security, and flexibility in foreign diplomacy” (Upton 2015). Foreign governments welcomed this change. The Central Europe Energy Partners, the European Union level industry association representing the central European energy sector, mentioned “U.S. exports of crude oil and LNG would diversify and strengthen European domestic markets, as well as increase the efficiency of numerous industries, such as the refining and chemical industries” (Central Europe Energy Partners 2016). Due to these incentives, the U.S. became a net exporter of natural gas in 2016 and is projected to become a net exporter of oil by 2026 (Figure 2).

<Figure 2> Net trade for natural gas, oil, and coal for the U.S. (McConnel et al. 2017).

The majority of natural gas is consumed in the electric power and industrial sectors (Figure 3). The share of natural gas in U.S. power generation has been steadily increasing during the past few years, as natural gas has become more readily available, less expensive, and less volatile in price.

<Figure 3> U.S. natural gas consumption by sector in 2016 (EIA, 2016b).

Retiring coal power plants have been mostly replaced by natural gas as gas became cheaper and environmental regulations to protect air and water quality became more stringent¹ (Figure 4).

¹ Natural gas represents a much “cleaner” energy source: about 117 pounds of carbon dioxide are produced per million British thermal unit (Btu) equivalent of natural gas whereas coal and fuel oil produce more than 200 and 160 pounds of CO₂ per million Btu, respectively (EIA 2016a). Also, NO_x, SO_x, particulates and mercury are significantly less compared to coal.

<Figure 4> U.S. energy consumption by sources (EIA 2017a)

Since 2015, natural gas and coal have been essentially tied as the dominant sources of fuel for U.S. power generation, representing about two third of the fuel mix. (Figure 5).

<Figure 5> Annual share of U.S. electricity by energy source (EIA 2017c).

And natural gas power generation capacity is expected to grow more in the coming years driving an increase in gas consumption (Figure 6).

<Figure 6> Net annual change of natural gas powered electricity capacity in the U.S. (EIA 2017c).

Inspired by the U.S. success in shale resource development, other countries around the world are now making efforts to exploit their own shale resources, including China, Argentina, Australia, U.K, among others. Since the development of any resource depends highly on resource availability, quality and economics, special attention is required to understand the key geologic and economic characteristics of shale resources.

1.2. PREVIOUS STUDIES

Numerous relevant studies have been conducted that advance the collective knowledge of the economics of unconventional resources as well as production optimization strategies.

Yuan, Luo, and Feng (2015) recognized the need for a distinct approach when evaluating unconventional resources. They emphasized that the economics of shale gas development is fundamentally different from conventional resource development in several ways, with total production volumes, rate of production decline and production methods being some of the biggest contributors. Total production volumes and rate of production decline are largely influenced by inherited geological conditions such as pressure and permeability but low permeability of unconventional resources necessitate horizontal drilling with hydraulic fracturing to allow economic production.

Ikonnikova and Gülen (2015) offer an explanation of why U.S. natural gas production was sustained, despite the dramatic price drop and declining rig counts. In the big picture, improved geologic understanding and better technology allow for more efficient recovery. More specifically, oil and gas companies are price takers. Therefore, managing costs is extremely important to profitability. Operators can reduce costs through improved drilling and completion technology and/or by infill drilling which utilizes existing drilling pads and surface facilities. Because infill wells are drilled near wide-spaced single wells which have depleted some of the resource, infill wells tend to register lower production compared to earlier drilled, more widely spaced wells. Ikonnikova and

Gülen 2015 show that despite lower per-well production, infill wells can lead to a higher recovery in a given lease area. They argue that since companies are financially strained in a low-price environment, infill drilling can be an option to generate revenue with lower expenditures.

Similar to infill wells, cluster wells are also drilled from a single drilling pad. As defined here, main difference is that cluster wells are drilled in an undrilled area, whereas infill wells are drilled where single wells have already been drilled. Naturally, cluster wells tend to report higher production per well compared to infill wells. In general, cluster drilling has a cost advantage as well. Chatib et al. (2008) suggest that, in their applications in Indonesia, cluster drilling has led to an average reduction in the drilling and completion costs of more than 20% due to effective utilization of existing drilling pad.

The two most widely used metrics to evaluate investment options are net present value (NPV) and internal rate of return (IRR). NPV offers a discounted value of the investment over its lifetime whereas the IRR is the discount rate at which NPV of all cash flows is zero that needs to be compared to the weighted average cost of capital for the investment. There is no single valuation method that dominates. Rather, a number of methods are widely adopted, including NPV, IRR and payback period (Oblak and Helm Jr 1980). Osborne (2010) suggests that one reason why debate persists as to which method is superior has to do with the delay of financial practice catching up with theory. He argues that although both methods are widely used across large multinational corporations, IRR is often preferred “because of the ease of comparison with [their] cost of capital”. According to his research, the inferiority of IRR comes from the fact that it focuses on a

single rate, “thereby ignoring information from the cash flows conveyed by the other unorthodox rates of interest”. On the other hand, NPV takes into account “all the differences between every possible IRR [for an investment] and its cost of capital”. As a result, he argues that NPV is a ‘richer’ concept than the orthodox IRR by itself.

The research of Dixit and Pindyck (1995) is fundamental to this work as it relates to valuing options when making investment decisions. They argue that an investment opportunity is fundamentally an option – “the right but not the obligation to take some action in the future”. Given this perspective, the roles of “irreversibility, uncertainty and investment timing” become all-important. They outline the most critical issues that emerge when calculating the NPV: “how should the expected stream of profits [from a new investment opportunity] be estimated, how should inflation and taxes be treated, and perhaps most importantly, what discount rate(s) should be used”. They also argue that the underlying NPV assumption is often misunderstood, meaning managers often assume investment is “reversible or, if [it] is irreversible, it is a now or never proposition”. In most cases, including shale gas and tight oil development opportunities, these assumptions are not consistent with reality: the option to delay an irreversible expenditure can deeply affect the decision to invest. In this option view of investment, uncertainty is critically important because a small increase in uncertainty, whether it is diversifiable or not, can lead to a significant delay for some investments (those that require executing the options such as decision to drill an oil well) and a significant acceleration for others (those that create options or reveal information, such as R&D programs).

Related to the option consideration, Smit and Trigeorgis (2004) have explored flexibility and commitment. According to them, the flexibility view (e.g. two-stage development in this study) recognizes that there is “value in a wait-and-see or staging approach to decision making”, especially in an uncertain business environment, whereas the commitment view (e.g. one-stage development in this study) draws on the argument that an irreversible investment commitment can influence strategic behavior in desirable ways. They incorporate the real options and principles from game theory to improve the weakness of the traditional NPV method, which views investment opportunity as a commitment, rather than an option. Their improved NPV method not only captures “the expected cash flows from preset operations and strategies, ... [but also] incorporates the new dimensions of flexibility and strategic commitment”.

Their analysis reveals that the riskier an investment and the more volatile market conditions, the higher option value will be. They point out an important distinction between different development stages: the first stage explores and creates options for the second stage. They also lay out the sources of uncertainties companies face in each view. The one-stage investment is more vulnerable to market uncertainties, that are exogenous to the firm, as the operating cash flow risk exposure is concentrated at the time the investment decision is made. The two-stage investment introduces exploratory steps but each step still consists of uncertainties that are unique to each individual firm (such as technical, strategic, and organizational risks) that may or may not be reduced by earlier stages. One of the most important advantages of the two-stage investment approach is the cost reduction via

learning. The more complex the tasks, the more significant the effects of learning curve become. However, the rate of learning is likely to vary from company to company.

1.3. CONTRIBUTION OF THE PRESENT STUDY

This study focuses on unconventional production investment strategies from both conceptual and empirical perspectives. There are trade-offs between unconventional development investment strategies that producers must keep in mind. The cash-flow analysis model presented will not only serve as a road-map for unconventional development strategy evaluation, but it will also shed light on sources of risk or uncertainties. The analysis will incorporate the traditional valuation concept, NPV, but it will also consider geological attributes and technological considerations in order to derive insights that address reality more closely.

More specifically, this study will look at one-stage versus two-stage development by investigating rationale and profitability behind each strategy. The two-stage investment, as the name suggests, is carried out in two steps with some time in between the steps: during the first stage, a few wide-spaced single wells are drilled and in the second stage the acreage is fully developed by drilling closely-spaced infill wells near the single wells. In one-stage investment, the entire acreage is developed at once by multiple closely-spaced clustered wells, leaving little room for further drilling opportunities on the given lease (Figure 7). One of the key contributions of this paper is to shed light on the intrinsic nature

of the trade-offs between two-stage and one-stage investment strategies and their economic consequences.

<Figure 7> Two-stage versus One-stage investment strategies

In Chapter 2, a conceptual framework is presented outlining a general approach to evaluate the aforementioned unconventional investment strategies. The conceptual model will include a detailed discussion of the key parameters. In Chapter 3, actual production and completion data of selected candidates from the Barnett play are used and analyzed to gain deeper understanding of the assumptions made in the conceptual analysis and address the importance of learning effect to reduce production uncertainty. Chapter 4 compares the hypothesis from the conceptual model and the empirical findings and discuss the implications of this study for unconventional producers. Finally, Chapter 5 will summarize the results of this paper.

Chapter 2. Analytical Approach

2.1. CONCEPTUAL MODEL

This chapter begins by introducing a general conceptual framework to analyze investment profitability. The general model will then be modified to incorporate the characteristics of two-stage and one-stage investment. The subsequent discussion will walk through a list of key parameters that are critical to understanding the profitability and the trade-offs between the two investment strategies.

Discounted cash-flow analysis considers revenue, costs, and the discounting factor. NPV is a very useful measure in project evaluation, however, the NPV calculation neglects other important factors that affect the decision-making process (Graham and Harvey 2001). As discussed in detail in Dixit and Pindyck (1995), factors such as timing of investment, opportunity cost, information availability, and uncertainty play significant roles in the decision-making process as well. In the case of drilling a natural gas well, producers may take following factors into consideration:

- Uncertainty about geologic attributes in the location where they are planning to drill
- Uncertainty about expected well production, which is affected by both technology and geology
- Flexibility to drill wells in other locations
- Flexibility to save or spend more per well or per lease

This study investigates how some of these considerations may affect the producer's decision and the cumulative recovery profile. In other words, it will investigate whether a producer should develop any given lease all at once or in a two-stage deterministic manner. Depending on their decision, producers face different recovery and revenue profiles:

- One-stage or cluster wells, which allow a reduction in costs per well (but higher combined upfront costs than two-stage investment strategy) and provide higher recovery in the early stage of the production life cycle, or
- Two-stage, whereby single wells can provide additional information about geology to gather insights on how to complete wells to potentially increase the productivity for infill wells. In terms of revenue, this strategy will generate more constant revenue profile compared to the one-stage investment

The differences in recovery and the revenue profiles introduce risk and discounting variabilities. Uncertain market conditions such as price and cost fluctuations can also greatly affect profitability of an investment.

2.2. MAJOR ASSUMPTIONS

In this section, the key assumptions and parameters of the NPV model, which are crucial to understand profitability and differences between the two investment strategies, will be discussed.

Revenue

Revenue consists of two components: production and price. Production is measured as the amount of natural gas extracted per period of time, q_t . By summing up or integrating the production from a given well, one can calculate an expected ultimate recovery (EUR)². EUR can be calculated by summing up the observed production with the expected future production for the remaining duration of the wells' lives. The total production lifespans are set to be 15 years as it is sufficiently long to discover the difference between the investment strategies.

Price is a critical component that affects an investment's attractiveness. However, future prices are uncertain. For this reason, a deterministic approach has been adopted in this study. For each well, price of the year which it was drilled is used for the remaining years. In addition, in order to take into account the net price effect, taxes and royalties are subtracted from the revenue. In mathematical notations, revenue can be expressed as:

$$\int_{t=0}^{15} q_{ti}^{s,l,c} \cdot \tilde{p} \quad (1)$$

Where q_{ti} represents the monthly, t , production for each well, i , for single, infill or cluster technologies. For each well, integration over 15 year of productions, the cut-off

² Although it might not be necessary to know the maximum potential recovery to make an investment decision, breakeven points can be derived from the process that can be used as a measure of investment attractiveness.

point, then becomes the EUR. $\tilde{p}$ represents the net expected price, after subtracting taxes and royalties, which do not change over time.

$$\tilde{p} = p \cdot (1 - \text{taxes} - \text{royalties}) \quad (2)$$

Costs

Capital investments and operating costs are required in order to undertake any project. In a shale gas drilling project, these costs include drilling and completion costs, operating costs and other infrastructure costs.

- K^S : Drilling and Completion costs for a single well
- K^I : Drilling and Completion costs for an infill well
- K^C : Drilling and Completion costs for a cluster well
- $K_{o,c}$: Operating costs required to keep production going such as maintenance, technicians and utilities
- K_{pad} : Costs required to prepare a drilling pad

Operating costs and drilling pad costs are ignored in the actual analysis as they cancel each other out in the calculation.

Discount Factor

Upstream oil and gas companies seldom fund the entire project with cash owing to the scale of investments and the high-risk nature of the operation. There are two primary sources of capital: equity and debt whether a company is privately held or publicly traded. Naturally, borrowing capital comes with a cost, which is the investors' expected return on their investment. For this reason, the role of the discount factor is crucial in any economic analysis because it accounts for underlying risks unique to the particular project and the time value of money.

In this study, a continuous discounting form is used to better reflect actual circumstances. The discount factor for each drilling technology is expressed as following:

$$\delta_t^s = e^{-r^s t} ; \quad \delta_t^l = e^{-r^l t} ; \quad \delta_t^c = e^{-r^c t} \quad (3)$$

Risk, r , consists of two parts: cost of borrowing and production risk. When thinking about risk, it is important to recognize that the production risk is related to geological understanding; thus, an important assumption underlying the production risk is that the more the operator knows about the geology, the better chance the operator has in terms of drilling and completion success. Infill wells are drilled after the single wells by definition. Thus, when infill wells are drilled, the risk involved should generally be lower owing to the improved understanding of the geology. In the case of cluster wells, if they are drilled in the same year as the single wells, the underlying production risk would be

similar. However, if they are drilled after the single wells, the risk would be lower.

Mathematically, it can be expressed as:

$$r^s > r^l ; r^s \cong r^c \text{ (drilled same year)} ; r^s > r^c \text{ (cluster drilled later)} \quad (4)$$

Strategic Choices

Evaluating a shale well project, one can calculate NPV in a discrete or continuous form as follows:

$$\begin{aligned} NPV &= \sum_{t=1}^T \frac{(R_t - Taxes_t - OC)}{(1+r)^t} - K_{D\&C} - K_{pad} \quad (\text{discrete}) \\ &\approx \int_{t=1}^T e^{-rt} (R_t - Taxes_t - OC) - K_{D\&C} - K_{pad} \quad (\text{continuous}) \end{aligned} \quad (5)$$

where R_t is the estimate of the expected revenues; OC is operational cost; $K_{D\&C}$ is drilling and completion costs and K_{pad} is capital expense to prepare a drilling pad. In the following discussion, which will focus more on the drilling strategies, OC and K_{pad} will be neglected as they are small and unaffected by the strategic choice. More importantly, as it will be shown, they get cancelled out during the calculation process. T represents time period. Also, the NPV calculations are assumed in real dollar value. Thus, no inflation adjustment is required.

The NPV formula can be further extended to adopt the above-mentioned investment strategies.

- i) NPV of one-stage investment (Cluster wells)

$$\int_{t=1}^{15} e^{-r^c t} [q_{it}^c \cdot \tilde{p}] - K_i^c - K_{pad} \quad (6)$$

- ii) NPV of two-stage investment (Single and Infill wells)

$$\int_{t=0}^{15} e^{-r^s t} [q_{it}^s \cdot \tilde{p}] - K_i^s - K_{pad} + \int_{t=\tau}^{\tau+15} e^{-r^l t} [q_{it}^l \cdot \tilde{p}] - K_i^l \quad (7)$$

τ represents the time difference. For example, if the infill wells were completed two years after the single wells, τ would be 2.

For the NPV comparison between two-stage and one-stage investment, the difference in net present value is calculated.

$$\left[\int_{t=0}^{15} e^{-r^s t} [q_{it}^s \cdot \tilde{p}] - K_i^s + \int_{t=\tau^l}^{\tau^l+15} e^{-r^l t} [q_{it}^l \cdot \tilde{p}] - K_i^l \right] - \left[\int_{t=\tau^c}^{\tau^c+15} e^{-r^c t} [q_{it}^c \cdot \tilde{p}] - K_i^c \right] \geq 0 \quad (8)$$

2.3. DISCUSSION OF TRADEOFFS

Before embarking on empirical analysis using actual production and completion data, it is important to explore probable outcomes from this conceptual analysis. First, in terms of recovery, one-stage and two-stage investments have very different recovery profiles. Two-stage investment has two ‘humps’ of production. The second hump is the result of infill wells. In contrast, one-stage investment has higher initial production than two-stage owing to drilling similar number of wells in an untapped reservoir. Recovery translates into revenue. If the price stayed constant, this would mean one-stage investment

generates higher upfront revenue, whereas two-stage investment generates more constant revenue stream.

Second, in terms of costs, one-stage investment has higher upfront costs compared to two-stage investment, but the two-stage investment usually requires bigger total costs (if the number of wells between the two strategies are the same and once the costs are controlled) as it involves more expensive single drilling technology (Figure 8).

<Figure 8> General recovery profile of two-stage versus one-stage investment strategies

The question of which investment strategy generates higher NPV would very much depend on well performance³, commodity prices, and the extent of cost-saving from infill and cluster drilling. This argument regarding key factors affecting profitability of shale gas

³ To ensure an accurate assessment, it is also important to make it as a required condition that both strategies have the same geological conditions including OGIP and other rock characteristics.

drilling is supported by Ikonnikova et al. (2015), where the sensitivity analysis of the Fayetteville shale play revealed that two most important parameters in NPV calculation for a gas well drilling investment are Henry Hub natural gas price and drilling cost (Figure 9).

<Figure 9> Key factors affecting profitability of shale gas drilling project (Ikonnikova et al., 2015)

To summarize: 1) The more mature the play, the more likely it is for one-stage investment strategy to be a superior option. If a play is more mature, then operators would know more about how to develop their geology and, thus, one-stage investment strategy should result in higher profitability due to higher up-front recovery profile and the related reduced discounting 2) Lower per-well costs for one-stage would also likely make one-stage investment strategy superior over two-stage investment strategy owing to economies of scale. On the other hand, if the play is at an early development stage, naturally the risk would be high, and it should make the two-stage investment strategy more profitable because of increased opportunity to learn (although it has higher per-well costs).

Based on the given model and analysis, the following hypothesis can be drawn: since the Barnett play is the oldest shale play in the U.S., good understanding of the geology would translate into optimal completion practices by companies and, as a result, the EURs of the two strategies would be similar. Therefore, one-stage investment strategy would prevail in recent years owing to its discounting advantage as well as economies of scale resulting from the higher cost-saving.

2.4. MOTIVATION FOR EMPIRICAL ANALYSES

The conceptual model and major assumptions suggest a possible play development pattern. Chapter 3 will focus on empirical data analyses. A set of selected candidates will be analyzed using actual production and completion data to gain deeper understanding of the assumptions made in the conceptual analysis and derive EUR and NPV to compare between the conceptual hypothesis and the empirical evidence.

Chapter 3. Empirical Analyses

3.1. METHODOLOGY

The empirical analyses focus on wells drilled after 2007, when drilling technologies had become more developed in order to adapt to challenging market conditions. In order to test major assumptions underlying the hypothesis, in particular whether the production uncertainty indeed falls as a play becomes more mature, the first empirical analysis looks at an acreage where, over the years, one operator has drilled many wells. This area, which is designated as the Learning Zone, consists of multiple drilling technologies. By combining production and completion data with information on past market conditions, one can see the rationale behind the operator's technology choices and gain a deeper understanding of the production uncertainty involved. In the second empirical analysis, ten pairwise candidates across the play are selected where each candidate exhibits both one-stage and two-stage investment strategies. Then the NPV for each investment strategy is calculated to perform a pairwise comparison in order to find out which investment strategy has higher profitability. To minimize geographic and geologic bias, the two candidates are selected in close proximity to one another. Also, to ensure that both strategies draw from an equal amount of resource, geologic coverage is set equal for both strategies. Following the empirical analyses, Chapter 4 will discuss the results by comparing the conceptual hypothesis and the empirical findings to understand where the discrepancies occurred, if any.

3.2. EMPIRICAL ANALYSIS I: ACREAGE-BASIS ASSESSMENT (PRODUCTION UNCERTAINTY IN THE CONTEXT OF LEARNING CURVE)

Conceptually speaking, the more mature the play, meaning the lower the uncertainty about production uncertainty, the more likely it is that companies will pursue the one-stage cluster drilling, given a constant price, in order to maximize their profit resulting from economies of scale and bigger capital savings. On the other hand, if production uncertainty is high, due to technological or geologic risks, companies should be more prone to choose the two-stage development strategy where drilling the first stage reduces uncertainty by providing more information for the later second stage.

This expectation about producer's technology choice pattern is confirmed by actual examples. Learning Zone is located on the border between Denton and Tarrant counties (Figure 10) and many horizontal wells are drilled between 2009 to 2012 in this location (Figure 11). Out of 37 wells drilled in Learning Zone in 2009, 28 have comprehensive completion and production data and were analyzed. Following these criteria, 46 wells were analyzed for 2010; 17 for 2011; and 11 for 2012.

<Figure 10> Location of Learning Zone within the Barnett original-gas-in-place (OGIP) Map (located in a high OGIP area, between 80 and 90 Bcf/mi²) (Ikonnikova et al. 2014)

<Figure 11> Learning Zone horizontal drilling map, shown by lateral well leg lines and colored by the year they are drilled. Red circles drawn around the mid-points of each well, with the radius of 200 ft., help to illustrate the proximity among wells

The period of 2009 through 2012 is characterized by relatively low price of natural gas compared to mid-2000s, averaging around 4 dollars per MMBtu (Figure 12). The low-

price environments forced producers to rethink their strategies and led some of them to revisit acreage. Observing the development pattern of Learning Zone allows for a better understanding of why companies might prefer certain drilling technologies over others.

<Figure 12> Henry Hub Natural Gas Spot Price (EIA 2017)

2009

Owing to aggressive drilling activities prior to 2009, the number of highly attractive drilling locations within the Barnett play was diminishing. In an attempt to save costs on drilling and completion, as well as recover commercially significant volumes of gas,

operators started experimenting with close-spaced drilling⁴ as indicated by blue-colored lateral wells from 2009 (Figure 11).

The operator tested different combinations of treatment fluid, which mainly consists of water and proppant, in an attempt to find out the optimal completion method to maximize production. Water volume ranged from 1660 to 2960 gal/ft. and proppant volume ranged from 1780 to 2840 lbs/ft. (Figure 13). Low production was registered in the low and high water application ranges – under 2,180 gal/ft. and above 2,480 gal/ft. In the medium range, production showed large fluctuations. The fact that there is a non-linear relationship between production and water/proppant applications suggests that the operator had not yet optimized completions using close-spaced drilling technology. It is worth noting that well spacing and landing depth horizon are inconsistent among the 2009 wells; some of them are extremely close (Figure 14 and 15). Studies have shown that closely-spaced wells can lead to interference and in the worst case result in decreased EUR (Ikonnikova et al. 2014).

⁴ Ikonnikova and Gülen (2015) conducted research on ‘Impact of Low Prices on Shale Gas Production Strategies’

<Figure 13> Water and Proppant used for completion in 2009

<Figure 14> Inconsistent well spacing for 2009 wells (McDaid 2016)

<Figure 15> Inconsistent landing depth horizon for 2009 wells

2010

Partially owing to the continuing low price environment⁵ and in the face of a decreasing inventory of good drilling locations, the infill drilling technique was widely adopted in the Barnett play in 2010. By drilling new wells in close proximity to the single

⁵ Prolonged low-price environment can put producing companies in a financially unfavorable position, making it harder to get capital for new investments and cover operational expenses. As a result, companies may be prone to cut their spending by drilling wells that require less capital.

wells from the original drilling pad, infill drilling allowed producers to reduce their drilling and completion costs. Grey-colored wells indicate the wells drilled in 2010 by the same operator (Figure 11).

As in 2009, the operator tested completions with varying amounts of water and proppant. Adopting the new infill drilling technology meant, however, that they had to reassess the water and proppant input ranges, as the previous year's learnings might not be applicable with this new approach. Water applications range from 600 to 3380 gal/ft. and proppant applications range from 1050 to 2800 lbs/ft. (Figure 16). The production shows that, similar to 2009, wells report very low production under 2,100 gal/ft. and above 2,600 gal/ft. of water, regardless of the amount of proppant injected. In the medium range, there are big fluctuations of production, suggesting that the operator had not reached the mature stage of their learning curve. It is also apparent that well spacing is irregular among these wells (Figure 17 and 18).

<Figure 16> Water and Proppant used for completion in 2010

<Figure 17> Inconsistent well spacing for 2010 wells (McDaid 2016)

<Figure 18> Inconsistent landing depth horizon for 2010 wells

In 2010, the operator learned several important lessons on how to approach developing this geology. First, they started with higher amounts of water in their testing. Initial water application jumped from 1,660 to 2,000 gal/ft., except for a few anomalies. This lesson is a direct result of the 2009 testing: wells below 2,180 gal/ft. water applications

all registered very low production. The 2010 wells within the range of 1,660 to 2,180 reported on average of 44% improvement in production compared to 2009, from 380,793 to 546,907 Mcf.

Second, it can be observed that some wells had extremely poor performance, thereby increasing the production uncertainty variability or risk. Investigating these wells more closely, one can see that these wells are drilled very close to one another (the top right corner of Figure 11). By looking at their geological attributes, with the help of 3D visualization, it was determined that these wells were drilled into faults (Ewing 1990). The orange line and the orange plane below represent the fault (Figure 19 and 20).

<Figure 19> 3D representation of the 2010 wells on top of a Ewing-mapped fault

<Figure 20> 3D representation of drilling design of the 2010 wells on top of a Ewing-mapped fault

Often times companies try to avoid drilling close to a fault in the Barnett because it can result in connecting into the Ellenberger aquifer which is sealed by the Viola Limestone. If a well penetrates this layer, “there is a danger that hydraulic fractures will propagate into the Ellenberger and flood out” (Sparkman, Belhadi, and Waters 2009) (Figure 21).

<Figure 21> 3D representation of landing depth horizon of the 2010 wells in relation to fault mapped by Ewing (1990) (dark green line represents the lower limit of Viola-Simpson formation and the light green line represents the lower limit of Lower Barnett formation. The light grey line below represents the upper limit of Ellenberger carbonate which is a porous, karsted limestone that is water bearing)

Third, the operator applied water and proppant in a much more gradual manner in 2010 than 2009 (Figure 22 and 23). This allowed them to make stronger conclusions about the relationships between the input parameters and the production, e.g. extremely low and high ranges of water and proppant applications usually result in low production.

<Figure 22> Water Application Level Difference (2009 and 2010)

<Figure 23> Proppant Application Level Difference (2009 and 2010)

2011

The operator adopted cluster drilling technology in 2011. Cluster drilling offers some advantages over infill drilling. First, cluster wells generate ample cash flow in the early years. Second, cluster technology makes designing wells easier because they are drilled into non-depleted rocks. Third, in some cases, cluster wells use less treatment fluid through improved engineering, thereby saving cost⁶. For these reasons, cluster drilling could be an appealing strategy although it requires higher upfront capital investments. Green-colored wells in the Figure 11 shows the cluster wells drilled in 2011.

With the application of this approach, the operator decided to cut the water level by more than half and started from 880 gal/ft. as opposed to 2,000 gal/ft. in 2010. Similarly, with proppant, operators started from 1,150 lbs/ft. as opposed to 1,950 lbs/ft. in 2010. Another important observation is that the operator started injecting proportionately more proppant than water.

The water applications range from 880 to 2,320 gal/ft. and proppant applications range from 1,150 to 3,000 lbs/ft. (Figure 24). Importantly, high production is reported even with very low water and proppant application (below 900 gal/ft and 1,180 lbs/ft, respectively). Relatively low production is registered in the higher water and proppant application range, especially above 1,900 gal/ft. of water. Another significant observation is that well number 16 stands out with good production performance, even with very little

⁶ With natural gas price staying low from 2014-2016, it is possible that companies encountered difficulty finding investors who were willing to lend them capital. In such case, the value of cash at hand increases.

proppant injection, signaling that operators did not need to inject a lot of proppant into other wells. Also, large production fluctuations in the medium application range suggest an inefficiency remains in well design, perhaps in well spacing. Some wells are drilled extremely close to each other, likely causing some interference (Figure 25 and 26).

<Figure 24> Water and Proppant used for completion in 2011

<Figure 25> Inconsistent well spacing for 2011 wells (McDaid 2016)

<Figure 26> Inconsistent landing depth horizon for 2011 wells

2012

A sharp decline in rig count began in 2012 (IHS 2014) (Figure 27). Not much drilling activity is seen after 2012⁷ in Learning Zone (Figure 11).

⁷ The price of natural gas declined further in mid-2011. Discouraging price projections forced companies to cut their spending budgets and minimize drilling activities.

<Figure 27> Barnett Rig Count

A total of 11 wells were analyzed for 2012. The operator maintained a cluster technology approach in 2012 as indicated by the yellow-colored wells (Figure 11).

Predictably, the operator injected lower amounts of water and proppant. Water applications range from 970 to 1,100 gal/ft. and proppant applications range from 580 to 1,270 lbs/ft. (Figure 28). In 2012, they felt confident enough to inject relatively steady levels of water and proppant. Somewhat surprisingly, there is noticeably less fluctuation in production level, suggesting that the operator has converged on an optimized method to develop this geology. This includes longer horizontal wells, averaging at 7,703 ft., and stable landing designs and consistent spacing (Figure 29 and 30).

<Figure 28> Water and Proppant used for completion in 2012

<Figure 29> Inconsistent well spacing for 2012 wells (McDaid 2016)

<Figure 30> Inconsistent landing depth horizon for 2012 wells

It is also worth noting that the operator concentrated landing wells in the right depth horizon, between -6,670 ft. and -6,860 ft., in later years (Figure 31).

<Figure 31> Landing Depth Horizon by Year

Now, using the first 12-month cumulative production data in conjunction with individual well attributes, one can develop insights regarding learning. The power function⁸ allows one to measure the rate of improvement in gas production by the operator through the process of trial and error of different completion combinations.

⁸ After testing various trendline options (including exponential, linear, logarithmic, polynomial, power and moving average), it was determined that using power function is reasonable for the purpose of this investigation. The parameter α serves as a scaling factor, either increasing or decreasing the value of x^β and the parameter β measures the function's rate of growth or decay. In this case, β measures the overall slope of the production curve (Mueller 2014).

$$\text{Power function: } f(x) = \alpha x^\beta \quad (9)$$

In Learning Zone, the data indicate that the operator achieved a 48% improvement in gas production using various combinations of water and proppant, and lateral length in 2009 (Figure 32). The 118% improvement in 2010 suggests that there was a significant improvement in gas production via the learning process compared to 2009. The improvement of 33% in 2011 suggests a slowing down potentially due to reaching mature stage of the learning curve. Finally, the 23% improvement in 2012 confirms that the operator has nearly reached an optimal position on the learning curve.

<Figure 32> Annual rate of improvement in gas production via completion and length improvement

The important learnings include i) an optimal range of water and proppant for any lateral length, ii) the importance of well spacing to reduce fracture interference, and iii) the importance of landing wells in the right depth horizon to minimize interference.

Since β reflects the learning process through improvement in gas production, one can test how it affects production uncertainty. Production uncertainty can be estimated by observing the magnitude of deviation in production. Production uncertainty should decrease as learning matures and it can be calculated by using the coefficient of variation (dividing the standard deviation of the first 12-month cumulative production divided by its average production). This is expressed as:

$$\sigma = \frac{\sqrt{\frac{\sum (x_i - \bar{x})^2}{n-1}}}{\frac{\sum x_i}{n}} \quad (10)$$

In Learning Zone, the production uncertainty for each year is as follows (Table 1).

Year	Gas Production Improvement (β)	Production Uncertainty
2009	0.4842	37.12%
2010	1.1775	52.57%
2011	0.3336	33.35%
2012	0.2347	19.14%

<Table 1> Annual rate of gas production improvement and production uncertainty

Learning process plays a critical role in understanding production uncertainty. The increase from 2009 to 2010 suggests that the production uncertainty may not necessarily decrease with time due simply to technology change when there is lack of geological understanding. Uncertainty decreases from 2010 to 2011 as the operator optimized drilling and completion practices from the improved knowledge of the geology. Consistent with the learning curve, risk continues to falling from 2011 to 2012.

From the empirical analysis of Learning Zone, the following can be discerned: i) how incremental knowledge of a particular geology is understood in the context of learning curve, ii) how underlying production uncertainty can be reduced through systematic experiments over a period of time, and iii) why the technology change alone cannot inform operators of an optimal method to develop a particular geologic region, i.e. risk remains unchanged without the learning from experiments.

3.3. EMPIRICAL ANALYSIS II: PLAY-WIDE ASSESSMENT (ECONOMIC EVALUATION VIA EUR AND NPV)

The second empirical analysis consists of evaluating various candidates across the play to test for an unbiased superiority of one investment strategy over the other. In doing so, ten candidates are selected according to the following criteria:

- Equal geological coverage (surface area) between the one-stage and two-stage strategy
- Proximity between the one-stage and two-stage strategy

- Well drilling pattern
- Time lag between the one-stage strategy and two-stage strategy
- Various examples across the OGIP zones in the play

The first criterion makes sure that both strategies have an equal amount of access for the resource. The second criterion ensures that, for each candidate, both strategies have the same geological characteristics⁹. If the play contained multiple horizons, like the Permian basin, a more sophisticated approach using 3D visualization mapping would be required. The third and fourth criteria ensure that the selected candidates fit the purpose of this study. Finally, the fifth criterion was set to eliminate any bias resulting from a particular geology.

Through pairwise comparison of the EURs and NPVs in these selected candidates, one should be able to see clearly whether the results unambiguously point to one strategy or not. The locations of the ten candidates are shown in the following map (Figure 33).

⁹ In spite of the fact that the Barnett play consists of a single horizon, it has many heterogeneities and the assumption of uniform geology may be incorrect in detail.

<Figure 33> Locations of ten selected candidates for pairwise comparison of strategies

The close-up images of these candidates are shown below (Figure 34). By observing the drilling pattern in each candidate closely, one can determine which strategy the operator chose. For instance, for candidate 1, the two-stage investment strategy was

performed on the left side (drilling a single well first in 2010, followed by the infill wells in 2012 and again in 2013) and the one-stage investment strategy was performed on the right side (drilling cluster wells in 2012).

<Figure 34> Close-up images of the candidates (McDaid 2017)

In order to calculate the NPV for each strategy in each candidate area, the mathematical framework developed in the conceptual analysis is used. Each component for the NPV is derived using actual production or completion data. In the following

subsections, the revenue component, comprising EUR and prices, is analyzed first, then the cost component, comprising drilling and completion and other costs, and finally the discount factor, is considered.

Expected Ultimate Recovery (EUR)

The per-well EUR's were originally generated by Patzek, Male, and Marder (2013). In their work, they calculated the EUR's of 8,294 wells in the Barnett Shale, using both actual production data and a conceptual approach¹⁰, to estimate the decline rates for shale gas production over 20 years. The result was a 1 over square root of time for the early-time regime and exponential decline for the late-time regime (Figure 35).

¹⁰ Their study is noteworthy in two ways. "First, it is an excellent example of parsimonious modeling: the development of a minimal-ingredients model that enables [it] to explain observations. Second, their theory can be used to estimate, with limited data, lower and upper bounds of cumulative production" (Cueto-Felgueroso and Juanes 2013)

<Figure 35> The gas production rate prediction model (Patzek, Male, and Marder 2013)

This analysis uses an expanded data set which consists of 18,184 wells for which EURs are determined in the same methodology as Patzek, Male, and Marder (2013). Then, the selected wells' EURs are selected from the 18,184 wells and added to determine the total EUR of each strategy (Table 2).

Candidate	Investment Strategy	Total EUR (Mcf)	Higher EUR Strategy ¹¹
1	2-Stage	1,842	1-Stage
	1-Stage	2,114	
2	2-Stage	8,338	2-Stage
	1-Stage	4,783	
3	2-Stage	12,215	2-Stage
	1-Stage	10,731	
4	2-Stage	10,083	2-Stage
	1-Stage	8,737	
5	2-Stage	4,983	2-Stage
	1-Stage	1,431	
6	2-Stage	704	2-Stage
	1-Stage	262	
7	2-Stage	11,694	2-Stage
	1-Stage	11,143	
8	2-Stage	4,935	2-Stage
	1-Stage	1,785	
9	2-Stage	7,001	2-Stage
	1-Stage	6,663	
10	2-Stage	11,150	2-Stage
	1-Stage	7,236	

<Table 2> Pairwise EUR comparison among ten candidates

Price

NYMEX futures prices are used for natural gas and oil (Table 3). If a well was drilled in 2012, the NYMEX futures price for year 2012 is used across the life of the well, assigned to be 15 years.

¹¹ Since the one-stage strategies were implemented after the learnings from the single well(s) in the two-stage strategies, it is actually part of a multi-stage process.

Year	Average Price of Gas	Average price of Oil
2007	6.46	74.00
2008	8.41	100.36
2009	3.69	58.31
2010	4.27	79.11
2011	3.94	95.10
2012	2.60	95.07
2013	3.67	97.69
2014	4.37	94.24
2015	2.57	49.61

<Table 3> EIA future price for natural gas and oil (EIA 2017d)

Drilling and Completion Costs

Drilling and completion costs for each well are calculated according to their unique attributes such as horizontal length, vertical depth and amount of water and proppant used. As mentioned earlier, infill and cluster drilling technologies allow operators to save some costs by drilling from the same drilling pad. The estimated drilling and completion costs for each well of the ten candidates and the sum of the costs for each investment strategy are summarized in Table 4¹². As assumed in the conceptual analysis, in 8 out of 10 candidates, the two-stage investment strategy has higher drilling and completion costs, confirming the cost-saving benefit of the one-stage approach.

¹² Risk-free rate adjustment is ignored since the effect is marginal at best.

No	Technology (year)	D&C Costs	D&C Sum	No	Technology (year)	D&C Costs	D&C Sum	
1	Single (11)	4,100,098	12,362,343	6	Single (09)	2,598,548	9,370,238	
	Infill (12)	3,036,054			Infill (11)	2,954,001		
	Infill (13)	2,540,204			Infill (11)	3,817,689		
	Infill (13)	2,685,987			Cluster (11)	3,658,258		
	Cluster (12)	3,790,821	Cluster (11)		3,603,877	11,168,803		
	Cluster (12)	4,099,246	Cluster (11)		3,906,668			
	Cluster (12)	3,434,389	Single (09)	3,762,031	7		Infill (11)	4,032,480
	Cluster (12)	3,469,046	Infill (11)	3,278,937				
2	Single (13)	3,221,963	Infill (11)	4,056,827		10,999,737		
	Single (13)	2,739,673	Infill (11)	3,165,550				
	Infill (14)	2,737,862	Cluster (12)	2,914,746				
	Infill (14)	2,747,475	Cluster (12)	2,432,540				
	Cluster (14)	2,465,425	Cluster (12)	2,901,920				
	Cluster (14)	3,268,108	Cluster (12)	2,750,531				
3	Single (09)	3,568,108	16,869,297	8		Single (09)	2,634,555	16,318,230
	Single (09)	3,342,894			Infill (12)	2,412,707		
	Single (09)	3,814,609			Infill (12)	3,469,451		
	Infill (11)	3,094,214			Infill (12)	3,897,765		
	Infill (11)	3,049,472	13,364,190		Infill (12)	3,903,752	15,742,219	
	Cluster (10)	3,432,901			Cluster (13)	3,943,311		
	Cluster (10)	3,253,503			Cluster (13)	3,896,159		
	Cluster (10)	3,876,258			Cluster (13)	3,866,488		
4	Cluster (20)	2,801,529	17,695,943		9	Cluster (13)	4,036,262	11,465,754
	Single (11)	2,939,823		Single (09)		5,117,790		
	Infill (14)	2,335,512		Infill (11)		2,973,826		
	Infill (14)	2,049,566		Infill (11)		3,374,139	9,389,160	
	Infill (14)	3,393,616		Cluster (11)		3,656,925		
	Infill (14)	3,568,511		Cluster (11)		2,843,014		
	Infill (14)	3,408,915		Cluster (11)	2,889,221			
	Cluster (13)	3,100,726		13,491,881	10	Single (07)	4,336,262	25,801,431
	Cluster (13)	3,718,772				Single (07)	5,142,490	
	Cluster (13)	3,398,992	Infill (08)			5,417,790		
Cluster (13)	3,273,391	Infill (12)	3,273,826					
5	Single (11)	2,476,772	11,060,089	Infill (12)		3,674,139		
	Infill (12)	3,082,249		Infill (12)		3,956,925		
	Infill (12)	2,761,929		Cluster (14)		3,143,014	9,905,998	
	Infill (12)	2,739,138		Cluster (14)		3,189,221		
	Cluster (14)	3,054,852	8,748,694	Cluster (14)		3,573,762		
	Cluster (14)	3,076,937						
	Cluster (14)	2,616,905						

<Table 4> Pairwise drilling and completion costs comparison among ten candidates

Other Costs

As previously mentioned in Chapter 2, the operating costs and drilling pad costs are excluded from the empirical analysis as they cancel each out in the NPV calculation, assuming that they don't change dramatically from one year to another. This is helpful since these costs are not usually publicly available.

Discount Factor

The discount factor is set at 8% per year. Generally 8% to 15% is considered reasonable for conventional projects for major producers (Smith 2003). Since unconventional projects have a lower dry hole risk, 8% is reasonable.

Net Present Value (NPV)

The cash flow analysis was run on Mathematica software following the same mathematical structure as demonstrated in the Equation 6 and 7 in the conceptual model using actual drilling and completion data previously shown in this chapter (Table 5).

Candidate	Investment Strategy	NPV ¹³	Superior Strategy
1	Two-stage	2,473,784	Two-stage
	One-stage	2,120,169	
2	Two-stage	14,404,700	Two-stage
	One-stage	3,065,425	
3	Two-stage	13,940,896	Two-stage
	One-stage	9,115,579	
4	Two-stage	10,745,322	Two-stage
	One-stage	3,069,129	
5	Two-stage	134,862	One-stage
	One-stage	4,885,160	
6	Two-stage	6,169,638	Two-stage
	One-stage	3,027,519	
7	Two-stage	4,847,896	One-stage
	One-stage	7,060,466	
8	Two-stage	1,306,321	One-stage
	One-stage	9,658,481	
9	Two-stage	3,865,447	One-stage
	One-stage	8,400,414	
10	Two-stage	4,664,694	One-stage
	One-stage	11,347,776	

<Table 5> Pairwise NPV comparison among ten candidates

The second empirical analysis has demonstrated the EUR and the NPV for each investment strategy from the ten selected candidates. In the case of EUR, the two-stage strategy is dominantly superior (8 out of 10). However, in the NPV result, the outcome is mixed (5 and 5 for each strategy). In the following chapter, these results will be further discussed to get better understanding of the reasons behind these discrepancies. Also, the

¹³ Risk-free rate adjustment is ignored for NPV calculations as well since the effect is marginal at best.

conceptual hypothesis will be compared with the empirical outcomes to derive useful insights for unconventional producers.

Chapter 4. Results

4.1. CONCEPTUAL HYPOTHESIS VERSUS EMPIRICAL EVIDENCE

In this chapter, a summary of what has been learned from the empirical analyses, as well as comparison between the conceptual assumptions and the empirical evidence, will be discussed. First, from the first empirical analysis, it was confirmed that the learning process leads to a reduction in production uncertainty. Without an improvement in drilling and completion practices as a result of improved understanding of geology, production uncertainty does not naturally decrease with time, thereby suggesting that our assumption about similar EUR between the two strategies in a mature play might be incorrect. In the second empirical analysis, it was shown that nine out of ten candidates generated higher EUR's for the two-stage investment strategy, confirming our assumption about similar EURs between the two strategies in a mature play was incorrect. From this, it is possible to derive the following insight: even if the Barnett is a mature play, there is enough heterogeneity in the geology and among all the variables in the completion process that producers still produce more from the two-stage process where they are incorporating learnings.

Second, the hypothesis that with increasing play maturity the profitability of the one-stage investment should exceed that of the two-stage investment is not confirmed by this analysis. As discussed in the previous paragraph, EUR was bigger in the two-stage investment strategy. But this does not mean that the two-stage strategy has superior

profitability because the profitability depends on factors other than just the production. In fact, natural gas price and drilling and completion costs play more important roles in determining profitability (Figure 9). As a result, the NPV analysis showed a mixed outcome; taking into account the price and cost effects, sometimes one-stage investment strategies can outperform two-stage strategies (Table 6).

Finally, the assumption regarding larger cost savings, per well, for the one-stage investment strategy turned out to be correct in eight out of ten candidates (Table 4), providing an additional incentive to pursue a one-stage investment strategy.

Candi-date	Investment Strategy	Year (Base Year)	Higher EUR Strategy	Higher NPV Strategy	Reasons for Switching the Position in NPV
1	Two-stage	2013 (2011)	One-stage	Two-stage	Low gas price in 2012, thereby deteriorating the profitability of one-stage investment (Figure 35)
	One-stage	2012			
2	Two-stage	2014 (2013)	Two-stage	Two-stage	-
	One-stage	2014			
3	Two-stage	2011 (2009)	Two-stage	Two-stage	-
	One-stage	2010			
4	Two-stage	2014 (2011)	Two-stage	Two-stage	-
	One-stage	2013			
5	Two-stage	2012 (2011)	Two-stage	One-stage	Low gas price in 2012, thereby deteriorating the profitability of two-stage investment (Figure 39)
	One-stage	2014			
6	Two-stage	2011 (2009)	Two-stage	Two-stage	-
	One-stage	2011			
7	Two-stage	2011 (2009)	Two-stage	One-stage	Higher capital costs for two-stage investment, thereby deteriorating the profitability of two-stage investment (Figure 41)
	One-stage	2012			
8	Two-stage	2012 (2009)	Two-stage	One-stage	These wells are oily and higher prices in 2013, thereby boosting the profitability of one-stage investment (Figure 42)
	One-stage	2013			
9	Two-stage	2011 (2009)	Two-stage	One-stage	Higher capital costs for two-stage investment, thereby deteriorating the profitability of two-stage investment (Figure 43)
	One-stage	2011			
10	Two-stage	2012 (2007)	Two-stage	One-stage	Higher capital costs for two-stage investment, thereby deteriorating the profitability of two-stage investment (Figure 44)
	One-stage	2014			

<Table 6> Reasons for discrepancies between the EUR and the NPV results

It is that market factors, mainly price and costs, have a strong impact on investment's profitability. In some cases, investments with much bigger EURs produced lower NPVs due to deteriorating price or higher capital costs (Compare Table 6 with Figure 36, 40 and 42 through 45).

<Figure 36> Cumulative Recovery Profile – Candidate 1

<Figure 37> Cumulative Recovery Profile – Candidate 2

<Figure 38> Cumulative Production Profile – Candidate 3

<Figure 39> Cumulative Production Profile – Candidate 4

<Figure 40> Cumulative Production Profile – Candidate 5

<Figure 41> Cumulative Production Profile – Candidate 6

<Figure 42> Cumulative Production Profile – Candidate 7

<Figure 43> Cumulative Production Profile – Candidate 8

<Figure 44> Cumulative Production Profile – Candidate 9

<Figure 45> Cumulative Production Profile – Candidate 10

4.2. IMPLICATIONS

Given the complex nature of shale resources, operators should pay close attention to the concept of a learning curve. Simply put, unless operators have accumulated in-depth knowledge about a particular geology through concentrated efforts, they would be better off with a two-stage investment strategy in terms of EUR. With a two-stage investment, companies have direct observation of the relationship between the input parameters and the output, which allows them to some degree to eliminate approaches that do not work.

Under certain scenarios, operators might consider choosing a one-stage well completion investment strategy. If the price is highly favorable in the current year, higher risk could be offset by higher revenue streams. Under such circumstances, it would be

preferable to financially hedge their assets, to eliminate the downside risks and protect their investment value from market volatility. Another scenario where one-stage might be a better choice is the case when operators can significantly reduce the capital investment for one-stage development. For example, an operator might have negotiated a favorable service company contract, or the costs of input materials might have dropped due to over-supply.

Companies must make prudent judgments when it comes to choosing their strategy based on available market information, knowledge about the geology, negotiations with contractors, and the financial and strategic circumstances of their company.

Chapter 5. Conclusion

This study has contributed to the understanding of unconventional resource development strategies by addressing the following question: should acreage be developed in a one-stage manner with all the wells drilled at once or in a two-stage manner where several individual wells are drilled first, followed by infill wells?

The uncertainties in market conditions (especially price and, to some degree, costs), production levels (due to sub-optimal practices in drilling and completion process) and the extent of infrastructure and operating cost reduction through technology choices pose great challenges for operators when evaluating investment strategies. The heterogeneous rock properties make one successful completion combination in one location unsuccessful in a different location. And, in order to reach a certain level of optimized practices, one has to go through much trial and error, the so-called learning curve. This imposes a significant risk on unconventional producers that can, at times, offset the high dry hole risk found in conventional resources.

This work establishes that there is no clear-cut superior strategy and preferred choice should depend on producers' unique circumstances as well as future market expectations. Major sources for uncertainty must be considered and evaluated by an operator: first, other things remaining the same, two-stage investment usually generates higher production. This is because having direct experience with the geology by drilling single wells first allow producers to gain additional information about the geology which then can be applied to increase the performance of the later-drilled infill wells. Second,

natural gas and crude oil prices can offset even large differences in EUR between the two strategies. Therefore, if market conditions improve and producers capture that opportunity by acting quickly, a one-stage investment strategy can be worthwhile. An important assumption here is that the producers lock in price through financial instruments such as forward or future contracts. Finally, cost reductions can bring about the same effect as higher prices. Thus, if producers can get a big discount in costs for cluster technology through favorable negotiations with contractors, this would also boost the profitability of the one-stage investment strategy.

In summary, assessment of unconventional resource projects requires producers to apply a bottom-up approach. Operators need to learn the geology and go through project-specific cost analyses; only then can they decide which strategy to undertake. Even with the best analyses and forecasts, there will always remain uncertainties that cannot be diversified nor eliminated.

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Vita

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