MARKET IMPACTS AND GLOBAL IMPLICATIONS OF U.S. SHALE DEVELOPMENT AND HYDRAULIC FRACTURING: AN ECONOMIC, ENGINEERING, AND ENVIRONMENTAL PERSPECTIVE

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Abstract

The United States oil industry is experiencing a revolution because of significant oil production from tight oil plays since the mid-2000s. Advancements in horizontal well drilling and hydraulic fracturing are powering this new chapter in oil development. Increased oil production has brought billions of dollars of new revenue to oil companies involved in tight oil exploration and production, new jobs in the oil industry, and more tax revenue to oil regions around the U.S. However, tight oil resources do not only exist in the U.S. An understanding of the U.S. tight oil development experience could bring value to stakeholders within and outside the United States, and provide lessons and templates applicable in other tight oil regions. This research examines the U.S. tight oil experience and draws lessons for aspiring tight oil regions on the engineering, economic, and environmental fronts.

On the economic front, I have examined an autoregressive distributed lag (ARDL) model on key oil industry macroeconomic data (West Texas Intermediate oil price, tight oil production, and rig count) from 2007 through 2016, and the impact of oil price on tight oil development for the Bakken, Eagle Ford, Niobrara, and Permian tight oil plays. The results show that oil companies in different plays react differently to oil price signals and do so in relation to oil field development characteristics. In addition, oil production and drilling intensity in the Eagle Ford play is found to be most responsive to oil price increases than the Permian, Bakken, or Niobrara oil plays. The Permian play was most resilient during the 2014 through 2016 oil price plunge. Oil production does not fall in response to a decrease in oil price, equally as it rises in response to oil price increase. Tight oil operators are quicker in bringing drilling rigs to service as prices rise than they take them away in response to falling oil prices, but do reduce drilling significantly in response to an oil price plunge. These results have significant ramifications for operators and assets in the respective oil plays or future plays with similar development characteristics.

On the engineering front, I used petroleum engineering oil production forecasting Decline Curve Analysis techniques, the Drillinginfo Software, and historical development data of U.S. plays, to conduct oil production forecast for seven U.S. tight oil plays. Forecast results are shown to be comparable to forecasts by the Energy Information Administration (EIA). Building on previous EIA geologic studies on non-U.S. tight oil plays, and by selecting best analogues from within

U.S. tight oil plays, I have completed an economic assessment and uncertainty analysis for 10 non-U.S. tight plays using a simple fiscal tax regime. The results indicate that the Eagle Ford play in Mexico, the Vaca Muerta play in Argentina, and the Qingshankou play in China rank highest among the plays studied. Of oil price, royalty rate, discount rate, well cost, extraction tax, and recovery factor parameters evaluated, results indicate that oil price and well cost are among the biggest drivers of profitability in these plays.

On the environmental front, I conducted case studies on the busiest U.S. tight oil plays (Bakken and Eagle Ford) and examined the impact of tight oil development on the environment. Local solutions to environmental challenges alongside environmental regulations are discussed and presented as possible templates for other aspiring plays. Since securing freshwater sources alongside wastewater management emerge as major issues in tight oil development, a cost comparison is conducted for reused water disposal versus one-use water disposal options, for a hypothetical development. Results indicate that on a cost-per-well basis, the reduction in water disposal volume from subsurface frack flowback retention improves water reuse economics; the water reuse option is preferable to one-use water disposal for U.S. oil plays. This result points to potential cost savings for reused water disposal in regions such as the Bakken with few disposal wells.

Table of Contents

List of Figures

List of Tables

Acknowledgement

Dedication

To my late parents and to my family.

Abbreviations

EIA	Energy Information Administration
EPA	Environmental Protection Agency
BDF	Boundary Dominated Flow
BOE	Barrels of Oil Equivalent
BOPD	Barrel of Oil per Day
WTI	West Texas Intermediate
DCA	Decline Curve Analysis
TOC	Total Organic Carbon
R%	Reflectivity Index
RF%	Recovery Factor (in Percent)
ARDL	Autoregressive Distributive Lag
MMbbl	Million barrels (M = 1000)
Mscf/day	Thousand standard cubic feet of gas per day
PSI/FT	Pounds per square inch of pressure per foot of depth (Pressure gradient)

CHAPTER 1. THE U.S. SHALE REVOLUTION

1.1.   Introduction

Oil and gas production in the United States has increased significantly, thanks to petroleum resource development in shale and other tight plays. U.S. oil production recorded an 88% increase from 2008 through 2015, and natural gas production increased by over 50% from 2005 through 2015 (IOGCC, 2016). Tight oil production has become a backbone of U.S. oil production and now contributes 52% of U.S. total crude oil production (U.S. Energy Information Administration (EIA), 2017a). The impact of this new era of oil production is seen in different aspects of the U.S. oil industry and the nation's economy in general. It has led to renewed revenue streams for mineral property owners, and increased tax revenue for local counties, state, and the federal government. The level and mix of U.S. crude import has also been affected. In 2014, domestic oil production broke a 20-year record by exceeding imported crude (IOGCC, 2016).

New levels of U.S. crude oil production have also led to structural changes in the global oil market. The U.S. constitutes a significant share of global crude oil consumption. Over the last 20 years the U.S. consumed over 20% of global crude oil supply (BP, 2016a). For the last decade, U.S. oil production has grown to cover a larger fraction of U.S. consumption. Thanks to tight oil production, the U.S. ranks first in gas production since 2011 and crude oil liquids production from 2013 through 2015 (EIA, 2016a). Crude oil and condensate production growth in the U.S. from 2010 through 2015 constituted over 75% of the net new barrels added into global oil production (IOGCC, 2016).

Prior to the U.S. tight oil revolution, U.S. production had been on a decline and the lifeline of oil production rested mostly on marginal wells and enhanced oil recovery operations in ageing fields. Marginal wells are wells that are not sufficiently profitable to keep online as a result of very low oil rates or very high costs of production (IOGCC, 2016). In 2005, over 70% of wells operated in the U.S. were marginal wells (IOGCC, 2016). Examples are wells that are far from the transportation (including roads, railways or pipeline) necessary to bring their product to market. Stripper wells, which constitute wells that have oil production under 10 barrels of oil per

1

day (bopd), or 15 barrels of oil equivalent (boe) (EIA, 2010), for a period of one year, also fall under the marginal well category (IOGCC, 2016). From 1995 through 2009, over 80% of the oil wells in the U.S. produced under 15 barrels of oil equivalent per day (EIA, 2010). These wells are costly to produce and require high oil prices to become profitable. As a result, regulatory changes alongside major, targeted state and federal tax breaks have been designed to sustain oil production from marginal wells. For example, in the state of North Dakota, marginal wells pay no production tax and EPA laws provide selective regulatory relief to this category of wells (EPA, 2000; ND Century Code, 2017a). The contribution of marginal well production to total U.S. oil production has declined from 14% in 1992 to 8% in 2015, thanks to production increases recorded due to tight oil resource development (Figure 1; IOGCC, 2016).
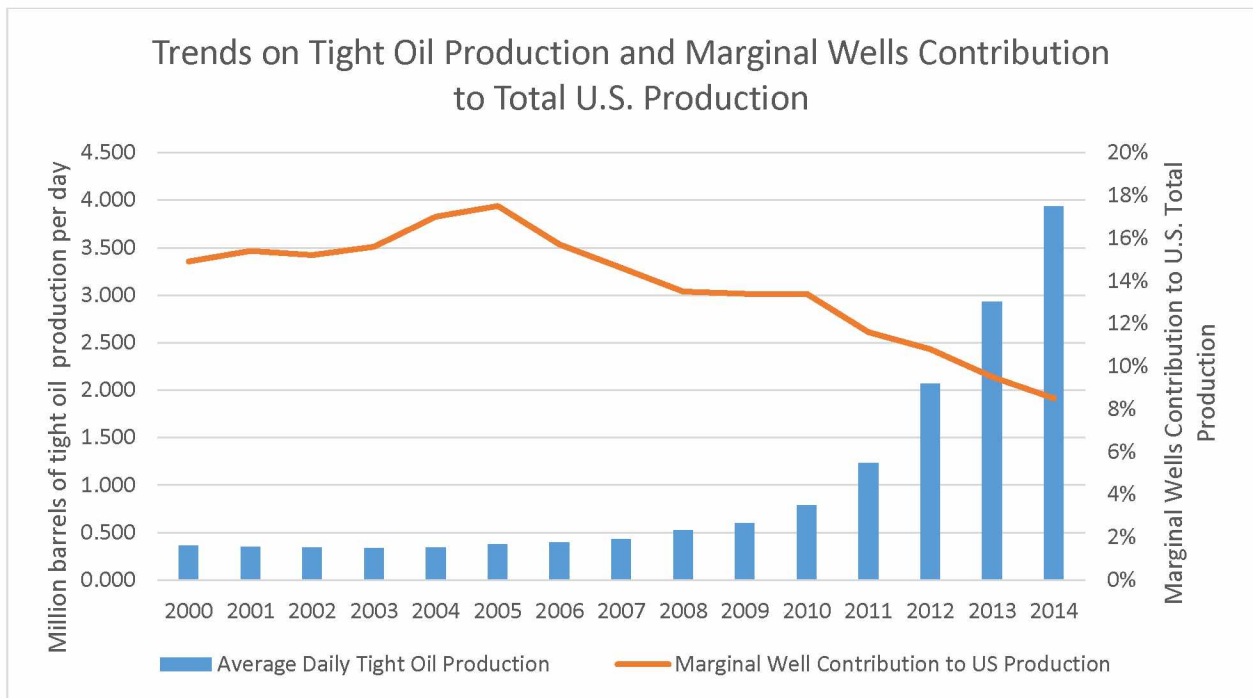
Figure 1. Impact of Tight Oil Production on U.S. Marginal Well Contribution to Production (EIA, 2017a; IOGCC, 2016)

Enhanced oil recovery has also been another pillar supporting U.S. oil development. For ageing fields that have undergone reservoir pressure enhancement techniques (e.g. waterflooding) other enhanced techniques are applied to keep production ongoing. The third tier of techniques

(tertiary/enhanced oil recovery (EOR) techniques) is typically aimed at altering the viscosity of the fluid or properties of the rocks containing hydrocarbons so as to increase the ability of the fluid to flow and be produced. These are typically costly techniques and often times the benefits are marginal. Examples are chemical flooding, polymer flooding, and carbon dioxide flooding. Examples like carbon dioxide flooding have been in use by the industry for over three decades and have also provided the twin incentive of furthering oil production and partially sequestering the CO_2 that is used. Policy makers and stakeholders of this idea have even pushed for a nationwide CO_2 pipeline network to further increase CO_2 EOR and carbon dioxide sequestration ambitions (IOGCC, 2010). But this has not worked so far and is likely to be delayed or pushed off consideration as a result of options requiring less effort in terms of public policy and infrastructural spending and delayed profitability compared to tight oil development in the U.S..

Tight oil development in the last decade has been powered mainly by technological leaps in two areas: horizontal well drilling and hydraulic fracturing (Financial Times, 2015; Maugeri, 2013). Horizontal drilling refers to a practice of drilling wells that target petroleum resources vertically into the ground until a specified depth and then deviating and continuing to drill horizontally within the rock formation, mostly in a 90 degree angle from the vertical direction. Hydraulic fracturing, on the other hand, is a well completion technique whereby water or other fluids containing chemicals and solid proppants are injected at high pressures down a well and into rocks, to fracture and extend fractures encountered within the zone a well has drilled through. Hydraulic fracturing is crucial to the development of oil because of the nature of the rocks that have powered this new era of U.S. production. The goal of the hydraulic fracturing technique is to allow the sand particles to fit into fractures and 'prop' or keep the rock spaces open to allow for the flow of petroleum liquids or gas from the rock formation into the well. That is why the solids mixed in hydraulic fracturing fluid are referred to as proppants. The rocks being fracture-stimulated are referred to as tight rocks because of their low permeability, and a good example of this category of rocks is shale.

Shale is a category of sedimentary rocks, known for its role as source rock for most petroleum basins. Shale contains organic matter that has existed under high pressure and temperature for millions of years and is buried sufficiently deep enough to transform into kerogen and then into

petroleum oil and or gas. Shales are known for low permeability, or limited ability to allow fluid flow through them. They are not the only low permeability rocks that exist, so this category of rocks is referred to as tight rocks. Examples of other tight rocks are fine-grained sandstones, carbonates, mudstones, and siltstones. Rock permeability refers to the ability of rocks to allow fluid to flow through them and tight rocks are characteristically of low permeability. Compared to conventional rock formations that range from 5 millidarcies to over 1000 millidarcies, tight oil formations are typically below 0.1 millidarcy and could go as low as a few hundred nanodarcies (100×10^{-9}) (Slatt, 2006). As a result of their low permeabilities, tight rocks require enhanced techniques to improve rates of oil or gas production and ultimately increase the quantity of petroleum oil or gas that could be recovered from the accessed formations.

The wide scale application of new horizontal drilling techniques derives from the use of better technology to position wells within thin layers of formation thousands of feet under the ground with greater precision, and the ability to drill for longer distances, oftentimes over two miles, horizontally within the rock. Additionally, hydraulic fracturing breakthroughs have enabled oil exploration and production companies to open up tight rocks that have been previously ignored due to difficulties in drilling within the layers or the very low and uneconomic production rates that result when these rocks are drilled. Low permeability rocks are considered tight because they don't allow oil and gas to flow at rates that could quickly provide a revenue base and make the business venture worthwhile. The ability to open these rocks further (stimulate the rocks) through hydraulic fracturing has increased production rates by several fold leading to greater profitability.

Tight formations have always existed in the U.S. and other places in the world. These formations are rocks like fine-grained sandstone, siltstone, and shale. These rocks are considered tight because of their characteristic low permeability which enable them serve as barriers to oil and gas flow and constituting development targets for oil and gas explorers. Shale makes up a significant share of tight rocks and is considered a source rock for all petroleum systems. In the presence of adjacent conventional or more permeable formations, hydrocarbon oil and gas migrate naturally until meeting some barrier, where it aggregates within this trap system and becomes a petroleum reservoir target for exploration. In tight formations, these resources do not

migrate at all or far enough and are still very much associated with the shale rock in which they formed or in other tight rocks closely associated with shale (Jarvie, 2012). Tight formations exist in several other nations across the world. The U.S.has 48 billion barrels of technically recoverable shale oil resources and alongside China, Argentina, Algeria, Canada, and Mexico make up over 65% of globally available technically recoverable shale gas resources (EIA/ARI, 2013). In 2015 the U.S. produced 4.9 million barrels of tight oil daily, and in the same year exceeded 13 trillion cubic feet of tight gas production (EIA, 2016b; EIA, 2016c).

Tight oil development is different from previous oil development waves in that, previously, oil development occurred in conventional rocks. Among other differentiating characteristics, conventional rocks are more permeable and do not require extensive stimulation to enable them produce economically. As a result of this relative ease in development, the number of associated business activities stimulated by conventional onshore resource development were less compared to tight oil development. Due to the resource intensive nature of tight oil development, other businesses involved in the logistics of sand and water supply are required to sustain the massive completion activities required for each tight oil well. Tight oil and gas development, because of hydraulic fracturing operations, require vast amounts of water during the completion stage of the well. A typical hydraulic fracturing operation requires between two to six million gallons of water and thousands of gallons of chemicals (Fracfocus, 2016). This water requirement leads to logistical challenges that include truck transportation of water among the other necessary activities that constitute drilling operations. This resource spread, energy involvement, and operational footprint has drawn criticism from environmental activists and the public.

Tight oil and gas wells typically experience faster decline especially in the first few years of production. Maugeri (2013) noted decline rates as high as 50% in the first year of production compared to the rate of production during the first month. The second and third years also see another annual rate decline of approximately 30% (Maugeri, 2013). As a result, maintaining healthy production from any asset requires continually drilling new wells. This is different from conventional oil and gas development where, after the initial capital outlay in wells and facilities, relatively minor capital and operating expenditures are required to maintain production over a 20 to 30-year field life. Since typical well costs are historically higher for tight resource wells than

conventional wells, while production is more sustained in conventional wells, the economics of tight oil and gas wells relies on a smaller margin, shorter cycle projects with more turn over to stay profitable.

1.2.   US Tight Oil Development Success Story

The implications of successful tight oil and gas production have been vast for the U.S. this past decade. Besides returning the U.S. to first place status in hydrocarbon liquids and gas production, oil and gas development activity has resulted in increased employment across the country and especially among the states where oil exploration is extensive. From 2005 to 2011, with shale development leading the oil and gas industry expansion, upstream oil and gas jobs grew by over 120,000 (Brown & Yucel, 2013). This excludes the support industries that have spun from activities powered by the upstream sector of the oil industry. The Oil and Gas industry contributes approximately 2.7% of non-farm employment in a state like Texas (Texas State Government, 2015). In 2011, thanks to the shale boom, the U.S. oil and gas industry contributed 1.6% to the U.S. GDP (Brown & Yucel, 2013).

The implications for tight resource development have also been global. The U.S. has consumed over 20% of the crude oil consumed globally since 1965 (BP, 2016a). As a result, the U.S. has become a dependable market for crude oil around the world. Strong shipping routes have been forged from major producers and producer blocs like the OPEC into the U.S. (BP, 2016a). The rise of shale and other tight oil production within the U.S. has been, simply put, disruptive to the world oil system as it was forged over the last half a century. Many OPEC nations that were major exporters of crude oil to the US, such as Nigeria, have seen remarkable loss of U.S. market share, due to the replaceability of those barrels by tight oil barrels (EIA, 2016j). Following this dire turn of events, new routes of oil transport are forged towards other global population centers and energy intensive economies in Asia, such as China, India, and developing economies like Brazil.

Due to advances in tight oil development, from 2011 to 2012, the U.S. recorded an annual crude oil and lease condensate reserve increase of 4.5 billion barrels, the largest yearly increase in oil reserves in over 35 years (EIA, 2014a). Petroleum reserves refer to those quantities of petroleum resources that can be produced with current technology and are economical to produce (PRMS, 2011) and a growth in reserves is the surest way of ensuring future oil production. Reserves also mean increased valuation of companies that hold those assets in their portfolio. Reserve reports for 2014 show another year-on-year increase in reserves for the sixth year in a row bringing U.S. reserves to over 39 billion barrels, driven by growth in tight oil development (EIA, 2015a).

Tight oil and gas development has also led to a surge of capital in the U.S. oil and gas industry. The EIA (2013a) reported that 73 deals in shale oil and gas plays, from 2008 through 2012, injected over $130 billion into tight resource development. In 2014 alone, over 40,000 wells were drilled and $120 billion invested in oil and gas production in the U.S. (BP, 2015). These investments mean organic and inorganic growth of companies, wealth for shareholders, benefits to support industry and revenue to state and local governments in major oil and gas regions of the country.

1.3.   Motivation for the Research

For the last half a century, shale rocks have been the rocks to avoid by drilling engineers while pursuing conventional targets. This is as a result of the huge instability of the rocks and the potential of losing the entire drilled wellbore upon an unplanned encounter with shale rocks downhole during drilling operations. In placing a range on porosity and permeability, the science of petroleum engineering considers porosity levels in the single digits and permeabilities of ~0.01 millidarcies as poor (Slatt, 2006). These characteristics have become almost axiomatic in the development of oil for almost a century. But following progressive changes in the technology of oil and gas development, this is the first period in the life of the oil and gas industry where these *forgotten* resources have been targeted systematically with astounding results.

In Oct 1970, the U.S. produced over 10 million barrels of oil per day on average thanks to multimillion dollar projects all across the finest rocks in the country and in the Gulf of Mexico

7

(EIA, 2017c). By year 2000 the local production had dropped to 5.8 million barrels of oil per day with a majority of that coming from over 400,000 marginal wells struggling at production rates of less than 20 barrels of oil a day around the country (EIA, 2010; EIA, 2017c; IOGCC, 2016). Following almost half a decade of successful shale gas development, by 2012 a new chapter was being written in the renaissance of oil production in many shale and other U.S. tight oil plays. By 2015, the amount of U.S. oil production contributed specifically by tight oil development reached 50% (EIA, 2017b). While tight oil development has seen some pilot projects and limited successes in places like Canada and China, only the U.S. has sustained a production momentum reaching up to 4.9 million barrels of oil per day from these tight rocks (EIA, 2017b). It is in the interest of most stakeholders of the industry to understand the new phenomenon cutting across the U.S. and this is the motivation for this work; also, to understand the possibilities and limitations to transferring this success to other regions with these same resources.

1.4.   Statement of Problem

The rise of U.S. oil production has had global ramifications on oil production, supply, and trade. Crude oil and refined petroleum products imported from 2000 to 2012 amounted to over 2.8 trillion dollars in trade deficit for the U.S. (CFR, 2014). Rebounding oil production translates into reduction in importation of crude oil of similar quality, reduction in national spending to overseas oil producing nations and major rebalancing in foreign trade. This also places some downward pressure on oil and gas prices locally, reduces spending on fuels in local manufacturing operations and increases profitability of businesses within the country.

Several nations around the world with tight oil resources similar to the U.S. would benefit from a similar reinvigoration of their economies, especially nations with high energy-intensive economies. The success of the U.S. in harnessing tight oil and gas, therefore, raises a wide range of questions in the minds of global stakeholders in the oil and gas industry. These questions range from the nature of the rocks and technology that yielded this windfall to the systems that have enabled it to thrive. And since several nations possess these same resources, the natural question that follows is: what key lessons can the U.S. experience provide for tight oil development in other countries?

While geologic understanding and engineering leaps have contributed to the tight oil revolution, the economic and regulatory dimensions of the tight oil experience have been no less contributory to the success of the phenomenon. With ramifications that spill into different sectors of the economy, questions into the nature of the success of the U.S. tight oil experience are best discussed within an unrestricted framework. As a result, this work explores the engineering, economic, and regulatory dimensions of the U.S. tight oil revolution.

1.5.   Research Scope and Focus Questions

To investigate the many sides of the U.S. tight oil experience, several questions and schools of thought are developing. This work addresses a single theme: What are the factors that have enabled the U.S. tight oil revolution which could help others keen to replicate this success story? To discuss this central theme the ensuing chapters discuss the geologic formations, the economic conditions, and environmental regulations that have enabled the U.S. to emerge successful in developing tight oil resources. Ialso investigate the impact of oil prices on the development of tight oil resources and the economic viability of tight oil development projects in other regions in the world that have significant quantities of tight oil resources.

1.6.   Structure of Research

This research is structured in six chapters. Chapter one introduces the research issue, the problem statement and the research scope. Chapter two discusses the U.S. crude oil industry and the systemic pillars that have enabled this major shift in this industry. This chapter concludes with a summary of the specific factors that have contributed to the flourishing of tight oil development. Chapter three introduces oil production forecasting techniques that are applied in planning and development of tight oil. This chapter conducts a tight oil production forecast for the US, and conducts an economic assessment of non-US tight oil plays, highlighting potential non-US regions where tight oil development could occur. Chapter four investigates the impact of oil price on oil development within an econometric framework, using the Autoregressive Distributive Lag model (ARDL) technique. Chapter five examines the evolving environmental

regulatory efforts that support tight oil development in some of the key U.S. oil plays. This chapter also shows cost assessment for two water disposal scenarios. The last chapter, chapter six, summarizes the key findings in this research and concludes on the possible future of tight oil development outside the US. This chapter also highlights areas of the research that would be relevant to the analysis, which are currently outside the scope of this work.

CHAPTER 2. THE U.S. PETROLEUM SYSTEM AND THE BIRTH OF U.S. TIGHT OIL DEVELOPMENT

2.1. Introduction

Petroleum resources are classified as conventional or unconventional resources based on the rock formations in which the resource is found or the flow properties of the resource. Most petroleum resources developed to date fall under the conventional category and the methods used in their extraction have come to be the conventional methods. Conventional oil and gas resources are oil and gas resources that have good viscosity or flow properties and exist in rocks with good porosity and permeability. The porosity of a rock is the amount of pore space the rock contains as a percentage of the rock volume; rock permeability refers to the ability of a rock to let fluids pass through it. Porosity is measured in percentages while permeability is measured in units called darcies. Formations with porosity values above 20% and permeability values above 100 millidarcies are considered of good quality (Slatt, 2006).

Another consideration in classifying conventional oil is the ease with which oil flows. This property is referred to as the viscosity of the fluid. Fluid viscosity also refers to the fluid's internal resistance to flow and is measured in units called poise or centipoise (cp) (Tarek, 2001). Rock porosity and permeability, alongside fluid viscosity are important properties for any oil and gas play because without that ability for fluids to flow easily or sufficient porosity and permeability of rock formations, the oil extraction process becomes more energy and cost intensive. Oil development in rocks with low permeability and porosity, such as is experienced in tight oil plays, or highly viscous fluid, constitutes unconventional resource development. Figure 2 shows a grouping of conventional versus unconventional resources.

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                    ┌─────────────────────┐
                    │ Petroleum Resource  │
                    │    Development      │
                    └─────────────────────┘
              ┌──────────────┴──────────────┐
    ┌──────────────┐                ┌──────────────┐
    │ Conventional │                │Unconventional│
    └──────────────┘                └──────────────┘
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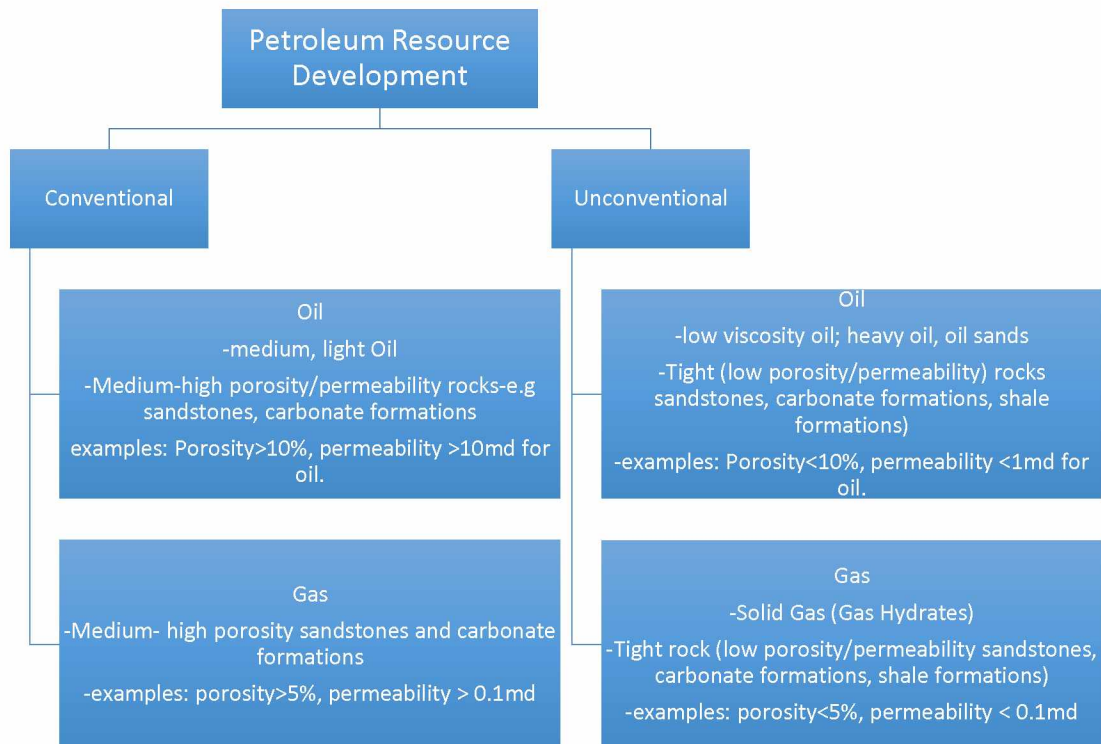
Figure 2. Classification of Oil and Gas Resource Types (Modified from Slatt, 2006)

Conventional — Oil
-medium, light Oil
-Medium-high porosity/permeability rocks-e.g sandstones, carbonate formations
examples: Porosity>10%, permeability >10md for oil.

Conventional — Gas
-Medium- high porosity sandstones and carbonate formations
-examples: porosity>5%, permeability > 0.1md

Unconventional — Oil
-low viscosity oil; heavy oil, oil sands
-Tight (low porosity/permeability) rocks sandstones, carbonate formations, shale formations)
-examples: Porosity<10%, permeability <1md for oil.

Unconventional — Gas
-Solid Gas (Gas Hydrates)
-Tight rock (low porosity/permeability sandstones, carbonate formations, shale formations)
-examples: porosity<5%, permeability < 0.1md

Tight oil and gas development entered the U.S. mainstream conversation in the mid-2000s with the successful shale gas production operations in the Appalachian Basin, east coast of the United States. Other plays in the South, such as Haynesville, Woodford, Fayetteville, Barnett, and Eagle Ford rank among the top gas plays in the US. The experience gained in gas developments was quickly applied in plays containing hydrocarbon liquids and in hybrid plays that included both conventional and unconventional formations (Financial Times, 2015). Resource development in conventional plays provided a pivot from which to test and push the boundaries of tight oil development while maintaining profitable ventures in areas where the producers were already comfortable and had sufficient understanding. The successes of operators like EOG Resources Inc. and Brigham Exploration in drilling wells that produced at economic rates in low quality rocks shone the light on tight oil development, which has now become central to U.S. oil production (Financial Times, 2015).

2.1.1.   Tight Oil Resources

Tight oil is petroleum crude oil found in low porosity and permeability rocks. These rocks are typically very fine-grained sandstones, siltstones, mudstones or shale. The permeability of shale formations is in the tens to hundreds of nano-darcies and the crude oil in these rock formations cannot be released without the help of well stimulation technology such as hydraulic fracturing (Medeiros et al., 2008). Unlike sandstones and siltstones, shale rocks are the most abundant clastic sedimentary rocks (EIA, 2015b) and are different because, for most of the history of oil development, they have served two key functions, as petroleum source rock and reservoir seal (Selley, 1998). Shale is the source rock from where hydrocarbons are generated because they contain large quantities of organic material. Also, shale rocks are renowned petroleum reservoir seals or traps because of their relatively low permeability and their ability to block continuous flow of fluid hydrocarbons through more permeable sandstone and other reservoir rocks, after hydrocarbons are generated.

Once generated and liquefied through millennia of pressure and heat, under subsurface pressure differentials and structural changes in rock, petroleum oil and gas migrate out of shale rock into more permeable rocks (Selley, 1998). Because of barriers to fluid flow posed by structural, lithological or stratigraphic changes in rock formations, oil and gas is trapped in portions of the formation known as reservoir traps. These trap locations become conventional targets for oil and gas exploration and development. In the case of tight oil, very little or no migration of petroleum occurs after it is generated in the shale rocks (Jarvie, 2012). For this reason, in tight oil development, the source rocks are closely associated with the reservoir rocks or are themselves the reservoir rocks (Jarvie, 2012).

Due to the role of shale in the origin of crude oil and its association with tight oil plays, most of the early literature on tight oil development referred more to shale oil development. And even other sources confused shale oil with oil shale (Maugeri, 2013). Oil shale is different and also a significant energy resource estimated at over 0.5 trillion barrels of globally recoverable volumes (Selley, 1998). But oil shale rocks cannot produce oil without being heated. The difference between oil shale and shale oil, according to Chaudhary (2011), is that oil shale contains solid

organic-rich kerogen which has not reached the thermal maturity required to generate liquid or gaseous hydrocarbon phases. On the other hand, shale oil is crude oil produced from shale or mudstone rocks that are rich in organic matter. Shale is just one among other tight rocks that are part of the U.S. oil production boom (EIA/ARI, 2013). The focus of this work is on tight oil, which is largely contained in shale rocks, but also in other tight sandstones, siltstones and carbonates. After drilling a well to access this resource, the technique of hydraulic fracturing is required to produce crude oil that is trapped in tight rocks.

Hydraulic fracturing is an operation carried out after the well is drilled into the oil-bearing formation, for the purpose of creating, extending, and maintaining fractures adjacent to the path the well has drilled through, to enable more fluids from the rock to flow to the well (Figure 3; EPA, 2016a). The process uses millions of gallons of water and mainly sand grains called proppants, to prop open the fractures, and thousands of gallons of chemicals to facilitate the operation. Water and sand make up over 95% of the fluid mixture. Hydraulic fracturing operations are carried out for both tight oil and tight gas development and over 60-80% of wells drilled in the next 10 years in the U.S. will require this operation (Fracfocus.org, 2010).

Chemical Mixing Phases

Pre-Pad: Acid and/or chemical may be injected to clean the well

Phase repeated for each stage:
Perforation: To create openings in the well to access targeted geologic formation
Pad: Inject base fluid and additives into the formation to initiate fractures
Proppant: Inject proppant with base fluid and additives to grow and prop open fractures
Flush: Fluid injected to push proppant remaining in well into fractures

Vertical Well Section

Hydraulic Fracturing Stages

Stage 1: Chemicals & Proppant Injected → Stage 2: Chemicals & Proppant Injected → Stage 3: Chemicals & Proppant Injected → Stage 4: Chemicals & Proppant Injected

Horizontal Well Section

Perforations

Figure 3. Overview of Hydraulic Fracturing Process (Modified from EPA, 2016a)

While the availability of tight oil resources and the application of hydraulic fracturing contributed to the increase in U.S. oil production, several other factors enabled the flourishing of tight resource development in the US. The next section investigates the systemic and direct drivers of tight oil development in the US.

2.1.2.   The U.S. Crude Oil System and Drivers of U.S. Tight Oil Development

Sustained U.S. tight resource development began in the mid-2000s and has changed the face of the U.S. oil and gas industry. Since the last decade, the U.S. tight oil industry has seen a steady expansion, even amidst fluctuations in production resulting from oil price fluctuations. To understand the inception, expansion and fluctuations in U.S. tight oil development, it is important to review the workings of the U.S. petroleum system. Since oil and gas is a global resource, some elements of the U.S. petroleum system will trace linkages to the global petroleum system. This section discusses the U.S. petroleum system as foundational to any structural shifts

15

in the U.S. petroleum industry, such as the birth of tight oil development. While in the last decade that shift was in the development of tight oil and gas, it is important to note that, the petroleum system is shown to broadly underpin potential future developments within this industry. Figure 4 is an illustration of the relationship between the U.S. petroleum system and the drivers of U.S. tight oil development.
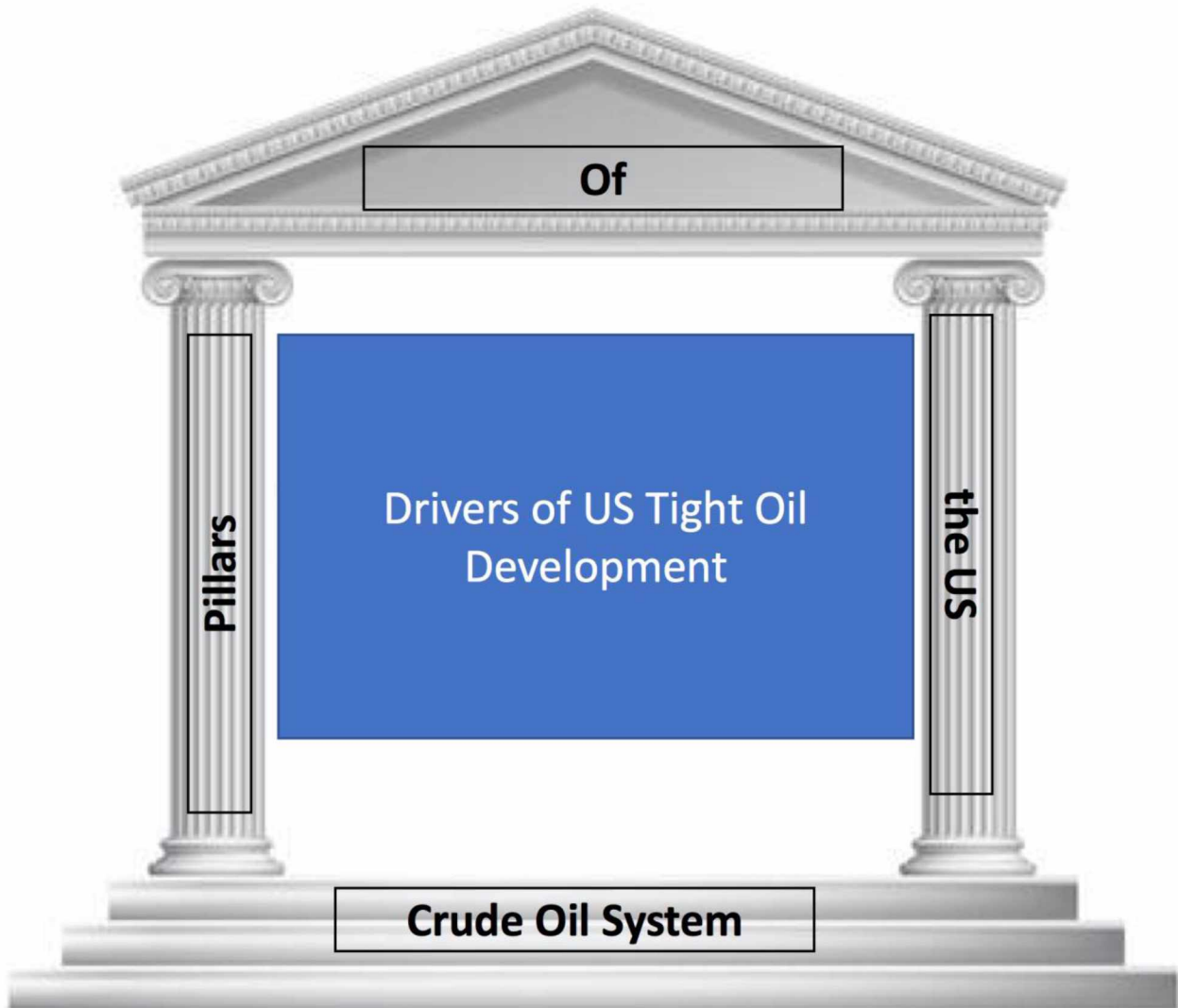
Figure 4. The U.S. Crude Oil System and Drivers of U.S. Tight Oil Development

2.2. Pillars of the U.S. Petroleum Crude Oil System

To understand the tight oil revolution that has sustained U.S. oil production in the last decade, it is necessary to review the functioning of the U.S. petroleum system. According to the EIA

(2017m) seven drivers of crude oil prices include (1) OPEC supply, (2) Non-OPEC supply, (3) OECD demand, (4) non-OECD demand, (5) crude oil spot prices, (6) crude oil stock or inventory balance, and (7) financial markets. While these may explain oil price movements, together with other factors they form the building blocks of the U.S. petroleum crude oil system. It is hard to consider the U.S. as a separate segment of the global oil market because of the integrated nature of the global oil system. For example, the U.S. oil industry is a price taker and so is influenced by global prices. For this reason, while the U.S. is a non-OPEC and an OECD nation, feedback from OPEC supply and Non-OECD are included in the list of components of the U.S. oil system as part of a global integrated system.

A more comprehensive picture of the U.S. crude oil system includes upstream, midstream and downstream sections of the oil industry. As a result, in addition to the EIA factors, other factors that constitute the U.S. crude oil system discussed in this chapter include crude oil transportation, crude oil refining and U.S. demand as a separate segment of OECD demand. These, therefore constitute 10 pillars of the U.S. petroleum crude oil system: (1) U.S. crude oil production, (2) U.S. crude oil transportation, (3) U.S. crude oil refining, (4) U.S. crude oil consumption, (5) crude oil inventory balance, (6) financial markets, (7) OPEC supply, (8) Non-OPEC supply, (9) OECD demand and (10) Non-OECD demand. The framework established by understanding the linkages within the U.S. system will facilitate assessment of the drivers within this system that enabled tight oil development. This understanding is necessary to discuss the potential workings of other petroleum states and their ability to sustain tight oil or other unconventional oil resource development.
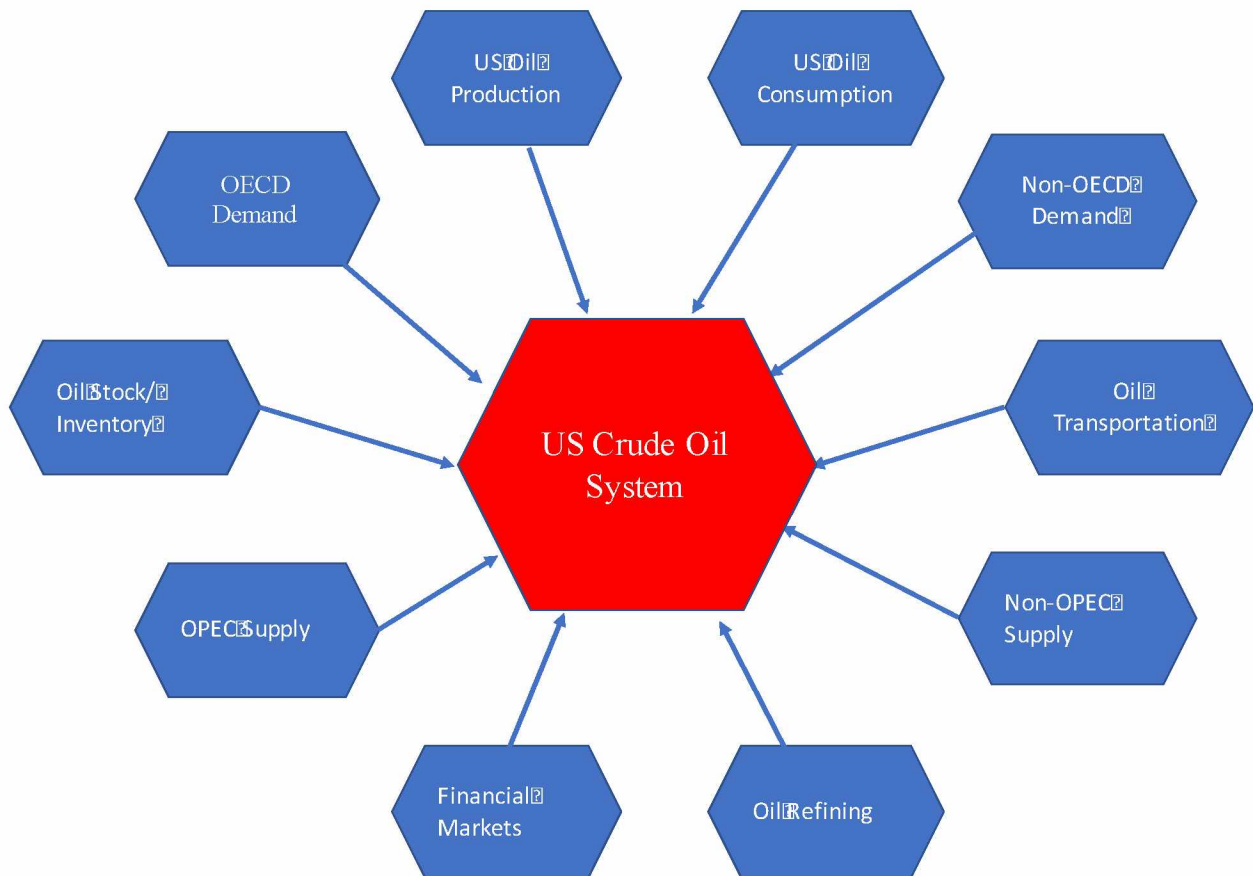
Figure 5. Ten Pillars of the U.S. Petroleum Crude Oil System

2.3.   Ten Pillars of the U.S. Crude Oil System

2.3.1.   U.S. Oil Production

The U.S. petroleum industry is made up of a beehive of producers ranging from family-owned oil firms, small independents, majors, supermajors, and oil servicing firms. This host of oil industry participants are purely profit driven and uncoordinated, resulting in an almost perfectly free market situation in the U.S. where competition is fierce and innovation is a tool of competition. This was not always the case; in the past, U.S. government regulations introduced imperfect market elements into the U.S. crude oil system. The height of U.S. federal involvement

in the oil industry could be traced to 1973, when the Emergency Petroleum Allocation Act instituted pricing systems that subsidized crude import and restricted the price of crude oil from already-producing fields as opposed to the price of crude from new fields, so as to control product prices during the Arab oil embargo (EIA, 2002). But over the years, with the absence of nationally-controlled oil and gas companies, and the flourishing of free market participation, oil production in the U.S. has been unrestrained driven by the innovation, creativity, and competition among several oil and gas producers.

US oil production is also supported by the U.S. federal governmental system where the nation's mineral rights ownership is not unified under a central government. As a result of this mineral ownership arrangement, states exist where individuals own mineral rights, and can forge commercial arrangements with willing operators to produce oil and gas resources (Maugeri, 2013). In most OPEC and some other major non-OPEC nations, this is not the case; oil production is coordinated around major National Oil Companies (NOC) and a slew of small contractors that orbit around its needs, and mineral rights are reserved to the national government. U.S. oil producers of different sizes and strategic interests provides a flexible, agile, and robust base, which is opportunistic and reactive to global oil production trends. Supported by this oil producing community, the U.S. currently produces approximately 13% of global crude oil production (BP, 2016a).

2.3.2.   U.S. Crude Oil Consumption

The recent rise in U.S. oil production often reduces attention on U.S. consumption as a defining part of the U.S. crude oil system. For the last 50 years, the U.S. has consumed at least 20% of global crude oil production and U.S. consumption constitutes approximately 40% of total consumption by the 34-nation OECD group (BP, 2016a). This level of consumption is also sustained by growth in population and income (BP, 2016b). As a result of this outsized appetite for crude oil, the U.S. is a major and reliable market for the world's crude oil. Therefore, events that impact oil consumption or oil trade in the U.S. are important to the world's producers. Policy or technological shifts that replace imported crude with locally produced crude oil, for example, also impact oil trade outside the US, as these producers reroute production to other

markets often leading to a downward pressure on global crude oil prices. This has been the case for the years 2014 through 2017, especially coupled with weaker global crude oil demand growth. The IOGCC (2016) estimates that over 2.5 billion barrels of crude oil imported annually for consumption in the U.S. could be replaced by local production.

Consumption of crude in the U.S. comes mainly from the making of gasoline, diesel, heating oil and other products, and major consumption centers exist in the East and West coasts of the US. Major consumer industries of produced oil are the refining, airline and petrochemical industries. An energy outlook report by BP (2016b) projects U.S. crude oil consumption to decrease through 2035. This is mainly driven by reduced energy intensity of U.S. power and manufacturing and increased fuel efficiency of the transportation and other sectors (BP, 2016b). But the possibility of reduced U.S. consumption may still not be reflected in refinery consumption levels. This is because without restrictions to the export of crude oil products, the refinery crude feedstock intake may remain high since crude oil products could be exported for sale in foreign markets. And this reliable consumption base gives the U.S. a systemic advantage in controlling shifts in global crude oil energy development.
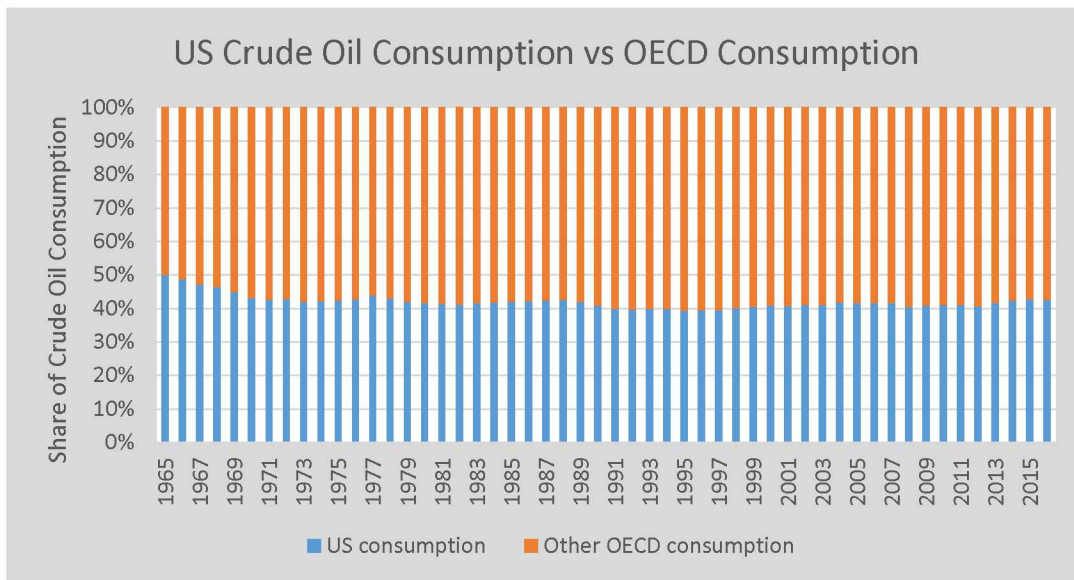
Figure 6. U.S. Share of Total OECD Consumption (BP, 2017)

2.3.3.   U.S. Refining Capacity

The U.S. refinery system is partitioned into five petroleum administration and defense districts (PADDs), and the U.S. refines over 18 million barrels of crude oil per day (BP, 2016a). These PADDs have different refining capacities. The PADD 3, located in the U.S. Gulf Coast has 45% of U.S. refining capacity and is the largest of all the five PADDs (Figure 7; Congressional Research Service [CRS], 2014; EIA, 2016h). Refineries in all the PADDs receive feedstock from crude oil fields via pipelines, rails, barges and in a few cases through trucks. The U.S. holds almost 20% of refining capacity in the world and produces over 20% of oil refining products (BP, 2016a). With this massive refining capacity, the U.S. could potentially maintain very high levels of crude oil import and processing and product export long after energy intensity and efficiency have reduced U.S. actual oil utilization.

Crude oil refiners can buy both local U.S. crude which is priced based on the West Texas Intermediate (WTI) crude as benchmark, or foreign crude oil benchmarked by the North Sea Brent crude oil. Margins of interest for refiners are the profitability margins referenced by the price of crude oil compared to the price of crude oil products, and also the margin between WTI and the Brent crude oil prices (EIA, 2017m). Better refiner margins result from the ability of refiners to buy crude oil at lower prices and sell crude oil products at higher prices. The Brent crude oil-WTI crude oil margin also affects profitability of refiners depending on what feedstock they use in making petroleum products. According to the EIA (2017m), crude oil products track the global crude oil benchmark, Brent crude, and when the WTI sells at a discount to Brent, refiners whose plants are set up for processing WTI use WTI crude as feedstock and are able to secure higher profitability margins. These margins were most pronounced before U.S. crude production increased significantly. Increase in U.S. crude oil production has led to improvements in U.S. crude oil transportation infrastructure and debottlenecking of supply infrastructure that has brought about cheaper transportation of U.S. crude from inland oil fields to coastal refineries (EIA, 2017m). These infrastructural improvements have reduced the Brent-WTI margin. Also, to improve refining margins, U.S. refiners could retrofit local refineries to be able to use heavy oil from sources like Venezuela, or improve utilization of light oil from local tight oil plays (EIA, 2017m).

The U.S. refining capacity therefore is another major advantage of the U.S. crude oil system. Due to this huge refining capacity, and the fact that the U.S. mostly serves as its own market for crude oil products, the U.S. refining system has been instrumental to the U.S. tight oil production growth in the last decade. U.S. refining is a major tool in the U.S. crude oil system that ensures its robustness and flexibility, because refiners have shown the ability to adjust refining capacity to suit emerging crude oil types from within or outside the US. In addition, the ability of U.S. refiners to export products in meeting foreign and domestic product demands has enabled the U.S. to continually mop up increased local tight oil production and support U.S. tight oil development.

Figure 7. U.S. Crude Refining System Segmentation through Petroleum Administration for Defense Districts (PADDs) (Modified from EIA, 2012)

2.3.4. Crude Transportation

The U.S. crude oil transportation system allows the U.S. to take advantage of its vast network of fields, refineries and crude consumption network. Crude transportation in the U.S. is through

pipeline, tankers, barge, trucks and rails (Figure 8). The U.S. has the largest pipeline network in the world (Pipeline 101, 2017). There are 200,000 miles of crude oil, natural gas liquids and crude oil product transmission pipelines in the US, about a third of which constitute crude oil product pipelines (Figure 9; Association of Oil Pipelines [AOPL], 2015). Rail transportation has also been on the increase since 2005 due to tight oil development. Barge transport typically complements transportation by pipeline or rail especially in the PADD1 and PADD 2 (EIA, 2013c).

The availability of pipeline infrastructure has given several regions more advantages in oil development by reducing the cost of transport and eliminating crude oil discounts otherwise suffered by producers. The EIA (2017m) observed that high oil prices in 2009 through 2013 increased U.S. tight oil and Canadian oil sands production and transportation to Cushing, Oklahoma, backing out volumes that were normally moved from the Gulf coast to Cushing, leading to a glut at the Gulf coast. This new accessibility of tight oil at Cushing required Brent crude imports to the Gulf coast to sell at near discount prices to WTI, hence closing in the Brent-WTI margins that had grown in the past (EIA, 2017m). With increased connectedness of oil fields to transportation hubs, operators and royalty owners in these areas do not have to suffer from reduced resource value due to higher cost of transportation. This enables projects that would have been marginal in more aloof fields to become more economic.

The economics of crude transport also influences the quantity of crude oil transported by different means, and the cost of crude oil transport varies across locations and means of transport. The cost of crude shipment by tankers from foreign crude oil locations to the U.S. Gulf and Atlantic coasts ranges from $1 to $2.5 per barrel, while crude pipeline transport costs $5 per barrel and rail transport cost ranges from $10 to $15 per barrel (CRS, 2014). Pipelines transported between 13 and 16 billion barrels of crude oil and products from 2010 through 2014 (AOPL, 2015). Pipeline transport contracts typically require 10 to 15 year contract terms which operators could find burdensome to commit to due to highly volatile oil prices (CRS, 2014). This disadvantage could price out small independents who require nimbleness in response to market signals to operate profitably.

Transportation of crude oil within the continental U.S. has experienced dynamic shifts historically and more so with the recent increase in tight oil production. While pipeline transport remains the main source of refinery crude oil receipts (Figure 8), regionally, the major means of transport could be different. Rail transport handled 70% of Bakken crude and 64% of Niobrara crude and reaching over 140,000 railroad miles, became one of the fastest growing means of crude transport from 2010 through 2015 (CRS, 2014; EIA, 2015f). Rails transported approximately 300 million barrels of crude in 2013 (CRS, 2014). And refineries in PADD 1 have historically depended on waterborne transportation of foreign crude until more recent rail transported crude from the Bakken, following production increases in the Bakken (EIA, 2015f). The cost savings afforded PADD1 refiners due to rail transport has led to a preference of Bakken crude over more costly West African crude, and improved the competitiveness of these refiners against their Gulf Coast counterparts who use lower cost crude feedstocks (CRS, 2014). Railroads are generally deregulated except in situations where specific routes have significant market dominance and attract oversight by the U.S. Surface Transportation Board (CRS, 2014). Total crude oil movements by rail in the U.S. peaked in 2014 to over 380 million barrels (EIA, 2017n). Crude transport by rail typically provides more flexible transport terms, such as 1 to 2-year contract terms, which provide flexibility to oil producers, especially smaller independents, to adjust to market signals (CRS, 2014). Rail transport also provides more scalability to transporters and is faster to construct with potentially less upfront impact and environmental scrutiny and hurdles. However, crude oil transport by rail has been found to be riskier than pipelines and has led to several spill incidents in the past, such as the Lac Megantic, Quebec fire incident in 2013 (CRS, 2014).

In summary, the spread, variety and economics of the crude transportation options that make up the U.S. crude oil transportation network, enables the U.S. to adjust to local and global dynamics of the oil and gas industry. The ability to grow different means of transport to better serve regional demands also affords the U.S. the robustness and flexibility to give platform to oil industry shifts. An example of this phenomenon is the growth of rail transportation in the wake of tight oil production in the Bakken.
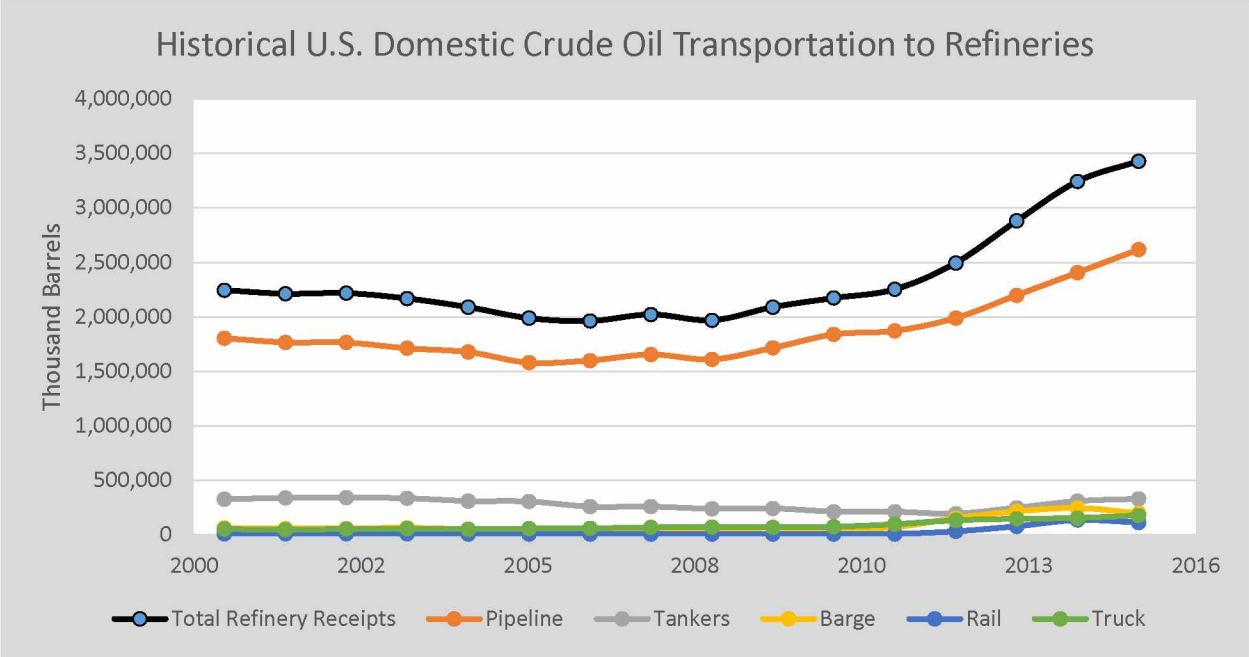
Figure 8. Alternative Means of U.S. Domestic Crude Oil Transportation to Refineries (EIA, 2017p)
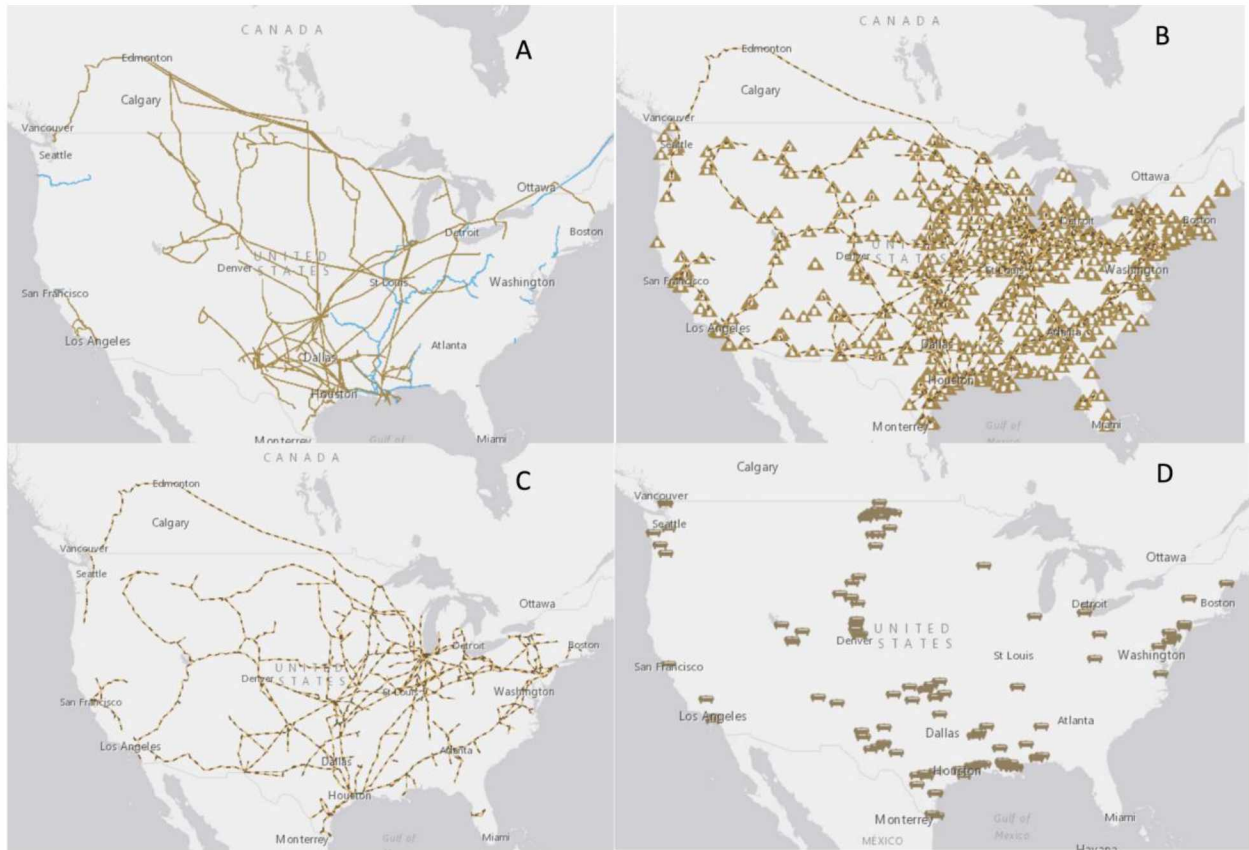
Figure 9. U.S. Crude Oil and Products Transportation System (EIA, 2017q) (A: Crude oil pipeline and Waterway for petroleum movement; B: Petroleum product terminals; C: Petroleum product pipeline; D: Crude oil rail terminals)

2.3.5.   U.S. Crude Oil Inventory

The U.S. crude oil inventory or stocks is another significant but less visible pillar of the U.S. crude oil system. Since excess crude oil needs to be stored, the availability of a reliable and well-managed storage system is key to a steady crude oil market. This crude oil storage system provides the pulse of demand and supply of crude oil and crude oil products. U.S. crude oil stock constitutes the volume of commercially available crude oil held by U.S. firms that can be traded in response to demand, and the U.S. Energy Information Administration tracks this data weekly (EIA, 2017m). This oil inventory volume is different from the U.S. strategic petroleum reserve (SPR), which is crude oil kept by the U.S. government in meeting its strategic objectives. The total U.S. storage capacity for commercially available crude oil and crude oil products, excluding the 727 million barrels of the SPR, is over 2.1 billion barrels, approximately 30% of which constitutes storage capacity for crude oil only (EIA, 2017o). Following the experience of the

Arab oil embargo of 1973, the US, together with the International Energy Agency members hold over 1.5 billion barrels of crude oil for emergency response (EIA, 2017m). The EIA also publishes biennial reports of working storage capacity for select facilities and crude products in different PAD districts (EIA, 2017r).

The fluctuation of inventory levels is also tied to U.S. and global crude oil supply and demand, and the commodity markets. The utilization rate of working crude oil and products storage volume informs crude oil analysts of the condition of the market since storage could be costly when the storage utilization rate is high and available storage capacity is slim (EIA, 2017m). Slimming storage capacity may signal bloating supplies and/or weak demand and increase the premium paid for storage, while drawing down inventories would imply tightening of the market and may lead to higher prices. The signals provided by movements in U.S. crude stocks informs analysts on the direction of the crude oil market and affects trading on the crude oil futures and financial markets. The EIA (2017m) also observed that inventory levels may increase when there is the expectation that prices will be higher in the future and that higher inventory levels are associated with market contangos (lower current prices and higher future prices) while low inventory levels indicate backwardation (higher current prices and lower future prices).

This crude oil stock or inventory system is important to the management and stability of the U.S. crude oil system. For example, U.S. stocks have climbed to record levels since the onset of strong tight oil production (EIA, 2017t,Figure 10). The last two years of reduced oil prices has highlighted the value of oil inventory in the life of the U.S. oil industry as prices are often seen to respond to the weekly data on inventory levels and utilization rates (CNBC, 2017). The increase of oil stocks often causes short term negative expectation of financial markets on the performance of operating companies, leading to lower market valuations. The EIA (2017m) also noted that the lag, insufficiency or absence of inventory data by most non-OECD nations injects more uncertainty into the market, heightens the game of expectations and impacts oil prices. While there is agreement as to the value of near real time data through the weekly tracking of crude inventory and the possibility of this transparency to have helped smoothen would-be major shocks, one could argue, this data could have also resulted in jittery market overreaction to inventory fluctuations as has been observed in the last few years. Overall, the presence of this

crude oil and products storage and management system provides a stabilizing force to crude oil marketing, and affords the U.S. oil industry a nimbleness that could sustain shifts in the local and global oil industry.
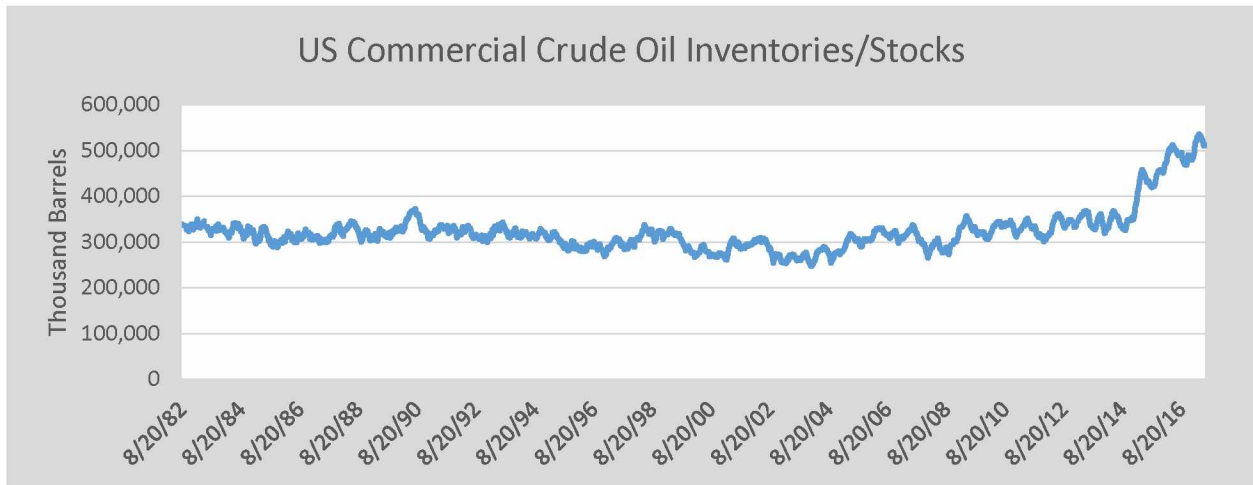
Figure 10. U.S. Crude oil inventory/stocks (EIA, 2017t)

2.3.6.   OPEC Oil Supply

The Organization of Petroleum Exporting Countries (OPEC) consists of 14 countries with disproportionately large oil reserves and oil production and local economies strongly tied to crude oil production. As a result, these countries have a high stake in favorable oil prices. As of June 2017 OPEC member states are: Saudi Arabia, Iraq, Iran, Kuwait, Venezuela, Qatar, Algeria, Libya, Nigeria, Angola, Gabon, Equatorial Guinea, United Arab Emirates and Ecuador (OPEC, 2017). OPEC was formed in 1960 and has as its mission to "co-ordinate and unify petroleum policies among member countries, in order to secure fair and stable prices for petroleum producers; an efficient, economic and regular supply of petroleum to consuming nations; and a fair return on capital to those investing in the industry" (OPEC, 2017). OPEC produces 40% of global oil production, and its volumes constitute 60% of international traded crude (EIA, 2017m). Through its activities in controlling supply, OPEC has influenced oil prices, and in some cases oil geopolitics, for several decades. Oil in most OPEC nations consists of crude oil in the light oil category and are less costly to produce compared to other non-OPEC nations, giving OPEC countries a cost of supply advantage (EIA, 2017m).

28

As a result of international coordination across OPEC member states, and because of the disproportionate supply power wielded by the group, OPEC has significant price-setting power in the world crude oil market. This makes the U.S. crude oil system especially attentive to feedback from actions by the OPEC. By a production quota system, OPEC assigns quotas to its members and ensures a curtailed supply to the world oil market. Another axis of OPEC power is the fact that it maintains significant spare production capacity that enables it to react to supply disruptions around the world. According to the EIA (2017m), spare capacity refers to the quantity of production that could be brought to the market in 30 days and sustained for a period of 90 days, and the absence of spare capacity tightens the market leading to oil price hikes. Saudi Arabia is the biggest OPEC supplier and has the largest spare capacity, and can affect world oil prices through its decisions on crude supply (EIA, 2017m).

Actions of the OPEC are outside the sphere of U.S. control but such actions are always closely monitored by the U.S. financial markets, U.S. oil industry, and U.S. policy makers. The U.S. has often responded by policy actions such as the institution of the Crude Oil Strategic Reserves, the crude oil export embargo and support for the institution of the International Energy Administration to coordinate response to energy issues among mostly OECD nations (EIA, 2002). Another response of U.S. oil and gas policy to OPEC actions, in the recent past, is the lifting of export restrictions in 2016.

U.S. tight oil production has affected and been affected by OPEC activities. The slow growth of crude oil supply, strong growth in global economy and crude oil consumption, and the resulting tight spare capacity contributed to high oil prices between 2003 through 2008 (EIA, 2017m). This period provided the backdrop against which the new and costly technology of tight oil recovery attained successful field trials and rapid expansion. Tight oil production growth across more U.S. plays continued to displace U.S. import, most of which comes from OPEC nations, hence increasing OPEC spare capacity. This situation required OPEC to decide between cutting back production, like it did often in the past, or maintaining production levels and risk collapse in global oil prices. Since a reduction in OPEC production could be filled by other non-OPEC

producers leading to a loss in OPEC market share, the OPEC members decided to continue producing at high levels in Q3 of 2014 leading to a precipitous fall in oil prices.

The actions of OPEC surprised many and has drawn several interpretations. According to an MIT (2017) study, OPEC's decision came against a backdrop of falling shale breakeven costs and weakening global demand. The study further noted oil consumption growth of less than 1 million barrels per day in 2014 and underwhelming global GDP numbers below IMF expectations, structural changes taking effect due to improving energy efficiency. Spencer (2017) further explained OPEC actions in line with its mission, as a stabilizing force for short term changes in the market and not for longer term structural changes, like that characterized by tight oil development. He explained that just like OPEC was not effective in supporting prices in the 1980s with the opening up of North Sea productions and strong volumes from Alaska, OPEC's refusal to cut volumes in 2014 was more in line with lessons drawn from past experiences and the group picking the scope within which it was most effective. OPEC's actions could also be understood within the context of Saudi Arabia's relationship with the next largest OPEC reserve holders, Iraq, Iran, Kuwait and UAE. According to Reynolds & Guthrie (2011), on crude oil supply policy negotiations with the world, Saudi Arabia, whose actions largely define OPEC's stance on crude oil supply issues, is truly negotiating with the greatest threats to its market power, such as Iran. While Iran's production still reflected the impact of sanctions in 2014 when the oil price crash began, oil prices hit their lowest point below $28 per barrel in Feb 2016, partly due to further increase in productions from Saudi Arabia meant to discourage the reintroduction of high Iranian oil volumes following the end of international sanctions on Iran (BBC, 2016). A reverse decision by OPEC to reduce supply in November 2016 is widely seen to have stabilized oil prices albeit at a lower price range of $45 to $55 per barrel (CNN, 2016; The Economist, 2016).

The price-setting power of OPEC, therefore, remains a critical factor important to the U.S. crude oil system and to structural changes in the U.S. oil industry such as tight oil development within and outside the US. And in the absence of the resilience to continue to improve the economics of tight oil development, making it comparable to lower cost light oil alternatives in OPEC and

other nations, the activities of OPEC will continue to be a key variable for tight oil developers across the globe.

2.3.7. Non-OPEC Oil Supply

Crude oil supply from Non-OPEC sources make up 60% of global oil production although just 40% of internationally traded crude (EIA, 2017m). These producers consist of nations like Russia, US, Brazil, Canada, Norway, and the UK. Some non-OPEC producers have major state-owned or state-directed producing companies, while others operate a purely free market with little or no state involvement. Examples of non-OPEC state oil players include Russia's Rosneft oil company and the Norwegian Statoil oil company. Other non-OPEC producers like the U.S. and the UK have no state-owned producers and operate mostly as free markets with hundreds of independent oil companies, and dozens of international majors.

The presence or absence of state-owned oil producers often impacts the involvement of non-OPEC oil producers in the oil and gas industry. Non-OPEC suppliers like Russia often coordinate with OPEC in exerting price-setting power on the market. Countries like the U.S. have no such abilities and typically remain as price takers. This has not always been the case. In much of the 20th century, the U.S. government restricted supply from Texas giant fields and with tight-fitting policies, attempted to control prices, support downstream sectors and maneuver adversarial policies from OPEC suppliers in the wake of the Arab oil embargo (EIA, 2002). These actions affected the supply of crude oil from the US.

Non-OPEC supply is also characterized by higher cost oil sources (EIA, 2017m). Examples of high cost oil sources in non-OPEC countries includes tight oil in the U.S. and oil sands in Canada. As a result of poorer rock quality and less abundance of light oil, the cost of oil supply from non-OPEC nations is higher, making oil production less profitable. As a result, lower prices more easily erode profitability of oil and gas business in these nations than in most OPEC nations. Historically, non-OPEC producing countries like the U.S. have sought to incentivize oil production through petroleum and tax policy actions such as tax credits and deductions with some success. In situations where supply fluctuations from non-OPEC sources is completely

31

covered by spare capacity from the OPEC, the loss of such supply has less impact on the oil market (EIA, 2017m). In the absence of complete coverage, for example if supply disruptions occurred in non-OPEC sources like Russia, the impact on the market could be more severe leading to higher prices, all things being equal, with palpable impacts within the U.S. crude oil system. And since oil prices are global, other non-OPEC supplies remain an important piece of the U.S. energy system and tight oil development decisions around the world.

Since the U.S. is among non-OPEC nations and the effect of crude oil supply fluctuation in some non-OPEC nations could be significant, this pillar is also important in the U.S. crude oil system.

2.3.8. The Financial Industry/Markets

The U.S. financial industry has always been part of U.S. crude oil development through bank lending. Given the capital-intensive nature of oil and gas development, this relationship has been necessary to kick-start or continue the expansion of several oil and gas operation ventures. The relationship between crude oil and the financial industry turned another chapter when crude oil futures trading started. The West Texas Intermediate (WTI) joined commodities trading on the New York Mercantile Exchange in 1983. This allowed oil suppliers and consumers to hedge risk and effect contracts for large volumes of crude oil transfer.

Crude oil and gas operation financing has also broadened past traditional bank lending channels and has played a pivotal role at every stage in tight oil development. For example, private equity funding typically enables the exploration and appraisal stage, reserve based lending and public bonds offerings have been applied to the development and production stage, while bank loans or internally generated cash flow enable the expansion stage of oil development operations (Brogan, 2014). The nature of tight oil development puts the development of the resource within appraisal-expansion mode for most of the project life (Brogan, 2014). Unlike conventional plays, the variability of the rock within and across tight oil plays and the steep decline in tight oil wells requires consistent drilling capital to maintain the productivity of petroleum assets. This character of tight plays translates to more wells being drilled, and a protracted season of

expansion stage than in conventional plays, requiring businesses to seek revolving doors of credit to ensure constant capital supply when needed.

The financial markets also serve as a hub of analysis and an information connection of U.S. industries with the world. This is because traditional financial institutions and traders constantly analyze and react to oil demand and supply signals from major and minor supply hubs like the Middle East and Africa or consumption hubs like Asia. This information is synthesized and affects capital availability and operation decisions of U.S. firms almost in real time. This value of the financial markets has affected the birth and sustenance of the U.S. tight oil industry, and continues to be a major pillar in the U.S. crude oil system for the future. And since other nations operate financial markets that are in many ways linked with one another, tight oil development in other non- U.S. nations will continue to have the financial markets as a source of information and capital.

Fattouh (2014) agrees that the existence of well-functioning markets, cheap credits, and liquid futures are among the unique advantages of U.S. tight oil development. Furthermore, this character of the market is seen through the following three elements of the U.S. financial industry: private equity, the design of risk instruments, and other novel funding mechanisms that kicked off within the last decade.

2.3.8.1. Private Equity Funding Industry

The world of private equity funding is linked but in many ways different from the traditional U.S. financial market. This is because of the increased role it has played in the development of ideas and business across the US. Private equity funding has under-written some of the major deals in the U.S. tight oil and gas industry. While most of the NOCs, IOCs, and integrated oil and gas companies are awash with financing from national government budgets or banks or through corporate bonds, this is very different for small independents who make up a larger share of oil development companies in the US. These companies often own single assets within single plays and are willing to be the test ground for technological innovations in search of the slightest edge. In partnership with small and large servicing companies, the small independents have applied novel techniques in drilling and completion and engineered different fluid samples that

helped power the tight oil revolution. In addition to technological innovations, these companies are characterized by financing difficulties and typically turn to private equity funds; large and small.

Private equity funds are typically manned by entities experienced in oil and gas investment deals or participants who were previously part of large oil and gas companies. They receive funds from limited partners and sponsors who typically require 7-8% return on capital per annum each (Fallon et al., 2017). The sponsors are more involved in decisions about the deployment of the capital and major decisions about the venture and upon a successful business, in addition to the previous percentage return they get an additional 20% share of the profits from the venture (Fallon et al., 2017). As a result of these layers of returns, private equity funding could be quite costly for oil and gas operators, but nonetheless provide much needed capital that would not otherwise be possible.

Some private equity funds in the U.S. are owned by private individuals or families or groups of investors willing to take the risk of funding projects requesting high returns in exchange. Some of these projects are typically too risky for banks beholden to shareholder institutional investors with more conservative investing philosophies. The private equity funds are typically more accessible to small independents, get more creative and are willing to develop an understanding for the business that allows them to adjust more rapidly to the ever-changing environment of the petroleum industry.

2.3.8.2. Price Hedging Financial Instruments and Derivatives

The U.S. financial industry has also developed products that have increased risk management within the tight oil development industry. Examples of these are oil futures and options. Oil futures are legal contracts that give the buyer and seller the obligation to exchange a set amount of crude at a specified price at or before a specified date (CME Group, 2013). Options are legal contracts that give the owner the right but not the obligation to take delivery of a given amount of crude on or before a set date (CME Group, 2013). Options and futures are sold at a premium and the buyers and sellers decide on what price they can afford to pay that allows them to make a profit. For example, when the maturity date of these contracts arrives, for put options, the

upstream oil and gas agent has the right to weigh his option of selling at the contracted price, or if the spot price at that date is high enough, pay the agreed premium and make higher profit in the spot market. These instruments have allowed producers and consumers to hedge risk and also enabled speculators to speculate on prices profitably.

A Put option, for example, is a variety of the options that give the owner the right to sell a set quantity of crude at a pre-arranged price. This instrument is useful to oil producers because, based on the amount of production that they have hedged, they eliminate the oil price uncertainty involved in planning, focus on cost reductions and could go on producing with *assured* profitability. The ability of oil producers to purchase oil futures or put options has enabled them sanction medium to long term projects based on contracted prices and manage price uncertainty effectively. As a result of these financial instruments, oil producers can proceed with projects, based on contracted prices for crude delivery, assured that future changes in price will not affect their operations or point forward decisions. In the oil and gas industry this is very valuable, as that amount of crude oil that is hedged factors into the amount of reserves the company can claim and also into its market valuation.

A call option gives the owner the right to buy a set amount of crude at a specified price before or at a given date (CME Group, 2013). This instrument has helped refiners and other major consumers of crude to lock in costs and stay profitable. Through the purchase of futures and call options on futures, refiners have also been able to secure products at prices that allowed them manage the cost of crude oil feedstock which constitutes input costs for their production processes (Stermole & Stermole, 2012).

These hedging instruments offer the U.S. crude oil system the flexibility to support the high risk involved in petroleum exploration and production. In managing risk, U.S. oil operators are able to manage the significant upside and downside potential that come from structural shifts in the local and global petroleum industry.

2.3.8.3. Other Funding Mechanisms

During the last decade, a new and more flexible funding scheme is also making inroads into official funding channels for oil and gas projects. This is crowdfunding. In 2012, the U.S. Congress passed the Jumpstart Our Business Startups (JOBS) Act which directed the SEC to remove prohibitions to general solicitation and advertising for business capital which was passed in the 1930s alongside the Securities Act (SEC, 2013). Currently, this funding style is rivaling traditional lending sources for capital needs of small independent oil and gas operators (Racusin, 2017). This funding practice is approved by the SEC through Title II of the JOBS Act in September, 2013, and is projected by the World bank to reach $90 billion by 2020 (Racusin, 2017). These multiple funding channels reduce the barrier to entry into high cost ventures and allow small operators to focus on oil production (Racusin, 2017).

2.3.9.   OECD Crude Oil Demand

Nations in the Organization for Economic Co-operation and Development (OECD) are developed nations with large economies that have historically consumed a large share of global oil production. According to the EIA (2017m) these nations constituted 53% of total crude oil consumption in 2010, declining from higher levels of consumption 10 years prior. The advances in OECD economies have led to development in sectors that consume less energy such as movements away from the heavy manufacturing base to a more service base of the 21st century. As a result, economic growth or GDP growth of OECD nations is not correlated with high crude oil consumption (EIA, 2017m). OECD nations also propagate oil efficient technologies which reduce global crude oil demand and consumption. In circumstances where global GDP growth is sustained by economic growth in these nations, the age-old tie between oil consumption and economic growth is not honored due to the structure of these developed economies. Non- U.S. OECD demand is expected to grow by ~0.6% annually through 2040 (IOGCC, 2016). Lower OECD demand, all else being equal, leaves more crude oil unused and will constitute a downward pressure on oil prices in the future. Lower oil prices negatively impact U.S. oil production due to the high cost of developing aging U.S. fields, and also impedes the expansion of high cost tight oil development. This impact of low oil price on tight oil production was

visible in the contraction and of the tight oil industry over the 2014 to 2017 period. Therefore, to the extent that crude demand in these 33 developed non- U.S. economies affects global crude oil system, this is significant to the U.S. Crude oil system.

2.3.10. Non-OECD Crude Oil Demand

Crude oil demand by non-OECD nations constitutes a large share of global crude oil demand growth in the last decade. The IOGCC (2016) noted that crude oil demand within this block of nations is expected to grow by 1.9% annually through 2040. And according to the EIA (2017m) non-OECD consumption grew by 40% from 2000 to 2010 and, for the next 25 years, is expected to constitute all the net increase in global oil consumption. For example, a non-OECD nation like India, according to the IEA (2016), is projected to increase its consumption by 6 million barrels per day through 2040.

Most non-OECD economies still rely on a huge manufacturing sector and economic growth in these countries is more directly linked to more crude oil consumption. To maintain high demand for crude oil and an upward pressure on oil price, a booming global economy sustained by economic growth in non-OECD nations is necessary. For example, the U.S. exports crude oil products to non-OECD nations in South America. These products provide fuel for industry and transportation services. Strong crude oil consumption from non-OECD countries and lower energy efficiency contribute to stronger global prices.

The impact of a strong dollar on non-OECD economies also affects crude oil consumption within this block of nations. Typically, non-OECD nations have less developed economies with currencies generally weaker than the U.S. dollar. A stronger dollar implies that more of the local currencies would be required for oil purchase which is traded in the U.S. dollar. This relationship should translate to less demand for crude oil. But the EIA (2017m) counters this view point by pointing to the fuel subsidies provided by most non-OECD nations, leading to a price insensitivity by consumers in these economies. Another impact of a stronger dollar is that it reduces most non-OECD demand for other capital goods and raw materials that are traded in the global market in U.S. dollars, leading to a potential slowdown in manufacturing economies.

Reduction in demand for these products suggests reduced demand for crude oil which serves as fuel for power generation or other manufacturing processes (EIA, 2017m). This indirect impact is relatively less in OECD economies which typically have currencies that are in par with (Euro zone nations), or stronger than the U.S. dollar (Britain).

The impact of non-OECD demand on crude oil prices is important for tight oil development in and outside the US. Higher oil prices, sustained by strong non-OECD demand, provide the capital and profit margins required to try new technologies in frontier fields. Strong signals of oil demand growth in non-OECD countries, powered by faster growing populations and economies, decreasing production from conventional oil sources, is a good sign for crude oil prices in the future and for unconventional resource development.

Policy actions by the U.S. government play a major role in the interaction among the pillars of the U.S. crude oil system. And in recent history, besides the U.S. Energy Policy Act of 2005, the lifting of the U.S. crude oil export embargo instituted in 1970s is the most significant policy change that could affect the working of the U.S. crude oil system. The next section discusses this policy shift and its potential impact on U.S. tight oil development.

2.4. U.S. Crude Oil System and U.S. Energy Policy Shifts: The Lifting of U.S. Export Restrictions and Potential Impact on the Global Oil Market

As a result of increasing production in the U.S. from 2005 through 2015, petroleum exports from the U.S. have increased from approximately 1.2 million barrels per day to over 4.5 million barrels (IOGCC, 2016). This is mostly crude oil products like distillate fuels and natural gas liquids. This level of export was possible while the U.S. export restrictions were in place. While the 10 pillars discussed in the previous section are important in understanding the dynamics of the U.S. crude oil system, for much of the last 30 years U.S. government policy has kept this system largely insular, with respect to crude oil export. This resulted directly from crude oil export restrictions put in place in the 1970s. As a result of these restrictions, crude oil could not be exported from the mainland US.

In 1973, the Arab oil embargo curtailed oil import from Arab nations to the U.S. leading to a sudden rise in crude oil and oil product prices. The Emergency Petroleum Allocation Act of 1973 was passed to place price controls that incentivized new and marginal production while keeping a price ceiling for lower cost oil (EIA, 2002). In 1975, the U.S. Congress passed the Energy Policy and Conservation Act (EPCA) that restricted crude oil exports. This bill was introduced in Feb 1975 by Henry Jackson and enacted by the U.S. president in December of the same year (Civic Impulse, 2017). This Act effectively banned the export of all crude oil produced in the U.S. and the outer continental shelf and allowed only the export of Alaskan North Slope Oil or oil of foreign origin (U.S. Department of Commerce, 2013). According to the U.S. Department of Commerce (2013), the Act eased exports based on conditions that met the U.S. national interest and in the following years, based on presidential findings, granted licenses to increasingly more exports. Export purposes that received this easement still required licenses from the Bureau of Industry and Security. In 1985, oil from the Cook Inlet of Alaska was allowed for export; in 1988, oil exports to and for consumption within the borders of Canada was also allowed; in 1992, exports from California and other exports in accordance with U.S. international energy supply agreements, and exports determined to be in line with national security interests were allowed.

In 2016, in the wake of low oil prices, the U.S. congress passed a law that lifted the crude oil restriction put in place 40 years prior. The low prices from the third quarter of 2014 were because of actions by OPEC to keep oil supply levels high despite sluggish growth in global consumption. Most experts agree that this was in response to OPEC losing more and more share of the global market to non-OPEC oil.

Higher oil prices from 2012 through 2014 had enabled technological advances in the U.S. that enabled higher cost oil in the U.S. and other non-OPEC countries to compete vigorously with low cost OPEC oil. Although margins were higher for OPEC producers under higher prices, this situation meant that markets like the U.S. oil market that historically consumed about a fifth of global daily production were no longer as dependent on imported OPEC crude as before. This reduction in U.S. crude oil demand creates more free capacity for OPEC and the need to source for other markets. So, at least for the U.S. market, it could be said that the major threat to loss of

market share for OPEC was U.S. production itself, bolstered by high productivity of tight oil plays due to technological innovations underwritten by high oil prices.

As oil prices plummeted in 2014 following OPEC's actions to increase production levels, the U.S. was also experiencing a glut due to record high levels of production. The argument among U.S. policy makers and the oil industry weighed more towards the opening of the global oil market to U.S. crude producers, so as to improve U.S. crude prices and not stymy the high levels of economic activity caused by an active oil industry. This change in U.S. policy is a major turnaround for the U.S. oil industry and was pushed for many reasons. The EIA (2015e) noted that fast increasing U.S. production, bolstered by tight oil development, could lead to the WTI, the U.S. benchmark for oil, selling at a larger discount to the Brent oil, if export restrictions were not removed. The EIA (2015e) also found that a WTI-Brent margin of $6-$8/bbl represents the cost of shipping WTI to overseas markets in which Brent crude sold. As a result, any WTI-Brent margin greater than $6-$8/bbl would create an arbitrage opportunity for U.S. oil marketers to sell overseas, and that opportunity would be lost if the ban was not lifted. Others hoped that the U.S. producers would also gain from current deals that allowed local and foreign refiners to pre-finance oil production (The Economist, 2015). More supporters of the lifting of the export ban believed that the superior light crude from the U.S. would be more competitive than the heavier Brent which is a cocktail of crudes, and that U.S. shippers could forge similar relationships with foreign refiners that will allow special crude blends from the U.S. that were tailored for specific refiners (The Economist, 2015). It is also possible that since businesses always preferred multiple sources of raw materials to diversify risk, the U.S. shipper, even in a tight global supply market would provide the premium of a stable supply to foreign refiners, especially if such refiners previously depended on crude from other less stable sources, such as some sources in Africa. In addition, more generally, by lifting the export ban, if global economic growth improved or non- U.S. supply is choked by some geopolitical event or other arbitrage opportunities exist, U.S. suppliers are not locked out of the race for profitable transactions around the world.

On the other hand, U.S. environmentalists contended that the lifting of the export ban would only exacerbate the problem of global warming if it encouraged more drilling for oil within the U.S.

(The Economist, 2015). Besides objections from environmentalists, other economists challenged the economic merit of the bill acclaimed by the bill's advocates. They believed that if the export ban reduced the Brent-WTI differential below a $6 - $8/bbl margin to say, zero, at least it would cost $3 to ship U.S. crude to European refineries, thereby eroding the competitiveness of U.S. crude to the foreign refiners (The Economist, 2015). This implies that a $3-dollar buffer would protect European crude from the U.S. producer and unless WTI sold at a discount to the Brent, it was not possible for U.S. crude to compete in Europe. Proponents of the bill to lift the U.S. crude export ban successfully passed the bill in an omnibus package for government spending that included credits for Wind and Solar energy, thereby reducing the challenge that would have otherwise been encountered from environmentalists.

In all, the lifting of the U.S. crude oil export ban creates an opportunity to test theories on oil marketing and market response rather than a gentle unfolding of some mapped response. Already in 2016, U.S. crude export, previously 92% to Canada, dropped to 58% and export destinations climbed to 26 countries in South America, Europe and Asia (EIA, 2017s). Lifting the export ban potentially opens a new chapter for the U.S. crude oil exploration and exploitation industry. And several new dynamics will be tested, including the dynamic within the 10 pillars of the U.S. Crude Oil System and the new relationship with the global oil benchmark, Brent. Lifting of the export ban increases the degrees of freedom in U.S. crude oil industry and improves opportunities for arbitrage around the world for U.S. producers. Following this policy change, and the increase in competition for crude oil trade around the world, there is potential for increased efficiency in oil logistics and transport.

The pillars of the U.S. crude oil system discussed in more general terms the framework within which oil production, conventional or unconventional, has historically occurred within the U.S. or how oil resource development could occur in the future. It is within such framework that the tight oil development of the last decade has occurred. In addition to that framework are direct drivers of the tight oil boom that began in the U.S. in the mid-2000s. These factors will be discussed in the next section.

2.5. Key Drivers for U.S. Tight Oil Development

Several researchers have reviewed the reasons for the tight oil boom in the US. Maugeri (2013) pointed out the persistence of drilling, the innovative technology, and managerial efficiencies that have supported the rise of oil production in shale plays. Fattouh (2014) highlighted the mineral rights ownership, dynamic private sector, rig availability, capital markets, and cheap credit as contributing factors. This section reviews and expands on the factors that have supported tight oil production increase in the U.S. in the last decade (Figure 11).
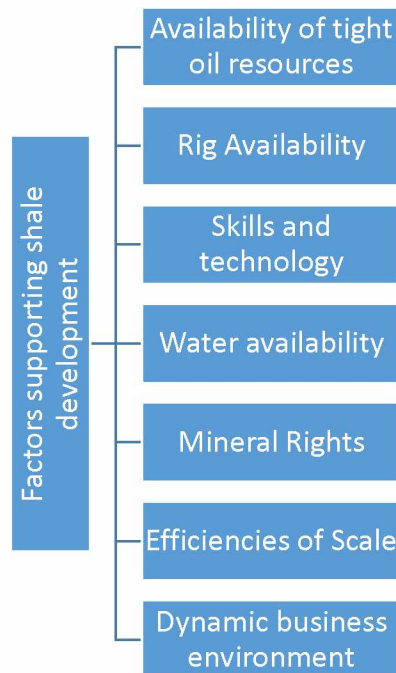
Figure 11. Factors that led to tight oil development in the US

2.5.1. Availability of Tight Oil Resources

The development of any resource depends, firstly, on the availability of the resource. The dominance of the Middle East and specifically Saudi Arabia in conventional oil production for several decades is chiefly driven by the fact that that region has the largest deposits of economically recoverable conventional crude oil. It is the presence of the unconventional resource in the U.S. that provides the bedrock on which enabling factors lead to shale oil

production. It is this same factor that raises the promise of similar or some commercial development in other nations with significant shale resources as well.

A study by the U.S. Energy Information Administration in conjunction with Advanced Resources International in 2013 generated estimates for total shale oil and gas in place and total technically recoverable volumes for 43 countries (Figure 12 andFigure 13; EIA/ARI, 2013). This report placed U.S. total technically recoverable shale oil resources at 47.7 billion barrels (14% of global recoverable shale oil) and estimated U.S. technically recoverable shale gas resources at approximately 1.2 Tcft. This does not imply such volume is commercially recoverable, since commerciality depends strictly on market conditions and permits and contracts in place, but it places the U.S. as a major force in global shale oil prospects.

Proved reserve estimate in Saudi Arabia, owner of the world's largest light oil reserves, are just over 260 billion (BP, 2016a). While the global estimate of shale oil appears quite significant, at 334 billion barrels (EIA/ARI, 2013), the need for costly and extensive drilling to achieve those volumes typically pushes development of these resources towards the high end of the cost curve. Hence, compared with nations that own reserves that are easier to produce, without other enabling factors, resource availability alone does not easily translate into serious developments in shale.
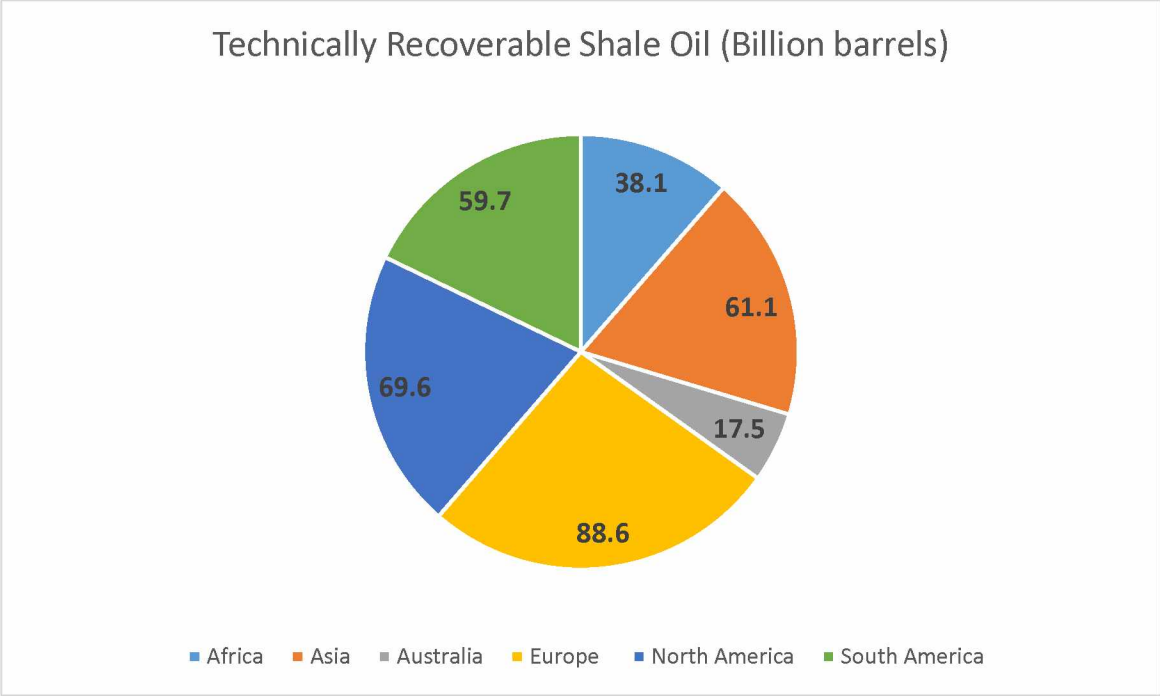
Figure 12. Technically Recoverable Shale Oil by Regions (EIA/ARI, 2013)
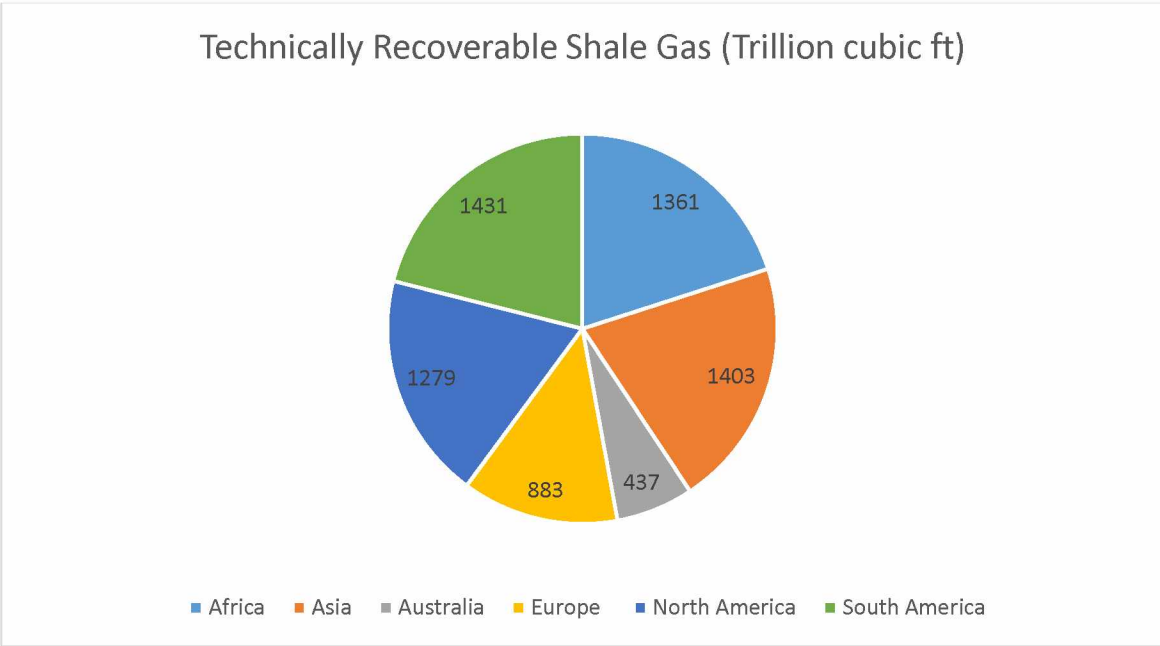
Figure 13. Technically Recoverable Shale Gas by Regions (EIA/ARI, 2013)

Availability of shale resources in itself does not make a region prospective for oil and gas development. The properties of the region must be conducive for development. The EIA/ARI

(2013) isolated five main properties that focused their analysis of global shale plays for prospectivity: (1) the total organic content of shale, (2) the maturity index, (3) reservoir pressure, (4) clay content, and (5) depth of the formation.

Total Organic Carbon (TOC)

The carbon content of rock is crucial to determining its hydrocarbon potential. Total Organic Carbon (TOC) refers to the amount of organic material present in shale rock. TOC is measured in weight percent of the rock sample and direct measurements are made using the Leco carbon analyzer while indirect measurements could be made through pyrolysis or well logs (Sorkhabi, 2016). During the process of sedimentation and rock formation, organic material is trapped in rocks and could be broken down by bacteria or spared depending on prevailing conditions. If this material is preserved, it contributes to the organic richness of the rock. Rocks with TOC ranging between 2% to 10% are good targets for exploration (Alexander et al., 2011; EIA/ARI, 2013). Sorkhabi (2016) concurs that for shale rocks, TOC ranging from 2 through 5 and above is excellent, while in carbonate rock, a good TOC range is 0.5% through 2% and above. Rocks that make up major U.S. plays fall within suitable TOC ranges (Table 1).

Maturity Index

Maturity/reflexivity Index or vitrinite reflectance is a measure of maturity of hydrocarbon source rocks by their level of reflectance, due to the amount of vitrinite they contain (Alexander et al., 2011; Sorkhabi, 2016). Thermal maturity indicates the extent of transformation of organic material into hydrocarbons (EIA, 2017g). According to Alexander et al. (2011) vitrinite is plant tissue transformed by heat and its standard measurement records the reflectivity of at least 30 grains of vitrinite from a rock sample. During the formation of petroleum, the effect of heat on organic matter transforms it into kerogen, further cracking its complex molecules into oil and finally into gas (EIA, 2017g; Sorkhabi, 2016). More thermally mature rocks have higher vitrinite reflectance values. This is a function of the temperature and pressure window in which the formation exists. Immature rock vitrinite reflectivity ranges from 0-0.6%, oil bearing rock reflectivity values range from 0.6-0.8%, and wet gas reflectivity values range from 0.8-1.1% and gas rock measures above 1.5% with maximum values at 3% (Alexander et al., 2011). The EIA

(2017g) also agrees that vitrinite reflectance values between 0.6-1.1% are associated with oil formation window, 1.1-1.4 with wet gas, and 1.4 – 3.2% with dry gas formation.

For rock samples that are older than the Devonian geologic age, beyond which plants did not flourish on earth, rock maturity is measured through bitumen reflectance values, thermal alteration index or by calculating hydrogen index, oxygen index or transformation ratio using parameters obtained through pyrolysis (Process by which rock sample is heated in the laboratory, in the absence of oxygen, to a point of decomposition to measure organic richness) (Sorkhabi, 2016). For example, thermal maturity in the Utica play is measured by bitumen reflectance (EIA, 2017g). Rocks that make up major U.S. plays fall within suitable maturity range (Table 1).

Reservoir Pressure

Reservoir pressure remains a crucial factor in productivity of conventional or unconventional formations. The pressure gradient of normal formations containing fresh or low salinity water is estimated at 0.433 pounds per square inch of pressure (psi) per foot of depth. Formations at specific depths are estimated to exist at pressures near or corresponding to normal pressure gradient of 0.433psi per ft. Rock strata with pressure, greater or less than would be determined by the 0.433psi/ft relationship, when compared to their depth of burial, are considered abnormally pressured. Reservoir pressure is also important because it determines the effectiveness of fracture clean up after a well is hydraulically fractured and for the productivity of formations. Over pressured rocks are considered to be more prospective for shale oil development purposes (EIA/ARI, 2013). This is because as wells produce, pressure is depleted, and while in conventional oil and gas operations formation pressure can be replenished through water or gas injection, in tight formations this is a major challenge. So, as pressure declines, gas molecules trapped in oil are released. These gas molecules compete for flow within the tight rock thereby reducing the amount of oil that can be produced. As a result of this relative permeability phenomenon, overpressured formations are more prospective as they offer a wider pressure buffer that allows more oil to be produced prior to gas coming out of solution. The key U.S. tight oil plays such as the Bakken and Eagle Ford and Permian are over pressured (Table 1).

Clay Content

The clay content of formations is important to shale play development, due to the impact of clays on the effectiveness of hydraulic stimulation. Clay or other mineral content of rock results from the depositional environment, the rock forming material brought into the basin through geologic time and the geologic processes such as diagenesis (change in rock composition after sedimentation). Non-marine depositional environments form plays that are typically more clay-rich than marine plays (EIA/ARI, 2013). This is because non-marine plays contain much smaller quantities of brittle rock minerals like quartz, feldspar and carbonates than marine plays (EIA/ARI, 2013). In clay rich environments where these minerals are less abundant, the rocks are more plastic and less likely to yield during fracking operations. As a result, just smaller segments of rock beyond the immediate vicinity of the well are contacted and fractured. With fewer fractures formed, the formation lacks the extensive and complex fracture networks that increase the pathways through which oil and gas get to the well for higher productivity. On the other hand, carbonates are more amenable to hydraulic fracturing. Of the U.S. plays studied in this research, the Utica play with approximately 70% clay content, is the most clay-rich (EIA, 2017g). On the other hand, most U.S. plays have low to medium quantities of clay and are more productive than the Utica (Table 1).

Depth

Formation depth is also important in determining prospectivity of shale plays. The depth of a formation impacts the cost of drilling and overall economics of play development. All things being equal, it is costlier to drill deeper wells than shallower wells. The well architecture may alter this to some extent; wells could be equally deep but longer laterals could make one costlier than the other. The Bakken is an example where wells are drilled approximately 21,000ft including 10,000ft of lateral, as opposed to shorter wells in the Eagle Ford play. According to the EIA/ARI (2013), depths between 3000ft and 12,500ft are optimal; shallower prospects are more likely to have higher water saturation while deeper prospects are much less permeable. The average formation target for U.S. plays fall within this range (Table 1).

Added to the availability of shale resources in the US, the suitability of the rocks in major U.S. plays, in terms of total organic carbon, maturity, reservoir pressure, clay content, and depth make U.S. plays prospective for tight oil development.

Table 1. Petroleum Properties of U.S. Shale Plays

Basin	Play	Recovery Factor (%)	TOC	Ro (%)	Depth (ft)	Clay	Pressure (psi/ft)
Williston	Bakken	8.4	10	0.8	**10,000**	low	0.6
Maverick	Eagle Ford	9	4.24	0.85	6,000	low	0.6
Permian	Wolfcamp	3.4	9.33	0.92	9,300	low	0.6
D-J	Niobrara	4.6	2.69	0.7	10,000	*medium*	0.433
Appalachian	Utica	2.1	1.96	0.8	6,100	*high*	0.75

	EIA/ARI (2013)
	EIA/IHS (2016)
	USGS (2005)
	Arthur M. (2013)
	Pollastro et al. (2012)

2.5.2.   Availability of Rigs

Tight oil development is a drilling intensive development for two main reasons. The low permeability of the rocks means a single well drains a smaller area than wells drilled in more permeable formations. And because wells drain a small area and are not pressure-sustained like conventional wells through waterflooding or gas flooding, the nature of the production profile of tight oil wells shows a steep decline in production early into well life. This implies that to maintain high enough volumes of production from any asset, new wells need to be continually drilled. Sustained by the number and early productivity of new wells, the EIA (2016i) reported that approximately 50% of U.S. oil production in 2015 came from wells drilled in 2014. Due to this reliance on number of wells that could be drilled, the availability of drilling rigs is crucial to drill the many wells required. The oil field servicing company, Baker Hughes Inc. started generating rig counts in Canada and the U.S. since 1944 and globally since 1975 (Baker Hughes Incorporated [BHI], 2015). For most of the four decades since 1970, over 50% of the global rig count were rigs operating in the U.S. (Figure 14; BHI, 2015). Due to the drilling intensity required by shale development, the availability of rigs places the U.S. in a very suitable position

for global dominance in drilling the most number of tight oil wells. As a result, new wells are able to offset declining production and sustain the boom. This is a factor in tight oil development that very few nations can replicate.
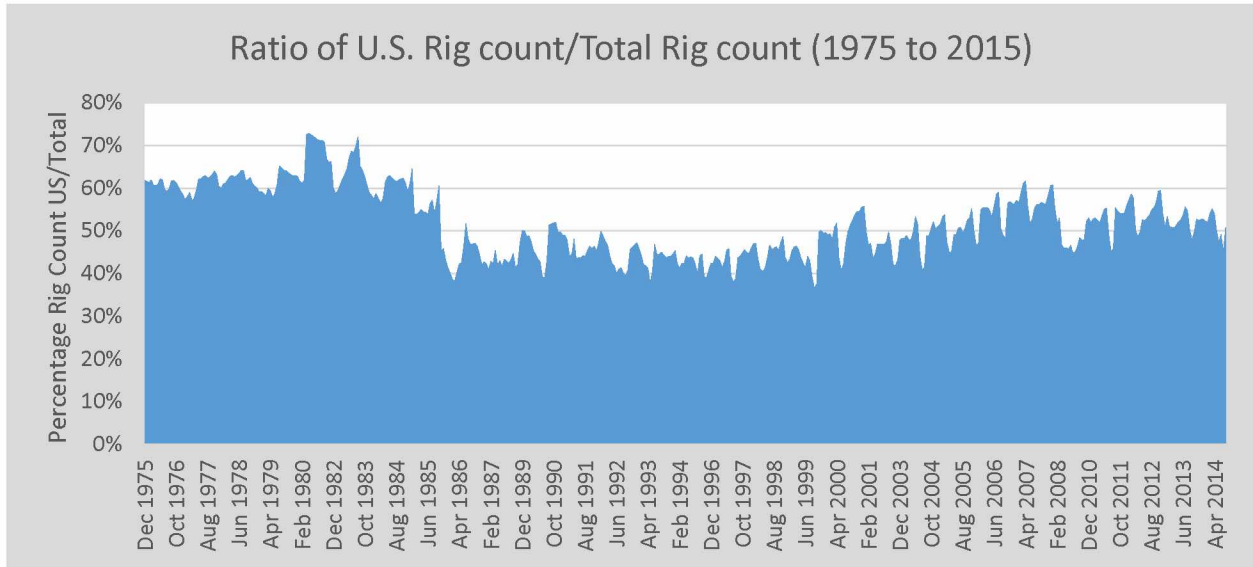
Figure 14. U.S. Share of Historical Global Rig Count (BHI, 2015)

In addition to number of rigs available, the capability of rigs has also improved. The success of developing resources in tight formations is mainly supported by new technologies in directional and horizontal well drilling. This is because horizontal wells allow a longer portion of the well to be drilled in the pay zone to access the most resources. New rigs are equipped to drill horizontal wells and old rigs are retrofitted, when possible, with similar abilities. Gulen et al. (2013) reported that horizontal well growth in the Barnet shale play moved rapidly from less than 1% in 2001 and 2002 to 8.5 % in 2003, 67% in 2005 and up to 92% by the year 2007. More than 75% of wells drilled in the U.S. are horizontal wells (Figure 15; BHI, 2015).

The availability of capable rigs also has the impact of reducing the cost of drilling in the U.S. as opposed to drilling in other places in the world.
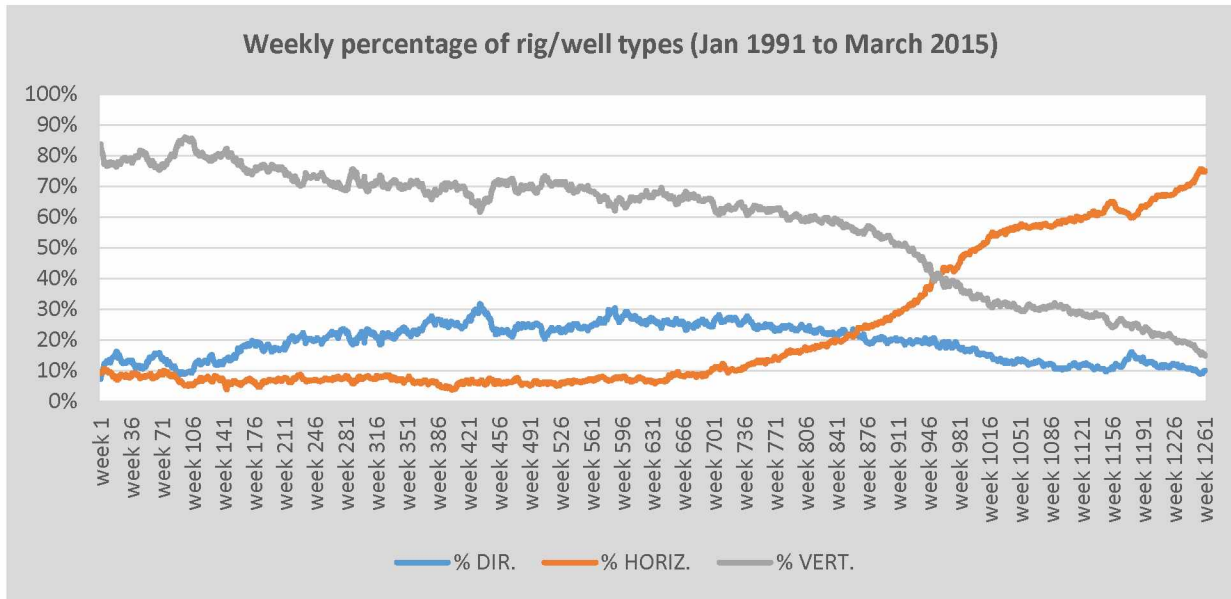
Figure 15. Well Types Drilled in the U.S. from 1991 through 2015 (BHI, 2015)

2.5.3. Mineral Rights Ownership

In most countries, mineral rights are owned by the state. In these countries, the development of mineral resources is impacted by the difference in investment philosophy of governments as opposed to private investors. Governments define successful business relationships more broadly than in monetary terms and the best interest of state entities is not always measured in profitability metrics. The best interest of a sovereign may also include general welfare of its people, care for its environment and its national interest. As a result, development is often slowed by several considerations of the many interests that constitute the wellbeing of the public and the need to pursue and balance other strategic development goals. This is often different from the goals of a private individual or enterprise which is typically measured by personal interests, shareholder value or more near term corporate strategic benefits. These circumstances affect mineral ownership and the pace and focus in the development of mineral resources.

The individual ownership of mineral rights in some states of the U.S. has contributed significantly to sustaining shale resource development. Private land ownership in the states of Texas and North Dakota exceed 95% (Rogers Oil and Gas Consulting, 2015;Figure 16,Table 2). This mineral rights structure has potentially facilitated negotiations, contracts and lease

acquisitions in these states. This is because there is high individual incentive for development. And since smaller independent oil and gas companies may not need a wide range of staff to help them navigate the intricate leasing procedures of mineral states, these companies can easily close deals with individual land owners. Also, it is easier for companies to form and to acquire oil and gas assets. This low transaction cost for lease ownership has contributed to much of the speed of development of shale oil and gas resources in the US. More broadly, the nimble, opportunistic and risk-taking character of small independent oil and gas businesses and the autonomy of individual mineral right owners to partner with them, has been a strong driver of shale resource development in the US.
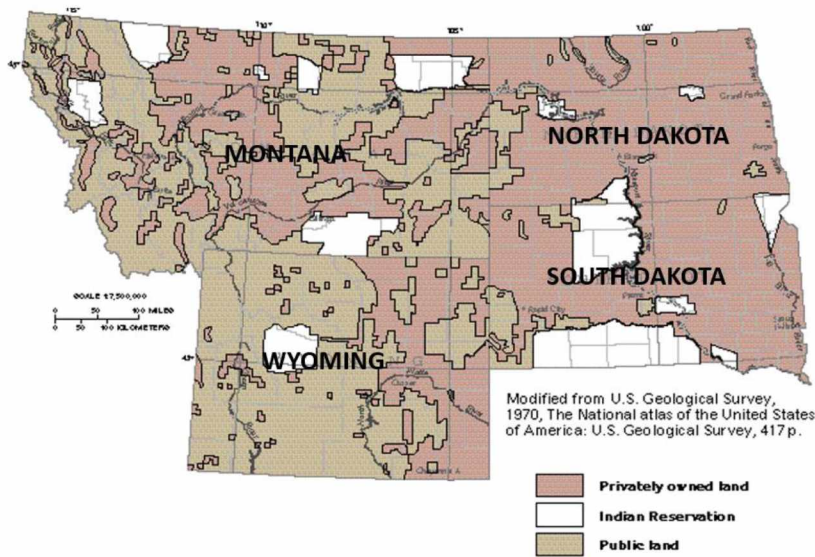
Figure 16 Land Ownership in a Few States in the U.S. (USGS, 1970)

Table 2. Distribution of Land Ownership in Select States in the U.S. (Rogers Oil and Gas Consulting, 2013)

U.S. State	Federal	State	Private
California	40.10%	2.35%	57.55%
Colorado	35.46%	4.39%	60.15%
Louisiana	4.97%	2.67%	92.36%
Montana	29.28%	5.58%	65.14%
New Mexico	29.42%	11.20%	59.38%
North Dakota	3.11%	1.84%	95.05%
Texas	1.43%	0.49%	98.08%
Wyoming	48.43%	6.22%	45.35%

51

2.5.4.   Availability of Water

Water availability is crucial to the success of shale resource development. This requirement is especially important during the completion stage of every tight oil well when it is hydraulically fractured. A typical hydraulic fracturing operation for each tight oil well requires 3-5 million gallons of water (Arthur et al., n.d). University of North Dakota (2013) researchers place a wider range of 1-5 million gallons for Bakken wells. This water is sourced from surface water bodies; operators prefer locations close to operation sites and in many cases will truck water to fracking locations. Freshwater is the preferred water quality although some reports have shown that brackish water could also be treated and re-used (Trent, 2016). But the cost of 100% recycle of produced water is prohibitively high. Trent (2016) noted that at a cost of $5 to treat a barrel of produced water, and associated cost of disposing the salt bi-product, producers in some counties in Oklahoma considered disposal a cheaper option. This suggests that the logistical challenges of aggregating and treatment of produced water far outweigh the cost of acquisition of freshwater and disposal after use. The economic preference for disposal as opposed to full reuse, points to the continued need for freshwater to satisfy tight oil development requirements in the US. Beck (2011) estimated that by 2019, demand for water in the Bakken play, ND would grow to over 16 billion gallons.

Zeihan (2014) points out the importance of geography and the presence of water as a key factor in the development of nations. The availability of water has contributed to tight oil and gas production rise in the US. The contiguous U.S. mainland has 2,110 watersheds draining the U.S. mainland into thousands of streams and lakes (Figure 17; ND SWC, 2014). The nation is drained by major rivers like the Mississippi, the Missouri, Delaware, Columbia, Colorado and thousands of small rivers and streams that make up over 3.5 million miles of rivers and streams covering the U.S. landscape (EPA, 2016b). These water bodies provide a good supply of freshwater that has contributed to alleviating the challenge of sourcing for hydraulic fracturing water.

Figure 17. Water Resource Regions in the U.S. encompassing over 2000 watersheds/drainage basins (USGS, 2016b)

2.5.5.   Technology and Skills

Shale formations have always existed in the US, even in the years of dwindling local production and heavy dependence on imported oil. It required improvements in well position and logging technology, by which formation characteristics are effectively matched with completion methods to improve oil and gas productivity (Mullen et al., 2010). Besides improvements in well logging, it took the combination of advancements in horizontal drilling and well completion technology, specifically hydraulic fracturing, to unlock the huge potential in shale plays across the country. These two technological leaps enable the accurate positioning of wells within specific formations for thousands of miles to access more resources and the opening of rocks that have been bypassed for over a century.

Besides the key developments in drilling and hydraulic fracturing there have also been a wide array of minor technological shifts that have supported the tight oil boom. They range from the use of big data to optimize the search of land titles by oil and gas landmen, to the use of drill bit vibration data to better place hydraulic fracture stages (Constas, 2017). According to Constas (2017), put together, this level of innovation has led to over 700% higher new well productivity between 2007 and 2015, as tracked by the EIA's drilling productivity report. There have also been improvements in drilling rig capabilities, seismic acquisition and processing technology, and water chemistry formulation that have enabled operators to move rigs quickly and drill faster, image rocks more clearly, and pump proppants into fractures more effectively -- leading to more economic development of tight resources.

The existence of a huge industry base has also enabled the training of personnel to sustain the U.S. shale oil and gas development. This has been a combination of learning by doing, development of new products and rapid field testing with a quick feedback loop for improvements. The existence of several small companies all looking for a small edge above the competition has also given room for faster field attempts of new technology. With quick penetration of companies into new plays and expansion of firms within plays, new job opportunities have been created that lead to easier mobility of skills. As a result, successful practices have quickly spread from play to play contributing to more production. Technology and skills have been a significant driver for the ongoing tight oil revolution.

2.5.6.   Dynamic Business Environment

The dynamic business environment in the U.S. undergirds almost every industry but especially so for tight oil resource development of the last decade. This factor could be broken down into three key areas: ease of starting a business, accessibility of a market, and financing.

The United States ranks third among 140 nations in the World Economic Forum's 2016 global competitiveness index ranking (World Economic Forum [WEF], 2016). This ranking aggregates disparate rankings in 12 categories that summarize the potentials within a nation to support a thriving economy. Among the sub categories in this ranking, the U.S. ranks first in 'efficiency

enhancers' which includes market size, labor market efficiency, and financial market development. The oil industry is among the key industries where this strength is apparent. The U.S. has consistently consumed approximately 20% of the world's crude oil energy for over two decades and built significant refining and crude oil products consumption capacity, and as a result provides a reliable and sizeable crude oil market for oil exporting countries. With this advantage, the production of tight oil resources could easily find a market.

The availability of venture capital financing contributed to the success of tight oil development in the US. The U.S. ranks fifth among 140 nations in the ease of accessing financing for start-up businesses (WEF, 2016). The pioneers of the U.S. tight oil development were hardly the major E&P companies. These were small companies that grew into medium-sized independents, e.g. Petro Hawk, EOG resources, and Continental Resources, and were mostly funded by private equity capital.

As part of the dynamic business environment in the US, is the ability to re-start businesses. This opportunity is afforded by U.S. bankruptcy laws. As a result of these laws, the failing entrepreneurial venture is allowed to restructure, raise new capital and return to profitability. From January 2015 to August of 2016, Haynes and Boons LLP (2016) tracked more than 100 oil and gas E&P bankruptcy filings. Following the plummeting of oil prices since late 2014, these bankruptcies largely affected company operations in high cost tight oil plays. While bankruptcy filings include a loss to equity and some debt holders of a company, often this legal protection allows a company the opportunity to reorganize and stay in business either as the same entity or with a parent entity. This factor fuels the risk-taking needed to maintain a vibrant business environment.

2.5.7.   Economies of Scale and Other Efficiencies

Progress in shale development over the last few years has also led to other efficiencies that are driving increase in production. A good example is pad drilling. In the past, single wells were drilled and completed before moving to other wells. But currently, more creative and cost-efficient solutions are being applied. During pad drilling, for example, six wells may be drilled at

once. After drilling the vertical section of one well, the rig is skidded about 25ft away to drill another vertical portion and so on, while casing is being run in all the vertical portions. After which the rig moves back to the first well to drill the build section and horizontal portions of the well. As a result of this practice, materials are bought in bulk and servicing crews are used more efficiently, leading to significant economies of scale benefits. Such pad drilling used by the biggest operator in the Bakken, Continental Resources, led to a savings of as much as $7.5 MM and 73 days in drilling six wells (Continental Resources, Inc., 2012). The wells are also fracked together leading to significant savings in cost of mobilizing the frack fleet and improved productivity (Jacobs, 2014). According to Jacobs (2014) the adoption of the zipper frack style, where operators frack wells concurrently rather than completing all fracturing stages in one well before moving to another has led to reduced costs and increased productivity for some operators.

2.6. Summary of Key Drivers of Tight Oil Development in the U.S.

Tight oil production in the U.S. has rejuvenated the U.S. oil industry. This new era was made possible by the general pillars of the industry such as U.S. crude oil production base, consumption, price impacting factors like (1) OPEC and Non-OPEC activities, (2) OECD and non-OECD demand factors, (3) Crude oil transportation, refining, storage system, and (4) U.S. financial markets. But more specifically, tight oil development was supported by availability of (1) shale resources of prospective quality, (2) mineral ownership, (3) the availability of drilling rigs, (4) availability of water for hydraulic fracturing, (5) the availability of the required technology and skills, (6) a dynamic business environment, and (7) Management efficiencies.

In addition to the factors discussed, two key factors require separate handling: Regulatory environment and Oil prices. These will be discussed in the next chapter. While the overall impact of oil price on the industry has been manifested in the change in rig counts and response of production, this general trend obscures the individual impact on different plays and the lessons for other plays around the world. Also, the overall increase in production and the speed of development activity takes attention away from the framework of regulation and laws that are required to make this development sustainable. These are the factors studied in the next chapter.

2.7.   Major U.S. Tight Oil Resources

Tight oil development in the U.S. comes from several plays. Some examples are the (1) Monterey (CA), (2) Austin Chalk (LA & TX), (3) Granite Wash (OK & TX), (4) Woodford (OK), (5) Marcellus, Haynesville, Niobrara-Codell (CO, WY), (6) Wolfcamp (TX & NM Permian), (7) Bonespring (TX & NM Permian), (8) Spraberry (TX & NM Permian), (9) Bakken (MT & ND), (10) Eagle Ford (TX), and (11) Yeso-Glorieta (TX & NM Permian) (EIA, 2017e). Oil production from these plays has led to reduced oil import. The EIA (2015c) noted that over 55% of reduction in crude oil imports from 2011 through 2014 was due to reduced light oil (oil above 35 API gravity) import, while importation of oil of heavier quality has increased slightly (EIA, 2016j). This is because, at the right price, heavy oil imports are still attractive to U.S. refineries that possess the coking capacity to process heavier crude (EIA, 2015c). Of these tight oil plays, seven have provided more than 90% of total U.S. tight oil (EIA, 2016d; Figure 1; Figure 18). This section discusses geological and development characteristics of the different plays.
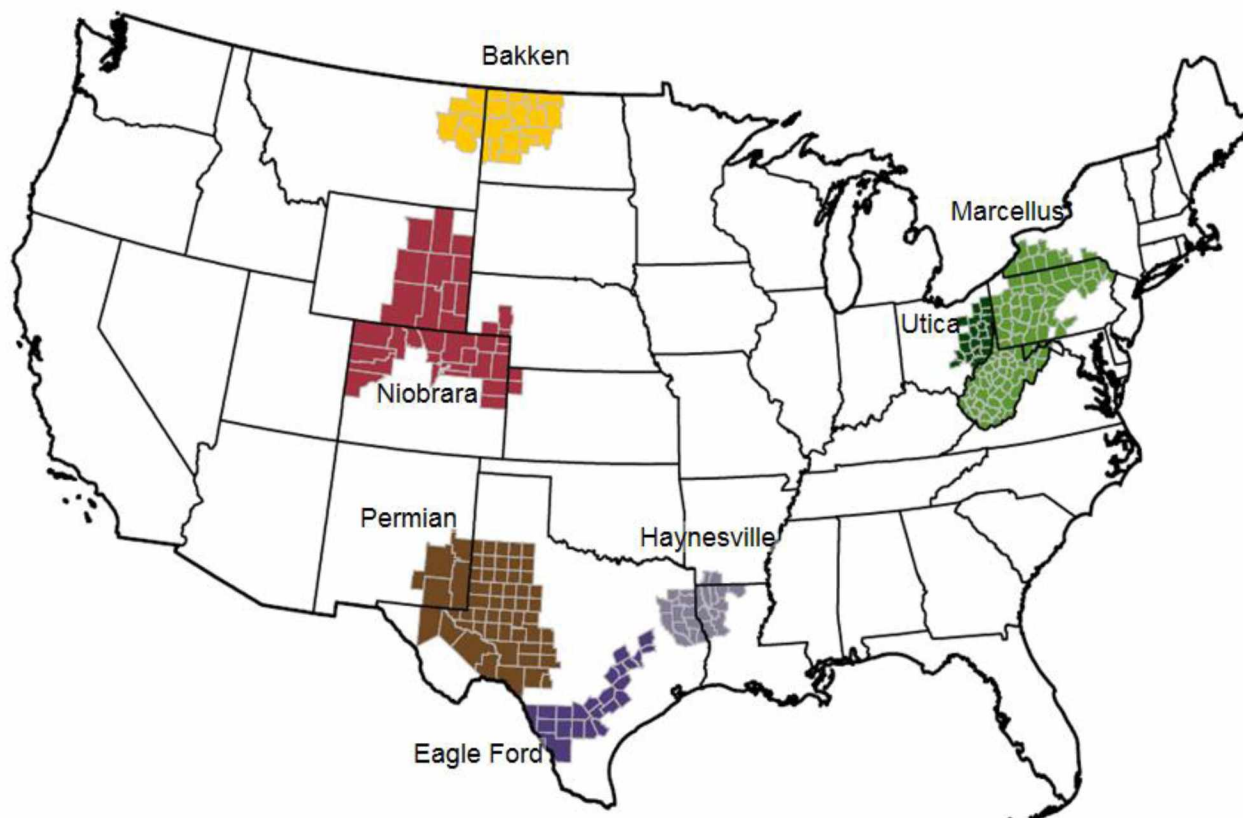
Figure 18. Seven Key U.S. Shale Plays (EIA, 2016d)

2.7.1. Bakken Play

The Bakken shale play is part of the Williston Basin that stretches from North Dakota, Montana, and Saskatchewan in Canada. This play covers an area of 200,000 square miles, ranges from 3,000 to 11,000 feet in depth and is considered the largest oil accumulation within the contiguous U.S. (Halliburton, 2017). It is deepest in the center of the basin and rises to 4500 feet towards the eastern edge reaching ~3100ft in the Canadian section of the play (U.S. ACE, 2013). This play contains 4.75 billion barrels of recoverable oil, more than 75% of which is within the U.S. portion of the play (Halliburton, 2017).

The Bakken is a very prospective oil play evident by the properties of the rock formation. The Bakken play consists of two layers of shale rocks that sandwich a middle siltstone layer. The National Energy Technology Laboratory (NETL) observed that the middle Bakken rocks contain dolomite, calcite and quartz while the shale members showed a more diverse mineralogy

dominated by quartz (5-85%), carbonate (5-40%) and clay (2012). The dolomite sections of the rock have higher porosity and permeability and provide sweet spots and enhanced well performance. The upper shale member is known to be siliceous and more suitable for hydraulic fracturing, and the NE-SW fault trend and NW-SE well placements contribute to better performance of wells (NETL, 2012). Rocks that make up this play are of the upper Devonian and lower Mississippian geologic age. The formation has a vertical depth of 10,000 – 11,000 feet, with temperatures that go as high as 300F and pressure of above 7000psi in some areas (Cramer, 1986). High temperatures and pressures within this formation contribute to downhole challenges faced while drilling through this rock.

Below the Bakken is a secondary target for development, the three-forks formation, which underlays over 60% of the State of North Dakota (U.S. ACE, 2013). It averages ~250 ft in thickness and is thought to contain ~1.9 billion barrels of technically recoverable oil, mostly in the 10-20 feet layer that overlays it, called the Sanish zone (U.S. ACE, 2013).

Private land ownership and access to freshwater are among the pillars sustaining tight resource development in the Bakken. Over 95% of the land ownership in North Dakota is private (Rogers Oil and Gas Consulting, 2013). This is important because it implies reduced transaction cost of lease acquisition and minimal bureaucratic red tape during development. Private owners typically negotiate with operators and speedily develop the resources within their acreage. Royalty rates within Bakken leases range from 12.5 to values above 20% (Drillinginfo, 2017; North American Shale, 2013). The State of North Dakota has access to surface and ground water sources that sustain freshwater demands for well stimulation. The Missouri river is the main source of surface water while ground water aquifers are primarily charged by glacial drift and other bed rock aquifer formations (Beck, 2011). The oil and gas sector also shares water resources with several other sectors like irrigation for farming and cattle.

Oil is the target resource for development in the Bakken (Figure 19). Oil production in the Bakken peaked in 2014 to over 1.2 million barrels of oil produced daily (EIA, 2016d). Bakken wells are typically 20,000ft in length and are estimated to cost approximately $7.1 million (EIA/IHS, 2016).
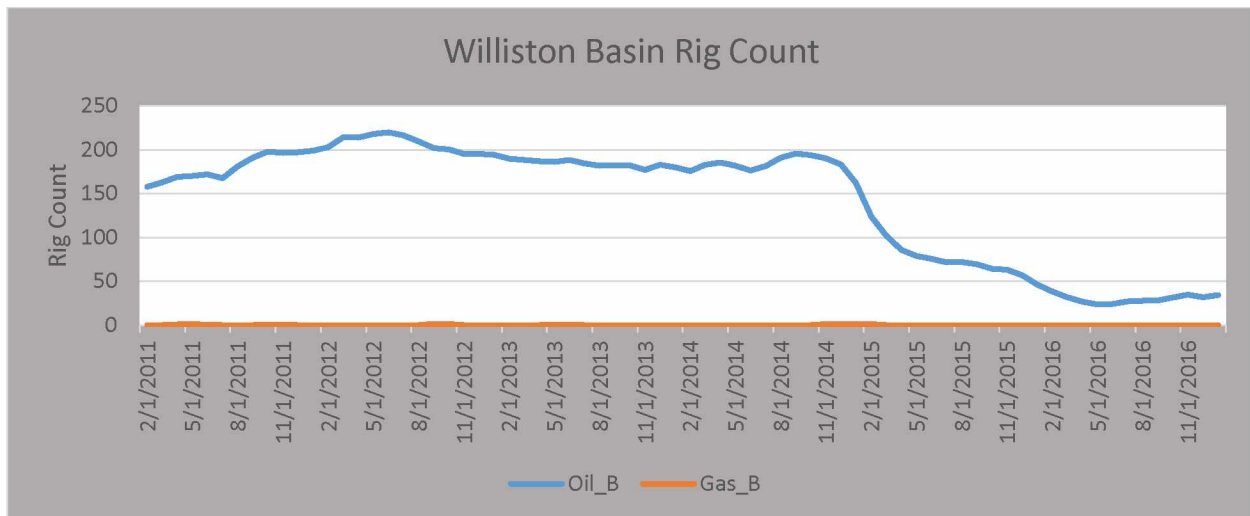
Figure 19. Rig count in the Williston Basin, North Dakota showing primarily oil development (BHI, 2017)

Crude oil produced in the Bakken is transported by way of trucks and tankers to pipeline terminals and by rail cars. Recently, ongoing efforts have been directed towards constructing pipelines because pipelines are considered to be the safest and least expensive form of transporting crude oil and crude oil products (U.S. ACE, 2013). Tankers could be as large as 3,300 to 6,600 gallons while rail cars range from 5,500 to 82,500-gallon capacity (U.S. ACE, 2013). Eight crude oil loading facilities existed in North Dakota by 2011 and the crude take-off capacity is estimated to now exceed 300M BOPD (U.S. ACE, 2013). Other estimates put rail capacity at over 700,000 BOPD costing more than a quarter of a billion dollars to install (Federal Reserve Bank Minneapolis, 2013). Increased transportation capacity improves the economics of projects in North Dakota and frees up the supply glut that typically resulted in operators selling off their crude at a discount.

2.7.2.   Eagle Ford Play

The Eagle Ford play stretches from the Western US-Mexico Border in Texas up into North East Texas. The play is 50 miles wide and 400 miles long in the western gulf basin (Railroad Commision of Texas [RRC], 2016a). This play contains oil, condensate, and natural gas sections. Some estimates put the gas potential of this play at 150 trillion cubic feet (Halliburton, 2017). Tight oil reserves for the play are estimated at over 4.2 billion barrels (EIA, 2017f).

The Eagle Ford tight oil play lies below the Austin chalk and above the Buda limestone. Rocks in this play were deposited in a marine environment during the late cretaceous geologic age, and consist of organic-rich calcareous mudrock (RRC, 2016a). The thickest sections of the play are in the Maverick Basin (EIA, 2014b). The rocks are rich in carbonate (40-90%), show clay contents that range between 15-30% and consist of 15-20% of silica (EIA, 2014b). The rocks targeted for development lie between 4000ft and 14,500ft total vertical depth, with oil sections shallower in the west, 4000ft – 6000ft and deeper in the east, ranging between 6000ft and 9000ft (EIA, 2010; EIA, 2014b; Halliburton, 2017). According to the EIA (2014b), the total organic carbon content ranges between 2-12% and thermal maturity ranges from 0.45% in the oil rich sections to 1.4% in the gas rich segments of the play. The Eagle Ford formation is slightly to highly over-pressured with pressure gradient values ranging between 0.5 to 0.8 psi/ft (EIA, 2014b).

Due to the high carbonate-richness of the rocks, the Eagle Ford shale is amenable to hydraulic fracturing (RRC, 2016a). Being over-pressured is important for oil recovery because as oil production continues, reservoir pressure declines until it drops past a pressure threshold referred to as the bubble point pressure and gas production increases and starts impeding further oil production. So, higher original pressures allow for a longer period prior to significant oil production impairment resulting from gases that come out of solution when pressure reduces below bubble point pressure. Another advantage of this play is that shallower oil sections reduce drilling time and cost of drilling, and the presence of carbonate-rich tight rocks, which are easier to fracture, contribute to lowering the cost of well stimulation. Gas producers also find this play attractive because of the condensate (light oil produced alongside natural gas), which is more valuable than dry natural gas (Figure 20; Allen, 2013). In all, high carbon content, ease of fracturing, and the presence of wet gas (in addition to significant oil reserves) contribute to the attractiveness of this play to oil producers (Allen, 2013). However, due to its relatively greater value, oil is the main resource targeted by producers in the Eagle Ford play (Figure 21).
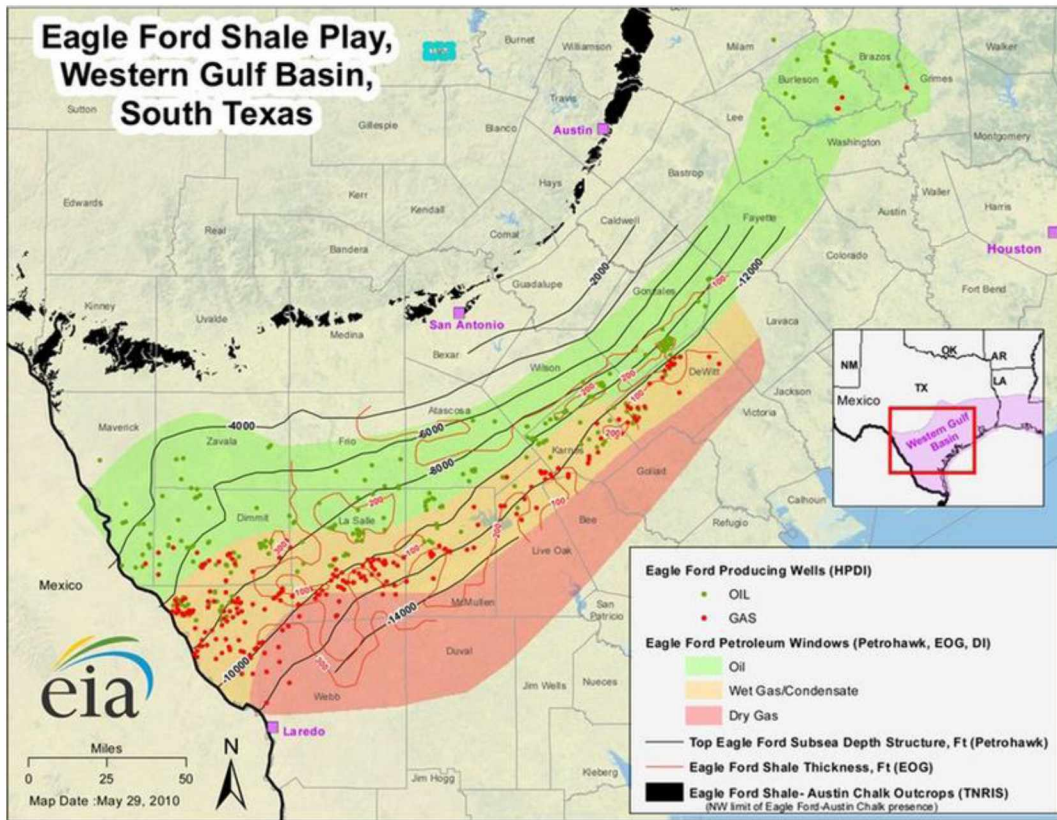
Figure 20. Eagle Ford Play showing oil, wet gas and dry gas resource windows
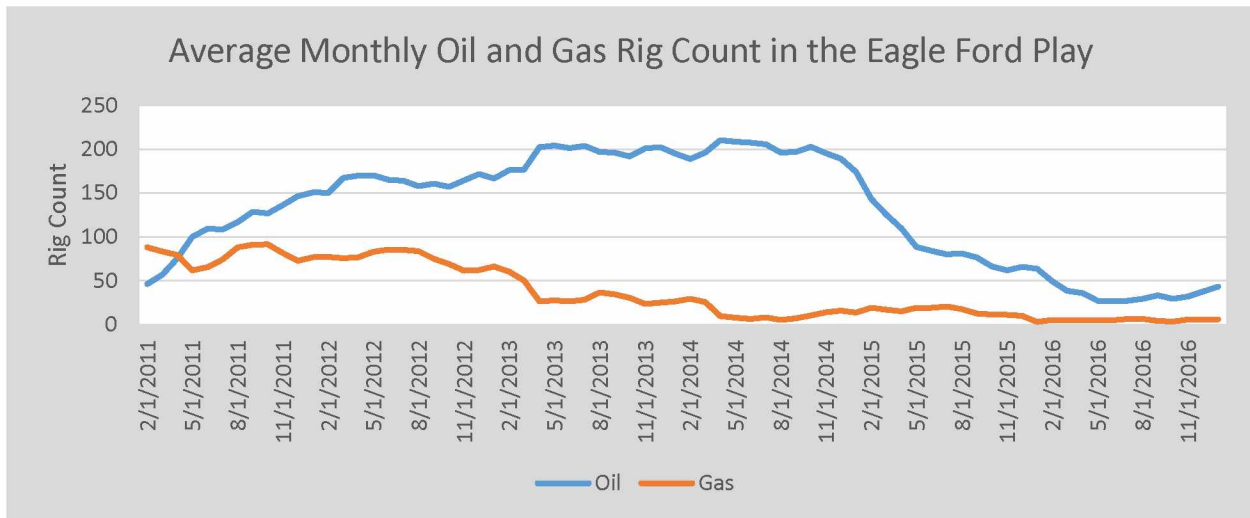
Figure 21. Eagle Ford Rig Count Showing Mainly Oil-targeted Drilling (BHI, 2017)

Besides the geologic and reservoir attractions of the Eagle Ford play, land ownership is another factor influencing developments in this play. Over 95% of land ownership in Texas, including

mineral rights ownership, is by private individuals (Rogers Oil and Gas Consulting, 2013). This contributes to lower transaction costs and speedy development of resources within the state. Also, the high concentration of oil and gas expertise within the state of Texas, following over half a century of conventional resource development, contributes to making this state the backbone of oil development within the US. The presence of significant conventional plays within the state has led to decades of experience and the development of a supportive environment for tight oil development within the Eagle Ford play. The robust service industry presence within the state of Texas also leads to more competition and quicker implementation of new oil and gas technology.

A typical Eagle Ford well requires approximately 4.8 million gallons of water for drilling and completion, mostly drawn from the state's municipal water supplies, wastewater or ground water sources, or surface water bodies (Allen, 2013). Ninety-five percent of the required water volume for well development goes into hydraulic fracturing leading to concerns about tight oil development (Allen, 2013). South Texas, where the Eagle Ford play is located, is known for very dry conditions which often raise concerns on the use of vast volumes of water for well development in this area.

In addition, well lengths vary widely in the Eagle Ford play because of the presence of both oil and gas targets which are located at different depths. Shallower wells in the North-west sections of the play are 6000ft deep while wells in the South-east of the play show higher gas-oil ratios and are about 15000ft in length (EIA, 2014b). Eagle Ford wells are estimated to be 12000ft on average and cost $7.6 million (EIA/IHS, 2016). Eagle Ford oil production rose from 15000 bpd to a peak of over 1.5 million bpd in 2015 and more than 16000 wells have been completed in this play (RRC 2016b; RRC 2016c).

2.7.3.   Niobrara Play

The Niobrara formation covers the NE parts of Colorado, SE of Wyoming, SW of Nebraska and NW of Kansas states. The Niobrara formation produces from organic-rich naturally fractured carbonate reservoir sections with thickness ranging between 50ft to 200ft, and sometimes up to

400ft thick (USGS, 2005). Some estimates put the formation thickness up to 1500ft thick in some sections and its organic content between 1 to 5 percent (Halliburton, 2017). The reservoirs lie 1200ft to 10,000ft deep and the natural fractures in the Niobrara formation contribute to improved reservoir performance for this play (Halliburton, 2017; USGS, 2005). The Niobrara formation is underpressured and records pressure gradients of 0.25 to 0.4psi/ft (USGS, 2005). In underpressured tight oil formations, oil production is quickly impeded by the production of associated gas which contributes to lower productivity for wells in this play.

On the other hand, during completion operations, low pressure formations may not require costly proppants of high crush resistance to stay sufficiently propped (Yu & Sepehrnoori, 2013). This low-pressure characteristic of the play potentially translates to lower proppant cost and ultimately lower well completion costs. Using comparable cost per foot and completion costs from the EIA/IHS (2016) study, Niobrara wells at 15000ft in total length are estimated to cost approximately $6.3 million. And operators in this play show estimated ultimate recovery for wells in the 400 to 600 MBOE range (Anardako Petroleum Corporation, 2017).

Colorado contains the largest portion of this play, and over 60% of land ownership in Colorado, and 45% of land ownership in Wyoming is privately owned (Rogers Oil and Gas Consulting, 2013). This play is not among the foremost oil development plays within the U.S. but still contributes significantly. While the play offers both oil and gas targets, oil production has become the primary focus of this play (Figure 22; BHI, 2017). By December 2015, the Niobrara play was producing approximately 470,000 barrels of oil per day (EIA, 2016b).
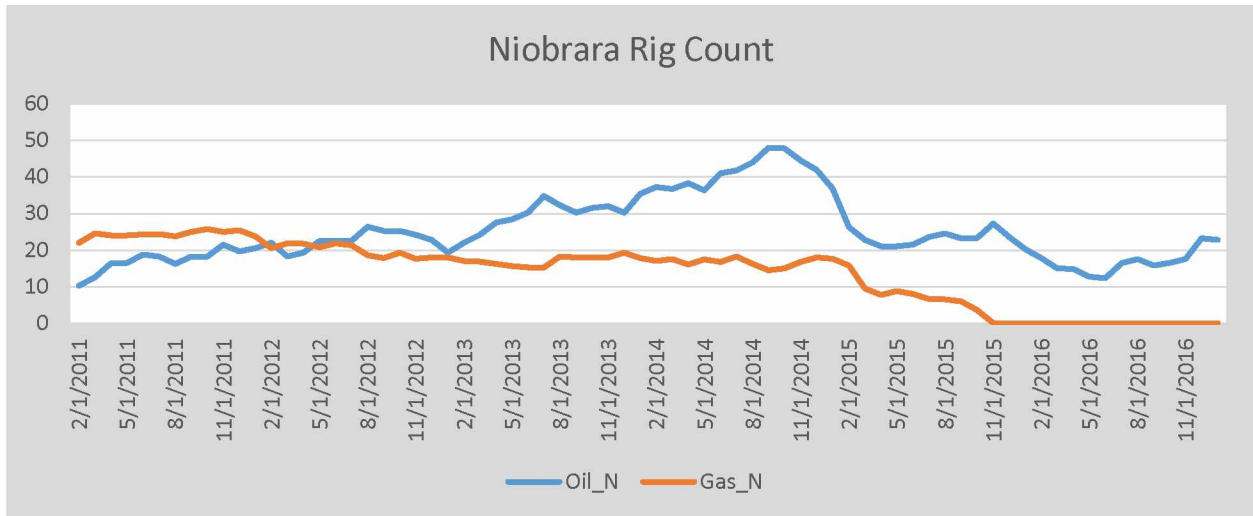
Figure 22. Niobrara Rig Count Showing Largely Oil-targeted Drilling (BHI, 2017)

2.7.4.   Utica and Marcellus Plays

The Utica shale formation is part of the Appalachian basin and underlays the states of Ohio and West Virginia. It covers an area of 115,000 square miles (EIA, 2017g), lies 6000ft deep and is 80 to 700ft thick (ODNR, 2011a). The Utica play is underlain by a more productive layer called the Point Pleasant formation, which runs for 108,000 square miles (EIA, 2017g). The Point Pleasant play has oil-rich sections towards the NW where it ranges in depth from 4000 to 8000ft, and has deeper sections in the SE which mainly consist of gas (EIA, 2017g). The Utica is carbonate rich and has higher clay content than the Eagle Ford (ODNR, 2011a). The plastic character of clay is known to reduce the effectiveness of hydraulic fracture operations and constitutes a disadvantage to well completion and development in this play. The Utica shale contains 10 – 60% of calcite and TOC values of ~3.5% while the Point Pleasant formation, which contains 40 – 60% carbonate, is more organically rich and has TOC values of 4-5% (EIA, 2017g).

Among the seven major oil producing plays that contribute over 90% of U.S. tight oil production (EIA, 2016d), the Utica play ranks among the lowest. On the other hand, this play is a more significant gas producing play (Figure 23).
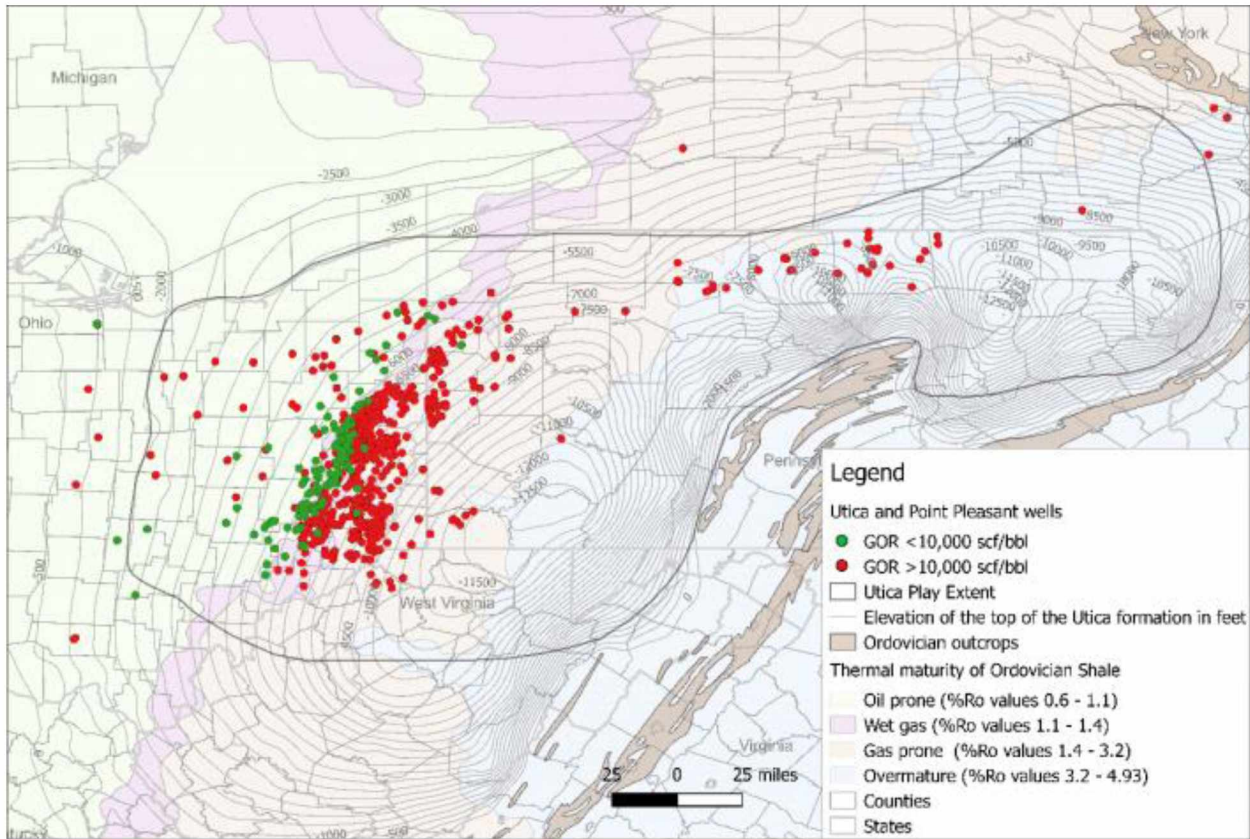
Figure 23. Utica Play Showing Play Extent and Formation Thickness (EIA, 2017g)

The Marcellus shale lies between 3200 to 5500ft deep across several states including Ohio, Pennsylvania, West Virginia, and Maryland (ODNR, 2011a). Other estimates put this play at 4000ft to 8500ft deep, 95000 square miles wide and 50 to 200ft thick (Halliburton, 2017). This is a major gas play in the U.S. although there have been interests in some of the liquids rich regions of the play. Although the Marcellus shale ranks low among the big U.S. tight oil plays, there has been a flurry of activities in this play even in the low-price periods of the recent years. Company mergers and acquisitions in the Marcellus increased eight-fold from 2015 to 2016 recording asset transfers of over $7 billion (Young, 2017). This play is comprised of a more organic rich lower Marcellus layer and an upper Marcellus layer and areas around SW Pennsylvania, West Virginia and SE Ohio that are more liquid rich (Figure 24; EIA, 2015d).
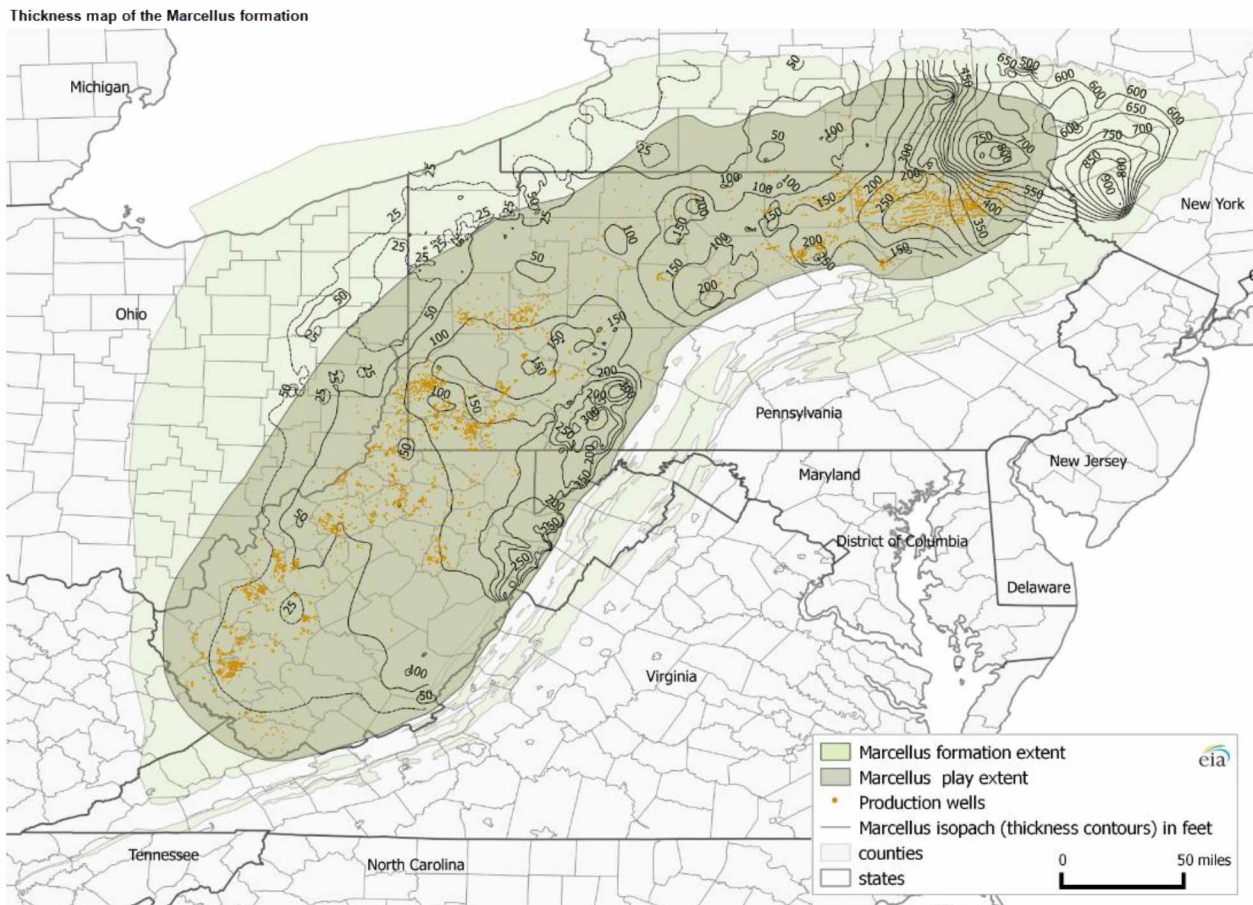
Figure 24. Marcellus Play Showing Extent and Formation Thickness (EIA, 2015d)

According to Halliburton (2017), the main challenges with development in the Marcellus play include the challenging terrain and difficulty in sourcing water for stimulation operations. By December 2015, the Marcellus and Utica plays were producing approximately 40000 barrels per day and 76000 barrels per day of oil, and 16 billion cubic feet and 3.4 billion cubic feet of gas per day respectively (EIA, 2016b). The EIA/IHS (2016) estimated well costs in the Marcellus play to be approximately $6.1 million. Using average drilling and completion costs for plays at different depths presented by the EIA/IHS (2016), the cost of a generic 10000ft well in the Utica play was estimated at $5.6 million.

The key economic drivers for development in the Utica and Marcellus plays are NGL and dry gas prices, and development efficiencies of operators within the plays (Hart Energy, 2015). According to Hart Energy (2015), while gas production was the priority in developing both plays, especially the Marcellus play, operators have shifted development within the oil window

to target wet gas portions in response to high oil prices, and moved off those regions when the cost of treating the wet components of gas was prohibitively expensive compared to the product prices. Also, drilling efficiencies and the presence of pipeline access to help move product easily are always factors at play in development within this area (Hart Energy, 2015).

2.7.5.   Permian Play

The Permian basin spans 59 counties in West Texas, and stretches for 250 miles wide and 300 miles long (RRC, 2016d). This basin contributes 50% of hydrocarbon liquid production in Texas and made up 18% of U.S. total production in 2013 (EIA, 2014c; RRC, 2016d). It contains both conventional and tight oil reservoir targets. Six formations within the Permian play have contributed most of the production surge in the last decade and three of them are shale-rich tight formations namely: Spraberry, Bone Springs, and Wolfcamp formations (Figure 25; EIA, 2014c). The Permian produces from formations as deep as 25000ft (RRC, 2016d) and most active horizontal oil wells in the basin target the Wolfcamp and Bone Springs formations. A key advantage of oil development in this basin is the existence of a thick reservoir column that extends for over 4000 feet, which creates multiple targets for individual wells (EOG Resources, 2017c). The USGS (2016a) estimates prospective (undiscovered technically producible) resources of approximately 20 billion barrels in the Wolfcamp Shale. This resource estimate highlights significant potential for this play, and the thickness of the formation provides operators with significant opportunity for more reservoir targets and the ability to grow reserves once they secure mineral position within the basin. This growth in reserves due to formation segments that could be developed in the future directly translates to company future production and market valuation. In December 2015, Permian tight oil production was approximately 2 MM bpd (EIA, 2016b). Permian wells are estimated at 12000ft in total length and cost $7.2 million (EIA/IHS, 2016). Major operators in tight oil regions of this play include Anadarko E&P onshore LLC and Cimarex Energy Company (Drillinginfo, 2017).
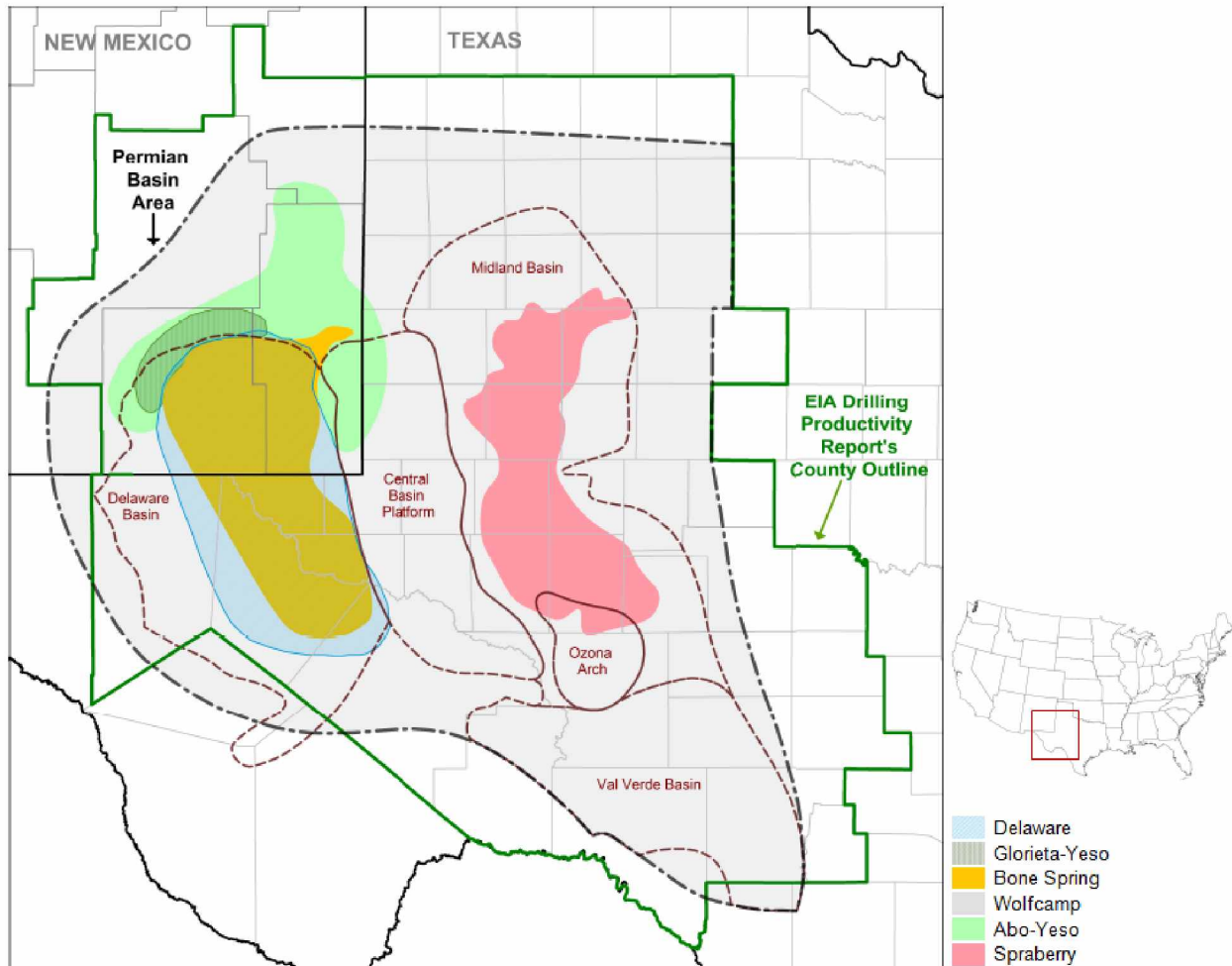
Figure 25. Permian Basin Showing SubPlays (EIA, 2014c)

The lack of sufficient transportation capacity for crude oil from the Permian basin to refining and sales centers in the U.S. Gulf Coast and other areas resulted in supply glut and discount prices of crude in this region in 2010 through 2014 (EIA, 2017h). The price discount between the West Texas Intermediate crude at Midland, Texas and the West Texas Intermediate crude at Cushing, Oklahoma almost reached $7/bbl in 2014 but has since narrowed to less than 10 cents by 2016 due to increases in pipeline capacity (EIA, 2017h). Over 700,000 bopd in pipeline capacity is expected in the 2017-2018, alongside other opportunities for gathering systems within the play (EIA, 2017h). These infrastructural modifications alongside premium oil and gas acreage composed of stacks of conventional and unconventional play targets within the Permian basin make the Permian a crucial player for tight oil development in the US.

2.7.6. Haynesville Play

The Haynesville shale play stretches across the Northwest of Louisiana, Southwest Arkansas and East of Texas. It is primarily a shale gas play of thickness between 200ft to 350ft, and producing from depths of 10000 to 14000 ft (Bureau of Economic Geology, 2016). Rocks that make up the Haynesville play were deposited in the Jurassic geologic age, and cover an area of approximately 9000 sq miles (Halliburton, 2017). There are several challenges to development in this play. High downhole temperatures of up to 380F and hydraulic fracturing pressures that go as high as 10000 psi present challenges in drilling and completion in this play (Halliburton, 2017). These conditions translate to the need for costlier specialty fluids and more hydraulic fracturing horsepower and therefore higher drilling and completion costs. Other challenges faced by operators in this play include the loss in productivity due to poorer conductivity of fractures to the producing wellbore (Halliburton, 2010). This is caused by high pressures that crush and embed proppants into the formation. Another challenge is that of large water volumes which could be costly to procure or dispose (Halliburton, 2010). In December 2015, the Haynesville shale formation contributed approximately 50000 bpd and 3.6 bcf per day of gas (EIA, 2016d). Using comparable drilling cost per foot and completion costs from the EIA/IHS (2016) study, Haynesville wells at 15000ft in total length are estimated to cost approximately $6.3 million.
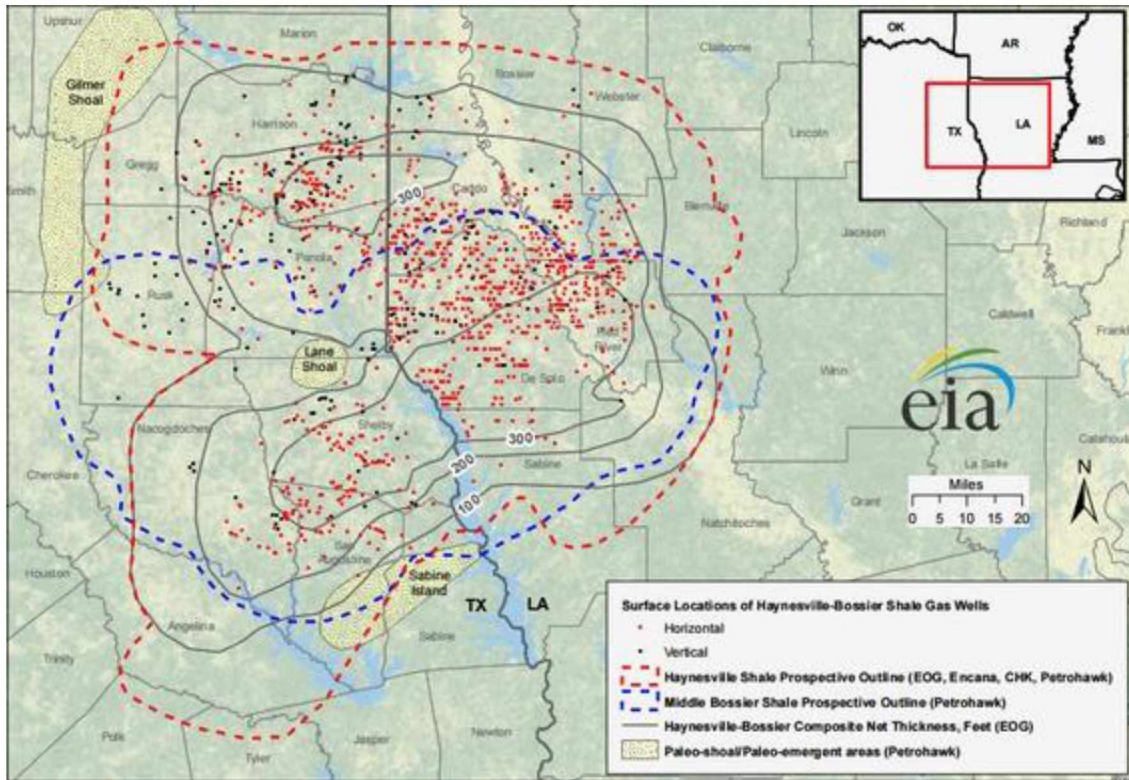
Source: Energy Information Administration based on data from HPDI, TX Railroad Commission, LA Dept. of Natural Resources, Operators.
Updated May 26, 2011

Figure 26. Haynesville Shale Play (Universal Royalty Company, 2017)

The plays discussed in this section are the most significant tight oil plays in the U.S. and contribute the majority of tight oil production within the U.S. (Figure 27). And as previously discussed, some of the plays, while primarily providing targets for oil, develop both oil and gas, such as the Eagle Ford. Others develop primarily gas targets, such as the Haynesville, Marcellus, and Utica plays (Figure 28). The following section discusses the significance of these plays in the U.S. tight oil story.

US Tight Oil Production

Legend: Others*, Monterey (CA), Austin Chalk (LA & TX), Spraberry (TX & NM Permian), Bakken (ND & MT), Eagle Ford (TX)
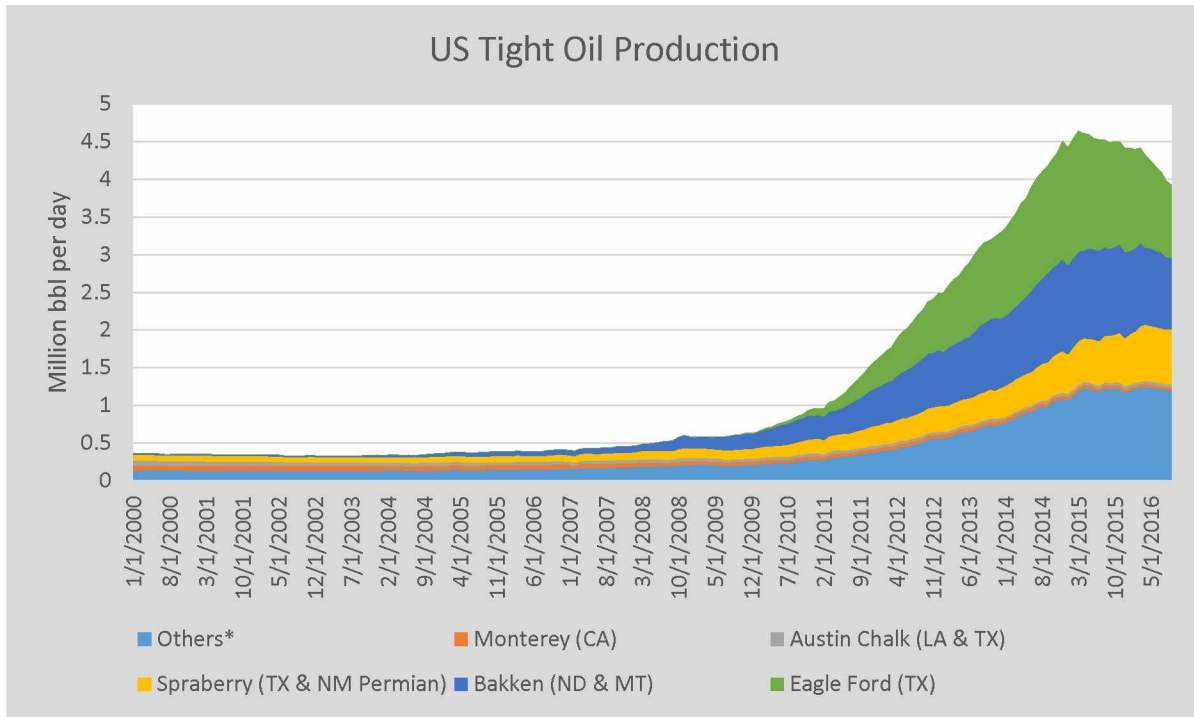
Figure 27. U.S. Tight Oil Production (EIA, 2016b)

*Others include: Granite Wash (OK & TX), Woodford (OK), Marcellus (PA,WV,OH &NY), Haynesville, Niobrara-Codell (CO, WY), Wolfcamp (TX & NM Permian), Bonespring (TX & NM Permian), Yeso & Glorieta (TX & NM Permian), Delaware (TX & NM Permian), Utica (OH, PA & WV).
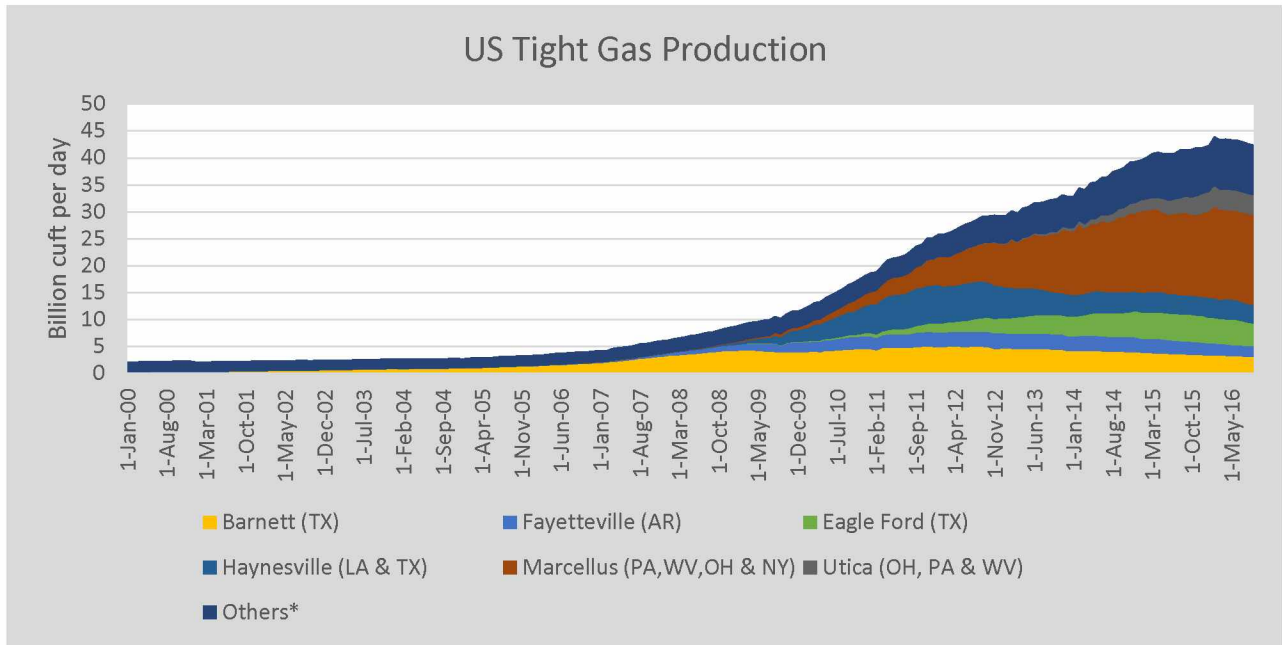
Figure 28. U.S. Tight Gas Production (EIA, 2016c)

*Other include Antrim (MI, IN, & OH), Bakken (ND & MT), Woodford (OK)

Generally, while current production is the focus of the industry, the future production outlook for the U.S. oil and gas industry, which depends on crude oil reserves, drives industry long term activity. The central method used in determining crude oil reserves is by oil production forecasting. Oil production forecasting could be conducted at the well, reservoir, or regional level. The next section reviews the literature on oil production forecasting techniques. These techniques are important for new tight oil regions within and outside the U.S. because they determine how few data points from new wells can help shape the outlook for tight resource plays. Oil production forecasting is also important for operators as they grapple with questions about the character of frontier tight oil regions and the crude oil reserves that is important to their market valuation.

CHAPTER 3. TIGHT OIL PRODUCTION FORECASTING FOR MAJOR U.S. PLAYS: ENGINEERING PERSPECTIVE

3.1.   Introduction

Production forecasting refers to the practice of determining future production in the life of a petroleum asset using current and historical production performance of the asset. The volume of production expected from an asset guides the sizing of tangible production assets such as processing plants. Oil and gas operators also conduct oil production forecasting to ensure reliable planning of investment and revenue. For this reason, oil production forecasting is at the center of overall petroleum asset management. The basis of oil production forecasting lies in classical production forecasting models that have been in use for over half a century.

Classical Production Forecasting Models and Arps Decline Curve Analysis (DCA)

Several methods have been proposed in forecasting production in oil and gas wells. Topical works done by Arps (1945) and advanced by Fetkovich (1980) are known and used throughout the oil industry. Arps (1945) described three different forms of decline trends for production from a well or reservoir: exponential, hyperbolic, and harmonic decline. He developed equations that use an initial production rate, a decline rate and a b-exponent to fit a trend on historical production and to determine future production. These equations have had wide use in the oil industry and are applied in understanding and forecasting production trends and in estimating producible volumes from reservoirs based on historical production volumes.

Arps (1945) observed that oil rates in some wells decline exponentially with a constant decline rate (D) or a constant loss ratio (1/D). The exponential decline shows a production profile where the rate of decline does not change over time. The decline rate is calculated as follows (Poston & Poe, 2008):

$$\text{Decline rate, } D = \frac{\ln\frac{q_1}{q_2}}{t} \tag{1}$$

And the production rate at any time could be described by the decline rate and the initial production rate as follows:

$$\text{Rate, } q_2 = q_i e^{-Dt} \tag{2}$$

And the cumulative production over a period is estimated thus:

$$Q_p = \frac{q_i (1-e^{-Dt})}{D} \tag{3}$$

The theoretical maximum cumulative production exists at infinite time where e^{-Dt} becomes zero and Q_p becomes qi/D. But this is not practical because production continues until a point where the well stops paying for the expense of keeping it on production. That point is referred to as the economic production limit. Hence in calculating the actual cumulative production, one takes into consideration the oil rate at which the operator shuts in the well because it cannot keep up with the expense of producing it, a rate q2. So, the practical cumulative production in a well that declines exponentially is calculated as follows:

$$Q_p = \frac{q_i - q_2}{D} \tag{4}$$

Arps (1945) also described production profiles where the rate of decline of production changes over time; wells whose oil rate profiles show a hyperbolic decline. Arps (1944) explained that the loss ratio of these wells showed an arithmetic progression and the difference between loss ratio at each time step was approximately the same. The curvature of the production profile in the decline equation is governed by the size of a non-zero b-exponent representative of well operating conditions. The production at any point for a well that declines hyperbolically is calculated as follows:

$$q_2 = \frac{q_i}{(1+bD_i t)^{(1/b)}} \tag{5}$$

And cumulative production from this well is determined thus,

Theoretical maximum cumulative production for wells showing hyperbolic decline,

$$Q_p = \frac{q_i}{D_i(1-b)} \tag{6}$$

As stated earlier, the theoretical maximum cumulative production is reached when the well is allowed to produce until it stops flowing (q_2=0), which is not practical in real life due to well operating costs. Where the actual rate when the well will be shut in is known (q2 $\neq$ 0) the cumulative rate is calculated as follows:

$$Q_p = \frac{q_i - q_2^{(1-b)}}{D_i(1-b)}$$ (7)

Arps (1945) also described oil rate profiles that showed a harmonic decline. For this category of wells, the b-exponent value is 1. Production rate at any point in calculated thus:

$$q_2 = \frac{q_i}{1+D_i t}$$ (8)

Cumulative production over a period where rate changes from an initial rate, qi to a new rate, q_2

$$Q_p = \frac{qi}{D_i} ln\left(\frac{q_i}{q_2}\right)$$ (9)

Arps (1945) simplified these equations with the observation that the b-exponent ranges between 0 and 1 ($0 \leq b < 1$). With that definition, for exponential decline, b=0; for hyperbolic decline, 0<b<1; and for harmonic decline, b=1. But, a b-exponent of 1 or greater describes an infinite reservoir with infinite drainage radius which is physically impossible (Poston & Poe, 2008). Hence, while b could take values $0 \leq b$, for the solution of rate and cumulative production to be bounded, b should be strictly less than 1 and within the range $0 \leq b < 1$.

Fetkovich et al. (1987) grounded empirical models developed by Arp's within an analytical framework. Through solutions to the diffusivity equation, Fetkovich linked Arps' observations to the physics of fluid flow and reservoir engineering (Clark, 2011). He posited that the b exponent has a physical significance tied to the reservoir production mechanism. Clark (2011) reported analytical findings of Fetkovich that associate b-exponent of zero to single phase liquids, weak waterfloods or formations with low gas permeabilities, b-exponents of 0.3 and 0.4 for solution gas drive and gas wells, and 0.5 b-exponent for water-drive and gravity drainage wells.

The b-exponent is also positively related to reservoir heterogeneity, as measured by the Dykstra-Parsons coefficient (Clark, 2011; Walsh & Lake, 2003). The Dykstra-Parsons coefficient is a measure of permeability heterogeneity and ranges from zero, for homogenous systems, to 1, for highly heterogeneous systems (Walsh & Lake, 2003). Poston and Poe (2008) also agree that highly heterogeneous systems or systems where prolonged crossflow occurs, from tight zones to the wellbore through highly permeable zones, result in high b exponents. This suggests that hyperbolic decline will be observed in layered reservoir systems, where production persists from less permeable layers long after more permeable layers are depleted, resulting in a long-sustained tail in the production profile, such as tight oil wells.

Tight oil wells yield hyperbolic declines (Harris & Lee, 2014). Since these wells produce with characteristically hyperbolic declines, the b-exponent values required to match well performance is above 1, which mathematically leads to a prediction of impossible, infinitely large reserves (Duong, 2010). Since hyperbolic declines generate unrealistic reserve estimates, petroleum engineers have warned against using these b values (Fetkovich, 1980); or more specifically, against using the values in predicting flow throughout the life of the well (Duong, 2014).

3.2. Oil Production Forecasting in Tight Rocks: How are Classical Models Deficient?

Decline curve analysis by Arps (1945), Fetkovich (1980), and Fetkovich et al. (1987) simplified understanding of production decline around some assumptions. In a well that produced a slightly compressible fluid phase under the same operating conditions for its entire duration of production, over a fixed drainage area and constant productivity index, specific characteristic profiles could be observed in its production rates (Poston & Poe, 2008). The absence of these conditions leads to inaccurate application of classical decline curve analysis models, causing errors in reserve estimates or forecasted production rates. Tight oil production flouts most of the conditions necessary for applying classical decline curve analysis models (Duong, 2010; Duong 2014; Poston & Poe, 2008).

For oil wells drilled in conventional reservoirs, when production begins, the pressure change experienced at the well bore quickly travels through the rocks and reaches the farthest extent within the *influence* of the well, its drainage boundary (Poston & Poe, 2008). When this happens, continued production occurs under conditions referred to as boundary dominated flow conditions. During boundary dominated flow, the well is in a steady or pseudo steady state. During this time, production is sustained by pressure from a defined boundary of the well, enabling a smooth profile of production behavior to be traceable. This is typically not the case for tight reservoirs where it takes a very long time for pressure changes at the well bore to reach the boundary of the well (Duong, 2010). And the pressure transience, due to very low permeability of the rocks, keeps expanding for a long time in the life of the well. According to Duong (2010) flow in shale and other low permeability formations does not stabilize for the entire life of the well. This observation in tight oil wells makes them unsuitable for the use of classical forecast models like the Arps model. Other transient flow models have been advanced to predict tight oil production when flow is still in the transient period. When production flow gets into the boundary-dominated phase, the classical models are applied (Duong, 2014). Since periods of erratic flow also exist in tight oil wells, to reduce errors in forecasting reserves, production forecasters use flowing pressure data or other means to identify periods of transient flow, for which transient flow models are applied, and periods for which the switch could be made to classical models (Anderson et al., 2012; Lacayo & Lee, 2014; Anderson & Mattar, 2003).

3.2.1.   Tight Oil Flow Regimes Identification

Tight oil wells experience flow regimes that are different from what is observed in conventional wells (Figure 29). For conventional wells, a brief transient period and a more prolonged boundary-dominated flow period are observed. In forecasting production in conventional wells, it is best practice to exclude the brief transient phase, as this symbolizes a period of instability in the well's productive life, which if included may lead to erroneous forecasting of future production rate or ultimate recovery.

Forecasting production rates for tight oil wells is different. After well stimulation through hydraulic fracturing, there are at least three reservoir segments created by this operation, leading to distinct flow regimes (Akoun, 2011; Duong, 2014; Figure 30). The hydraulic fractures, now packed with sand proppants, have better permeability than the rock matrix itself and provide a flow path to the wellbore. Next, there is the segment of rock in the immediate vicinity of the fracture which is impacted, weakened, or cracked by the force that led to the creation of the hydraulic fracture. Many authors have referred to this segment as the stimulated reservoir volume, which is characterized by enhanced permeability from the original permeability of the unaltered rock (Section B in Figure 30, with Permeability K_{SRV}) (Duong, 2014; Lee, 2014; Mayerhofer et al., 2010). Finally, there is the portion of the formation around the well which is unaltered by the fracturing operation known as the unstimulated rock volume or the unaltered formation matrix (Section A in Figure 30). Akoun (2011) referred to the three linear flows occurring simultaneously through all three segments of the reservoir early in the well life as compounded linear flow.

The models developed to describe flow in tight oil wells assume that negligible or no flow goes directly to the well and all flow into the wellbore goes through the hydraulic fractures (Duong, 2014). This is because tight formations permit very little flow without stimulation, and also because hydraulically fractured wells are typically cased hole completions, and the only openings from the wellbore to the rock is through perforations from which hydraulic fractures emanate or from where hydrocarbons from the rock flow into the wellbore. Duong (2014) referred to flow from the unaltered rock into the stimulated rock region as influx while flow from the stimulated rock into the fractures as inflow. He also determined an influx-inflow ratio which is governed by the rock formation permeability anisotropy (difference in rock permeability when measured in different directions), but also the well spacing and fracture spacing which could be optimized to improve production contribution from different rock segments.

The transient phase in tight oil wells is prolonged and the flow regime at this time is generally referred to as transient flow. It consists of all flow that occurs, from the fracture to the wellbore or from the unstimulated rock to the stimulated rock volume, prior to any interference by neighboring fractures or the boundary of the well (Lee, 2014). Akoun (2011) noted that flow

regimes during the transient phase could be (1) fracture linear flow, going from within the fracture to the wellbore (typically unobserved in well tests because of its brevity); (2) formation linear flow, fluid flow going from the rock volume towards the fractures; and (3) bilinear flow, which occurs when the previous two linear flows occur simultaneously in a low conductivity fracture. While bilinear flow is observed in low conductivity (finite conductivity) fractures, only formation linear flow occurs in highly conductive (infinite conductivity) fractures, because in formations with highly conductive fractures, fracture linear flow is too brief to measure (Khanal et al., 2015). Infinite conductivity fractures discharge fluids they contain quickly to the wellbore and are theoretically understood to mean fractures within whose length there is no pressure drop. This suggests that fluids that enter infinite conductivity hydraulic fractures are quickly discharged into the wellbore, making that flow duration insignificant and unnoticeable when compared to the flow of fluids from the rock formation into the fractures themselves. At the end of transient flow phase, there is a transition phase that follows as some boundary effects become apparent due to interference from neighboring hydraulic fractures, referred to as the boundary-influenced phase (Lee, 2014). Finally, there is a boundary dominated flow phase at the later life of the well when the entire drainage area of the well is being drained. This means, the well is now draining from the farthest location in the formation within its capacity to drain. The engineer's ability to identify these regimes is central to any endeavors to apply the right models in the process of forecasting production in a tight oil or gas well.
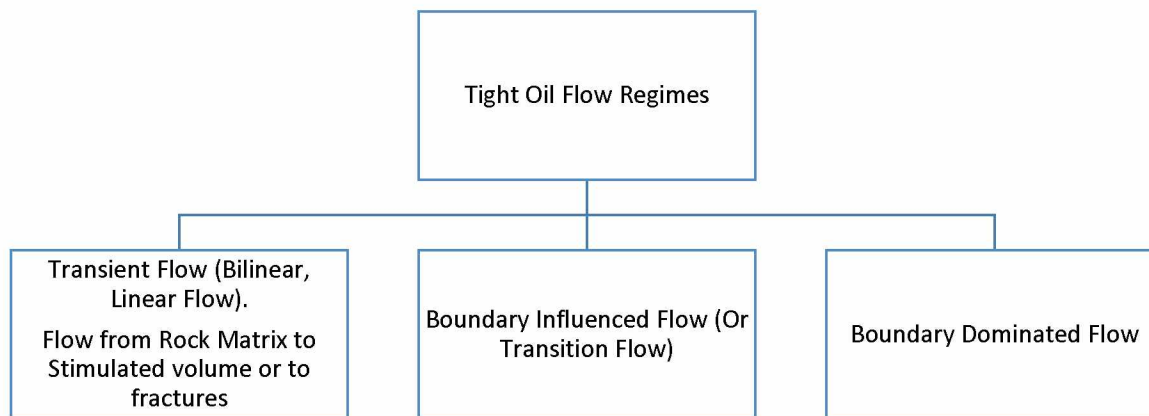
Figure 29. Flow Regimes in Tight Oil Formations (Akoun, 2011; Lee, 2014)
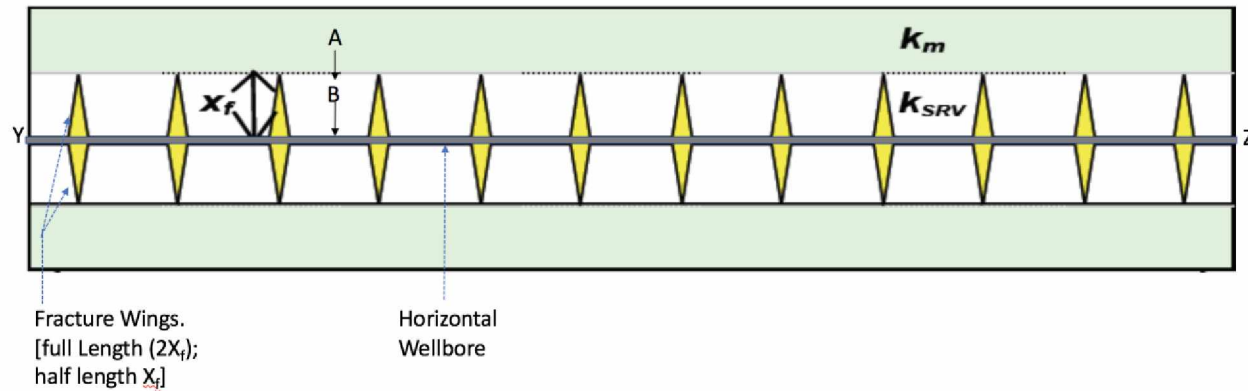
Figure 30. Illustration of Wellbore and Hydraulic Fracture Showing Segments Governing Flow Regimes (Modified from Lee, 2014)

The recognition of flow regimes is key to production forecasting in oil wells when applying the Decline Curve Analysis technique. This is important because it enables the forecaster to move from mere curve-fitting to applying the right models for the right sections of well history. For example, it is through these methods that wellbore storage effects, fracture fluid flow or some restricted flow can be noticed. Recognition of flow regimes is achieved using several plots that

expose trends characteristic of known reservoir and well phenomena. These graphs are referred to as diagnostic plots. Some of the popular diagnostic plots are discussed next.

3.2.1.1. Log Rate Vs Log Time Plot

This is a graph of the production rate plotted against time on a log-log scale. A negative half slope of this plot is characteristic of linear flow in the rock, while a negative quarter slope indicates bilinear flow (Akoun, 2011; Alotaibi et al., 2015; Sharma & Lee, 2016). The portion of the graph that makes this slope represents transient flow regime which is typically a dominant flow regime for tight oil wells.

3.2.1.2. Log Rate Vs Log Material Balance Time Plot

This is a graph of the production rate plotted against the ratio of cumulative production to production rate (referred to as material balance time (MBT)) on a log-log scale. A negative unit slope on this plot is diagnostic of the onset of boundary dominated flow (Sharma & Lee, 2016). This plot also helps identify and exclude outliers. For example, Sharma and Lee (2016) showed that to easily exclude data that falls away from the trend of normal data or data resulting from production shut in times, it was necessary to use only points where MBT and time increased simultaneously. Harris and Lee (2014) advised that this plot could be made more accurate if the production rate is normalized for pressure changes by using a ratio of production rate (q) to pressure drawdown [which is the reservoir pressure (Pi) minus the flowing bottom hole pressure (P$_{wf}$)]. This pressure normalization of production rates would adjust for pressure changes that occur during well operation which result in non-characteristic shifts in production rate. Often, data on bottom hole flowing pressure is not available to forecasters and conducting this analysis on mainly production data presupposes that the noise to signal ratio is minimal and will not significantly affect the results. But with very erratic production, as is experienced in very early data such as during fracture cleanup, this could be a problem. Sharma and Lee (2016) advised that outliers noticed in this plot ought to be taken out during analysis so that a smooth trend is visible. The slope of the curve changes from 0.5 to 1 signaling the onset of boundary dominated flow and the point where Arps' models could again be useful in prediction.

After these diagnostic techniques are applied, it becomes easier to identify what sections of the well data to apply specific models for the purposes of predicting production. The accurate identification of this point in the data trend is crucial to reducing the error in forecasts. This is because assuming that production stays longer in the transient stage leads to overestimation of reserves while assuming a faster change to boundary dominated flow (BDF) will lead to a more conservative reserve estimate (Harris & Lee, 2014). It often takes analysis of production data in a geologic region over a group of wells to determine what time in well life is typical and most representative of an area. This exercise is possible only if these wells are producing from similar reservoir, were completed in similar fashion and operate in similar way. But this is typically more challenging for new tight oil regions from the start of development with few wells and few production data points.

Since determining the onset of boundary flow is important for selecting the proper model and applying it in a timely fashion, some forecasters have made attempts to translate this time when flow regime changes into a decline rate that signals the switch between empirical models. For example, Sharma and Lee (2016) prescribed a shift from using Duong's model or Arps' hyperbolic model in the transient flow regime to using the Arps exponential model in the boundary flow regime, when production decline rate reaches 5%. Harris and Lee (2014) observed that for a small sample of 65 wells selected from Elm Coulee formation in the Williston Basin, the decline rate when boundary dominated flow begins could be quite variable. This formation was selected for study because its wells are older and provide more production data, had better permeability, and more likely to show boundary effects than less permeable rocks. The decline rate at the start of BDF showed a right skewed lognormal distribution with an average of 22% for the wells studied, which decreased to 17% when later term linear flow wells were added to the mix (Harris & Lee, 2014). Seidle and Connor (2016) reported a narrower range of 2 to 12% on this decline rate where a transition is made to BDF. The benefit of using this decline rate signal derived from analogues is greater for new fields where there is hardly any data to start with (Harris & Lee, 2014). But as more information is gained, these regions will depend less on analogues from other regions to a narrower range of values determined in the specific region. This would be the case of non- U.S. aspiring tight oil plays where historical data will be few and where a reliance on U.S. analogue plays may be significant.

3.3.   Tight Oil Forecasting Techniques

The advent of tight oil and gas development has opened yet another chapter in oil and gas well forecasting. This is because, unlike classical reservoir engineering forecast methods that rely on boundary dominated flow (BDF) conditions for forecasting, tight oil wells typically stay transient for a long time. Petroleum engineers often liken the progression of pressure transience away from a well and through the rock to the ripples formed by a stone dropped in a pond (Khataniar, 2009). In conventional rocks, when a well starts producing, it takes a short time for changes in pressure caused by the well to reach the farthest edge of the area from which that well will ultimately produce, or its well boundary. Classical decline curve analysis models forecasting production in conventional wells use equations that assume boundary-dominated flow conditions; this implies that at the least, the first ripple has reached the 'edge of the pond' and the well is now producing from a constant drainage area. For tight plays, the ripples are slower due to extremely tight (low permeability) rocks and typically don't reach the 'edge of the pond' for years hence the initial drainage area when the well starts producing continues to increase for most of the well's operating life (Lacayo & Lee, 2014). As a result, different equations and models have been developed to handle these conditions. Examples of these models are the (1) Logistic Growth Analysis model, (2) Power Law Exponential model, (3) Stretch Exponential model, (4) Exponential Truncation of Hyperbolic model, (5) Duong's rate forecasting model, (6) Multiple b-exponent model, and (7) the use of hybrid models (Agboada & Ahmadi 2013; Clark, 2011; Duong, 2014; Paryani et al., 2016). Some of these perform better at different points in the life of the well with significant consequences to the overall forecasted reserves (Agboada & Ahmadi 2013; Paryani et al., 2016). The most successful applications of the models have acknowledged that, because of the changing characteristics of tight oil wells throughout their production lives, rather than the use of a single model, multiple models ought to be applied. The two models reviewed show this phenomenon.

3.3.1.   Multiple b-exponents and The Use of Hybrid Models

Some forecasters propose the use of multiple b exponents in forecasting referred to as the Multiple Transient Hyperbolic Exponent (MTHE) method (Clark, 2011). This method proposes a

change in Arp's hyperbolic b-exponents corresponding to observable changes in flow character. This method is based on the fact already clarified in one of the key assumptions of the Arps decline analysis, which bases decline forecasts on the presumption of a steady b-exponent value. Because this value is transient due to changes in well operating conditions that impact well flow, the MTHE method changes this exponent to mimic production behavior. Spivey et al. (2001) suggested a b-exponent of 2 to mimic linear flow of gas in the fractures at early time. Kupchenko et al. (2008) proposed a b value of 0.25 to match boundary dominated flow regime. This technique therefore applies a hybrid of Arp's model exponents in forecasting production for a single well.

Multiple b-exponent or hybrid models are mainly empirical and present a simple way to trend production over time. Lacayo and Lee (2014) observed that these models improve forecasting by reducing the error caused by non-boundary flow conditions experienced in tight wells. By adjusting the b-exponent, the MTHE models also improve the handling of the transition between linear and boundary dominated phases in the wells' flow (Lacayo & Lee, 2014). On the other hand, Clark (2011) argued that this technique of switching b exponents is discontinuous and still presents a non-unique, bias-prone solution as forecasters still need to observe and guess when to apply the accurate b-values.

Some forecasters recommend switching between models rather than applying a change in b exponents. This technique is referred to as the hybrid model forecasting technique. Harris and Lee (2014) showed the impact of switching between Duong's model and Arp's hyperbolic and exponential models when the decline rate of wells reaches set values. This showed an improvement in reserves forecasting in the applications they presented. Yet, even with the strength of these empirical models, the level of uncertainty in reserve estimation could vary based on how much of historical production is known from the well or region for which the forecast is being conducted. And, as is the case with conventional wells, the use of erratic data or insufficient data has its risks. Harris and Lee (2014) proposed eliminating the first six months of data to improve accuracy of forecasts. They also observed that since rates are higher during early times in the life of the well, errors at that period will affect reserve estimates more. As a result, rate forecasting techniques that recommend hybrid models or the use of select decline rates when

BDF regime is reached, will be more erroneous if those changes are made early in the life of the well. Harris and Lee (2014) also showed that if BDF starts earlier than it is assumed to start, there is a risk of overestimation of reserves by switching late to an Arps BDF model from a linear flow model; and if BDF starts later than assumed, there is risk of underestimation. This selection of starts of BDF further highlight the openness for bias on the part of a forecaster or chance for non-unique solution across different forecasters.

3.3.2.   Duong's Rate Forecasting Model

Duong (2010) proposed a method of production rate forecast and estimated ultimate recovery (EUR) forecast for shale formations in which the main contribution to flow is from fractures. Although this model was developed using gas wells, it has been put to wide use in oil production forecasting (Agboada & Ahmadi, 2013; Duong, 2014; Haris & Lee, 2014; Lacayo & Lee, 2014). Duong (2010) observed that shale oil and gas wells show a characteristic straight line with negative slope when rates are plotted against time on a log-log scale. This flow regime is identified as transient linear flow (slope of 0.5) or bilinear flow (slope of 0.25), and could run for different durations, with some wells showing up to five years and other wells staying in this flow regime for their entire productive life (Duong, 2010). Duong (2010) reported that this phenomenon was observed by several other studies in (1) natural and hydraulic fractures, (2) single and multistage fractures, and (3) finite conductivity fractures (pressure drop along the length of the fracture), or (4) infinite conductivity fractures (no pressure drop along the length of the fracture). He explained that the sustained linear flow is a result of enhanced connected permeability caused by the reactivation of faults or fractures in response to pressure changes in the rock during production depletion. This could be likened to the movement of crushed ice fragments in a bowl as water is drained out from a single spot or sucked out with a straw.

Duong (2010) also plotted the ratio of production rate and cumulative production, q/N_p against time on a log-log scale to obtain a slope 'm' and an intercept 'a'. A plot of production rate and t (a, m) produces a straight line of positive slope, q_1 and intercept, q_∞, production rate at infinite time. The production rate at any point in the well's life is forecasted thus (Duong, 2010):

$$q = q_1 t (a, m) + q_\infty \tag{16}$$

Where

$t (a, m) = t^{-m} e^{\frac{a}{1-m}(t^{1-m}-1)}$

q_1 = Flow rate at day 1

q = Daily production rate

N_p = Cumulative production

q_∞ = Rate at infinite time (forced to an intercept of 0 reflective of a production rate at infinite time of zero according to (Khanal et al. 2015)

Cumulative production from the well is calculated as follows

$$N_p = \frac{q_1}{a} t(a, m) t^m \tag{17}$$

And, upon determining an economic limit of production, q_{econ}, and the time when that rate is reached, t_{econ}, the total reserves or estimated ultimate recovery (EUR) is determined as follows (Duong, 2011):

$$EUR = \frac{q_1}{a} t(a, m) t_{econ}^m \tag{18}$$

While Duong's model has received wide acceptance in the early life of tight oil development, several works have found it too optimistic because it presumes that the well stays in transient linear flow for most of its productive life (Lacayo & Lee, 2014). Recent applications in forecasting well production show that some wells enter boundary dominated flow late in their life leading to faster decline. Lacayo and Lee (2014) argued that Duong's model is prone to overestimating future production (reserves) because it assumes longer transient conditions for the well and protracts production over a longer time on a slower decline. For tight oil wells with up to two years or more of non-erratic production data, the Duong model is shown to work well (Paryani et al., 2016). This is evident in the level of acceptance it has received in academic and industry circles for wells in transient flow (Sharma & Lee, 2016) including software applications such as the Drillinginfo Software.

However, for young tight oil plays with very few months of production, the challenge in forecasting remains. Harris and Lee (2014) tested the ability of Duong's model to accurately

determine reserves using a hindcasting technique on already known data and observed that the model overestimated production. They observed that the removal of the first six months of data, which is typically more erratic, improved the accuracy of the model. Seidle and O'Connor (2016) re-echoed this concern when they realized that using just the first six months of production history, gave erroneous predictions whether the Duong model, Stretched Exponential Decline Model, or the modified Arps model were used. Others have praised the accuracy of Duong's model especially for transient flow periods, while maintaining that it did not capture flow at the boundary dominated flow well (Kanfar & Wattenbarger, 2012).

Following this shortcoming of the model, Duong (2014) updated his model to include a transition point from transient flow to boundary dominated flow to rein in high reserve estimates observed by previous applications of the model over the entire life of the well. In this update, Duong (2014) noted that the influence of nearby fractures places wells in boundary dominated flow regimes. He also recommended pressure normalization of rates, where pressure data is available. But since most forecasts are conducted with public data which hardly includes continuous pressure data from wells, such as well head pressure or flowing bottom hole pressure, Duong (2014) made some assumptions around which forecasts could be generated. Different from previous attempts by other authors (Kupchenko et al., 2008; Sharma & Lee, 2016) to recommend switch points for boundary influenced or boundary dominated regimes based on some select decline rate, for example when decline rate reaches 5%, Duong (2014) recommends some quasi-analytical formula at deriving the switch point and the decline rate at which the Arps exponential (b < 1) model could be applied to arrive at bounded estimates of reserves. Duong (2014) thus applies hybrid models in a manner that acknowledges the changing regimes in wells, and also reduces the problem of non-unique solutions by analytically selecting the point at which the Duong (2010) model runs out of use.

The start of fracture interference in hydraulically fractured wells is determined thus (Duong, 2014):

$$t_{sfi} = (1.82a)^{1/(m-1)} \qquad (19)$$

Dimensionless start time to fracture interference (t_{Dsfi}) ranges between 0.2 and 0.4 depending on whether the well was in constant flow pressure mode or constant rate production mode respectively (Duong, 2014). The decline rate at which transition occurs, D_{ye} is determined using dimensionless time to the start of fracture interference, t_{Dsfi} and time to the start of fracture interference, t_{sfi}, as follows:

$$D_{ye} = \frac{t_{Dsfi}}{t_{sfi}} \qquad (20)$$

Then the production rate after this transition point is determined using the Arps exponential decline formula thus:

$$q = q_{sfi}e^{-D_{ye}t} \qquad (21)$$

For plays in medium development stage, where some historical data is available, this model has been shown to predict production reliably (Duong, 2014).

The use of well analogues allows forecasters to anchor modeled production on actual observations in the field in question. And more production data from analogue wells and formations within a region provides a better understanding and forecasting of the range of production that is possible for a new well. Production from analogue wells are used to develop type wells for that same region or comparable region in which similar wells are planned. This implies that while tight oil forecasting models are useful for new plays within or outside the US, analysts of those plays cannot rely completely and verifiably on these models when production is still very immature. New tight oil plays may have to rely more on type wells from analogue plays within the U.S. or other developed fields, until enough data and understanding is gathered for specific wells or regions to conduct more reliable forecasts from local analogues.

The next section reviews U.S. tight oil reserve estimates and tests a technique on arriving at regional forecasts based on expected future well counts and the use of type wells alongside Duong's modified rate forecasting model. Reserves are determined based on what volumes

producing wells and future wells can produce technically and economically. The section further shows how Duong's modified model can be used to develop longer profiles from type wells with insufficient data to produce 20-year production life well profiles and a tight oil reserves forecast for the continental U.S. (Figure 31).

Log-log plot: Daily rate/Cumulative Production (q/Np) versus time
Using a power law data fit: determine intercept "a" & power "m"

Cartesian plot: daily rate vs t (a, m).
Using a linear data fit trend line: determine slope (q1) and intercept (q_∞). q_∞ forced to zero

Apply equation 19 through 21 to derive the time until start of fracture interference, the decline rate from that point onward, and the Arps formula as applied in Duong (2014) is applied for rate forecast onward until zero or economic limit of the well.

Figure 31. Step by Step Application of Duong's Modified Rate Forecast Model (Duong, 2014)

3.4.   US Tight Oil Production Forecasts by Play

Prior to the oil price meltdown in Q4 of 2014, U.S. tight oil production was projected to grow through 2021 after which some decline was expected (EIA, 2013b). This projection seemed quite plausible given the annual rate additions and level of investments going on in the different plays. The EIA (2013a) numbered 21 joint ventures between U.S. companies and foreign investors that injected over $25 billion into tight oil and gas plays. The EIA currently projects tight oil production in the U.S. to exceed 7 million barrels per day in 2040 from 2015 levels slightly above 4.5 million bpd (EIA, 2017b). Most of this production is expected to come from a play like the Bakken, which spans an area of approximately 37,000 square miles and is thought to contain 23 billion barrels of technically recoverable reserves (EIA, 2016g). The difference

between the EIA's projection of growth from 2013 through 2021 and the actual tight oil production decline experienced in 2015 and 2016 highlight the challenge with regional production forecasts.

Forecasting production on a regional scale could seem herculean especially for a price sensitive resource such as high cost tight oil. Some attempts have been made in the past in this regard for the Eagle Ford (Alotaibi et al., 2015). However, a thorough look at the historical performance of different plays could provide some insights and make the forecasting exercise manageable. As a result, the estimation of production at the regional level could be simplified in a few steps (Modified from Alotaibi et al., 2015):

- Determination of reserves in the play (In new regions, applying analogue recovery factors to the assessed volumes of oil in place; to serve as check and potential ceiling on overall forecasted production).
- Determination of representative type wells for each major play or sub-play based on a baseline technology assumption.
- Determination of number of wells drilled annually within the play based on the commercial climate.

3.4.1.1. U.S. Tight Oil Reserves

Total U.S. oil production has increased by over 1 million barrels of oil per day every year since 2012 mainly due to tight oil development, and tight oil production now contributes almost 50% of total U.S. production (EIA, 2017a). Tight oil plays like the Bakken and the Eagle Ford have seen average year-on-year increase in oil production from 2010 through 2015 of above 30% and 100% respectively (EIA, 2017e). This increase in production occurred on the backdrop of high oil prices. Of the 9.4 million bpd produced in the US, tight oil production in 2015 reached 4.9 million barrels per day (EIA, 2017b). Oil production is sustained by oil reserves growth; the amount of oil that is available for production.

Oil and gas reserves is defined as:

...those quantities of oil and gas, which, by analysis of geoscience and engineering data,
can be estimated with reasonable certainty to be economically producible—from a given
date forward, from known reservoirs, and under existing economic conditions, operating
methods, and government regulations—prior to the time at which contracts providing the
right to operate expire, unless evidence indicates that renewal is reasonably certain,
regardless of whether deterministic or probabilistic methods are used for the estimation.
The project to extract the hydrocarbons must have commenced or the operator must be
reasonably certain that it will commence the project within a reasonable time. (Code of
Federal Regulations, 2017)

The key elements of this definition, according to the U.S. Securities and Exchange Commission
enforcement, include the existence of technology to produce the resource, commercial and
contractual conditions to access, produce, and bring the resources to market, and the fact that
current prices can sustain a profitable venture. In the absence of any of these economic and
commercial conditions, the resources take on less certain qualifiers such as 'contingent resource'
(PRMS, 2011). Therefore, the availability of reserves determines the amount of oil that is known
with high certainty, and this certainty incentivizes the deployment of capital needed to produce
the volumes within a specific period. From 2011 to 2012, US tight oil reserves grew by 3.7
billion barrels and by 2014, the U.S. recorded a sixth year of reserves growth, thanks in large
part to strong tight oil development across the country (EIA, 2014a; EIA, 2015a). According to
the EIA (2015a) the U.S. added 3.4 billion barrels of oil and condensate reserves from 2013 to
2014. This reserve addition came on the background of rapid tight oil development activities in
the nation's shale and other tight oil plays, and high oil prices within the $100/bbl range.

The major U.S. tight oil basins that have contributed to reserve additions in the last few years
include the Williston, Western Gulf, Permian, Denver-Julesburg, and Forth Worth Basins. These
basins contain the major shale oil and other tight oil projects that have increased U.S. oil
production in the last decade. These formations are the Eagle Ford, Bakken, Bone Springs,
Wolfcamp, Niobrara, Utica, and Marcellus formations. Projects in these formations are typically
driven by horizontal wells drilling and costly hydraulic fracture completions. Expensive

stimulation and well completion techniques are required to unlock the resources in the formations but also require high oil prices and are vulnerable to price swings.

According to the EIA (2017f), the U.S. has over 11 billion barrels of recoverable tight oil reserves. These are portioned in the main tight oil plays as follows:

Table 3. U.S. Proved Reserves 2013 through 2015 (Million bbl) (EIA, 2014d; EIA, 2017f)

Basin	Play	State(s)	2013 Reserves	2014 Reserves	2015 Reserves
Williston	Bakken	ND, MT, SD	4,844	5,972	5,030
Western Gulf	Eagle Ford	TX	4,177	5,172	4,295
Permian	Bone Spring, Wolfcamp	NM, TX	335	722	782
Denver-Julesburg	Niobrara	CO, KS, NE, WY	17	512	460
Appalachian	Marcellus*	PA, WV	89	232	143
Fort Worth	Barnett	TX	58	47	33
Sub-total			**9,520**	**12,657**	**10,743**
Other tight oil			523	708	859
U.S. tight oil			**10,043**	**13,365**	**11,602**

New assessments continue to change the figures for technically recoverable resources as well as tight oil reserves. Some estimates place reserves for North Dakota at 7.4 Billion barrels, which would include the Bakken, Three Forks formation, and other formations within the state (ND SWC, 2016). New United States Geological Survey estimates have declared technically recoverable resources for the Permian to approximately 20 billion barrels and as technology and efficiency drives down development costs or as oil prices rise, estimates for these plays will change (EIA, 2017t).

The impact of falling crude oil prices since the Q4 of 2014 has been severe on tight oil production and tight oil reserves. This is because with low prices, the economic characteristic of the reserves definition becomes a higher hurdle for most tight oil projects to meet. As a result,

reserves attributed to those high-cost projects are excluded from consideration. Following the fall in oil prices in Q4 2014 and consistently low prices through 2016, U.S. tight oil reserves from 2014 to 2015 changed from 13 billion to 11.6 billion barrels (Table 3). Figure 32 shows an annual oil price calculated by averaging the prices on the first day of 12 consecutive months in the year. This specific price definition is important because it is the price that is used in evaluating reserves in each year in accordance with SEC rules (Code of Federal Regulations, 2017).
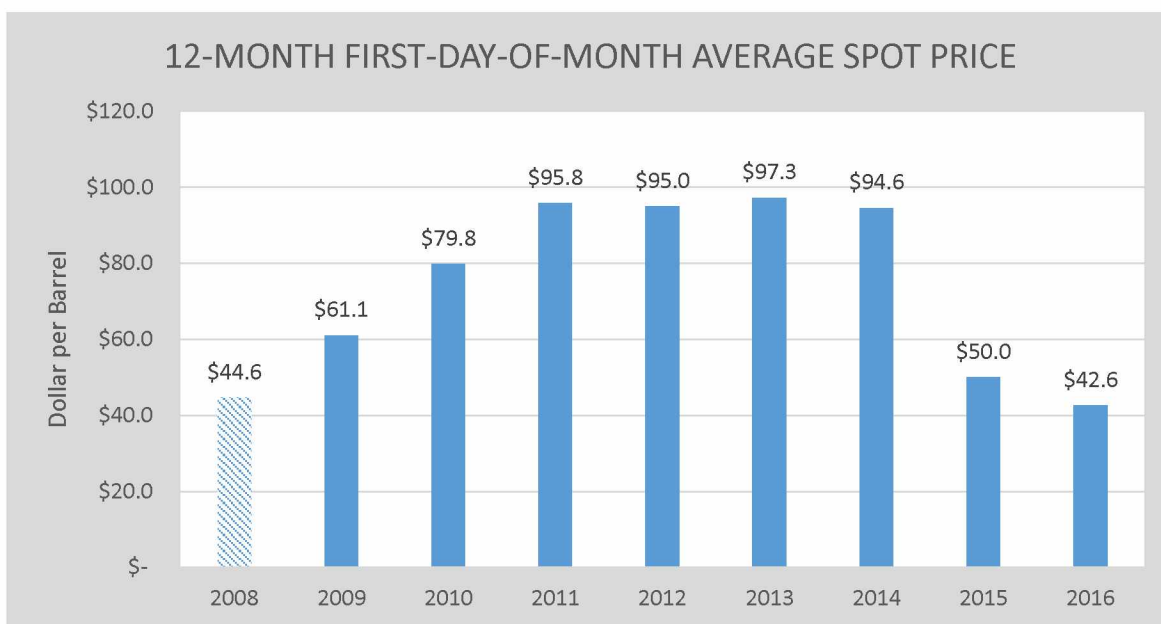
Figure 32. Crude Oil Spot Prices for Crude Oil Reserve Estimation (EIA, 2017k)

(2008 and prior had last day of the year prices; 2009 onward shows average of 12 consecutive first day of the month prices)

3.4.1.2. Determination of Type Wells

A type well is a production profile representative of wells of similar geologic, reservoir, mechanical, and operational characteristics drilled within a given play. Due to unique geologic characteristics of tight oil plays and sections within plays, and differences in development styles, production profiles across oil plays could be different. The underlying assumption is that wells in any given play are developed to take advantage of the properties of the rocks, sizes of lease tracts

and other operator and play parameters. For example, some plays are more pressurized than others, some are tight shale without fractures, some are fractured shale and others are hybrid shale where shale is associated with non-shale and more permeable rock, such as carbonates, making them more suitable for hydraulic fracturing (Jarvie, 2012). Table 4 summarizes the key geologic and petrophysical characteristics of four major U.S. tight oil plays.

Table 4. Shale Plays and Basic Characteristics (Jarvie, 2012; EIA/ARI, 2013)

Shale Play	Basin	Age	State	Tight Shale	Fractured Shale	Hybrid Shale
Wolfcamp, Spraberry, Bone Springs, Delaware	Permian	Permian	Texas			X
Eagle Ford	Austin Chalk Trend	Cretaceous	Texas			X
Bakken	Williston	Devonian	North Dakota		X	X
Niobrara	South Park (Denver-Julesburg)	Cretaceous	Colorado		X	X

Type wells are developed by aggregating wells of similar geologic and well-design characteristics within a reservoir. Production from these wells are time-shifted to begin on a set date, and the data from that date becomes the production rate of the first period (day or month). For every period, oil production from all wells are then summed across and divided by the number of wells that contributed to the total production (Alotaibi et al., 2015). The production profile that results is the type well profile. This type well production profile could then be used to represent the potential profile of any future well with similar completion and planning drilled within this formation. Others have referred to these type wells as type curves (Alotaibi et al., 2015), although another usage of the type curve terminology is for production profiles developed from solutions to dimensionless flow equations under specified conditions (Petrowiki, 2017). For

this research, these terms are used interchangeably to mean the production profiles developed from aggregating actual profiles from tight oil wells. While this profile is hardly the exact profile for any specific well within the play, in a general sense, it provides an industry-accepted representation of wells, and is used in analyses that run from play economics, cumulative production to entire development plans (Drillinginfo, 2016). Several commercially-available software packages are employed to easily develop type curves for different plays. A good example of such software, also used in this research, is the Drillinginfo Software.

A review of the type curves across the major U.S. plays using the Drillinginfo software show time, location and operator variables that are worthy of note. Firstly, the type curves of key oil plays show that generally, oil and gas producers increase well productivity progressively (Figure 33). The steady increase in well performance shows the impact of learning and technology improvement, especially in well completion technology. Secondly, the variability in initial production rates across the different plays also shows that the performance of wells is different across U.S. plays. Since well performance directly impacts the economics of projects, ownership of operations within a high productivity play, for example, has a place in the strategy of operators, pertaining to overall company production volumes and economic performance. Thirdly, even within the same oil play, operators perform differently (Figure 34). This suggests differences in operator tenure and learnings within the play, ownership of premium acreage and operational efficiency.
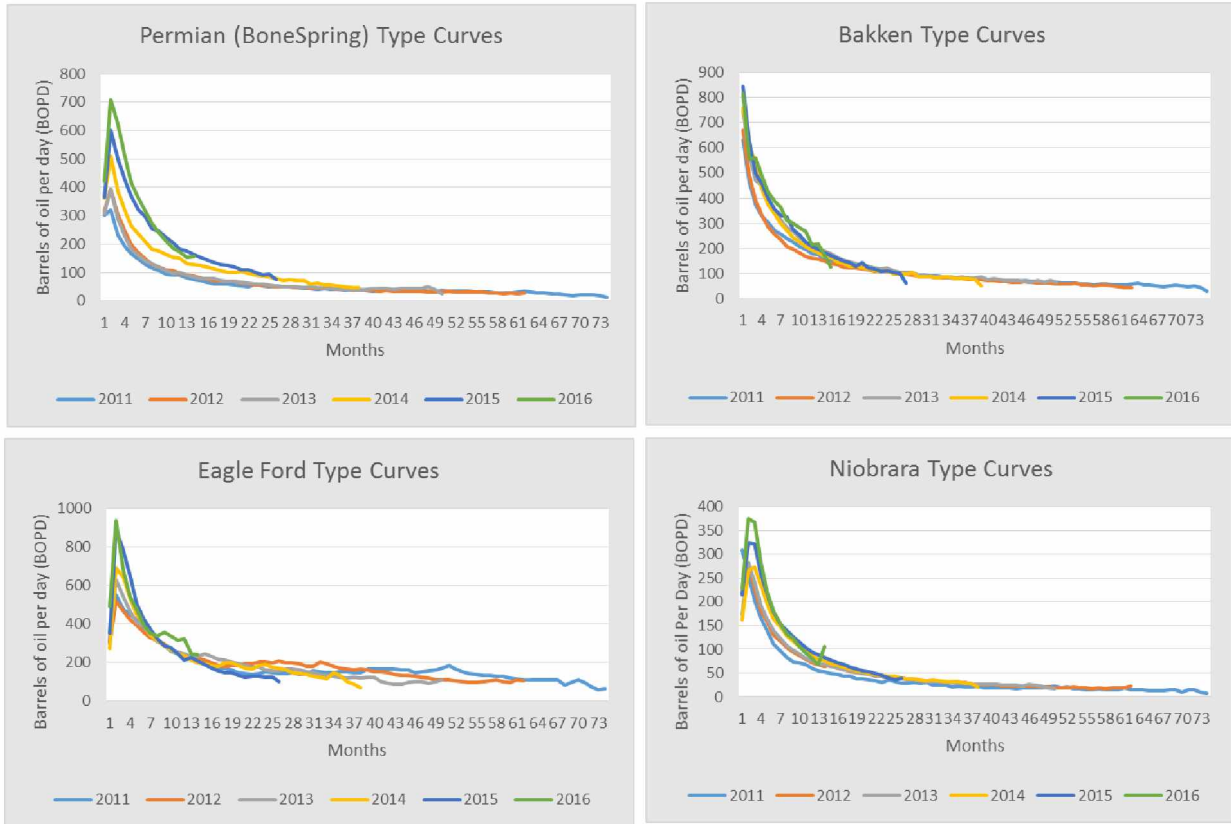
Figure 33. Type Curves of U.S. Tight Oil Wells across Multiple Operators Showing Progressively Increasing Well Productivity (Drillinginfo, 2017)
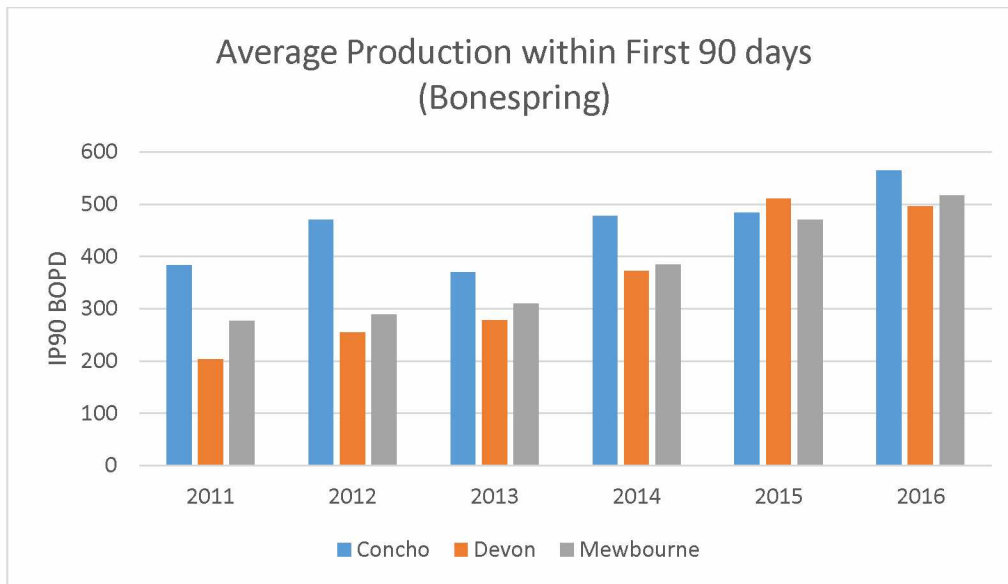
Figure 34. Variability in Operator Performance within the same oil Sub-play (Permian: Bone Springs)

This variation in operator performance, temporal and spatial well productivity show the challenges in conducting a blanket forecast at the play level, even in mature tight oil plays. This task will be a bigger challenge in a new play without historical data. However, overall, the type well for specific plays, while arguably simplistic, carries in it these variations somewhat elegantly. Towards the goal of answering questions as to the direction of changes given different levels of drilling, this level of detail is considered sufficient for this research.

3.4.1.3. Forecasting Number of Wells within Tight Plays

Given the reigning oil price at any time, records exist of the number of wells that are drilled within each of the major tight oil plays. Oil operator activity is seen in the number of wells that can be carried by the current oil price environment and outlook, cost of development, cost of capital and typical return companies seek.

Data on the number of active rigs in major plays is available through the U.S. Energy Information Administration's Drilling Productivity Reports and oil price records. Within these reports are a few highlights worth mentioning: Firstly, individual well productivity within oil plays have continued to rise, signaling an increased productivity of wells through better drilling and completion techniques. This is also reported by investors in the main plays who have seen an increase in wells' total ultimate recovery from 600 thousands of barrels of oil equivalent (MBOE) to 900MBOE over a few years (Purdy et al., 2016). This suggests that in the future it could take fewer wells to maintain similar production rates. It follows, therefore, that if those wells are drilled at similar or cheaper costs, the breakeven price of wells will continue to decrease, at least until premium acreage is exhausted, and fewer rigs may be required for the number of better-preforming wells required to keep production levels up. Also, if the economics of wells improve as a result of better technology and productivity, rig counts will not drop so precipitously even with slight reductions in oil prices.

Although oil price provides a gauge on oil development activity, this is not always a direct relationship for several reasons. There are observable lags in this relationship for several reasons

(Figure 35). For example, oil and gas operators hedge production through contracts on platforms provided by financial markets, based on their oil price outlook (Umekwe & Baek, 2017a). Hedging at high enough prices over the period covered by contracts allows oil and gas operators to continue development operations even during lower spot prices. As a result, the spot price of the day may not represent the price that is incentivizing development at the time.

Another factor that could thwart the historical relationship between oil price and drilled wells holding steady into the future, is the availability of quality acreage. As operators develop fields, quality acreage within the fields diminish, as the 'low hanging fruit' is drilled up. This leads to less premium acreage being drilled and potentially fewer and probably less productive wells in the future even when the same historical oil prices are attained. Conversely, cumulative tight oil production from the Permian (including all sub-plays), the Bakken and the Eagle Ford are 2.8 billion, 2.2 billion and 2.1 billion barrels of oil respectively while the reserve estimates for these plays show potentially greater volumes still to be produced (Table 3; EIA, 2017e). Given that current and potentially future reserve estimates show more economic resources available for production, it is possible to see similar well counts in the future. In addition, it is also possible that improvements in technology continue to improve profitability of less premium acreage by pushing down development costs. For these reasons, this research assumes that drilling levels similar to that observed would hold for a 20-year outlook time, in deriving a high drilling case (year 2014) and low drilling case (year 2015) range for U.S. Tight oil production (Table 5).
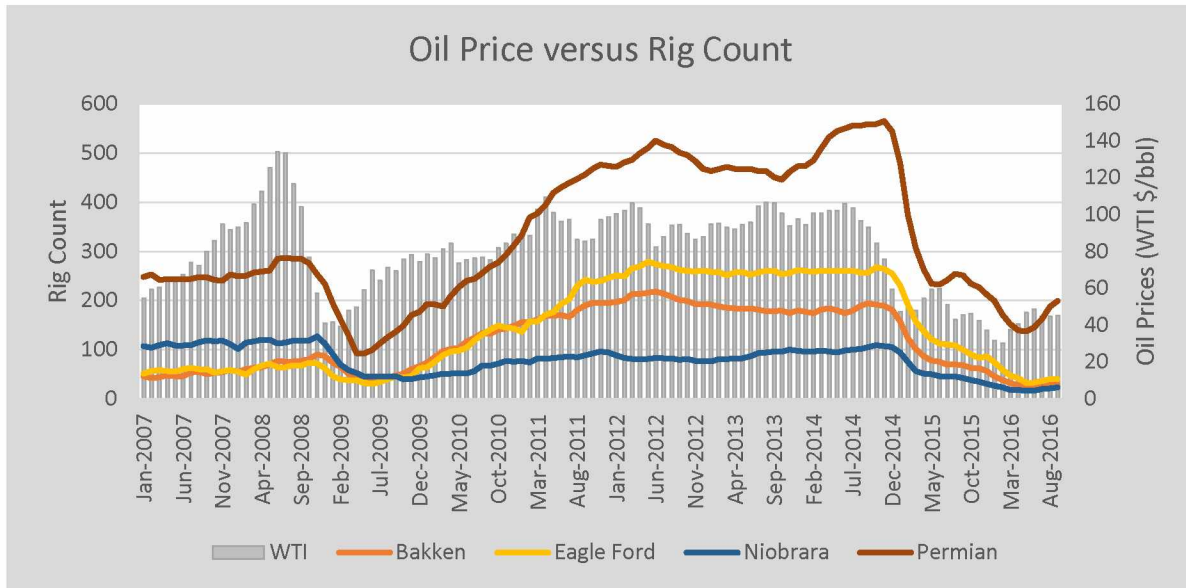
Figure 35. Well count and Oil Prices within Tight Oil Plays (EIA, 2016d; EIA, 2016f)

Table 5. Average Monthly Rig Count (proxy for wells drilled) in Major U.S. Tight Oil Plays
(EIA, 2016d; EIA, 2016f)

	WTI average spot price ($)	Bakken Rig Count	Eagle Ford Rig Count	Haynesville Rig Count	Marcellus Rig Count	Niobrara Rig Count	Permian Rig Count	Utica Rig Count
2007	72	49	57	182	48	112	246	8
2008	100	73	64	206	50	116	265	6
2009	62	51	41	160	64	52	137	4
2010	79	116	113	224	108	59	242	5
2011	95	175	199	149	131	85	424	8
2012	94	205	264	65	110	81	496	18
2013	98	182	257	45	87	89	464	30
2014	93	183	260	51	84	100	536	40
2015	49	84	127	36	60	51	276	25
2016*	41	30	45	19	28	20	166	12

* Only Jan to Sep of 2016

At oil prices of approximately $100/bbl, as seen in 2008 and 2013, two things are apparent
(Table 5). For most of the major oil plays, more rigs are used in 2013 than in 2008. This points to
drilling activity levels responding to the impact of learning, better technology, and lower
breakeven costs.

The EIA (2016e) Annual Energy Outlook estimates that oil prices will rise between $48 in 2017 to approximately $130/bbl in 2040 with or without Clean Power Plan initiatives staying in place (Figure 36). Under this price outlook, tight oil production in the seven major tight oil plays was forecasted under two scenarios: The as-is scenario (low oil price) assuming prices stay within the late 2016 price range of $45-$50/bbl and the EIA reference case scenario (price rebound). Under the low oil price scenario, we assume that oil prices stay at $48/bbl and drilling levels stay as was the case in 2016. Under the price rebound scenario, oil prices average $93/bbl through 2040 and we assume that drilling levels stay at 2014 levels for the purpose of forecasting regional production rates.
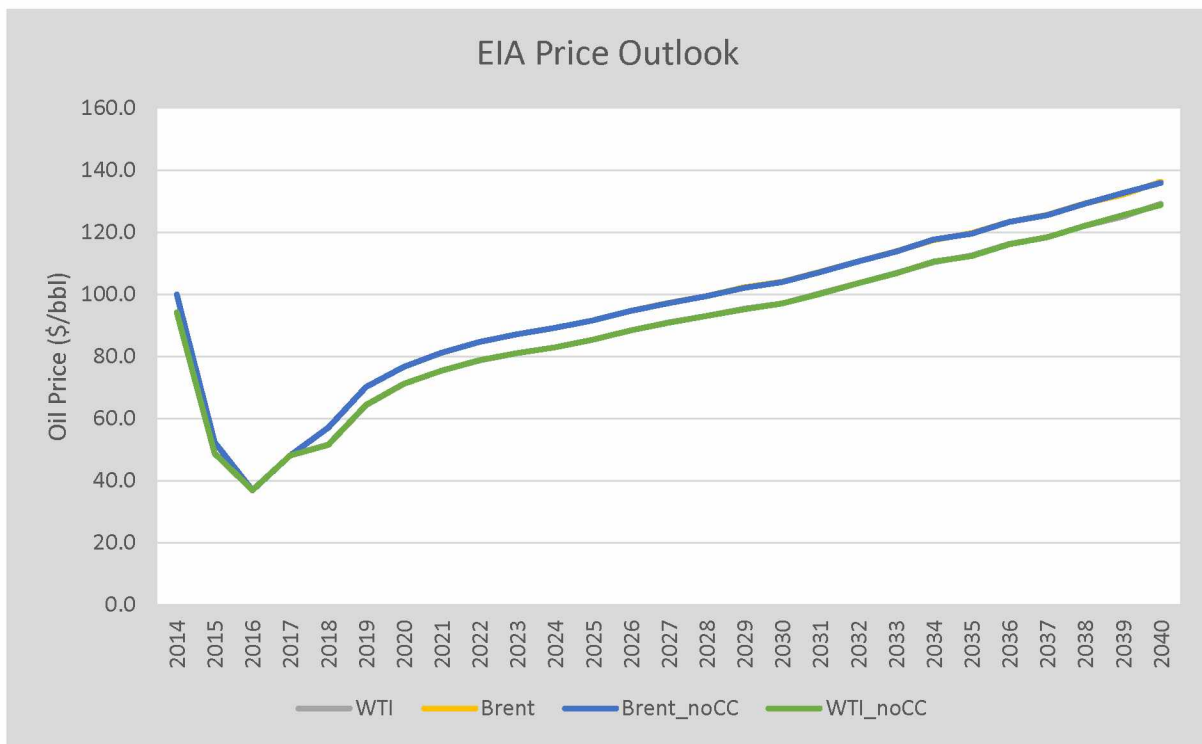
Figure 36. EIA Oil Price Outlook (EIA, 2016e)

3.4.1.4. U.S. Tight Oil Production Forecast

A simple step-by-step assessment approach was used to develop a forecast for tight oil production in the U.S. (Figure 37).
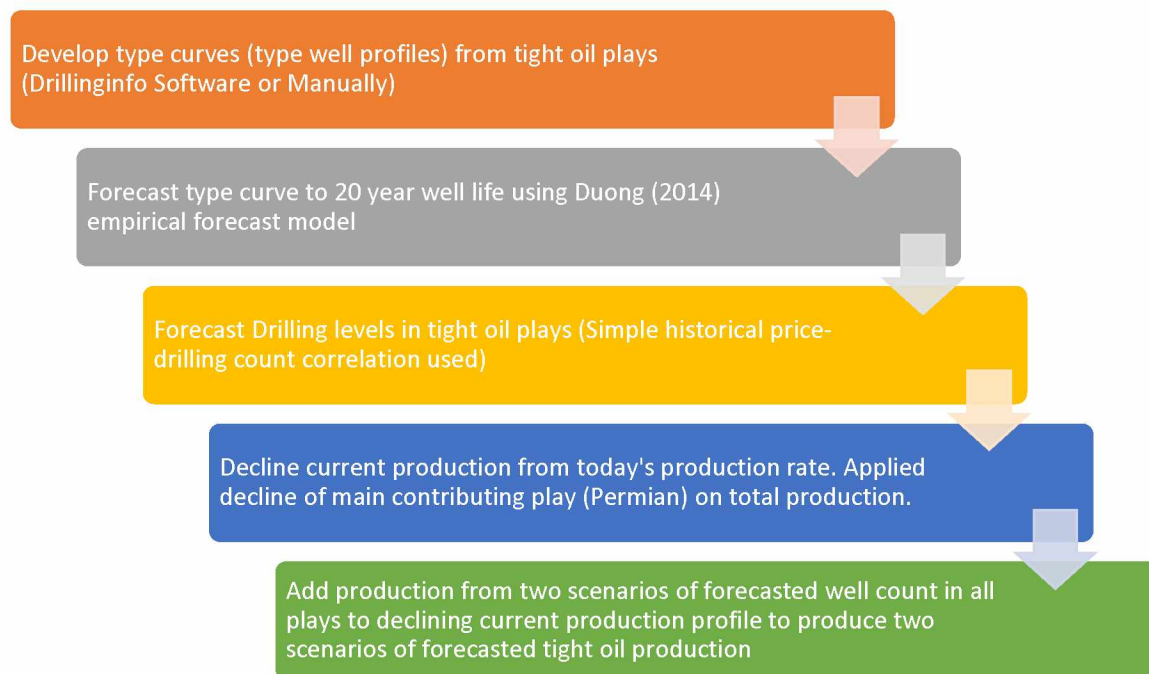
Figure 37. Simplified Approach for U.S. Tight Oil Production Forecast

Firstly, type curves were developed for each of the major seven U.S. tight plays using the Drillinginfo software. In the absence of commercial software, these type curves could be developed as was discussed earlier, by pulling together well production data in select plays. To ensure some uniformity and longevity of production data, wells from 2012 were used to develop seven 'type well profiles' for each of the major plays from where tight oil is produced: Bakken, Eagle Ford, Permian, Niobrara, Haynesville, Utica, and Marcellus. These wells showed over 60 months of production from oil targeted drilling in each play. While wells from more recent years would provide initial well production rates more reflective of current technology and well performance, more importance was placed on generating longer term production data (60 months) to improve the reliability of focasting models.

Secondly, the 60 months of production data in type wells were forecasted out to develop production profiles for a 20 year well productive life using the modified Duong forecast model (Figure 38). Unlike the other models that depend on analyst observation of data only, this method reduces the subjectivity in selecting the point at which boundary-dominated flow regime starts and increases the replicability of results. The production profile from the wells were

normalized using the total production over a 20-year period so as to show profiles of each month's contribution to total well production (Figure 39). The normalized profiles were transferred into a Microsoft Excel spreadsheet forecast model. The Drillinginfo Software was used to produce a tenth percentile, fiftieth percentile, and ninetieth percentile (P10, P50, P90) range of typical estimated ultimate recovery (EUR) for wells in all seven plays (Table 6). The Program Evaluation and Review Technique (PERT) statistical distribution was applied to generate an expected or mean well EUR. This distribution was selected because it is flexible, is applied in conditions where three-point estimates of a variable exist and where the intention of the analyst is to place more weight on the central value (P50 EUR) (Palisade, 2017a). The production rate for every month in each play is determined by multiplying this expected well EUR with the normalized forecasted type well profile for each play.
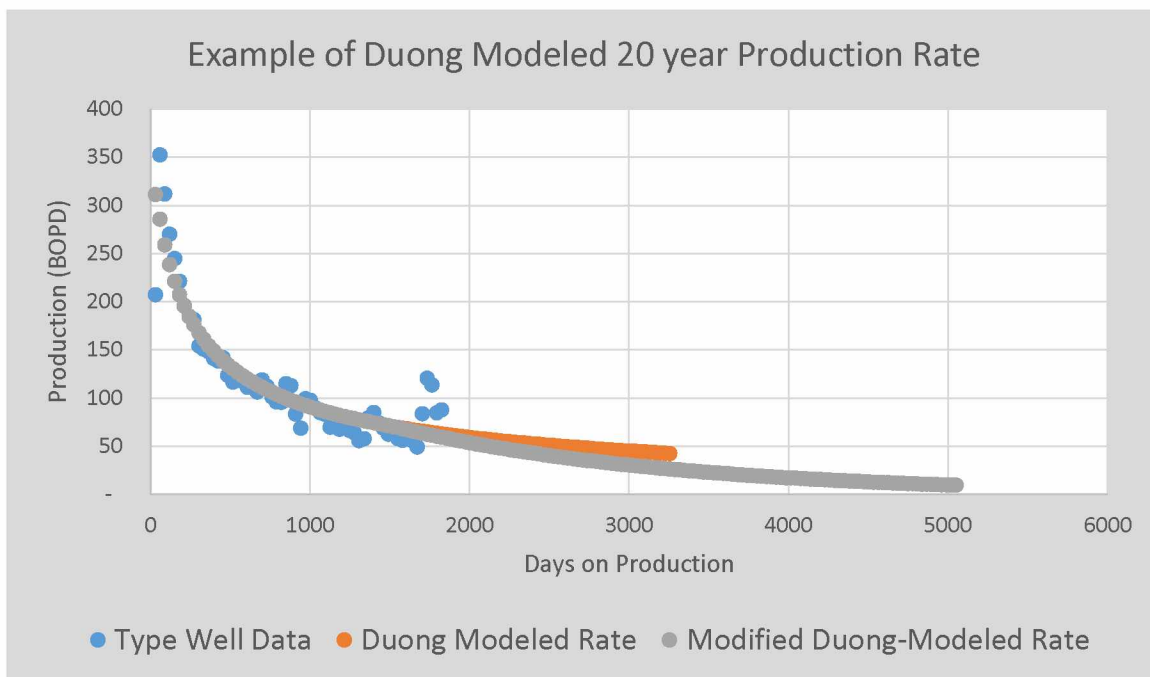
Figure 38. Twenty-year Forecasted Tight Oil Production
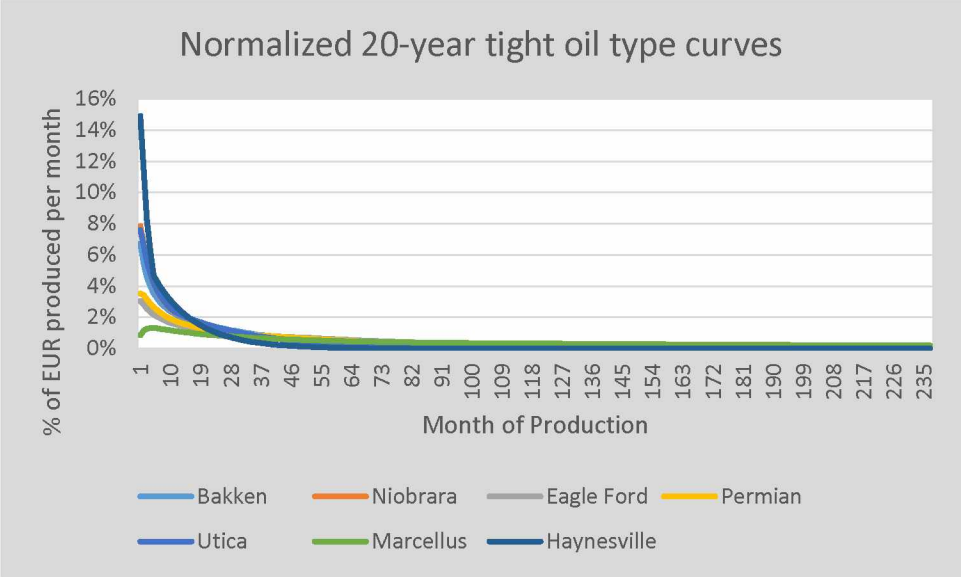
Figure 39. Normalized Tight Oil Production Profiles

Table 6. Twenty-year Total Well Production Ranges for Select U.S. Tight Oil Plays (Modified Drillinginfo, 2017)

Thousand Barrels of Oil	P10	P50	P90	Mean (P10+4 (P50) +P90)/6
Bakken	300	257	200	255
Eagle Ford	200	180	170	182
Haynesville	60	55	50	55
Marcellus	45	40	35	40
Niobrara	150	130	110	130
Permian	300	260	210	258
Utica	30	29	25	29

Next, I used historical oil prices and drilling rig count data, proxy for well count data, from the EIA Drilling Productivity Reports to extract data on historical drilling levels in 2014 (average oil price ~$100/bbl) and 2015 (average oil price $49/bbl) for potential future high and low drilling levels respectively (Table 5).

The current tight oil production in the U.S. is at 4.4 million barrels per day with the bulk of that production from the Permian play (EIA, 2017e). This production rate was declined through year 2040, assuming that no additional well was drilled, so as to generate a production background

upon which to add future scenarios of drilling productivity. The decline profile used the profile of a typical Permian well. This is because the Permian formation provides the largest share of U.S. tight oil production today and the decline of current tight oil production largely depends on the profile of the largest contributing share. In addition, the exercise also shows that a reasonable forecast could be conducted by applying standard petroleum engineering principles while using easily available non-proprietary data.

By allowing this current level of U.S. Tight oil production to decline at the rate of the Permian basin and adding new wells in the pace of high oil price (2014) or lower oil price (2015) levels, two production forecast scenarios were determined. The low drilling production profile assumed that drilling for the next 20 years is similar to 2015 drilling levels typified by low oil prices averaging $48/bbl. The high drilling production profile scenario assumes drilling levels stay at the 2014 drilling level. These two scenarios show the impact of prices on levels of production. These profiles were compared against the U.S. Energy Information Administration Tight Oil Production estimates from their Annual Energy Outlook 2017 Publication (EIA, 2017l; Figure 41)..

The U.S. EIA Energy Outlook 2017 publication provides a rigorous look at energy projections until year 2050, using an integrated model, the National Energy Modeling System, which handles the interactions of changes in the economy with energy demand and supply factors (EIA, 2017l). Oil production projection is a major part of this publication. The projections include high, low and reference cases for oil production. The reference case for oil production is simply the best guess of experts on potential outcomes, including all foreseeable interactions of oil demand and supply drivers. This is the status quo case that applies current regulations with sunset and kickoff dates for different aspects of laws as currently known, economic trends from expert opinions and other factors that impact the energy sector (EIA, 2017l). The reference case for tight oil production, for example, assumes increasing production through 2030 due to trends in existing technology that lead to increased well productivity and after some years reduced productivity as less productive areas start getting targeted (EIA, 2017l). The production forecast developed in this section makes a simplifying assumption to arrive at two scenarios for production and an average that compares with the EIA oil production outlook. The fact that these

compare well with the more rigorous EIA reference case, shows that by applying engineering principles, other stakeholders of tight oil production in the U.S. and outside the U.S. can estimate future production at a regional scale effectively (Figure 40, Figure 41).
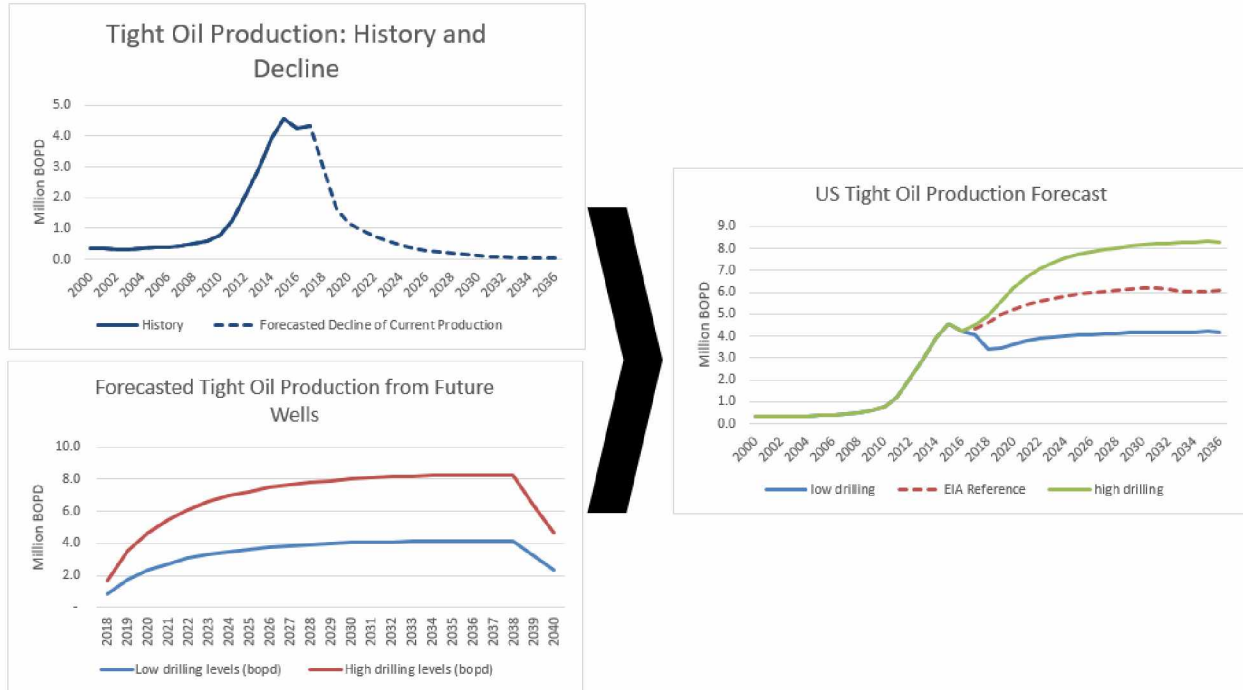
Figure 40. U.S. Tight Oil Production Forecast Approach
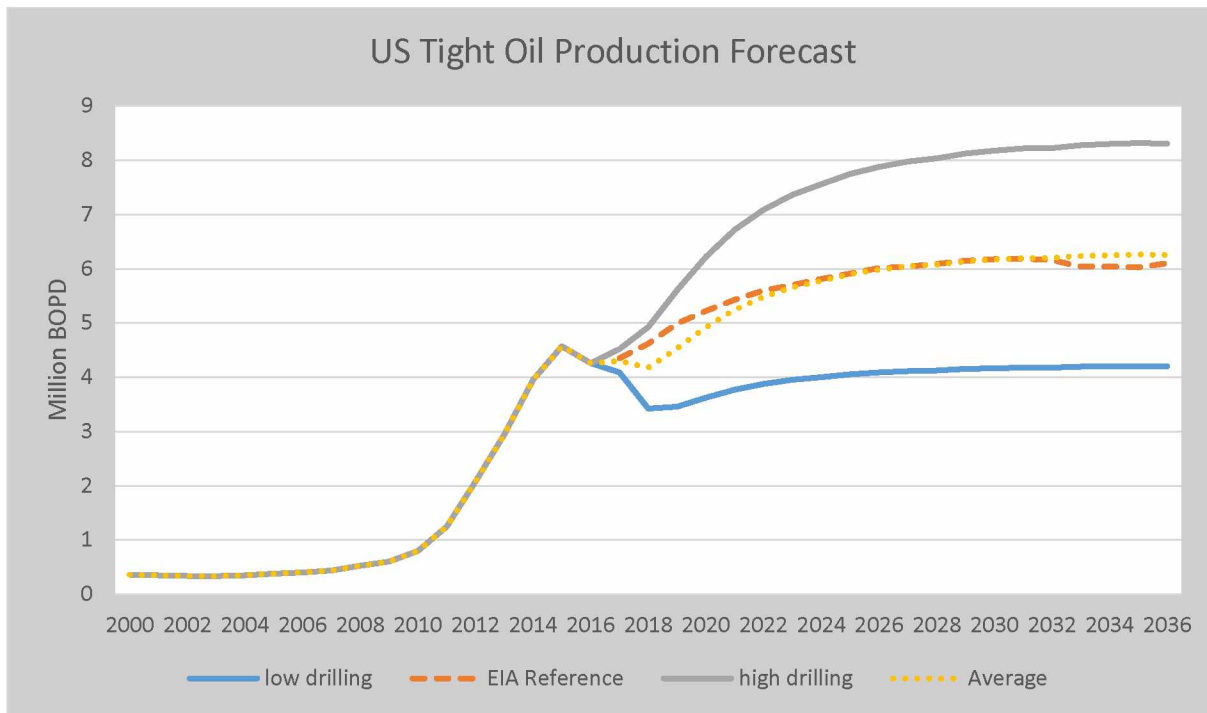
Figure 41. U.S. Tight Oil Production Forecast Showing Low Drilling, High Drilling, the EIA (2017l) Reference case Profiles

3.4.2.   Summary on U.S. Tight Oil Production Forecast

The high drilling and low drilling forecast scenarios discussed above illustrate the impact of high oil prices on rig count, drilling and production rates. This illustration suggests that if the commercial climate sustains more tight oil production activity and the pace of drilling continues to rise in response to high oil prices, there is an even brighter chapter ahead for tight oil development within the US. But low oil prices change this story. This is the experience of the oil industry since Q42014 when prices dropped by over 40% in 1 month and by mid-2017 still hover around the $45 to $55 per barrel range.

In summary, this chapter discussed tight oil resources, the key characteristics of major plays within the U.S. that are sustaining tight oil production and the techniques applied by the industry in forecasting production. A key application of forecasting techniques is determining reserves at well and regional level. A simple workflow for determining regional forecasts has been

demonstrated. The next section examines how tight oil regions outside the U.S. could apply similar techniques to evaluate frontier tight oil plays.

3.5. Tight Oil Development outside the US.

Energy development in the different U.S. shale plays has created millions of dollars of new revenue local and state governments leading to thousands of employment opportunities (UT San Antonio, 2012). Following this huge success of shale resource development is a natural question as to where else in the world such potential might exist.

The previous sections discussed tight oil development success in the U.S. and concluded that resource availability, good quality rocks, drilling and completion technology, and a vibrant energy investment climate are among the major drivers of tight oil development success. This section identifies key qualities of non-U.S. plays that make them suitable for development. The focus on non-US plays is on the availability of the resource and existence of viable U.S. formation analogues. An underlying assumption in this section is that skills within the petroleum industry are highly mobile and global and similar levels of technology can be drawn into tight oil plays outside the US. While the business climate that supports cost intensive oil and gas development may exist in some non-U.S. climate, the system and laws that enable huge, confident capital outlays exist to different degrees. The objective of this section is to show that with resource levels comparable to the U.S., and rock quality analogues, it is possible to conduct basic economic assessments that incorporate key economic parameters, uses production forecasting, development style and capital availability measures reflected in the risk-adjusted cost of capital, to develop an economic ranking of projects across non-U.S. plays. A review of infrastructural and logistical factors required for tight oil development in non-U.S. locations is outside the scope of this section.

3.6.   The EIA/ARI World Shale Gas and Shale Oil Resource Assessment Methodology and Summary Findings

In 2013, the United States Energy Information Administration (EIA) in partnership with the Advanced Resources International (ARI) conducted an assessment on shale plays in 41 countries outside the U.S. (EIA/ARI, 2013). They identified 137 shale formations with potential technically recoverable oil. They screened non-U.S. shale regions using data from public, private and government resources, in light of the advances in shale development in the US. The methodology of the EIA study is similar to previous methodologies used in assessing conventional resources except for the sparseness in available data, which the study acknowledges, given the novelty of shale development in the U.S. and other locations around the world (EIA/ARI, 2013). For some plays with planned or ongoing private industry activity where geologic data was available, the EIA/ARI (2013) study conducted more specific analyses. In assessing less familiar plays, this study relied on better-known U.S. analogues.

The EIA/ARI screening study methodology could be summarized in five steps. Firstly, they conducted a broad preliminary screening of basins using available information to determine basins that could be studied further. Information on the age of the basin, nature of source rock, stratigraphy and well logs was used to determine depositional environment, depth, structure and thickness of the shale layer, total organic content and thermal maturity.

The second step was to estimate the areal extent of the shale formation by developing regional cross sections and an overview of the general basin architecture.

Thirdly, assessments were made of the portions in the basin that were likely to be amenable for development. At this level, information on the depositional environment, well logs, depth, thickness, and organic content of the shales and other data was applied. For example, the report noted that shales deposited in marine environments, are typically less ductile and more easily *frackable* due to lower clay content. It also determined that prospective shale depths ranged from approximately 3500-16500ft, recorded total organic carbon levels above 2% by weight and mainly containing type I & II carbon (EIA/ARI, 2013).

The fourth step was a determination of the oil in place estimate. This involved using porosity data, depth and thickness data from core and log analysis, and stratigraphic and mineralogical studies to estimating organically-rich thickness and fluid saturations. Upon gathering information from multiple sources, including U.S. analogue regions, on the prospective area extent (A), organically-rich rock thickness (h), porosity (Ø), water saturation (S_w) and formation volume factor (B_{oi}), the EIA/ARI (2013) determined the oil in place (OIP) of a region as follows:

$$OIP = \frac{7758 \ x \ A \ x \ h \ x \ \emptyset \ x \ (1 - S_w)}{B_{oi}} \qquad (26)$$

The calculated oil in place number was adjusted using two risk factors: A play success probability factor, which estimates the probability of the play being developed, and a prospective area success risk factor, which captures the risks posed by insufficient exploration and production data from some segments of the prospective area (EIA/ARI, 2013). These two factors reduce the calculated OIP number even further to yield a risked oil in place value. The EIA/ARI (2013) study determined composite risk for the 10 largest tight oil play provinces (Table 7).

Finally, a recovery factor was assigned to plays based on the play geology, reservoir complexity, potential success in stimulating the shale formation and recovery factors of analogue plays that have been developed in the US. Recovery factors (RF%) ranged from 3% to 6% with some exceptional cases of 8% and 2% (EIA/ARI, 2013).

Table 7. Recoverable Tight Oil Estimates in 10 Non- U.S. Shale Nations (EIA/ARI, 2013)

Region	Basin	Formation	Risked Oil In-Place (Billion, bbl)	Tech recoverable (Billion, bbl)	Play Success Factor	Prospective Area Success Factor	Composite Success Factor
Russia	Western Siberian Central	Bazhenov Central	965	57.9	100%	45%	45%
	West Siberian North	Bazhenov North	278	16.7	75%	35%	26%
China	Jianghan Basin	Longmaxi	1	0	60%	40%	24%
		Qixia/Maokou	5	0.2	50%	40%	20%
	Greater Subei	Mufushan	0	0	40%	30%	12%
		Wufeng/Gaobiajian	5	0.2	40%	30%	12%
		U. Permian	1	0.1	40%	30%	12%
	Tarim Basin	M-U. Ordovician	31	1.6	50%	50%	25%
		Ketuer	129	6.5	50%	50%	25%
	Junggar Basin	Pingdinquan/Lucaogu	109	5.4	60%	60%	36%
		Triassic	134	6.7	60%	60%	36%
	Songliao Basin	Qingshankou	229	11.5	100%	50%	50%
Argentina	Neuquen	Los Molles	61	3.7	100%	50%	50%
		Vaca Muerta	270	16.2	100%	60%	60%
	San Jorge Basin	Pozo D-129	17	0.5	60%	40%	24%
	Austral-Magallanes Basin	L.Inoceramus-Magnas Verdes	131	6.6	75%	60%	45%
Libya	Ghadames	Tannezuft	104	5.2	100%	50%	50%
		Frasnian	26	1.3	100%	50%	50%
	Sirte	Sirte/Rachmat	406	16.2	80%	50%	40%
		Etel	51	2	80%	50%	40%
	Murzuq	Tannezuft	27	1.3	100%	50%	50%
Colombia/ Venezuela	Maracaibo basin	La Luna/Capacho	297	14.8	70%	50%	35%
Mexico	Burgos	Eagle Ford Shale	106	6.3	100%	60%	60%
	Tampico	Pimienta	138	5.5	70%	50%	35%
		Tamaulipas	13	0.5	70%	50%	35%
	Tuxpan	Pimienta	12	0.5	70%	50%	35%
	Veracruz	Maltrata	7	0.3	70%	75%	53%
Pakistan	Lower Indus	Sembar	145	5.8	40%	30%	12%
		Ranikot	82	3.3	40%	30%	12%
Canada	Alberta Basin	Banff/Exshaw	11	0.3	100%	40%	40%
	East & West Shale Basin	Duvernay	67	4	100%	70%	70%
	Deep Basin	North Nordegg	20	0.8	100%	50%	50%
	NW Alberta Basin	Muskwa	42	2.1	100%	50%	50%
	Williston Basin	Bakken	22	1.6	100%	60%	60%
Indonesia	C. Sumatra	Brown Shale	69	2.8	75%	60%	45%
	S. Sumatra	Talang Akar	136	4.1	50%	35%	18%
	Tarakan	Meliat	1	0	40%	50%	20%
		Tabul	11	0.3	40%	50%	20%
	Kutie	Balikpapan	17	0.7	40%	40%	16%

This research builds on the EIA/ARI (2013) effort and sharpens that comparison using key shale play geologic and economic parameters. By isolating the key properties of these plays and comparing them to successful developments in the US, a ranking is produced that demonstrates the key advantages and challenges in developing the plays. This evaluation intends to show a method for analyzing development potential of the plays.

The objective of this section is to compare the economic viability of shale oil production in ten other countries outside the US. These countries account for more than 61% of total technically recoverable shale oil among the countries studied (EIA/ARI, 2013). For ease of comparison, these plays are evaluated under a single oil and gas fiscal system. The use of a single fiscal system provides a commerciality assessment baseline and intends to show that major changes within tax systems could be one more lever for facilitating the development of these challenged resources and altering the commercial attractiveness of the plays. This is more so for countries in which other elements of the commercial assessment, such as project discount rates, put them in a more challenged spot in attractiveness for global capital.

3.7. Analogue Selection for Non- U.S. Tight Oil Plays from More Mature U.S. Tight Oil Plays

The most successful examples of shale resource development are found in the U.S. And few plays have been central to the U.S. tight oil boom. In finding play analogues for the non-U.S. shale provinces, it was necessary to use a few parameters shared by all shale regions (EIA/ARI, 2013). These parameters are the total organic carbon (TOC), which refers to the amount of organic material present in tight rock, rock thermal maturity index (R%) which measures the maturity of hydrocarbons based on the level of the reflectance and the amount of vitrinite they contain. The third parameter is the reservoir pressure which determines the productivity of formations, making overpressured rocks more prospective for tight oil development. The fourth parameter is clay content which, if low, highlights the effectiveness of hydraulic fracturing in a given formation (EIA/ARI, 2013). The fifth parameter is the formation depth, which determines alongside other factors, the cost of drilling.

With successful regional deployment of hydraulic fracturing technology, seven plays have been at the center of U.S. oil production resurgence: Bakken, Eagle Ford, Permian, Niobrara, Marcellus, Utica, and Haynesville (EIA, 2016d). Based on the performance of wells in U.S. plays, the EIA/ARI (2013) study and this research draw on U.S. tight oil examples for analogues of non-U.S. plays. This section shows a comparison of the geological characteristics of these major U.S. plays to the non- U.S. plays (Table 8).

Table 8. Parameters of U.S. tight oil plays

Basin	Play	Recovery Factor%*	TOC	R%*	Depth	Clay	Pressure (psi/ft)*
Williston	Bakken	8.4	10	0.8	10,000	low	0.6
Maverick	Eagle Ford	9	4.24	0.85	6000	low	0.6
Permian	Wolfcamp	3.4	9.33	0.92	9300	low	0.6
Denver-Julesburg	Niobrara	4.6	2.69	0.7	~8000	medium	0.433

	EIA/ARI (2013)
	EIA/IHS (2016)
	USGS (2005)
	Pollastro et al. (2012)

3.7.1.   Prospectivity Map Technique for Tight Oil Analogue Play Selection

The determination of geologic prospectivity of any play is hardly without major uncertainties, and the description of shale or other tight oil plays could be a challenge. This is because tight oil plays are not composed of a single rock type. Rocks that make up a tight oil play could include shale, carbonates, siltstone, or mudstone, making uniform definition or accuracy of predicted performance difficult. However, in the literature of shale unconventional development, which constitutes a major portion of tight oil development, a few factors could be isolated for comparison across tight oil plays (EIA/AIR, 2013). This section discusses a comparison of those factors across non-U.S. plays and U.S. plays as a means of identifying play analogues.

In addition to identifying the governing parameters across prospective tight oil plays, it could be difficult to compare across plays due to the many factors that should be considered. This section

presents a simplified method of viewing the several dimensions of characteristics for play-by-play comparison through prospectivity description radar/spider plots. These plots were developed using indexed versions of quantitative measures of prospectivity. These maps provide an easy visual comparison across tight oil plays. Each play was described by the five parameters discussed earlier: TOC, pressure, maturity index, clay content, and depth. To ensure that these parameters were scaled uniformly across each play, normalized versions of the parameters were developed.

In situations where only qualitative measures of a play characteristic were provided by the EIA/ARI (2013) research, we derived rankings. For example, descriptions of parameters like clay content and reservoir pressure for the non- U.S. plays in the report were provided in qualitative terms. Qualitative descriptions of reservoir pressure in the shale plays and numeric translations ranged from underpressured (0.3psi/ft), slightly underpressured (0.35psi/ft), normal pressure (0.433psi/ft), slightly over-pressured (0.5), to highly over-pressured (0.65psi/ft) reservoirs (Table 9). A clay content ranking was also developed using the qualitative descriptions of clay content of individual formations (Table 10).

Parameters of each shale play were indexed against the extreme values observed in the EIA/ARI (2013) study (Table 11) using a method shown in Table 12. This was to ensure that comparisons among individual formations could be made on a uniform basis. Finally, the figures show a comparison of the most prospective play within non- U.S. regions against the two most comparable analogues among the U.S. key tight oil plays.

Table 9. Estimation of Reservoir Pressure from Pressure Qualifiers in the EIA/ARI (2013) Report.

Description	psi/ft	Example Formations (EIA/ARI (2013))
Under pressured	0.3	Colorado Group, Southern Alberta, Canada
Slightly underpressured	0.35	Eagle Ford, Sabinas Basin, Mexico (slightly underpressured)
Normal pressure	0.433	
Slightly overpressured	0.5	Llanos Basin in Colombia; Baltic Basin, Poland
Moderately overpressured	0.55	
Overpressured	0.6	Los Molles shale, Argentina
Highly Overpressured	0.65	Eagle Ford, Burgos Basin Mexico; La Lunar-Middle Magdalene Valley Basin
	0.7	Wolfcamp Shale in Permian Basin TX, Cooper Basin in Australia
	0.78	Etropole Shale, Eastern Europe
	1	Kutei Basin, Indonesia

Table 10. Estimate ranking of clay content descriptions

Clay Content Ranking	
Low	5
Low-medium	4
Medium	3
medium-high	2
High	1

Table 11. Extreme parameters used in normalization of overall shale parameters (EIA/ARI, 2013)

	Extreme parameters (Pmax)	Examples (EIA/ARI, 2013)
TOC	11	Bakken Formation, Williston Basin, Canada
Reservoir Pressure	1 psi/ft	Meliat formation, Tarakan Basin, Indonesia
R%	1.15	Longmaxi, Wufeng/Gaobiajian/Upper Permian formations in China
Clay Content	5	Low clay content (introduced here by author)
Depth(ft)	13,500	Etel Formation, Sirte Basin, Libya

Table 12. Heuristic for Indexing Parameters (Example shown is for Qingshankou formation, Songliao Basin, China)

	Extreme parameters (Pmax)	Qingshankou formation parameters (P)	Formation parameters without qualifiers	Index = (P/Pmax)*10
TOC	11	4	4	3.6
Pressure (psi/ft)	1	moderately overpressured	0.55	5.5
R%	1.15	0.90%	0.9	7.8
Clay	5	medium	3	6.0
Depth (ft)	13500	5500	5500	5.9*

Depth index scaled differently

The depth parameter was rescaled to ensure that shallower formations ranked higher, thus reflecting the advantage of lower cost of development for those formations, all else being equal. The depth parameter index was carried out as follows: [(Pmax – P)/Pmax] * 10. As a result of this adjustment, all the parameters were scaled to range from low to high; the higher the values, the larger the pentagons in the figure and the more prospective the shale play (Figure 42).
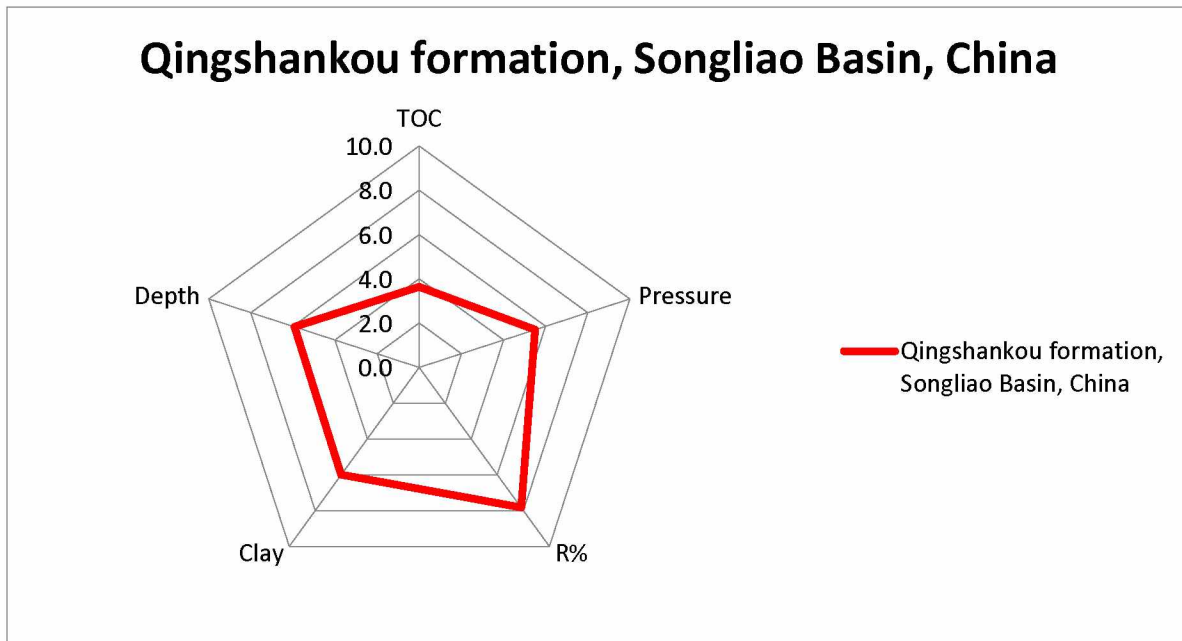
Figure 42. Example of Prospectivity Map (The Qingshankou shale formation in China)

3.8.   Major Non-U.S. Tight Oil Plays Presented in the EIA/ARI (2013) Report

The EIA/ARI (2013) reported that, of the 137 formations studied in 47 nations, the top nine countries are China, Russia, Mexico, Indonesia, Pakistan, Libya, Venezuela/Colombia, Argentina, and Canada. We compared the technically recoverable oil in each formation and selected plays with the largest volumes for side-by-side comparison. All the geologic descriptions and petroleum characteristics of non- U.S. plays presented in this research and used in this analysis were derived from the EIA/ARI 2013 report. This section highlights the characteristics of the primary shale plays in these countries as presented in the EIA/ARI (2013) report (Table 13) and compares them against the closest analogues among U.S. tight oil plays.

Table 13. Key parameters of Non-U.S. shale provinces (EIA/ARI, 2013)

Country	Basin	Formation	Clay Content	TOC	Maturity Index	Depth	RF%	Pressure (psi/ft)
Russia	Western Siberian Central	Bazhenov Central	low	10	0.85	8200	6.0%	0.65
Argentina	Neuquen	Vaca Muerta	low-medium	5	0.85	5000	6.0%	0.65
Libya	Sirte	Sirte/Rachmat	medium	2.8	0.85	11,000	4.0%	0.433
Colombia/ Venezuela	Maracaibo basin	La Luna/Capacho	low	5	0.85	10,000	5.0%	0.433
China	Songliao Basin	Qingshankou	medium	4	0.9	5500	5.0%	0.55
Mexico	Burgos	Eagle Ford Shale	low	5	0.85	3500	5.9%	0.65
Pakistan	Lower Indus	Sembar	low	2	0.85	5000	4.0%	0.433
Indonesia	S. Sumatra	Talang Akar	high	5	0.7	7000	3.0%	0.433
Canada	East Shale Basin	Duvernay	low	3.4	0.9	9000	6.0%	0.65

3.8.1.   Russia

According to the EIA/ARI (2013), Russia has the world's largest technically recoverable shale oil resource and the eighth largest shale gas resources. The Bazhenov Central and Bazhenov North formations in the West Siberian Central and West Siberian North basins were assessed in

the EIA/ARI study. The study estimates that these basins contain a total Original Oil in Place (OOIP) of 1,243 billion barrels of which six percent, 75 billion barrels are thought to be technically recoverable. The Bazhenov central shale in the West Siberian central basin is the most prospective play in Russia and contains 78% of the total shale oil and 62% of shale gas resource. The prospectivity map of the Bazhenov Central shale in Russia's West Siberian Central basin alongside the closest analogues in the U.S. (Figure 43). The prospectivity map illustrates that good TOC values and low rock clay content are the key drivers for productivity in the Bazhenov central shale in Russia, and that this tight oil play is most analogous to the Permian play within the US.
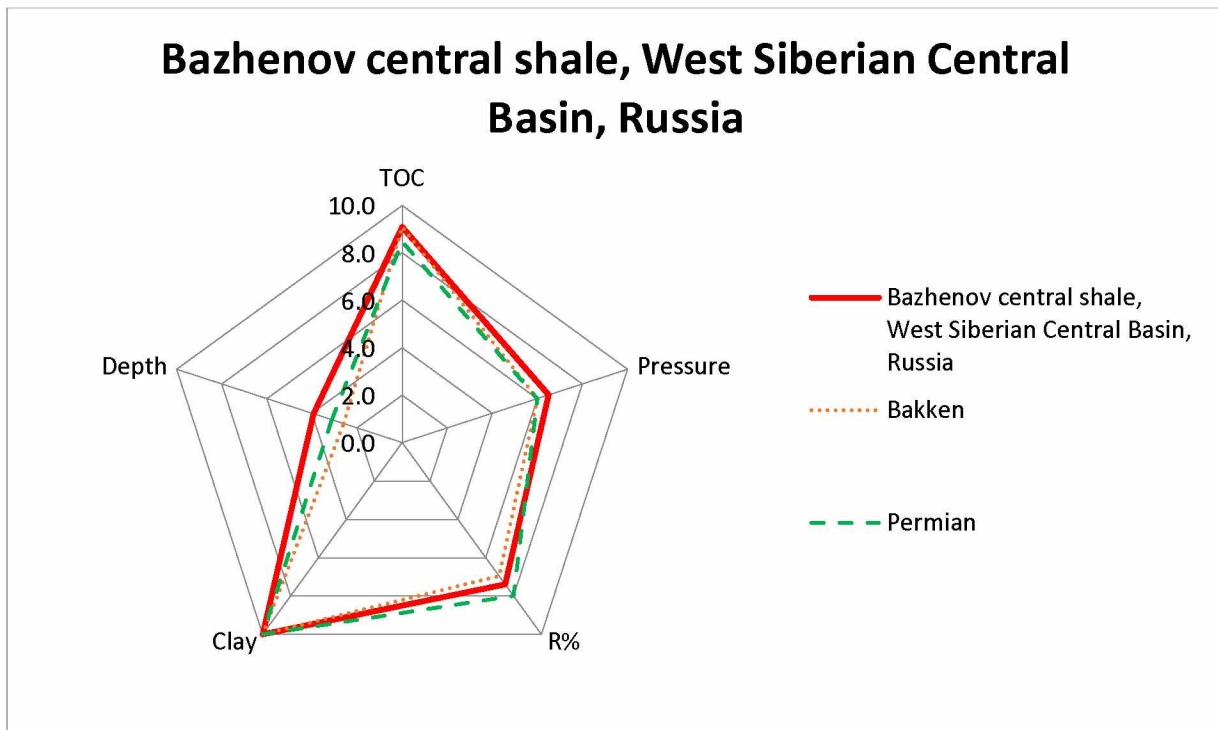
Figure 43. Prospectivity Map for Bazhenov Central Shale, Russia.

3.8.2.　　China

According to the EIA/ARI (2013), China ranks second in recoverable shale oil volumes and first in recoverable shale gas resources among non-U.S. global shale regions. There are 12 basins and 13 formations covered in the EIA/ARI (2013) study. The study estimates that these basins

contain a total OOIP of 644 billion barrels of which five percent, 32 billion barrels are thought to be technically recoverable. The Jungarr, Sangliao and Tarim basins contain 98% of shale oil in place resources and 30% of shale gas in place resources. The Sangliao basin contains 34% of shale oil resources and is the most prospective in the country. The Qingshankou formation contains the largest resources among formations in the Sangliao basin presented in the EIA/ARI (2013) report. The prospectivity map illustrates that shale oil maturity and depth make a case for attractiveness of the Qingshankou formation in the Sangliao Basin, and that this tight oil play is most analogous to the Eagle Ford play in the U.S. (Figure 44).
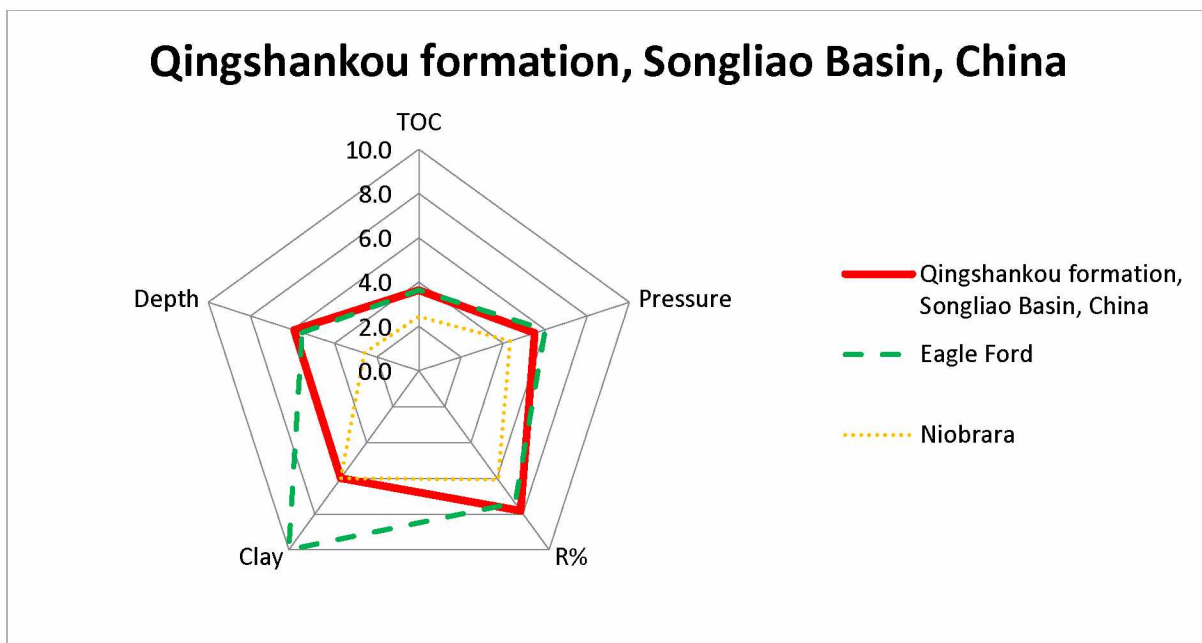
Figure 44. Prospectivity Map for the Qingshankou formation, China

3.8.3.   Argentina

According to the EIA/ARI (2013) among non-U.S. global shale regions, Argentina ranks third in recoverable shale oil volumes and second in recoverable shale gas resources. There are four basins and six formations covered in the EIA/ARI (2013) study on shale resources in Argentina. These basins are the Neuquen, San Jorge, Austral-Magallanes, and Parana basins. The study estimates that these basins contain a total OOIP of 480 billion barrels of which 5.6%, 27 billion barrels are thought to be technically recoverable. The Neuquen and Austral-Magallanes basins

contain 97% of Argentina's shale oil in place resources and 86% of shale gas in place resources. Of these volumes, the Neuquen basin contains 69% of shale oil resources and is the most prospective. The main formation in the Neuquen basin is the Vaca Muerta shale formation. The prospectivity map for the oil section of the Vaca Muerta shale in Argentina's Nuequen basin, is shown to be most analogous to the Eagle Ford tight oil play (Figure 45).
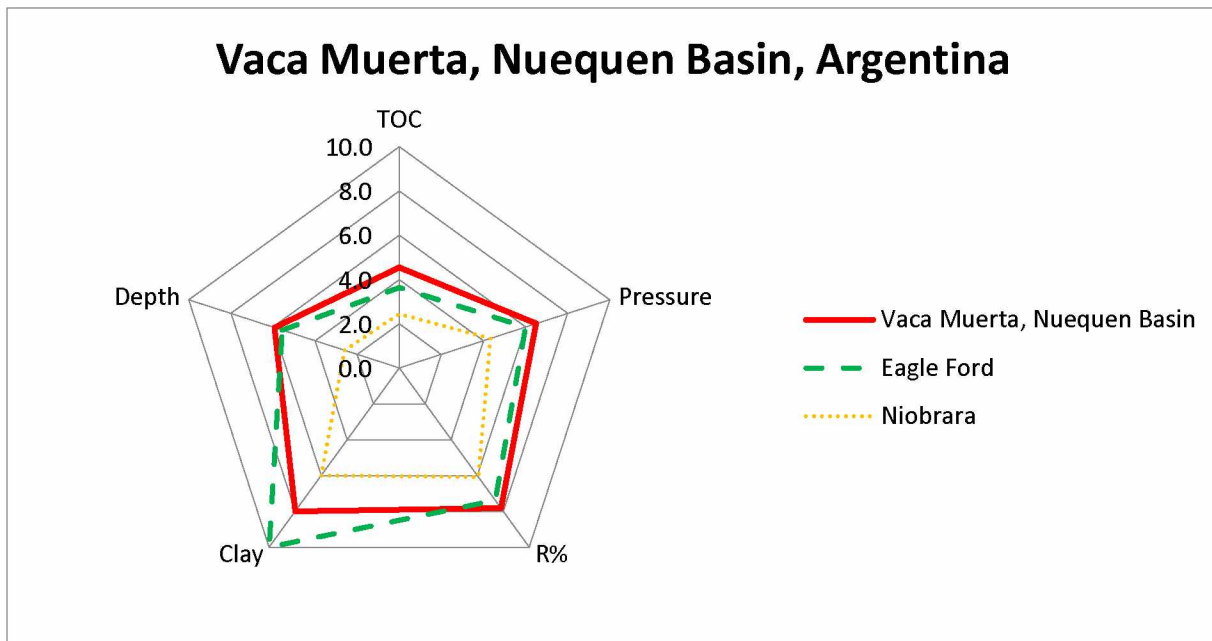
Figure 45. Prospectivity Maps for Vaca Muerta Shale, Nuequen Basin, Argentina

3.8.4. Libya

According to the EIA/ARI (2013), Libya has the fourth largest recoverable shale oil resources among non-U.S. global shale oil nations. The EIA/ARI (2013) study covered three basins and seven formations covered and estimates that these basins contain a total OOIP of 613 billion barrels, of which four percent, 26 billion barrels is thought to be technically recoverable. The Ghadames and Sirte basins contain 96% of Libya's shale oil in place resources and 98% of shale gas in place resources. Between both basins, the Sirte basin contains 74% of the total shale oil resources and is considered more prospective. The Sirte/Rachmat formation within this basin contains the largest resource volumes. The prospectivity map illustrates that oil maturity index is the key advantage of the Sirte play. The depth of the formation could lead to high drilling and

well completion costs. The Sirte/Rachmat shale play is noted to be most analogous to the Niobrara tight oil play in the US.
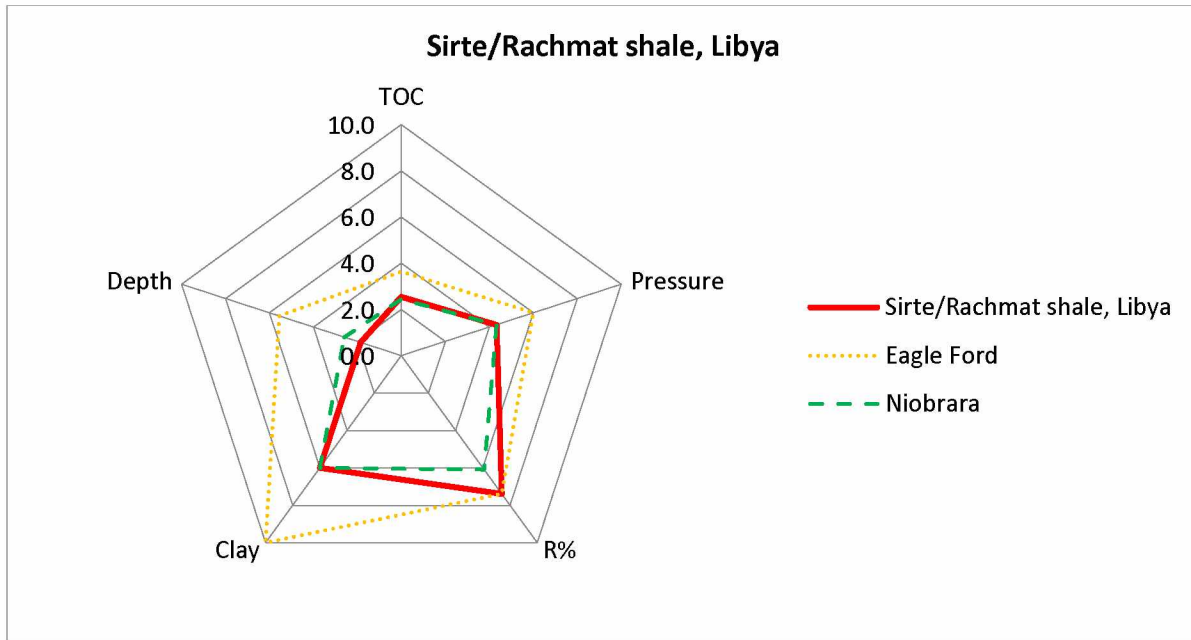
Figure 46. Prospectivity Maps for Sirte/Rachmat Shale, Libya

3.8.5. Colombia /Venezuela

According to the EIA/ARI (2013), a basin that is located across the border between Colombia and Venezuela has the fifth largest recoverable shale oil resources, among non-U.S. shale provinces. This basin alongside one shale formation was covered in the EIA/ARI (2013) study on shale resources in Colombia/Venezuela. This basin lies across the Colombia-Venezuela border and is called the Maracaibo/Catatumbo basin and contains 269 billion barrels of which 4.8% or 13 billion barrels is thought to be technically recoverable (EIA/ARI, 2013).

The high cost in Venezuelan heavy oil production places the cost of oil supply in that nation closer to par with development in tight oil, making the cost of switching developments quite low and presenting some incentive for tight oil development. But the huge reserves of heavy oil and already-existing infrastructure in Venezuela may keep that nation busier in its development. This is not so much the case for Colombia which is experiencing significant decline in current production. This situation presents a stronger incentive for tight oil development through the

Colombian side of this basin. According to Worldcrunch (2017) Colombia's reserves have dropped to 1.7 billion due to low oil prices and current resource extraction rate and a focus on tight oil would allow close to a 300% growth in reserves.
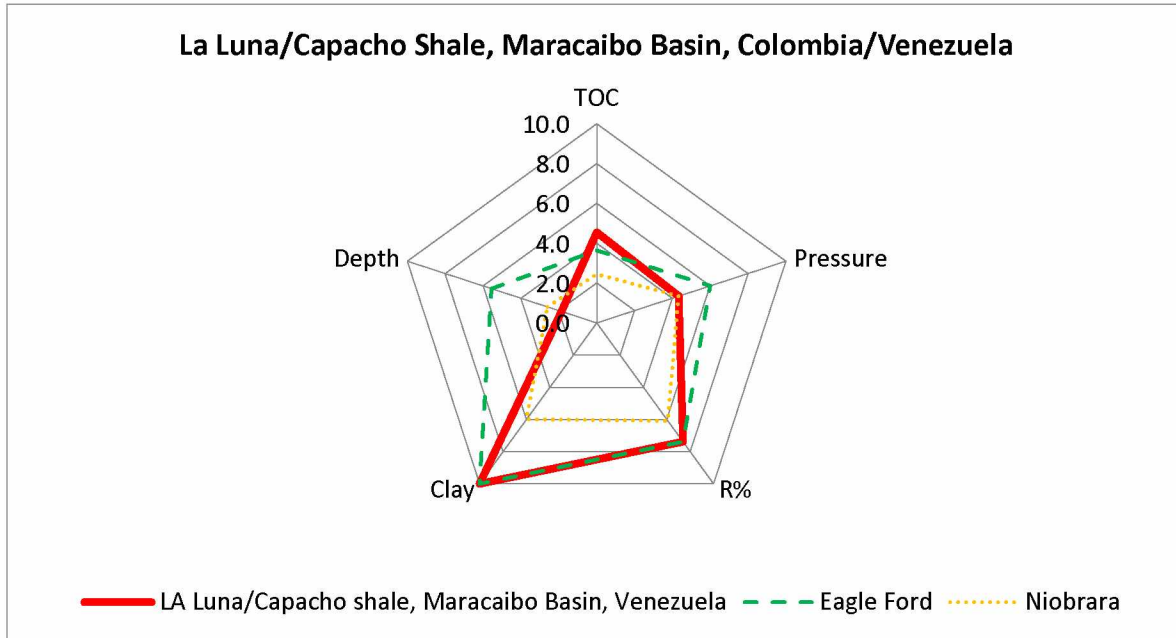
Figure 47. Prospectivity Maps for La Luna/Capacho Shale, Maracaibo Basin, Venezuela

The prospectivity map illustrates that low clay content and oil maturity are the key attractiveness of this play while depth of the formation could pose the greatest challenge to development. Due to its similarity with the Eagle Ford in low clay content, oil maturity and total organic carbon, the U.S. Eagle Ford is selected as its analogue.

3.8.6.   Mexico

Mexico has the sixth largest recoverable shale oil volumes and fifth largest recoverable shale gas resources, among non-U.S. global shale regions (EIA/ARI, 2013). There are five basins and eight formations covered in the EIA/ARI study on shale resources in Mexico. The study estimates that these basins contain a total OOIP of 275 billion barrels of which 13 billion, five percent is thought to be technically recoverable. Of the Burgos, Tampico, Tuxpan, Sabinas, and Veracruz basins reported by the EIA/ARI (2013) study, the Burgos and Tampico basins contain 88% of shale oil in place resources and 71% of shale gas in place resources. The Burgos basin contains

38% of shale oil resources and is most prospective. The prospectivity map illustrates that several factors make this play attractive; the low clay content and mature oil resources located at shallower depth top the list. A close analogue for this play is the Eagle Ford shale of South Texas of the United States.
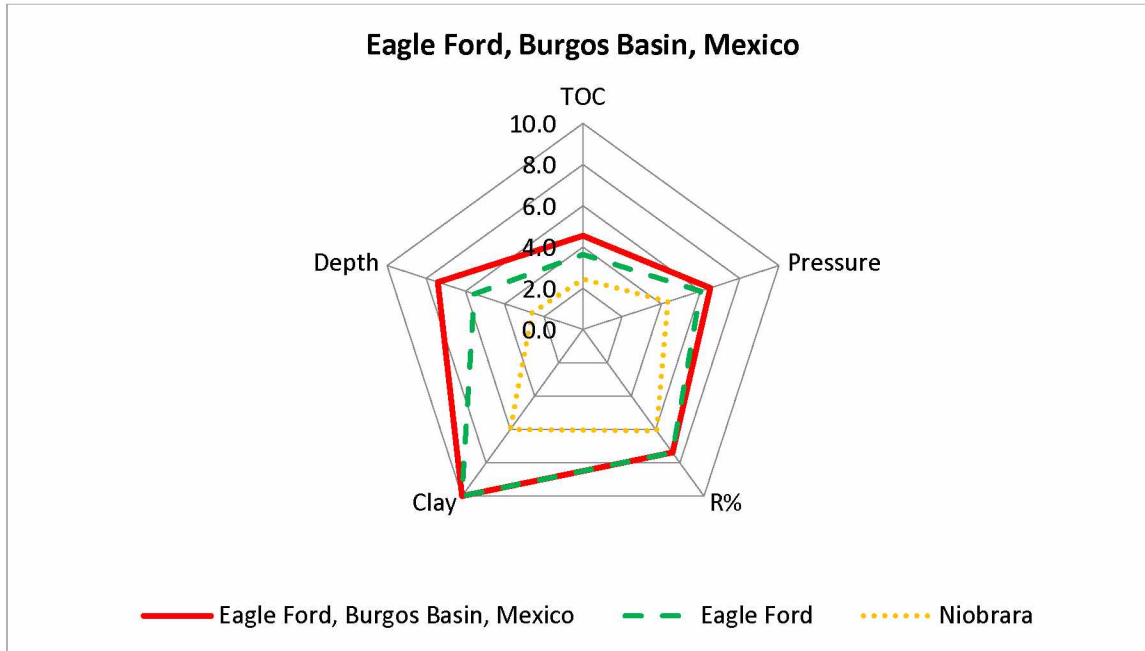
Figure 48. Prospectivity Maps for Eagle Ford, Burgos Basin, Mexico

3.8.7.   Pakistan

According to the EIA/ARI (2013) among non-U.S. global shale regions, Pakistan ranks seventh in recoverable shale oil volumes. There are five basins and six formations covered in the EIA/ARI (2013) study on shale resources in Pakistan. The study estimates that these basins contain a total OOIP of 227 billion barrels of which 9 billion, four percent is thought to be technically recoverable. Of the basins in India and Pakistan discussed in the EIA/ARI (2013) study, only the Indus basin of Pakistan was considered mature and with sufficient prospectivity for quantitative analysis. The main formation in the lower Indus basin is the Sembar shale which contains 68% of the total shale oil resources and over 90% of shale gas resources in Pakistan. The prospectivity map illustrates that the low clay content and shallow depth of mature oil resources in the Sembar play could be its main attractiveness, but the low carbon content of the

play could be its major disadvantage. The U.S. Eagle Ford tight oil play was considered its closest analogue.
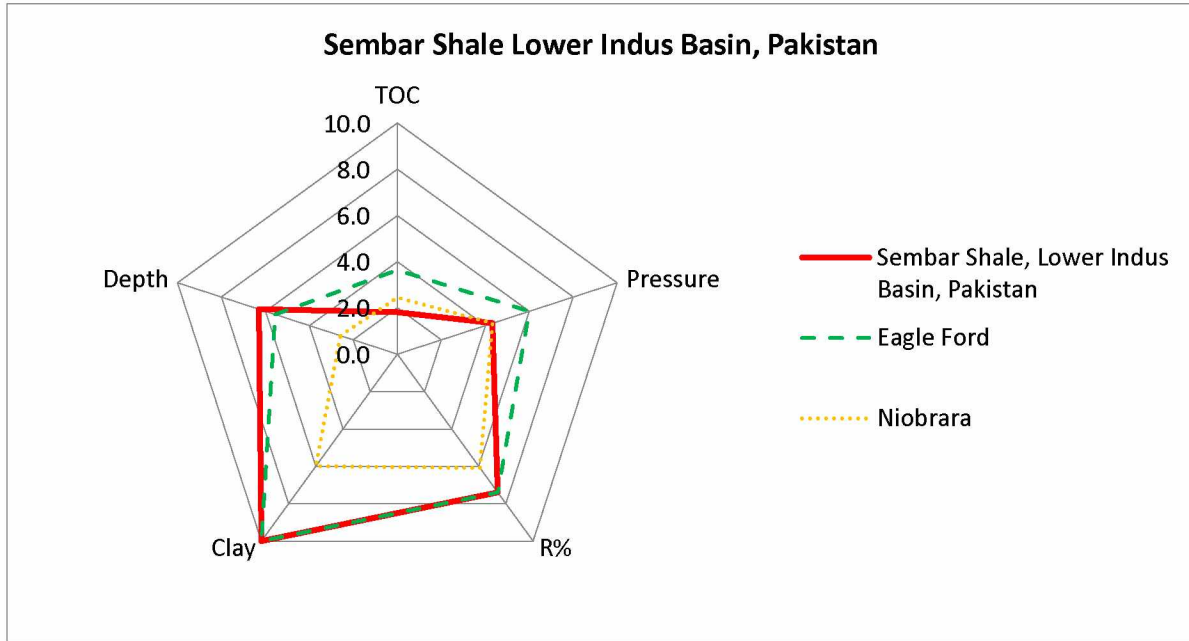
Figure 49. Prospectivity Maps for Sembar Shale Lower Indus Basin, Pakistan.

3.8.8.   Canada

According to the EIA/ARI (2013) among non-U.S. global shale regions, Canada ranks eighth in recoverable shale oil volumes. There are 12 basins and 13 formations covered in the EIA/ARI (2013) study on shale resources in Canada. The study estimates that these basins contain a total OOIP of 162 billion barrels of which 9 billion, four percent is thought to be technically recoverable. Of the basins in Canada discussed in the EIA/ARI (2013) study, the leading basins are the East and West Shale basin, North West Alberta Basin, and the Williston Basin which contain 80% of total shale oil and 27% of total shale gas resources. The East and West Shale basin and the Williston Basin, which continues into prolific sections in North Dakota, are the two most prospective basins in Canada (EIA/ARI, 2013). The Duvernay shale is the main shale formation in the East and West shale basin and contains 41% of the shale oil resources. The prospectivity map on the Duvernay shale in Canada's East and West Shale Basin shows it to be

analogous to the U.S. Eagle Ford (Figure 50). The prospectivity map also illustrates that the low clay content, well pressured and mature shale oil are the main attractiveness of the play.
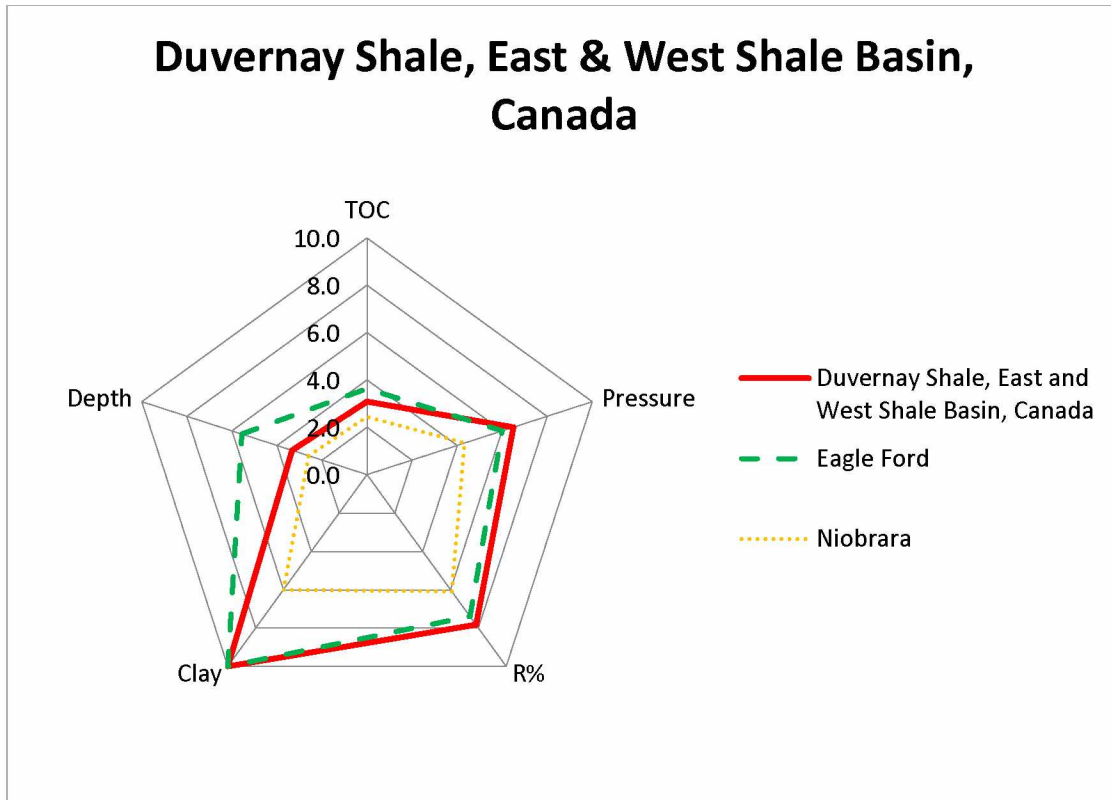
Figure 50. Prospectivity Maps for Duvernay Shale, Canada.

3.8.9.   Indonesia

According to the EIA/ARI (2013) among non-U.S. global shale regions, Indonesia ranks ninth in recoverable shale oil volumes. There are five basins and six formations covered in the EIA/ARI study on shale resources in Indonesia. The study estimates that these basins contain a total OOIP of 234 billion barrels of which 8 billion, 3.4 percent is thought to be technically recoverable. Of the basins in Indonesia discussed in the EIA/ARI (2013) study, the Central Sumatra was considered most prospective. The main formation in the Central Sumatra basin is the Brown shale formation which contains 29% of the total shale oil resources and over 14% of shale gas resources in Pakistan. The prospectivity map on the Brown shale in Indonesia's Central Sumatra basin shows it to be most analogous to the U.S. Niobrara tight oil play and illustrates that oil maturity could be the main attractiveness of this play (Figure 51).
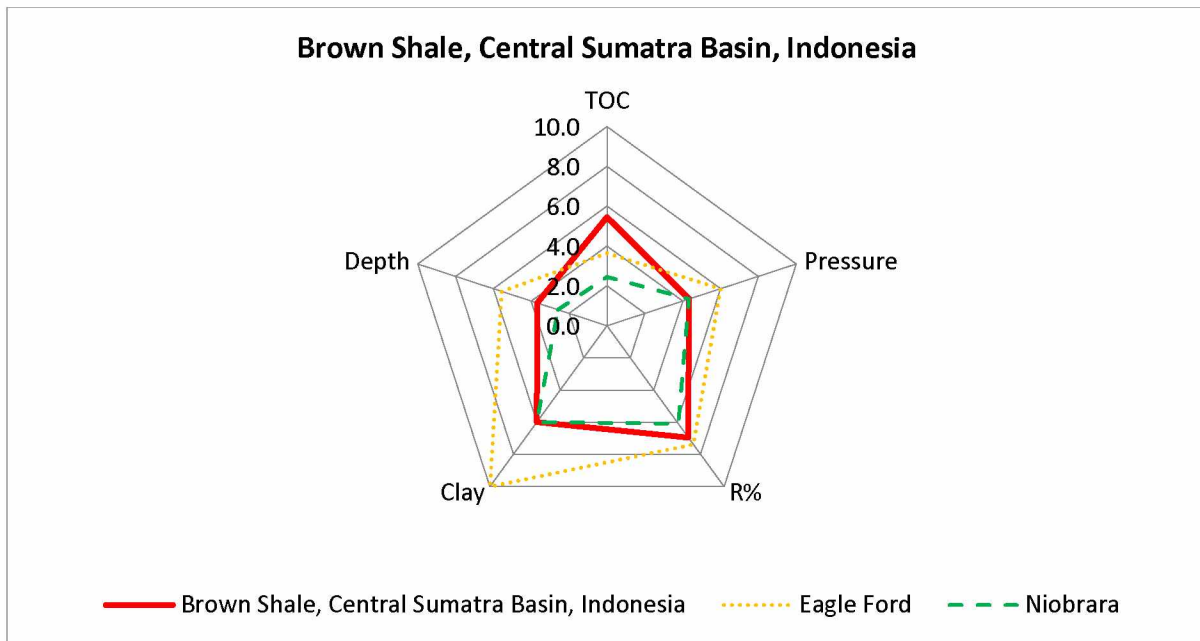
Figure 51. Prospectivity Maps for Brown Shale, Indonesia

3.9. Economic Evaluation of 640-acre Developments in Non-U.S. Plays

3.9.1. Recovery per square mile (640-acre)

One of the characteristics of unconventional resources is the close association of the source rocks to reservoir rocks (Jarvie, 2012). As a result, in the absence of conventional traps, resource location is spread over wider prospective areas, with occasional high permeability zones characterized by dense natural fracture networks, often referred to as sweet spots. One of the characteristics of the non-U.S. regions studied by the EIA/ARI (2013) is resource concentration per square mile (640 acre). The EIA/ARI (2013) noted that this high resource concentration refers to more attractive areas for development within the broad prospective area. The more such areas exist in a play, the more prospective that play is. In conventional resource developments, oil and gas resources accumulate over geologic time into traps, which are typically locations of a smaller areal spread, which could be targeted for development. The EIA/ARI (2013) study presents the volume of resource per square mile for non-U.S. shale oil plays. In a sense, large

resource concentration per square mile is a measure of how similar the play is to conventional oil play and how easily it lends itself for development with fewer wells. Using the resource concentration of the non-U.S. regions and the recovery factors estimated by the EIA/ARI (2013) study, I find an analogue type well for each development, the number and cost of wells required to produce the estimated volumes and conduct an economic assessment for the venture. The recovery estimates or recoverable resource density are determined by applying the recovery factors for each formation on the resource concentration (Table 14). Resource concentration measure bypasses the actual geologic structural complexity involved in developing the play or the infrastructural readiness of the region in which such development occurs, which both lie outside the scope of this assessment. But this measure conceptually presents the spread of development and drilling intensity that could be required for such development to occur.

Table 14. Resource density for selected formations in non-U.S. shale plays and estimated EUR (EIA/ARI, 2013)

Countries	Formation	OOIP MMSTB/ 640 acre	Recovery Factor %	Recoverable Resource Concentration (EUR/640 acre) (MMSTB)
Russia	Bazhenov Central	18.5	6.0%	1.110
Argentina	Vaca Muerta	77.9	6.0%	4.674
Libya	Sirte/Rachmat	28.8	4.0%	1.149
Colombia/ Venezuela	La Luna/ Capacho	92.3	5.0%	4.599
China	Qingshankou	66.4	5.0%	3.334
Mexico	Eagle Ford Shale	43.9	5.9%	2.609
Pakistan	Sembar	36.6	4.0%	1.464
Indonesia	Talang Akar	50.2	3.0%	1.513
Canada	Duvernay	7.1	6.0%	0.424

A review of mature plays in the US, such as the Bakken, Eagle Ford and Permian plays show that operators have been able to downsize well spacing quite successfully. While there is more desire for longer wells, due to the lower recovery factors for tight plays, wells are now spaced as closely as 660ft (Continental Resources, Inc., 2013; EOG Resources, 2016). With such spacing possible and the ability for operators to stack the wells at some offset from each other (Figure 52), it is possible to assume a 640-acre development of say 10,000ft by 2,788ft instead of the

regular 5280ft by 5280ft, which would allow longer wells to achieve the recovery factors of middle single digits as shown in Table 7.
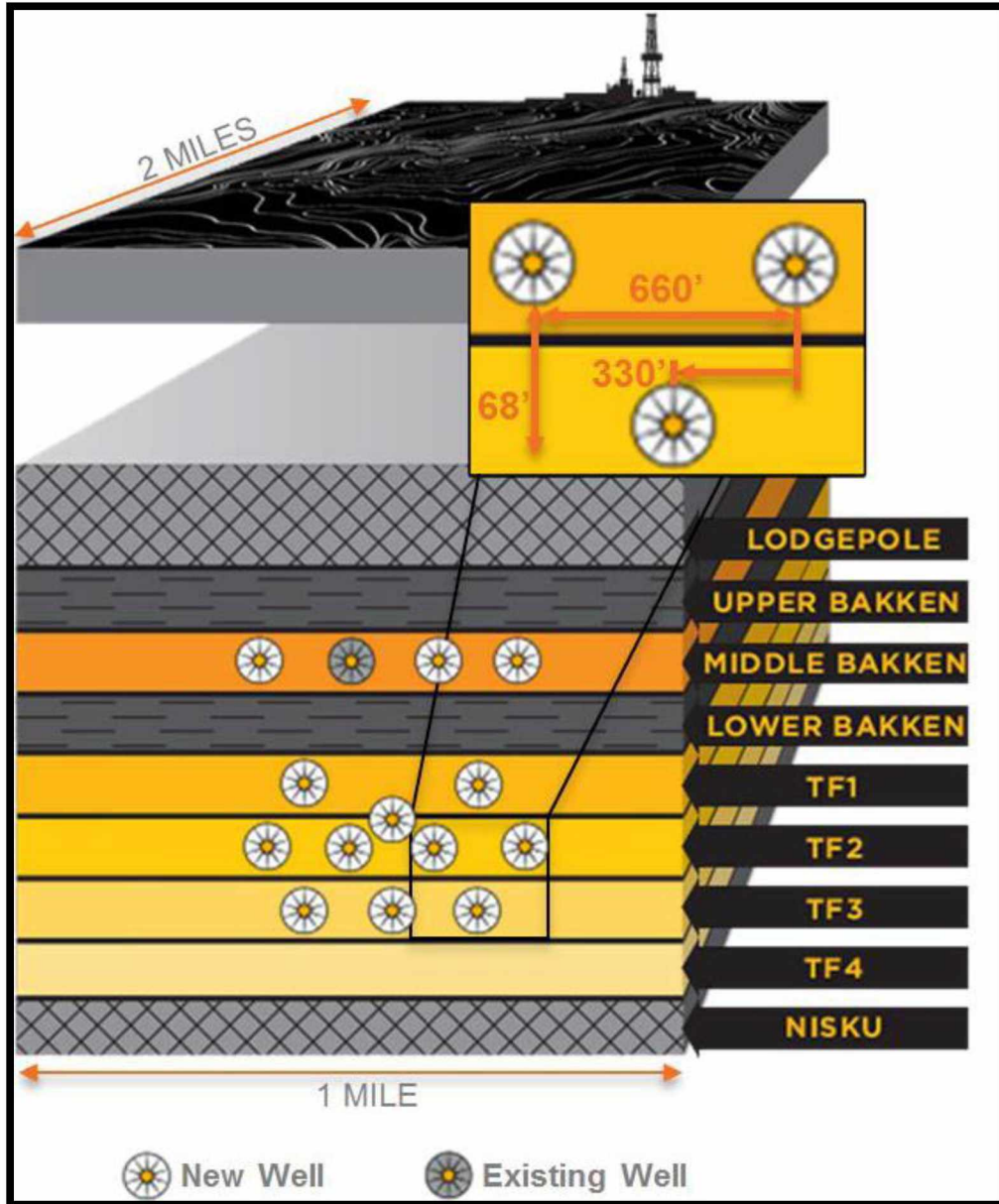
Figure 52. Cartoon Development Plan Showing Possible Well Placements (Continental Resources, Inc., 2014)

This chapter goes on to show a comparison of a 640-acre tight oil development across these 10 countries by applying the number of wells (represented by the appropriate type well and per well reserve) required to produce the reserve estimated within the EIA/ARI (2013) study (Table 14).

3.9.2.   Production Rate Analogues

To evaluate the economics of producing wells in the non-U.S. plays, it is essential that some estimate of a production profile is developed. It is also generally understood that tight oil wells have a high initial production and fast decline in the early life of production. To adequately select analogues for these plays, the geological and petroleum properties of the plays were compared against the known properties of major U.S. tight oil plays, and where a suitable analogue is determined, the type curve of the U.S. play was considered a suitable proxy for that non-U.S. play (Table 15).

Table 15. Non-U.S. Play Formations and U.S. Tight Oil Analogues

Country	Formation	U.S. Tight Oil Analogue
Russia	Bazhenov Central	Bakken
China	Junggar Basin, Pingdinquan/Lucaogu	Eagle Ford
Argentina	Nuequen, Vaca Muerta	Eagle Ford
Libya	Sirte, Rachmat	Niobrara
Colombia	Maracaibo, La Luna/Capacho	Eagle Ford
Venezuela	Maracaibo, La Luna/Capacho	Eagle Ford
Mexico	Burgos, Eagle Ford	Eagle Ford
Pakistan	Lower Indus, Sembar	Eagle Ford
Canada	Duvernay Shale	Eagle Ford
Indonesia	C Sumatra, Brown Shale	Niobrara

Using the Drillinginfo commercial software, DI Desktop (Drillinginfo, 2016), we developed type curves for the Eagle Ford, Bakken, Niobrara, and Permian (represented by the tight oil dominated Wolfcamp formation) formations. Since most tight oil plays have produced for less than a 10-year period, to develop a 20-year well profile, these type wells were forecasted out to 240 months of production by applying the modified Duong model described earlier in this research (Figure 53).
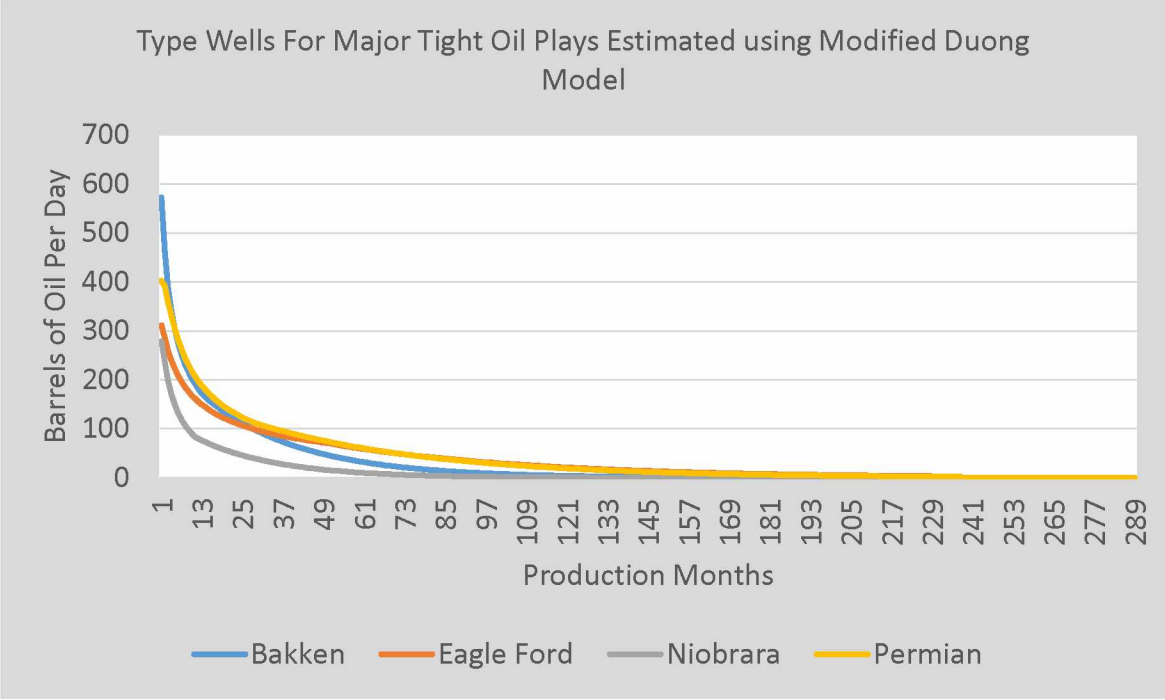
Figure 53. Type Wells for U.S. Tight Oil Plays

3.9.3. Cost of Drilling and Completion

A study by the EIA/IHS (2016) on oil and gas upstream costs shows that a few factors drive development costs in tight oil and gas plays. Among the main drivers, well depth, well design, and completion design were identified as largest cost components in unconventional wells. This section discusses the cost estimates for non-U.S. shale plays based on well length, using costs from analogous U.S. plays discussed in the EIA/IHS (2016) study.

Given the advancements in drilling and completion technology in the US, to apply a uniform geometry across the non-U.S. plays, it was assumed that wells in these non-U.S. plays will be drilled applying similar technological standards as represented by those in the EIA/HIS (2016) cost study. This assumption ensures that it is technically feasible to drill the well lengths proposed for each development. Given that regions like the Bakken have horizontal lateral sections of up to 11,000ft long, and that, barring tract size limitations, operators prefer longer laterals, the laterals in each formation were assumed to be at least as long as the depth of the formation. This assumption was considered appropriate because, evidence in investor

131

presentations showed that operators would prefer longer wells where the mineral rights ownership allowed mineral leases to be conveniently sized (EOG Resources, 2016). Hence, for a formation that is 7000 ft deep, the horizontal lateral was assumed to be at least 7000ft long, resulting in a total well depth of 14000ft. This assumption provides a basis for an objective well cost determination using drilling cost per foot analogues.

The EIA/IHS (2016) report on upstream oil and gas development costs provided completed well costs for the Bakken, Permian, Eagle Ford from which dollar per foot completed well costs were derived (Table 16). Whiting Petroleum company, a major operator in the Niobrara play reported total well drilling and completion costs ranging from $4.0 to $4.5 million by the end of 2016 due to approximately 50% reduction in drilling time from levels in 2014 (Whiting Petroleum, 2017). Drilling costs constitute approximately a third of total well costs (EIA/IHS, 2016). At $4.5 million for total 2016 well costs, after a 30 to 50% reduction in drilling costs since 2014, escalating 2016 costs back to 2014 levels, implied that drilling costs alone for a 15000 foot Niobrara well was approximately $2 million. Total completed well cost for a Niobrara well, therefore, was estimated at $5 million. Due to higher oil prices in 2014, oil services costs were much higher then than in 2015 or 2016 drilling costs (EIA/IHS, 2016). However, in frontier regions, the cost of services is expected to start at high levels due to low supplies of drilling and well services and costs will be expected to gradually decrease with efficiency improvements and learnings. For that reason, higher well costs for 2014 were considered adequate to use in frontier play economic assessments conducted here. Using estimates for per foot drilling and completion costs, total well costs for the non-U.S. play wells were derived (Table 16 and Table 17)

Table 16. Cost of drilling and completion for select shale plays based on 2014 costs (EIA/IHS, 2016)

Play	Well Costs ($MM)	Well Total depth (ft)	$/ft
Bakken	7.1	20,000	355.00
Permian	7.7	11,750	655.32
Eagle Ford	7.6	12,000	633.33
Niobrara*	5	15,000	333.33

*Niobrara 2014 well cost derived from Whiting Petroleum (2017) cost estimates

Table 17. Cost Estimates for Wells in Non-U.S. Shale Plays

Province	Formation	Total Vertical Depth (TVD) (ft)	Total Measured Depth (ft)	Well Cost ($ million)
Russia	Bazhenov Central	8,200	16,400	5.82
Argentina	Neuquen, Vaca Muerta	5,000	10,000	6.33
Libya	Murzuq, Tannezuft	11,000	22,000	7.33
Colombia	Maracaibo, La Luna/Capacho	10,000	20,000	12.67
China	Songliao Basin, Qingshankou	5,500	11,000	6.97
Mexico	Burgos, Eagle Ford	3,500	7,000	4.43
Pakistan	Lower Indus, Sembar	5,000	10,000	6.33
Indonesia	C Sumatra, Brown Shale	7,000	14,000	4.67
Canada	Williston Bakken	9,000	18,000	11.40
Venezuela	Maracaibo, La Luna/Capacho	10,000	20,000	12.67

3.9.4.   Cash Flow Modeling for Development in Tight Plays

The main elements of the cash flow modeling for evaluating tight oil development in plays cannot exist outside a fiscal system of the mineral state. For this assessment, the net present value was selected as the economic measure of project viability. To derive the net present value of projects calls for the selection of appropriate discount rates for deploying capital in locations were the operation occurs and not just were the company is incorporated (Damodaran, 2016a). This section discusses the selected fiscal system and the basis for the discount rates used.

3.9.4.1. The Fiscal System

The fiscal system of any region provides the framework within which all investments are assessed, and is important to attracting investments to any region. For this reason, mineral states adjust the incentive structure of their systems to achieve policy objectives. Countries that intend to attract capital to develop challenged resources within their borders realize that they compete against other locales with different and often other resources with a lower cost of supply. For this

reason, the dynamism of rapidly changing global cost structures for bringing resources to market, fluctuations in oil prices and the attractiveness of developing certain resources, keep mineral states busy figuring out ways to stay competitive, while getting the greatest value for their resources for the benefit of their people.

For comparing projects in different tight oil plays against one another, it is necessary that a simple fiscal system is selected. Guidance for such a system was sought from successful mineral states within the U.S. where shale and other tight oil resource development is prevalent. The tax system of a major tight oil producing state in the U.S. was selected. For reasons of its simplicity and attractiveness to independent producers, the fiscal system selected for this comparison was modeled after the state of North Dakota. Unlike an older oil state like the state of Texas, which has a continuum of field types ranging from conventional, quasi-conventional and unconventional resources, which could blur the understanding of incentives for development, the emergence of North Dakota as a key oil producing state after the year 2000, is primarily due to tight oil development, and the favorable tax system that attracted massive investments.

The main elements of this tax system prescribe a gross oil extraction tax of 5% from January of 2016, a production tax of 5% and a marginal corporate income tax rate of 4.31% for incomes above $50,000 (North Dakota Petroleum Council, 2015; NDCC, 2016). The state of North Dakota eliminated its oil and gas property tax and replaced it with the gross production tax stated above (North Dakota Petroleum Council, 2015). The oil extraction tax increases to 6% when the oil price calculated at the well head exceeds $90/bbl for three consecutive months and is waived for wells producing at 35 barrels per day, if such wells are producing from the Bakken formation or the Three Forks formations (North Dakota Petroleum Council, 2015; North Dakota State Government, 2016). Royalty rates in North Dakota run in the 20% range (North Dakota State University, n.d) which is comparable with royalties of 20-25% charged by private land owners in the Eagle Ford (Dallas Federal Reserve Bank, 2012). These elements of gross production and extraction taxes, royalty rates were applied in a Microsoft Excel Cash Flow model used in evaluating projects in the different non-U.S. plays.

3.9.4.2. Discount Rate Estimation for Net Present Value Determination

To estimate the cash flow generated from oil production from any given play, the discount rate is required to account for the time value of money and the cost of investment capital to the oil and gas operator. Since business capital could be generated from debt or equity capital, the discount rate was estimated using the weighted average cost of capital (WACC) methodology (Damodaran, 2017). This methodology selects discount rates for the cash flow model to reflect the weighted cost of equity and debt capital for investments in the nations in which shale development projects occur. The decision to invest in any non-U.S. play by an operator, for example a U.S. operator, would depend on the rate of return on capital from the non-U.S. project when compared against the operators' other projects. This non-U.S. project would have to be analyzed using the appropriate cost of capital reflective of the risk of doing business in the location where the operation exists, to ensure a fair comparison across all projects in the operator's portfolio.

Tight oil development in the U.S. was facilitated mostly by small operators and independent exploration and production (E&P) companies. These independent companies are typically more leveraged and carry over twice as much debt capital on their books than major integrated companies (Damodaran, 2017). Damodaran (2017) assessed over 300 U.S. oil and gas non-integrated companies in January of 2017, and observed that they carry 68% of equity capital and 32% of debt capital compared to 9% of debt capital carried by integrated companies. In determining the appropriate cost of capital, this analysis poses the question: how will a typical independent E&P company compare its investment in projects in non-U.S. shale plays in a manner that accounts for the market risk that results from the countries in which these plays exist? According to Damodaran (2016a), this would include the interest rate an investor would require to invest in a company, whether incorporated in the U.S. or not, if it does business in the location of this tight oil play.

The reason for assessing this cost of capital using a weighted approach is that different investors require different interest rates. The interest rate demanded by investors whom the business is contractually obligated to pay a fixed rate (bond-holders) is different and much less than the

135

interest rate demanded by investors who buy a piece of the business and are ready to lose if the business fails, or profit if the business succeeds (stock holders). From the allocation of the business capital that comes from bond-holders and the portion that comes from stock holders, one could determine what it costs that business to raise capital.

Damodaran (2016a) identified several factors that determine the market perception and possibly the existence of risk to investments in a country. He noted that nations with political systems that increased the cost of doing business, such as nations with corrupt systems or weak laws, impose new costs and inefficiencies in the conduct of business. He also pointed out that countries with single resource economies or a highly lopsided tax revenue base pose significant threats to foreign investments because fluctuations in commodity prices, for example, or events that impact tourism in a country with only that industry, drags down the entire economy of the country. The clearest signal to the market of the struggles of potential investment destination is the ability of a country to pay or default on debt, often referred to as the sovereign default risk (Damodaran, 2016a). This is the risk measured by rating agencies and through other market signals (Damodaran, 2016a). Damodaran (2016a) concluded that the interest rate charged on long term sovereign debt of a country and the price that market agents charge to 'insure' or hedge those who buy the debt of a country (Credit Default Swaps), present a real-time tractable instrument to measure the level of risk involved with investing in a country. This also provides a guide in determining the discount rate appropriate for evaluating cash flows from projects in those countries (Damodaran, 2016a).

A direct estimate of the cost of debt and the cost of equity capital applies the interest rate a bond holder and a stock holder in the operating company would require to give up other investment opportunities to invest in the operator carrying out the project in a non-U.S. tight oil play. According to Damodaran (n.d) this investor evaluates the riskiness of his investment against the riskiness of a low risk asset in a mature market like the US. This introduces the concept of spreads. A large default spread, according to Damodaran (2016a), implies that the risk of default of investments within the location of the firm's operations is much larger than the risk of default of investments in a matured financial market, i.e., the U.S. market. The risk-free benchmark

security instrument often used in this analysis is the U.S. 10-year Treasury bond (Damodaran, 2016b; Damodaran, n.d).

The estimation of the weighted average cost of capital (WACC) requires information such as the fraction of debt and equity capital used in the project, interest on debt capital, and interest on equity capital as follows (Damodaran, 1999a):

$$WACC = K_e \left(\frac{E}{(D+E)} \right) + K_d \left(\frac{D}{(D+E)} \right) \tag{27}$$

$$K_e = T_b + \beta \, (MERP + CRP) \tag{28}$$

$$K_d = I_d \, (1 - T) \tag{29}$$

Adjusted for the cost of debt for a non-U.S. operated asset (Damodaran, n. d)

$$K_d = (I_d + CRP) * (1 - T) \tag{30}$$

Where
K_e = cost of equity (E) = Total equity risk premium

K_d = After-tax cost of debt (D) = After-tax total debt risk premium

I_d = Interest rate on debt in U.S. (which consists of risk free rate + company default spread)

CRP = Country risk premium or added risk exposure to investing in this country as inferred from the risk of its equity market when compared against default risk of a matured market.

MERP = Mature market equity risk premium above the risk-free rate

T = Company's U.S. marginal tax rate.

T_b = U.S. 10-year Treasury Bond Rate

β = U.S. Oil and Gas E&P Industry stock relative volatility (levered) (Damodaran, 1999b)

Damodaran (2017) assessed groups of oil and gas exploration companies within U.S. and globally to generate general financial statistics useful in this analysis, which include the level of debt capital (Table 18). He also assessed a group of countries for the added risk of investments within those countries posed by the relative risk of default on their debts as indicated by rating agencies like Moody, and from inference from market data on the risk of default assessed by companies who *insure* buyers of U.S. traded foreign bonds (Table 19). Assessments from

Damodaran (2017) for January 2017 are considered to be representative of conditions of the equity and bond markets for the end of year 2016.

Table 18. Financial Statistics of Oil and Gas Companies (Damodaran, 2017)

Oil/Gas (Production and Exploration)		
	Global	US
Number of firms	1140	392
After-tax Return on Capital Investment	11.72%	11.84%
Average effective tax rate	34.94%	41.46%
Unlevered Beta	1.10	0.91
Equity (Levered) Beta	1.48	1.27
Cost of equity	12.82%	9.45%
Standard deviation in stock prices	73.94%	71.93%
Pre-tax cost of debt	5.13%	4.17%
Market Debt/Capital	31.98%	32.51%
Cost of capital	9.87%	7.19%

Table 19. Country Total Equity Risk Premiums (Damodaran, 2017)

Country	Total Equity Risk Premiums	Credit Default Spread (Net of US)
Argentina	14.94%	4.76%
Canada	5.69%	0.00%
China	6.55%	1.27%
Colombia	8.40%	2.04%
Indonesia	8.82%	1.87%
Mexico	7.40%	1.82%
Pakistan	9.24%	2.08%
Russia	19.90%	30.44%
Venezuela	14.94%	3.80%
Libya*	19.90%	30.44%

*Libya CC2 credit rating absent from Damodaran (2017) assessments was found to be comparable to the credit rating for Venezuela (The Economist Intelligence Unit, 2017)

The cost of equity capital was assessed for operations in the foreign tight oil operations (Equation 28). The cost of debt was estimated by adjusting the overall cost of debt used for tight oil development operations in a foreign country to the cost of debt for operations within the U.S.

(Equation 30). The adjustment of the interest rate on debt by the tax rate also reflects the beneficial tax treatment that this source of capital enjoys within U.S. tax policy as opposed to the cost of equity capital (Graham, 2000). Since profit income generated by corporations is taxed within the corporation, and corporation's dividends paid out to the investor is also taxed as personal income, Graham (2000) noted that the investor would want a return high enough that compensates for what he loses to taxes. This level of return required by investors could erode the profitability of projects for operators. Graham (2000) therefore reasoned that the beneficial treatment of debt in U.S. tax policy is seen as necessary to incentivize companies to shoulder the risk involved in making investments, aware that the tax system allows them to deduct the interest paid for debt generated. Dubay (2015) also notes that this tax treatment eliminates the problem of double taxation by ensuring that returns from same investments are only taxed as dividends to investors.

Finally, the weighted average cost of capital was determined using the cost of equity and cost of debt and the overall weight of each component of capital among U.S. companies (Equation 27; Table 20).

Table 20. WACC (Discount Rates) for discounted cash flow analysis for non-U.S. tight oil asset cashflows

Country	Total Equity Risk Premium for Country (EOY2016)	Cost of Equity (Oil and Gas, E&P)	After Tax Cost of Debt	WACC
Argentina	14.94%	18.27%	5.80%	14.218%
Canada	5.69%	6.55%	2.71%	5.304%
China	6.55%	7.64%	3.54%	6.308%
Colombia	8.40%	9.99%	4.04%	8.052%
Indonesia	8.82%	10.52%	3.93%	8.375%
Mexico	7.40%	8.72%	3.89%	7.151%
Russia	9.24%	11.05%	4.06%	8.779%
Venezuela	19.90%	24.55%	22.50%	23.885%
Pakistan	14.94%	18.27%	5.18%	14.015%
Libya*	19.90%	24.55%	22.50%	23.885%

*Libya CC2 credit rating absent from Damodaran (2017) assessments was found to be comparable to the credit rating for Venezuela (The Economist Intelligence Unit, 2017)

In tight oil development, a single well in a 640-acre spacing unit does not effectively develop the acreage (IOGCC, 2015). A review of development practices in most tight oil plays in the U.S. show that tighter well spacings are used especially for the development of oil resources from low permeability formations in tight oil plays. This analysis starts off with the estimated recovery from 640/acre parcels determined by the U.S. EIA/ARI (2013) report. We apply the estimated ultimate recovery from U.S. wells analogous to the types of wells that would be drilled in similar non-U.S. tight formations, to determine the number of wells a given development would require. The number of wells a development plan requires also adds to the cost of that development. As a result, for a 640 acre (1 square mile) development that is resource rich and where the rock quality makes it analogous to the best tight oil plays in the US, more resource would be produced using fewer wells, contributing to the overall profitability of the venture. The discounted cashflow analysis resulting from the forecasted production was estimated using the appropriate discount rates to determine the net present value of each investment in 10 non-U.S. tight oil plays.

Table 21. Well length, well cost, and well count required to achieve EIA/ARI (2013) recoveries in non-U.S. tight oil plays

Province	Formation	Recoverable/ 640 acre (million barrels)	Total Depth (feet)	Well Cost ($ millions)	Well Count
Russia	Bazhenov Central	1.11	16,400	5.82	4
Argentina	Neuquen, Vaca Muerta	4.67	10,000	6.33	9
Libya	Murzuq, Tannezuft	1.15	22,000	7.33	11
Colombia	Maracaibo, La Luna/Capacho	4.60	20,000	12.67	9
China	Sangliao Basin, Qingshankou	3.33	11,000	6.97	6
Mexico	Burgos, Eagle Ford	2.61	7,000	4.43	5
Pakistan	Lower Indus, Sembar	1.46	10,000	6.33	3
Indonesia	C Sumatra, Brown Shale	1.51	14,000	4.67	15
Canada	Williston Bakken	0.42	18,000	11.40	1
Venezuela	Maracaibo, La Luna/Capacho	4.60	20,000	12.67	9

Other inputs used in the cash flow model to assess the economic viability of cashflows from non-U.S. tight oil cash flows under the base fiscal system of North Dakota.

Table 22. Cash Flow Model Inputs and Elements of an Oil and Gas Tax Regime Designed after the North Dakota Oil and Gas Tax System

Model Inputs for an Independent Oil and Gas Company	Estimates
Netback costs	$3.00
Base Oil Price ($/bbl)	55
Royalty percent	20%
OPEX ($/boe)	$18
Intangible Development CAPEX (Independent E&P)	For Income Tax purposes, 100%
End of project life undepreciated Capital Write-off	100%
Depreciation Tangible CAPEX	MACRS 7-yr
State Severance (Extraction) Tax (%)	5%
Production Tax (%)	5%
State Corporate Income Tax Rate (%)	~5%
Federal Corporate Income Tax Rate (%)	35%

3.9.5.   Results and Discussion

The results illustrate the economic viability of tight oil development projects in 10 non-U.S. tight oil plays, assessed within a fiscal system modeled after the State of North Dakota with the following key elements:

- Royalty rate of 20%

- Gross oil production tax rate of 5%

- Gross oil extraction tax rate of 5%

- State oil and gas property tax rate of 0%

- State Corporate Income tax of 5%

- U.S. Federal Corporate Income tax rate of 35%

However, this assessment is not a full cycle economic assessment as it excludes components like bonus bid and mineral lease rentals, which occur before the project even commences, or the tax treatment of those cost components through cost depletion. Cost depletion allows the operator to recover the cost of acquiring the mineral as a deduction from taxable income, so that as the mineral is gradually depleted, the operator recovers their full cost (Stermole & Stermole, 2012).

141

The cost of acquiring leases is governed by the mineral rights laws of the different localities. For simplicity and comparability, this assessment excludes lease acquisition cost and also excludes sunk cost elements like facility cost incurred such as pipelines and other well site facilities and module costs required. The assumption made here is marginal in that, the operating company already has footing within this asset and is assessing investment in that next 640-acre development.

Another deduction this assessment excludes is the percentage depletion deduction. This is a special tax treatment for most extractive mineral companies which allows them to deduct up to 100% of taxable income, depending on how that amount compares with a fixed percentage of gross revenue net of royalties (Stermole & Stermole, 2012). According to Stermole and Stermole (2012), the fixed percentage of gross revenue, net of royalties, allowed for oil and gas operators (only independent operators, i.e operators who explore, produce but do not refine into petroleum products), is 15%.

The base case of this analysis applied the elements of the cashflow model alongside best estimates for costs. We use a base oil price of $55/bbl, recovery factors of each 640-acre parcel as stated in the EIA/ARI (2013) report, and royalty rate, tax elements as listed above. To conduct the sensitivity analysis, ranges were selected for the parameters to represent the potential for higher or lower oil prices, severance tax, recovery factors, well costs, discount rates (Table 23). Oil price was varied between $35/bbl to a peak of $100/bbl to cover a good portion of the spread in prices between 2007 through 2016. Well cost was assumed to vary to as high as 150% of the estimated cost to reflect the high cost of initial developments in frontier plays with fewer rigs and drilling services than the US. The recovery factor was varied to be able to achieve the highest recovery factor at 10%, to reflect some of the ground-breaking recovery achievements with tighter spacings in the Eagle Ford and Permian plays in the US. The extraction tax of 5% of gross production is the same as the production tax of 5% in North Dakota and together are applied against the gross value of the resource at the wellhead, after royalty is taken out. For our sensitivity analysis, the change in extraction tax between 2% and 10%, therefore, serves two purposes. Firstly, in North Dakota the extraction tax rate could vary to as low as 2% to incentivize production from marginal wells. A sovereign in one of our tight oil locations could

choose to apply this provision or some variant of this incentive on extraction taxes and our sensitivity range attempts to capture that scenario. Secondly, with this same tax rate applied to both production and extraction taxes, it is possible for U.S. to see the impact of a decision to allow a variable production tax instead.

Table 23. Parameter range evaluated for sensitivity Analysis

Parameter	Units	Low	High
Oil Price	($) value	$35	$100
Well cost	△%	-5%	+50%
Recovery Factor	△%	-10%	+100%
Royalty Rate	Value	12.5%	30.0%
Extraction Tax	Value	2.0%	10.0%
Interest Rate	△%	-25.0%	+25.0%

Most of the assets assessed prove to be uneconomic at the base case. Figure 54 through Figure 73 show the results of the assessment of 640/acre development assessments within tight oil plays in Russia, China, Argentina, Mexico, Canada, Indonesia, Pakistan, Venezuela, Libya, and Colombia. The stochastic results (probability density histograms and tornado charts) were derived applying ranges on key parameters (Table 23) using the Palisade Inc software, @Risk version 7.5 add-on to Microsoft Excel, to generate ranges of NPV from 10,000 iterations across the range of variables.

The stochastic results are presented in histogram and tornado chart plots. The height of the probability density histograms shows the fraction of results at each output value, relative to the total count of results for the entire number of iterations. The tornado charts rank the selected input parameters for their impact on net present value (NPV) and the shades in the bars show whether high or low input values result in higher or lower NPVs (Palisade, 2017b). Numbers on the tornado bars show the mean NPV value generated from the top and bottom percentile values of the input being assessed (Palisade, 2017b).

Results for Tight Oil Development Project on 640/acre in Russia
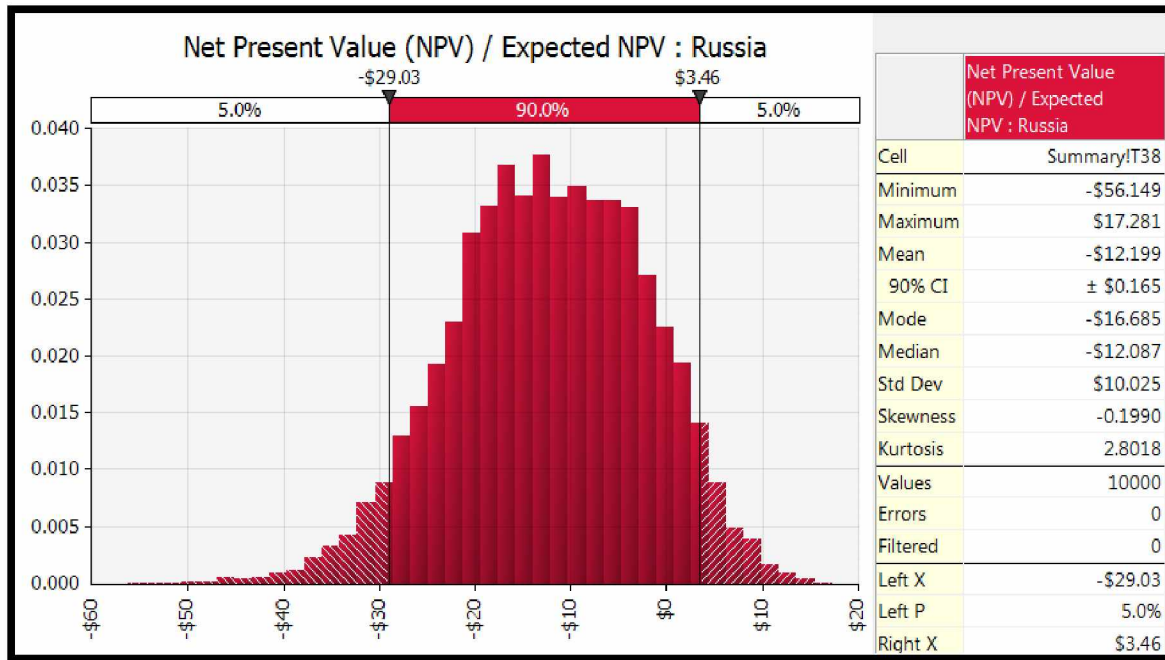
Figure 54. Net Present Value Distribution of Tight Oil Development Project in Russia
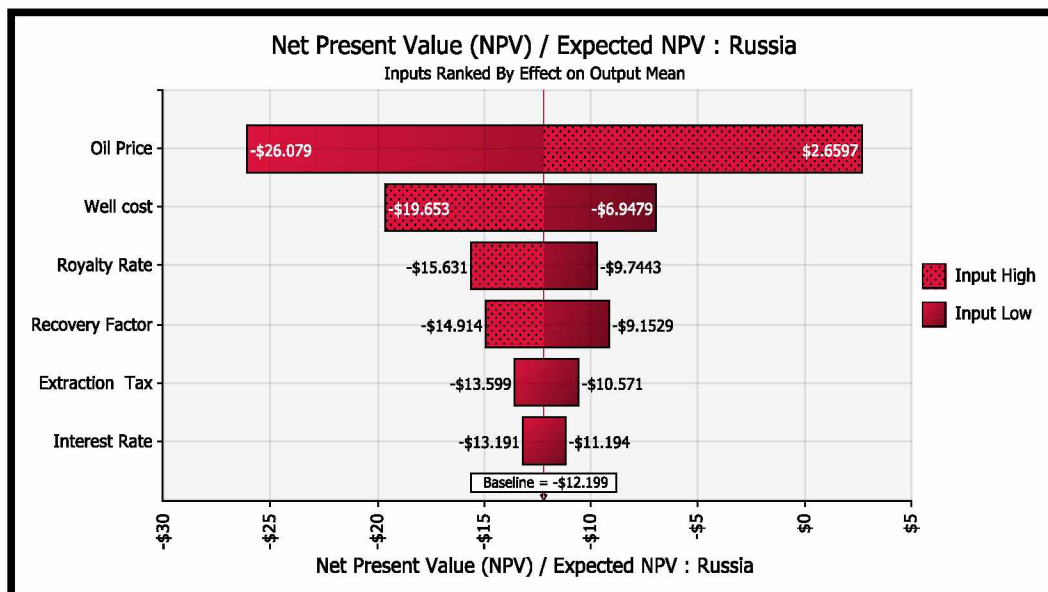
Figure 55. Sensitivity of NPV Tight Oil Development in Russia to key Modeling parameters

Results for Tight Oil Development Project on 640/acre in China
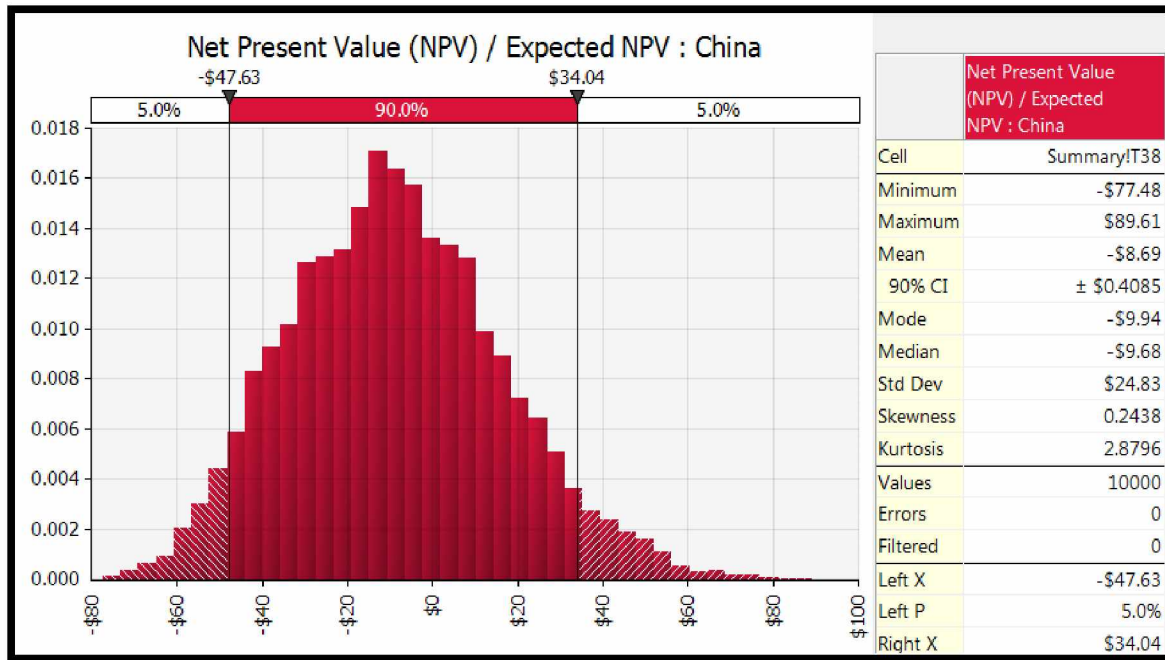
Figure 56. Net Present Value Distribution of Tight Oil Development Project in China
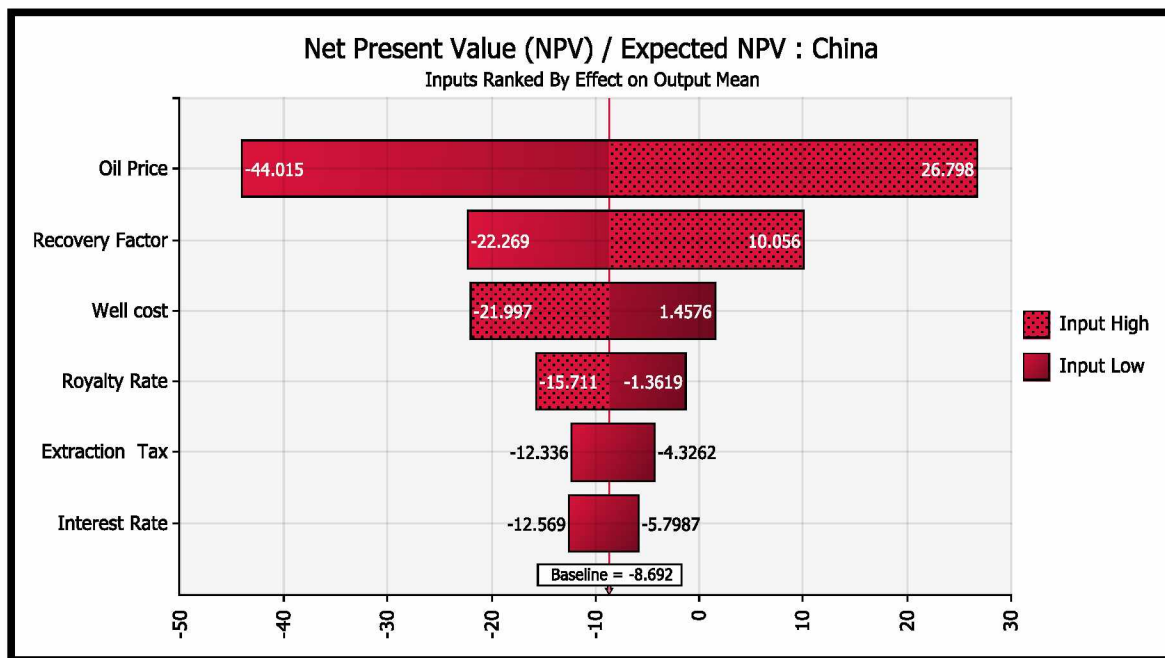
Figure 57. Sensitivity of NPV Tight Oil Development in China to key Modeling parameters

Results for Tight Oil Development Project on 640/acre in Argentina
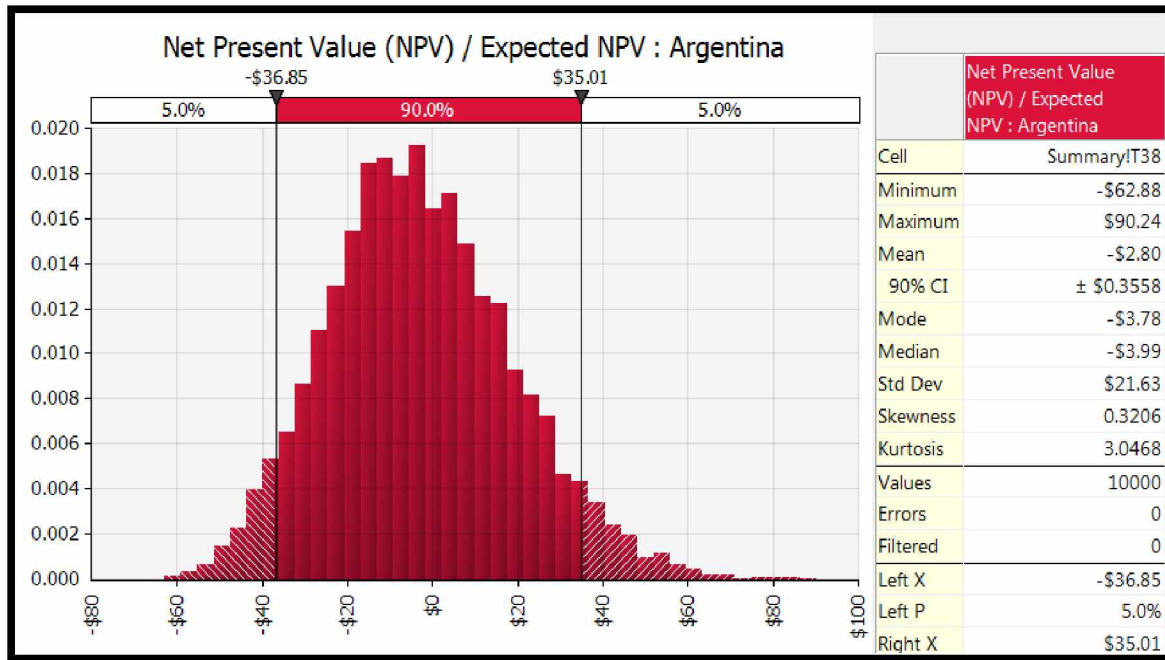
Figure 58. Net Present Value Distribution of Tight Oil Development Project in Argentina
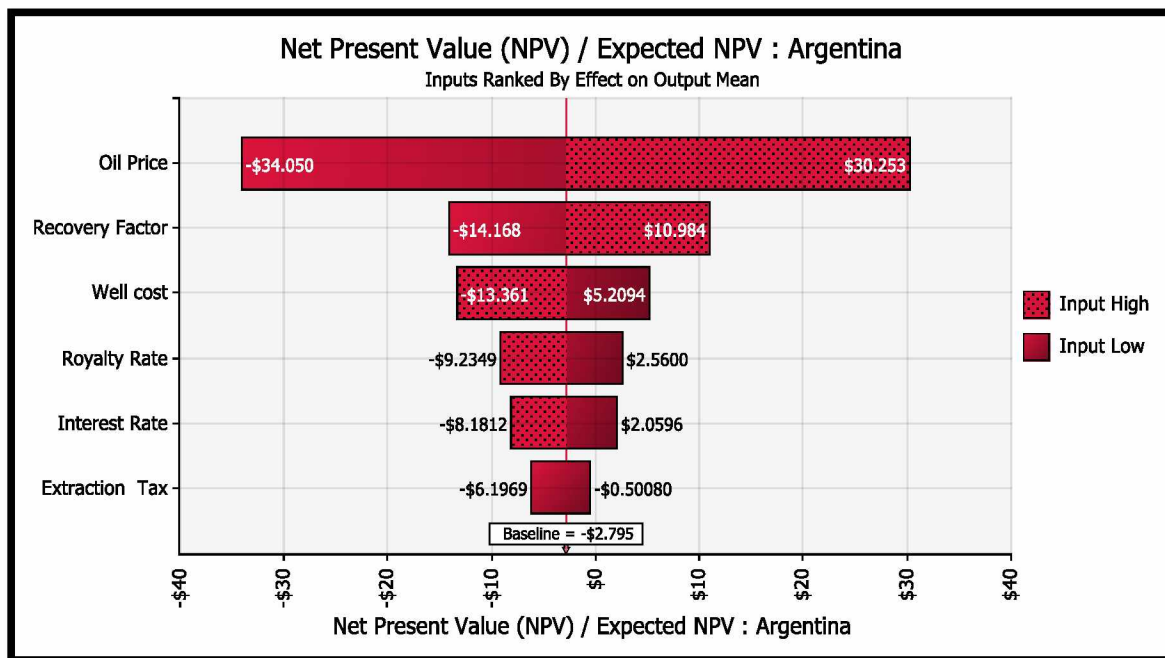
Figure 59. Sensitivity of NPV Tight Oil Development in Argentina to key Modeling parameters

Results for Tight Oil Development Project on 640/acre in Mexico
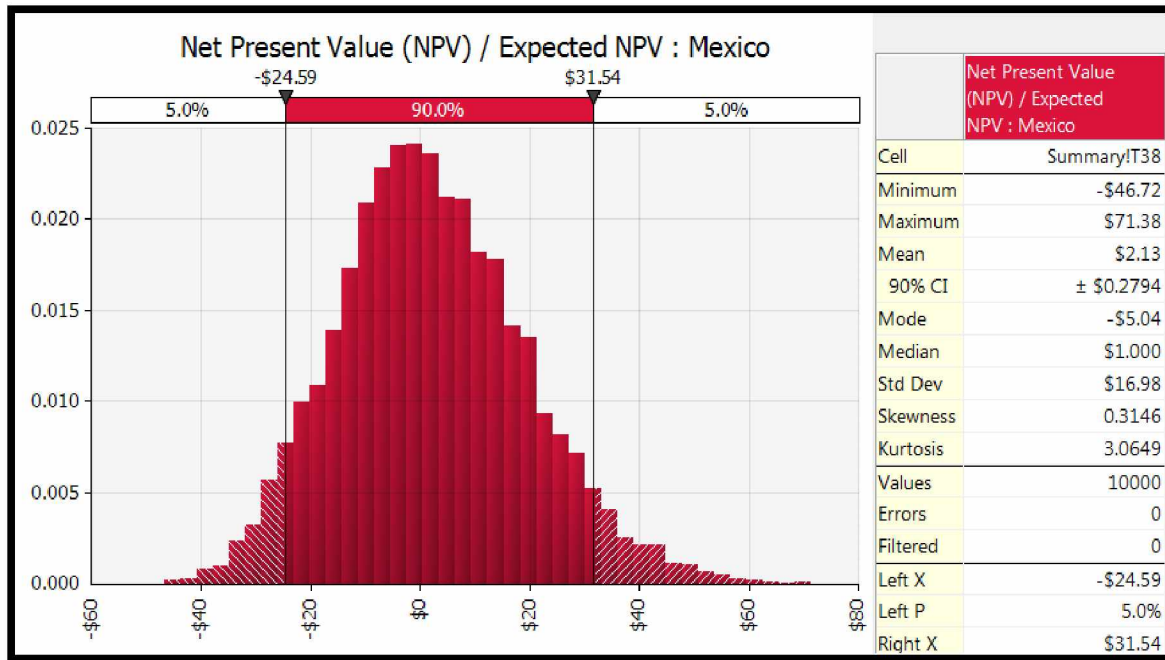
Figure 60. Net Present Value Distribution of Tight Oil Development Project in Mexico
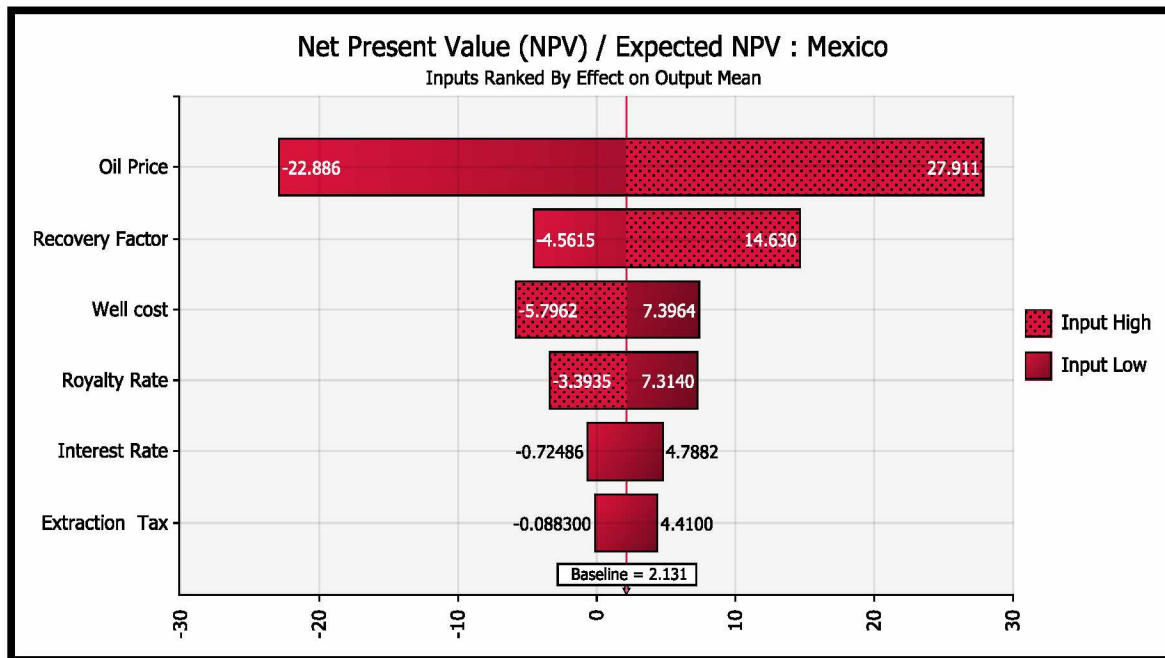
Figure 61. Sensitivity of NPV Tight Oil Development in Mexico to key Modeling parameters

Results for Tight Oil Development Project on 640/acre in Canada
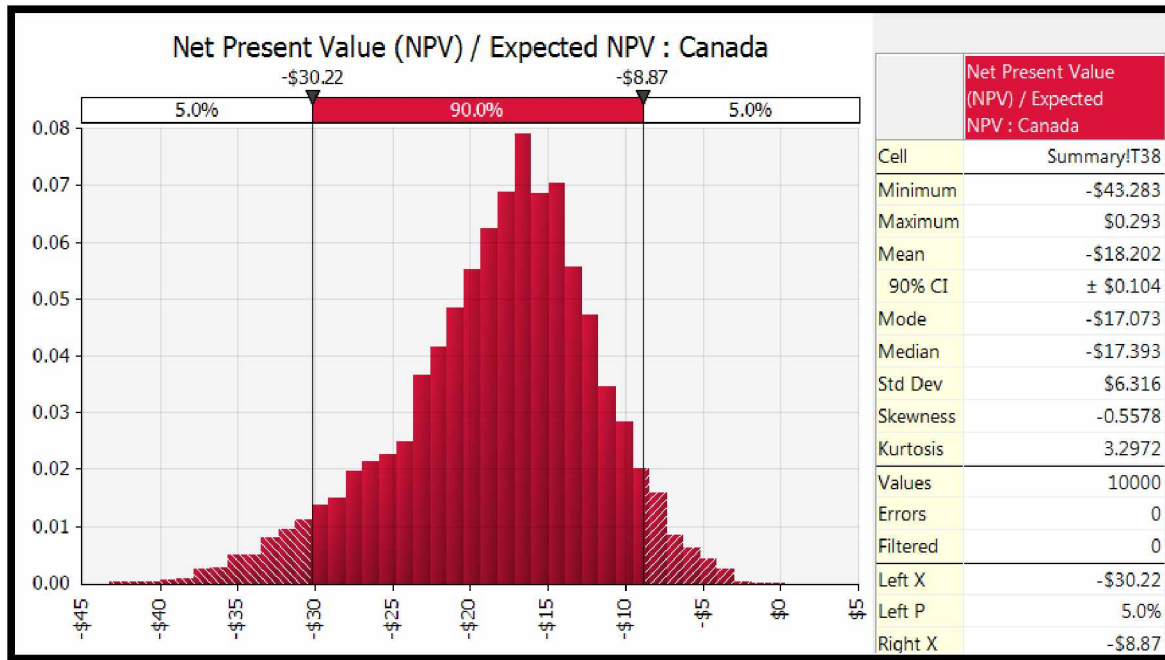
Figure 62. Net Present Value Distribution of Tight Oil Development Project in Canada
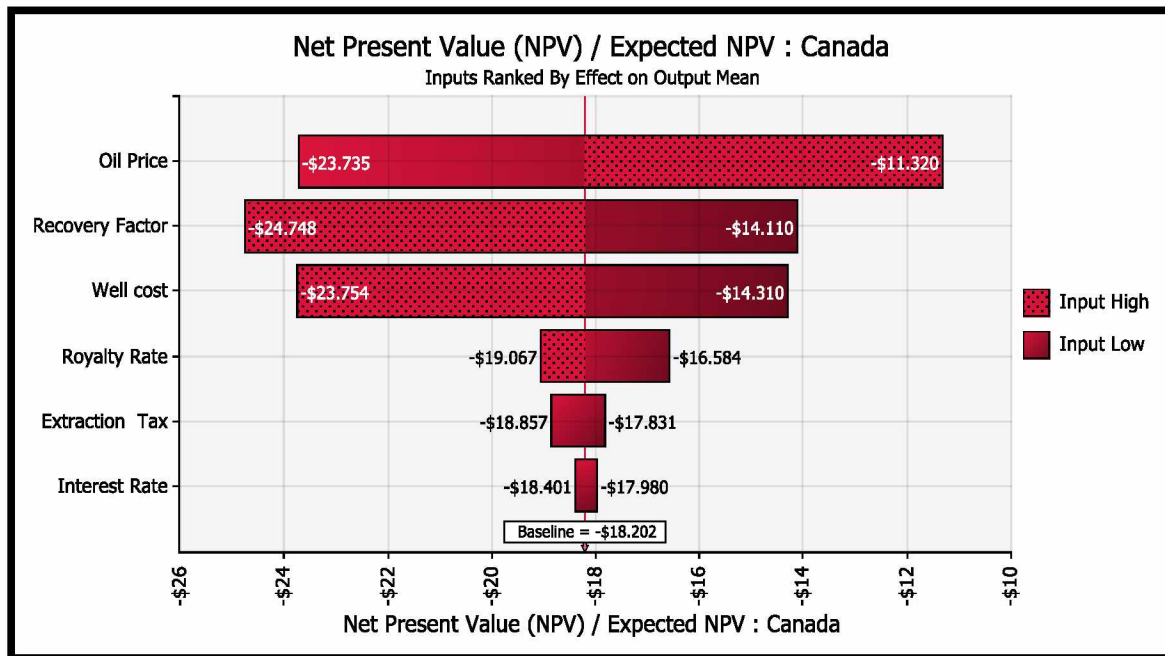
Figure 63. Sensitivity of NPV Tight Oil Development in Canada to key Modeling parameters

Results for Tight Oil Development Project on 640/acre in Indonesia
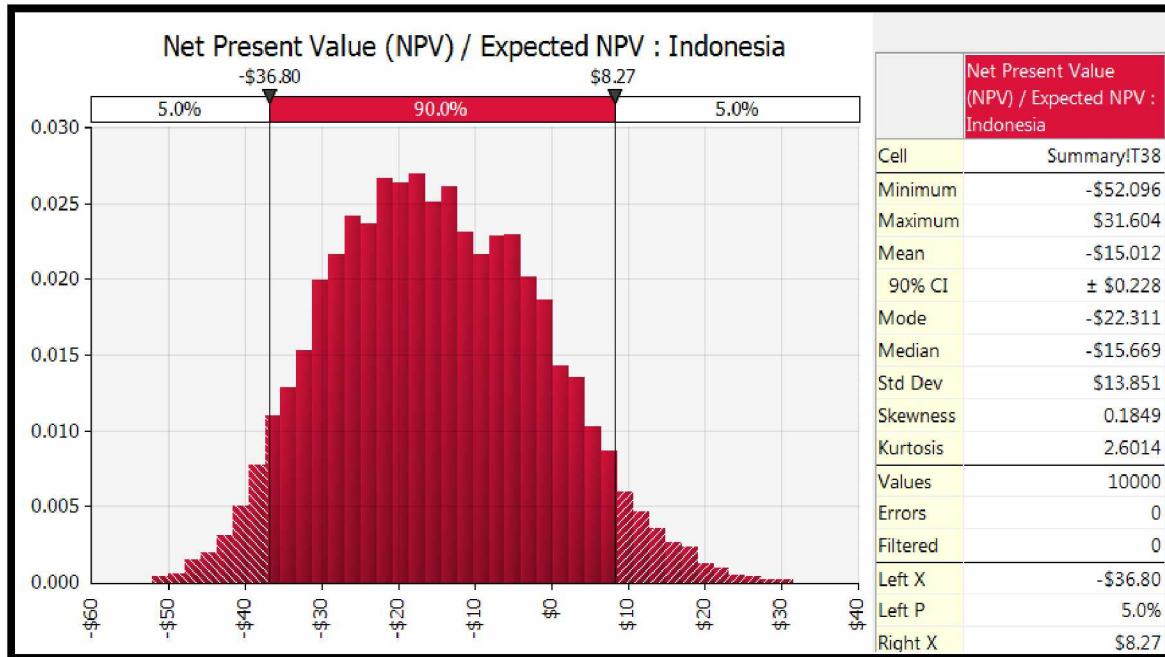
Figure 64. Net Present Value Distribution of Tight Oil Development Project in Indonesia
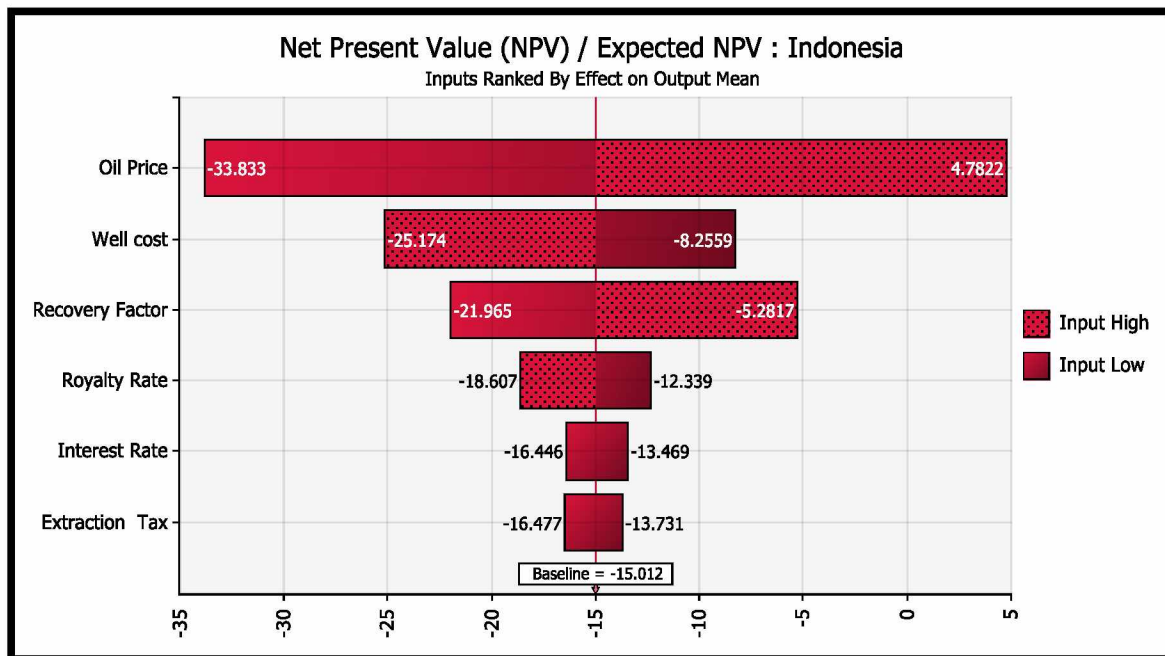
Figure 65. Sensitivity of NPV Tight Oil Development in Indonesia to key Modeling parameters

Results for Tight Oil Development Project on 640/acre in Pakistan
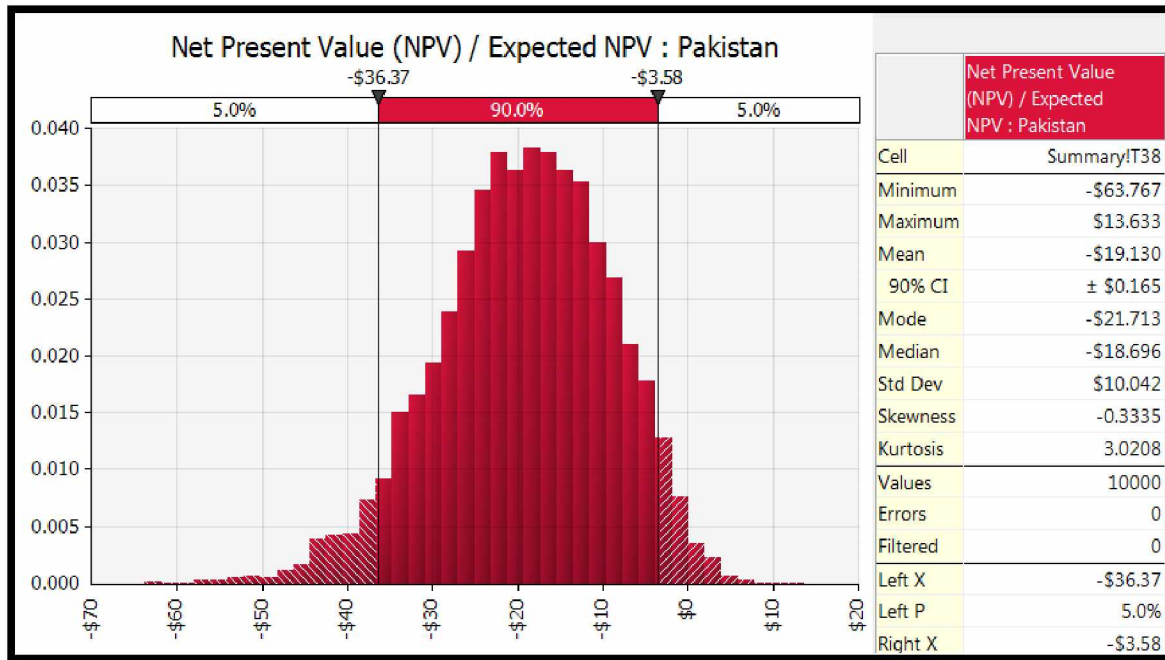
Figure 66. Net Present Value Distribution of Tight Oil Development Project in Pakistan
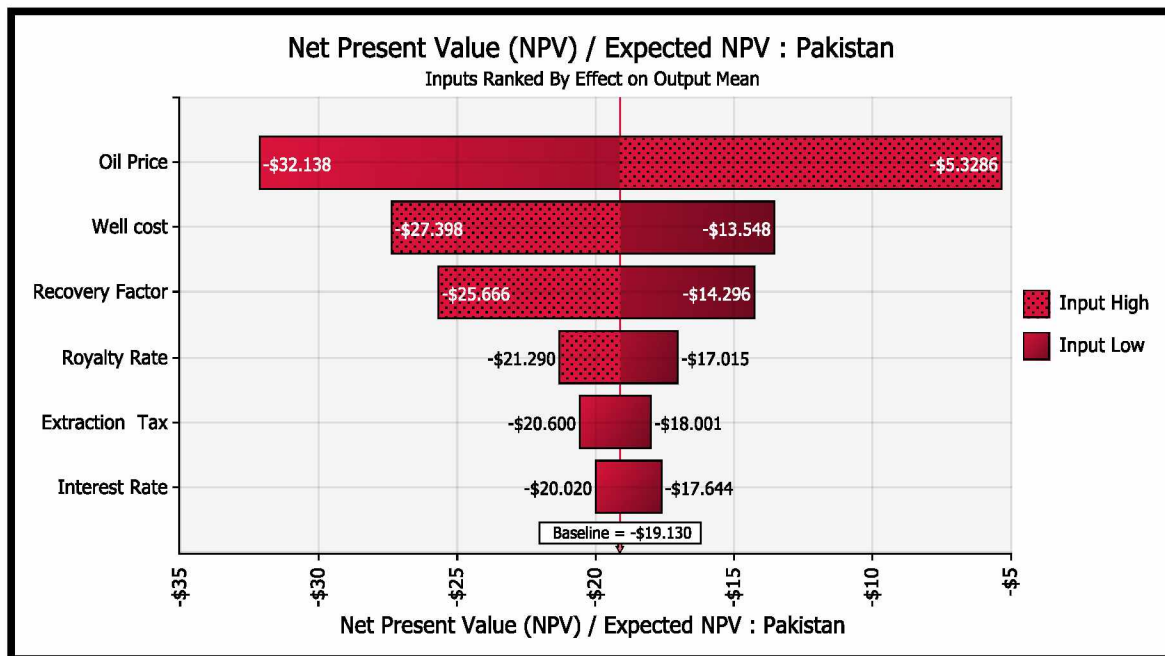
Figure 67. Sensitivity of NPV Tight Oil Development in Pakistan to key Modeling parameters

Results for Tight Oil Development Project on 640/acre in Venezuela
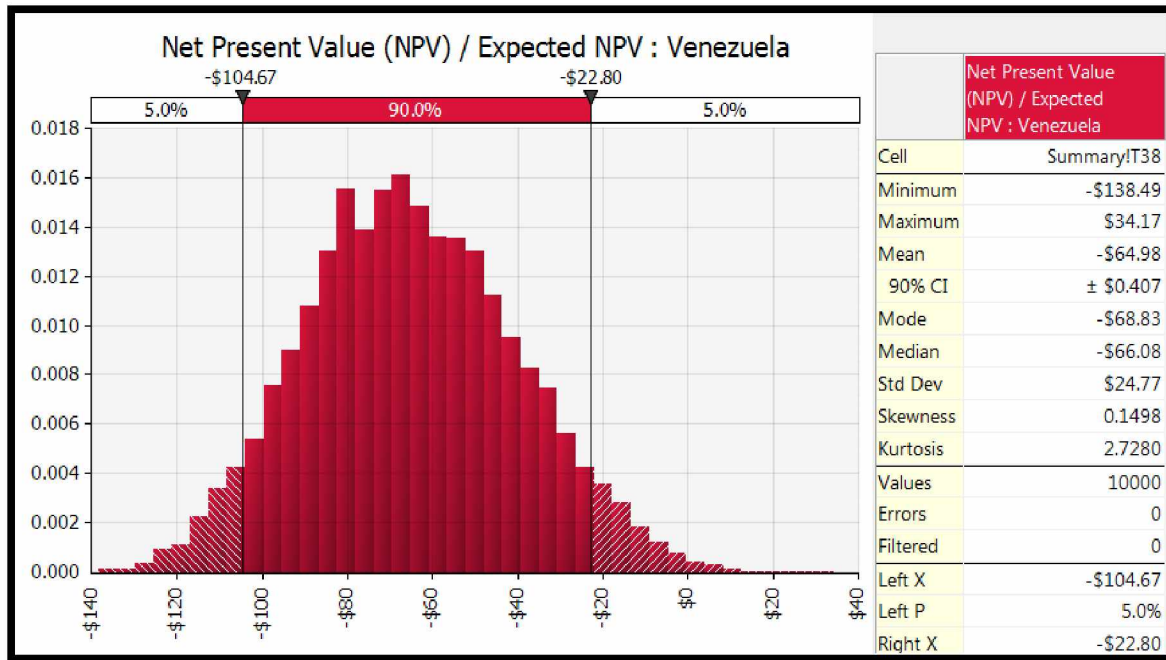
Figure 68. Net Present Value Distribution of Tight Oil Development Project in Venezuela
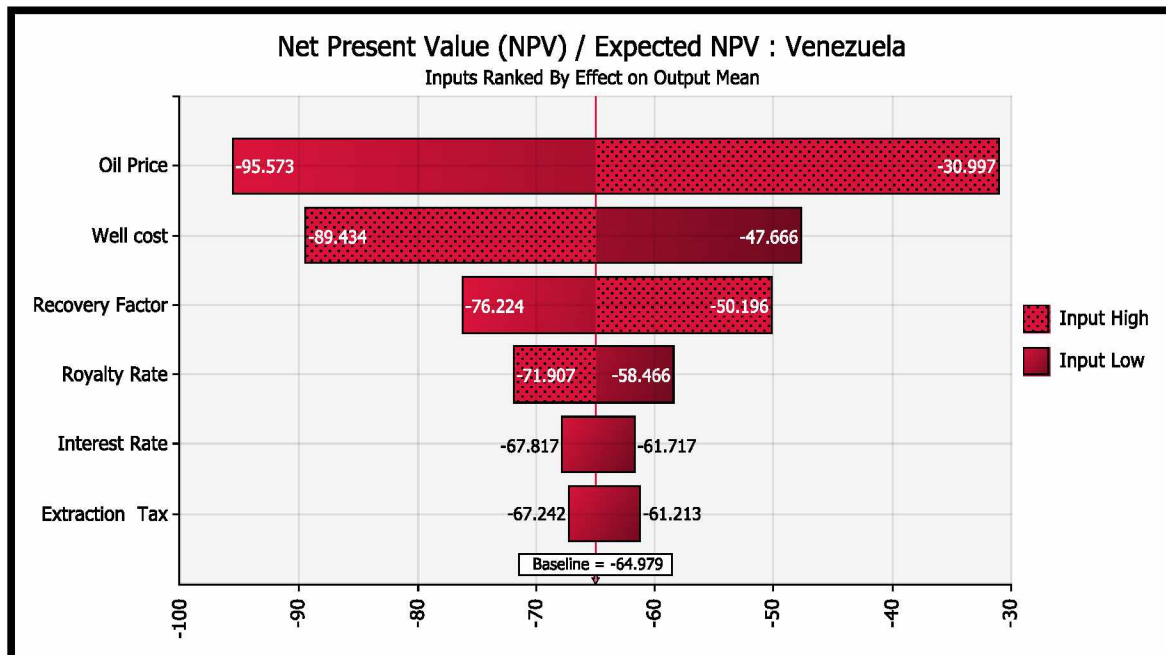
Figure 69. Sensitivity of NPV Tight Oil Development in Venezuela to key Modeling parameters

Results for Tight Oil Development Project on 640/acre in Libya
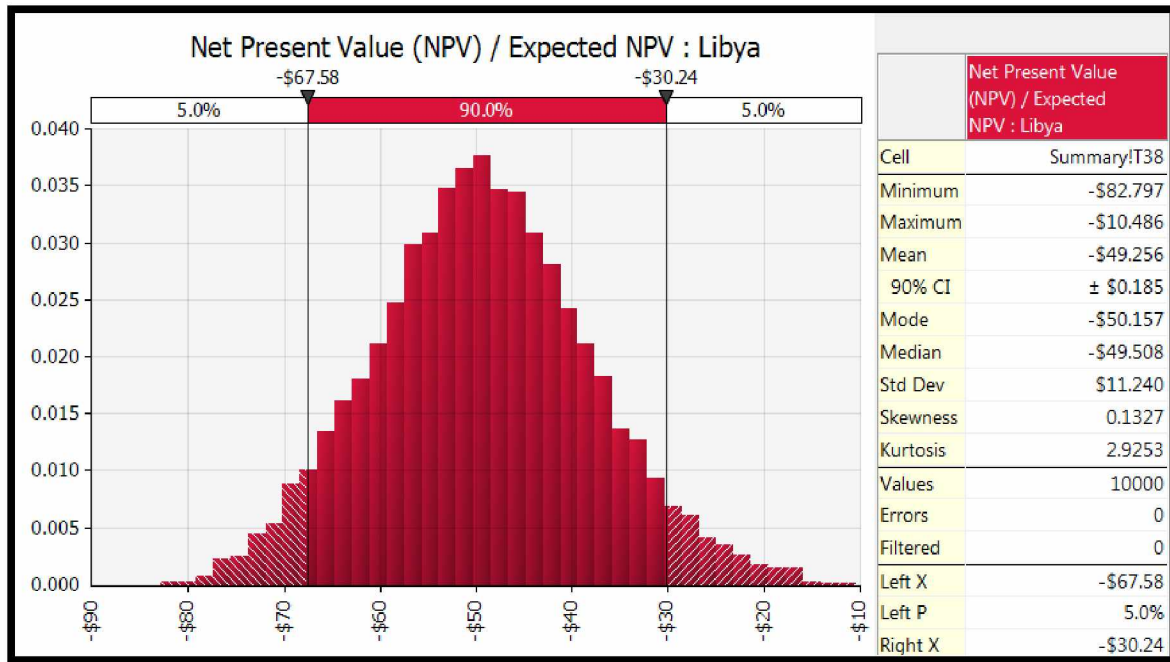
Figure 70. Net Present Value Distribution of Tight Oil Development Project in Libya
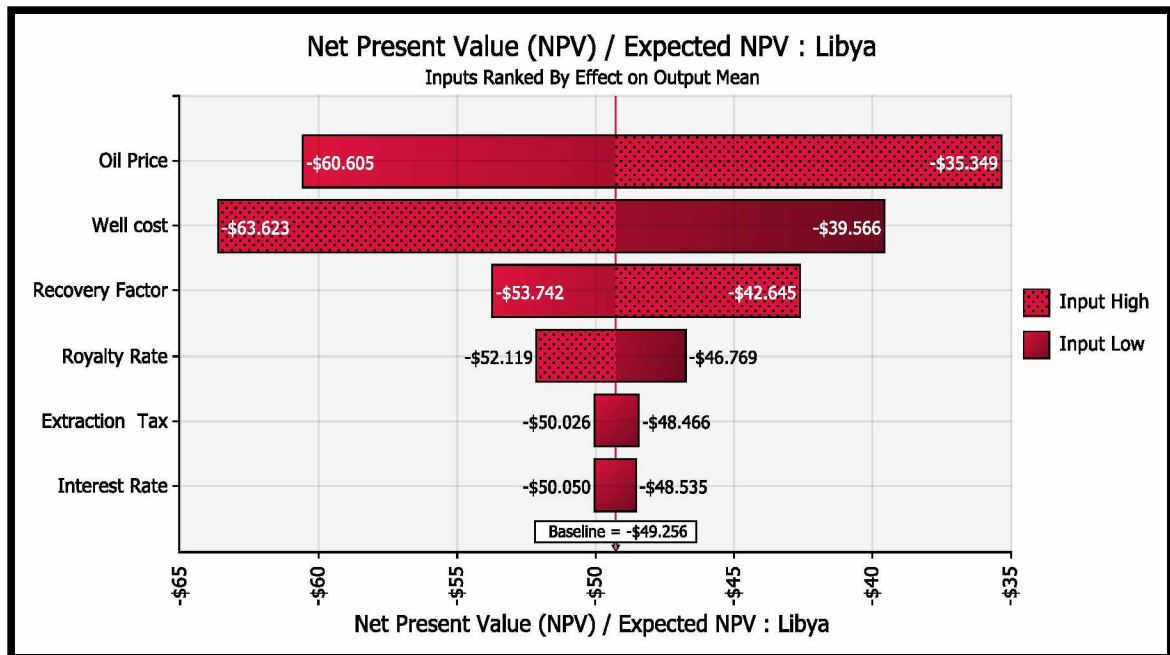
Figure 71. Sensitivity of NPV Tight Oil Development in Libya to key Modeling parameters

Results for Tight Oil Development Project on 640/acre in Colombia
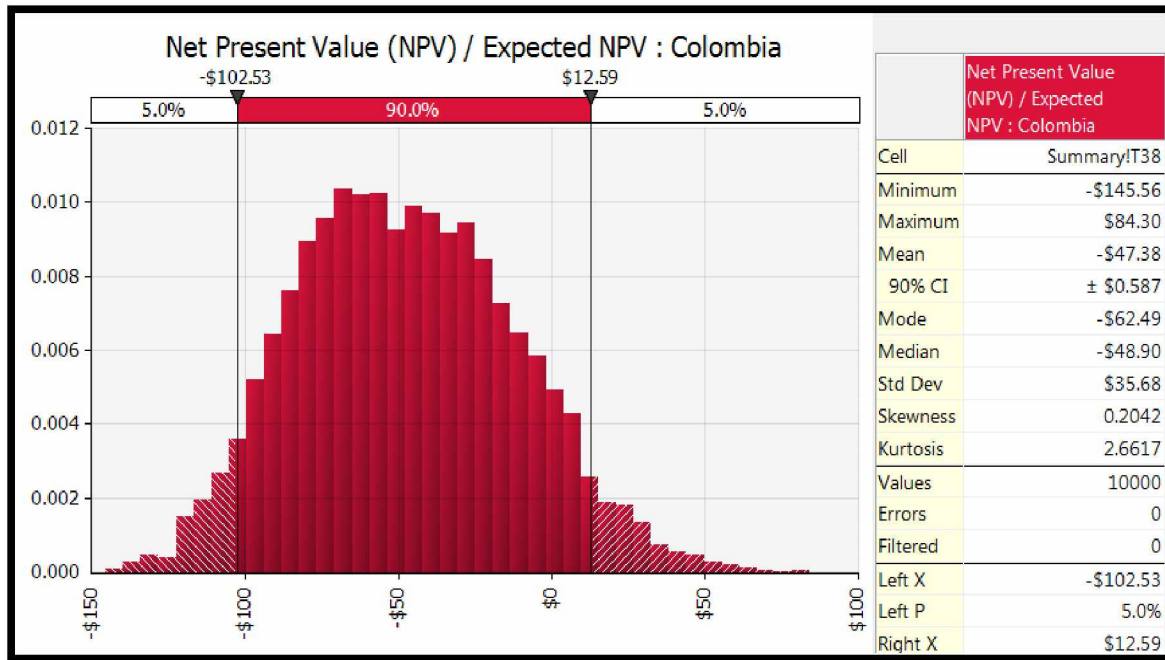
Figure 72. Net Present Value Distribution of Tight Oil Development Project in Colombia
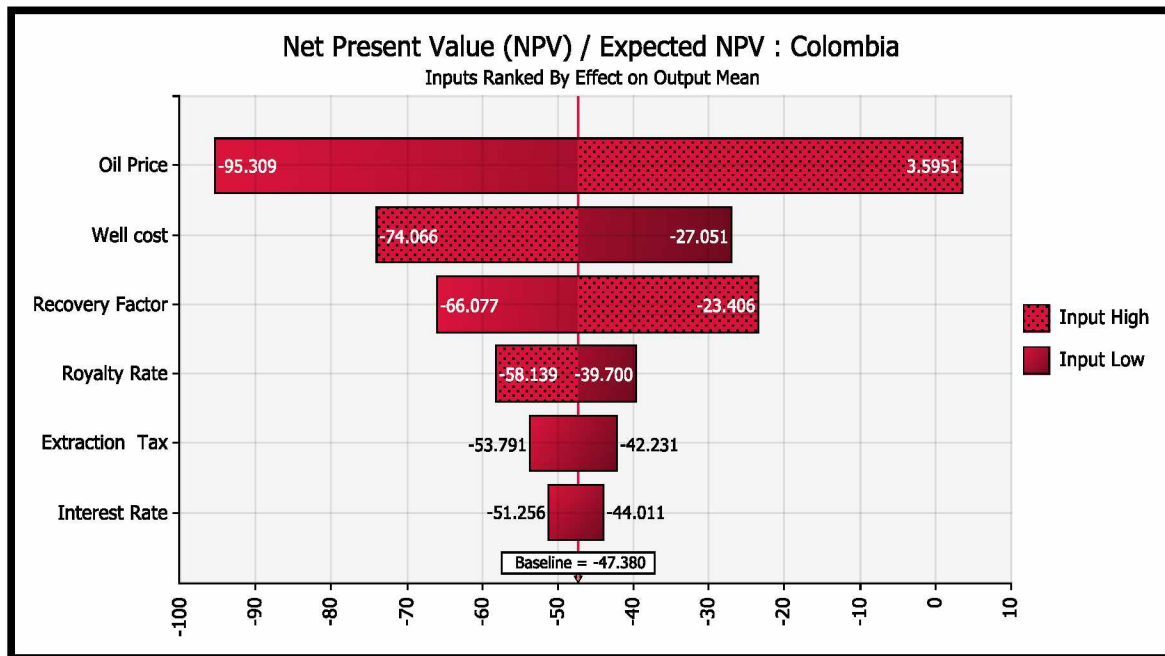
Figure 73. Sensitivity of NPV Tight Oil Development in Colombia to key Modeling parameters

Table 24. Non-U.S. Tight Oil Plays Ranked by Economic Viability

Province	Mean NPV ($millions) @oil price of $55	Rank of Parameter to NPV sensitivity (Rank of 6 being the most influential parameter)					
		Oil Price	Well cost	Recovery Factor	Royalty Rate	Extraction Tax	Interest Rate
Mexico	2.13	6	4	5	3	1	2
Argentina	-2.8	6	4	5	3	1	2
China	-8.7	6	4	5	3	2	1
Russia	-12.2	6	5	3	4	2	1
Indonesia	-15	6	5	4	3	1	2
Canada	-18.2	6	4	5	3	2	1
Pakistan	-19.1	6	5	4	3	2	1
Colombia	-47.4	6	5	4	3	2	1
Libya	-49.3	6	5	4	3	2	1
Venezuela	-65	6	5	4	3	1	2

Table 25. NPV Range for Non-U.S. Tight Oil Plays

Tight Oil Province	P05 NPV ($millions)	P50 NPV ($millions)	P95 NPV ($millions)
Russia	-29.0	-12.1	3.5
China	-47.6	-9.7	34.0
Argentina	-36.9	-4.0	35.0
Libya	-67.6	-49.5	-30.2
Colombia	-102.5	-48.9	12.6
Venezuela	-104.7	-66.1	-22.8
Mexico	-24.6	1.0	31.5
Pakistan	-36.4	-18.7	-3.6
Canada	-30.2	-17.4	-8.9
Indonesia	-36.8	-15.7	8.3

This assessment shows that only the tight oil development in Mexico proved to be economic in the mean case (Table 24). The tight oil asset development in Mexico has the Eagle Ford as an

analogue, with a well length of 7000ft which is shorter and cheaper than wells in the other plays. Cash flow from investments in Mexico also apply a discount rate of just over 7% which is quite comparable to U.S. or Canadian discount rates at say 5% to 6%. Capital acquired at higher interest rates would make this development uneconomic. Other geological advantages of this development, such as good rock quality, are also highlighted. With a recovery factor of 5.9% predicted by the U.S. EIA/ARI (2013) study for a play like this, it takes just five wells to recover oil in this one square mile development as opposed to twice the well count in a tight oil play like Indonesia. As a result of highly productive U.S. Eagle Ford analogue, competitive capital cost, shallower and less expensive wells, this development rises to the top as the most economically prospective non-U.S. play.

Other formations that still show negative NPV although ranking high among the plays assessed include Argentina, China, and Russia (Table 24). The range of NPV values from all the plays assessed show that seven plays show a positive NPV at the 95th percentile (Table 25). This suggests that there is a 5% chance that those investments turn a profit under the parameter ranges applied.

In addition, the ranking of factors that most affect the economic viability of projects in the different plays is a noteworthy finding. Oil price remains the most influential factor for economic viability of tight oil plays, followed mostly by well cost (Table 24). This result underscores the contribution of oil prices in kick-starting tight oil development in the US. The influence of well costs is also remarkable. The possibility of very high cost of drilling in frontier regions and regions with fewer rigs or drilling service and the impact of these factors on cost of drilling is seen here as quite influential to tight oil asset development economics. The total cost of wells also increases as a result of the number of wells required to develop a 640-acre asset, and recover the volumes predicted by the EIA/ARI (2013) study. Productive wells, represented by analogue type wells from the best U.S. plays, like the Bakken, Eagle Ford or Permian would require fewer wells to recover the oil resource identified as recoverable for individual 640-acres in the tight oil region. A low quality tight oil formation will require more wells to develop the same resource than a better quality tight oil formation, resulting in a less profitable development.

Across all the tight oil plays assessed, the cost of capital and extraction tax rate show the least impact on NPV. While this is the case, it is worth noting that regions with higher cost of capital like Venezuela and Libya are shown to rank low among the tight oil plays assessed. This factor becomes more significant on the results of assets in Colombia and Venezuela because this analysis assessed the same oil play developed on different sides of the Venezuela-Colombia border. The difference in the NPV of both results stems only from the cost of capital for both nations. While this assessment shows that the mean NPV is negative for both locations, the high case result is positive for Colombia, showing a 5% chance of a profitable venture. It is worth noting that under the best economic scenario, represented by our P95 case, the cost of capital for investments in Venezuela generates over $30 million less net revenue compared to the same investment in Colombia. This result highlights the importance of a favorable investment climate and its impact on the cost of capital and profitability of tight oil developments.

On the other hand, tight oil plays like the Duvernay shale in Canada, with favorable low cost of capital, showed that recovery factor is a bigger driver than oil price for some assets. The result for the Duvernay shale in Canada is an unexpected result because the economic prospectivity of this is shown as poor, contrary to its positive development factors such as attractive well cost, cost of capital and well productivity. Despite the favorable well cost resulting from shallower formation and good rock quality analogous to the U.S. Eagle Ford, the lack of resource density appears to harm the economic viability of this play. The EIA/ARI (2013) report shows this play to have a recoverable resource density of 0.4MM/640-acre which is just approximately 10% of the recoverable resource density in the Vaca Muerta shale in Argentina. Because of the small volume of resource within the development acreage, this development is not assessed to be able to carry the development cost or turn a profit and is uncompetitive within the fiscal system and other assumptions of this analysis. A region with low resource density portends that much costlier wells or a very widespread development would be required to develop any significant resource.

3.9.6.   Conclusion

The economic analysis of non-U.S. tight oil developments considering sub-surface and above ground characteristics show that a project's economic viability depends on a combination of factors. While the typical approach of engineering focuses more on aspects of the subsurface and productivity of the tight formation, I have examined above-ground characteristics of a play, such as cost of capital in assessing the viability of tight oil developments.

The fiscal system under which this assessment was carried out is also critical to the results obtained. This simplified version of a fiscal system uses a gross tax and not a net profit tax system, like some other states or sovereigns may employ. This gross tax system deducts production and severance taxes from the gross revenue of operators at the well head, even before the operator recovers their costs incurred in operations and development. On the other hand, the net profit tax deducts the same taxes only after the operators' costs have been taken out. This gross tax fiscal system as applied here also excludes other explicit credits and other incentives applied by some sovereign states. While this system is simple to administer and understand, opponents of the gross tax system contend that it does not do enough to share in the changing costs during field development. For a field with low ongoing maintenance costs, already developed, where fewer new capital costs are incurred, it may work well, as the operators' gross revenue is not much reduced by major cost items. But this is different for a frontier tight oil field trying to attract initial capital investments in its resource. Other sovereigns in non-U.S. tight oil plays, still have the option of adjusting their tax systems to tilt the economic assessment results shown, to achieve broader national mineral development goals.

This study relied heavily on a 2013 report by the U.S. Energy Information Administration and Advanced Resources International that detailed 137 non-U.S. plays. The report was mainly geo-technical and did exclude the economic prospectivity of the said plays. This analysis, therefore, contributes to the ongoing effort of searching for new frontiers of tight oil development by applying a framework that integrates well costs, based on play characteristics, and analogue production profiles to areas without tested production and conditions that determine investment capital. While the engineering efforts to develop analogue well productivity is not new, or geological attempts to use formation properties in doing same exist, an attempt towards a

comprehensive assessment that merges components of: (1) analogue formation determination through scaled indices, (2) well profile determination, (3) well cost determination, and (4) capital cost assessment to produce an economic viability assessment for projects is a major contribution of this work. As the search for more affordable energy continues, these factors will shape the discussion and analysis for the next big non-U.S. unconventional play.

Chapter 4. CRUDE OIL PRICES AND U.S. TIGHT OIL PRODUCTION: ECONOMIC PERSPECTIVE

4.1.   Introduction

The U.S. tight oil revolution provides a framework for understanding the impact of oil prices on tight resource development. This framework has been shaped over the last decade beginning with a growing interest in tight oil and gas development in the early 2000s, through the economic downturn of 2008-2009 and high oil prices in 2011 through the first half of 2014, and the oil price crash beginning in the fourth quarter of 2014 through 2016. Because the structural changes in tight oil and gas development seem to be more continuous than of discreet clear-cut periods, it is always a challenge to gain full insight into the workings of the industry within the framework of a slice of time. Yet, the cycle of high points and low points in tight oil and gas development experienced thus far provides some framework within which future changes could be understood. Also, insights gained from this cycle could serve as a template for new tight oil plays within and outside the US.

This chapter investigates the impact of oil price on development activities in four tight oil plays within a data analysis and econometric framework. This section of the research tests for the relationship between crude oil prices, drilling rig counts, and oil production in the major U.S. tight oil plays. Given that these formations are not uniform or in themselves homogenous, the research hypothesis put forth here is that those differences in the plays could be more clearly traced by their response to swings in key variables that characterize the industry's macroeconomic changes, such as oil price and drilling rig count.

4.1.1. Candidate Plays for Oil Price Impact Assessment: Selection by Drilling Target

According to the EIA (2016d), 92% of all oil and gas production growth in the U.S. between 2011 and 2014 are traceable to production in seven major U.S. plays. These are the Bakken, Eagle Ford, Permian, Niobrara, Haynesville, Marcellus, and Utica plays.

The oil and gas servicing company, Baker Hughes Inc. provides data on rig counts for drilling activities within North America and internationally. This data is demarcated based on rigs drilling for oil and gas well targets. With this breakdown, it is possible to identify the primary resource target in different plays. An assessment of the number of rigs targeting oil and gas production drilling in the major plays shows that rigs in the Williston basin plays (Mainly the Bakken formation and some Three-forks formation wells), Permian plays, Eagle Ford play and Niobrara play typically target oil production (Figure 74; BHI, 2017), while rigs in the Utica, Marcellus and the Haynesville plays drill primarily gas targets (Figure 74). This implies that the development activities within these three plays typically target the production of dry gas and wet gas (gas reservoirs containing oil of high API gravity), or in a few cases, crude oil. Plays whose symbols lie above the straight line in Figure 74 are those in which at least two oil wells are drilled for each gas well that is drilled. The four tight oil plays Bakken, Permian, Eagle Ford and Niobrara become the focus of this analysis on the relationship between oil price, rig count and oil production variables.
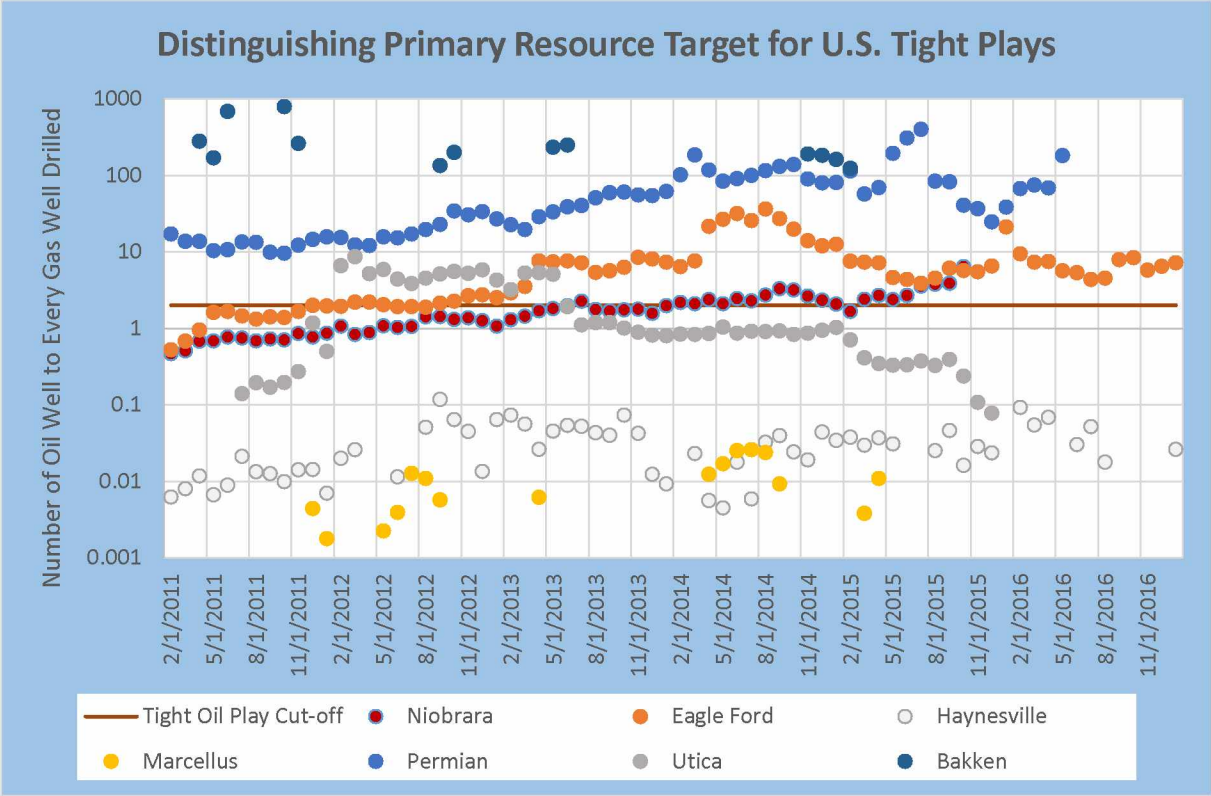
Figure 74. Tight Play Type Selection (Haynesville, Marcellus, Utica shown as primarily gas Plays; BHI, 2017)

4.1.2. Econometric Assessment of Oil Price Impact on U.S. Tight Oil Development

The level of oil production within a region is a key indicator of the impact of oil industry macroeconomics (mainly oil price) on industry activity in that region. Besides oil price, another major indicator is the number of drilling rigs operational in oil development regions. The rig count is a significant indicator of oil industry activity because it informs oil servicing companies of the trend of demand for products used in drilling and completing wells (BHI, 2016a). In response to the oil price slump in 2014, global rig count dropped by 20% and U.S. rig count dropped more than 50% since May 2015 through most of 2016 due to unfavorable oil prices (BHI, 2016b). This slowdown in drilling activities also signaled a withdrawal of several companies from development activities, layoff of oil field workers, reduced corporate capital budgets and spending cuts, and bankruptcy filings. According to Haynes and Boone LLP (2017)

161

over a hundred oil and gas firm bankruptcy filings have occurred since 2015, four months after the precipitous fall in oil prices.

The geologic and well cost differences of the Bakken, Niobrara, Permian and Eagle Ford plays have been discussed in previous sections. It remains to be seen how each of the plays fared throughout the price cycle and whether there are any lessons to be learned This section presents an econometric analysis of oil price on tight oil activity and production in the four tight oil plays. The goal of this section is to assess whether the uniqueness of different plays translates to observable differences in the impact of oil price on rig count and oil production. This will improve understanding on how development strategies respond to price fluctuations and highlight the impact of the uniqueness of tight oil plays on the survival of companies that participate in them. This should provide value to decision makers in the oil industry and other stakeholders in the development of tight play resources in the US. The insights gained from U.S. plays could have global implications. As stakeholders in non-U.S. plays advance decisions on how best to develop their resources, the lessons learned from U.S. plays, during high and low oil price cycles, will be valuable to their own frontier plays.

The impact of oil price on oil plays is investigated within an Auto Regressive Distributed Lag (ARDL) cointegration framework, using time series data from four tight oil plays in the US: Bakken, Eagle Ford, Niobrara, and Permian. The ARDL regression method analyzes variables in a multivariate regression equation including lags of the dependent and independent variables. This is an appropriate method to analyze the interaction within oil and gas industry because it allows the analyst to assess the relationships across variables while considering potential lags in such relationships. This is important because there are often technical lags among oil and gas industry variables, for example, delays are inevitable between well drilling, when rigs are required, and completion of wells, first production and reporting of production data. Also, operators' response to the commercial climate may not be immediate. This makes the ARDL approach a fitting one to test for relationships without losing potential lags.

It is also important to understand the character of the variables being used and to ensure that an appropriate model is employed for the analysis. To produce valid conclusions, results from most

regression models rely on the use of stationary variables (Duke University, n.d -a). Stationary variables are variables whose means and variances are constant for the entire length of the time series data (Duke University, n.d -a). Additionally, stationary time series easily lend themselves to forecasting since past behavior is likely to predict future performance and it's always possible to regain the raw data, even if the forecasting process required the historical data to be transformed by some mathematical operation (Duke University, n.d -a). Stationary variables could be used with ordinary least square methods (Duke University, n.d -a). However, often, it is also challenging to determine the character of a data series whether it is stationary or not. And applying ordinary least square methods on nonstationary data may lead to the observation of false relationships and statistically invalid conclusions (Duke University, n.d -a). This is where the ARDL model comes in handy; the ARDL method allows the analyst to test long term cointegration relationships among variables whether they are stationary or not (Pesaran & Shin, 1999). The benefit of a successful test of cointegration of variables is that it shows that the variables have a stable, long term relationship, which is the basis for reliable conclusions.

For this research, the following two broad questions are evaluated across all U.S. plays: what is the impact of oil price on tight oil production? And what is the impact of oil price on drilling activity in tight oil plays? Answering these questions will yield more insights into the nature of U.S. tight oil plays and these insights could be transferred into the development of analogue plays in other tight oil regions around the world.

4.1.2.1. Data

To investigate the impact of oil price on tight oil production and rig activity, the following variables were selected: (1) oil price, represented by the West Texas Intermediate crude oil price, (2) tight oil production in each play, and (3) rig count in each play provided in drilling productivity reports that are published by the U.S. Energy Information Administration (EIA).

1) Oil Price Data

The West Texas Intermediate price data was derived from EIA data sources (EIA, 2016f). This price benchmark represents crude oil spot prices as traded in Cushing Oklahoma, which is the nation's biggest oil hub for crude oil storage and sales. The natural logarithm of oil price was determined and used in the analysis. The logarithm of raw data also has the advantage of making exponential trends more linear and "stabilizing the variance" observed in data (Duke University, n.d -b). The logarithm smoothening effect is also observed because on a log scale, fewer data points in time series data go beyond an order of magnitude in difference from previous data points. The natural log transform was also applied to allow for a form of econometric model that answers the question on the elasticity of price on production or rig counts (Greene, 2008).

2) Tight Oil Production Data

Tight oil production data was derived from the EIA drilling productivity reports (DPR) (EIA, 2017e). The EIA provides tight oil production data at the regional or geographic level and also at the geologic formation level to track changes in subsurface targets drilled by operators over the same area (EIA, 2014e). In the event where, for example, two oil plays are stacked one on the other, DPR reports for production at the geographic level for a county, for instance, show production data from both stacked formations as being from the same play, while geologic production data reports differentiate production from separate geologic tight oil formations (EIA, 2014e).

To the extent that operators will produce from all zones intersected by the well, where overall recovery and economics support such decision, the regional data aligns with production from all the composite formations within an area. On the other hand, when geologic formations cross county lines into counties with mainly non-tight oil production, aggregating production data based on geographic or county level production will miss that production from the formation that sprawls outside the county. While aggregating data based on the geologic formation level will follow the formation into whatever county it goes. For this reason, tight oil data aggregated at the geologic formation level was preferred for this analysis. This is also seen in a comparison between geographic and geologic data sets which show almost identical production profiles except for the Permian play which contains a mixture of conventional and unconventional stacked plays (Figure 75).

In arranging the data for this analysis, tight oil production was tallied for all the four plays. The Permian play, being a composite play, showed oil production data segregated into the Bonespring, Spraberry, Delaware, Yeso & Glorieta tight formations from the EIA (EIA, 2017e). For the Permian play only, all subplay production data was rolled up to represent the total tight oil production in the Permian.
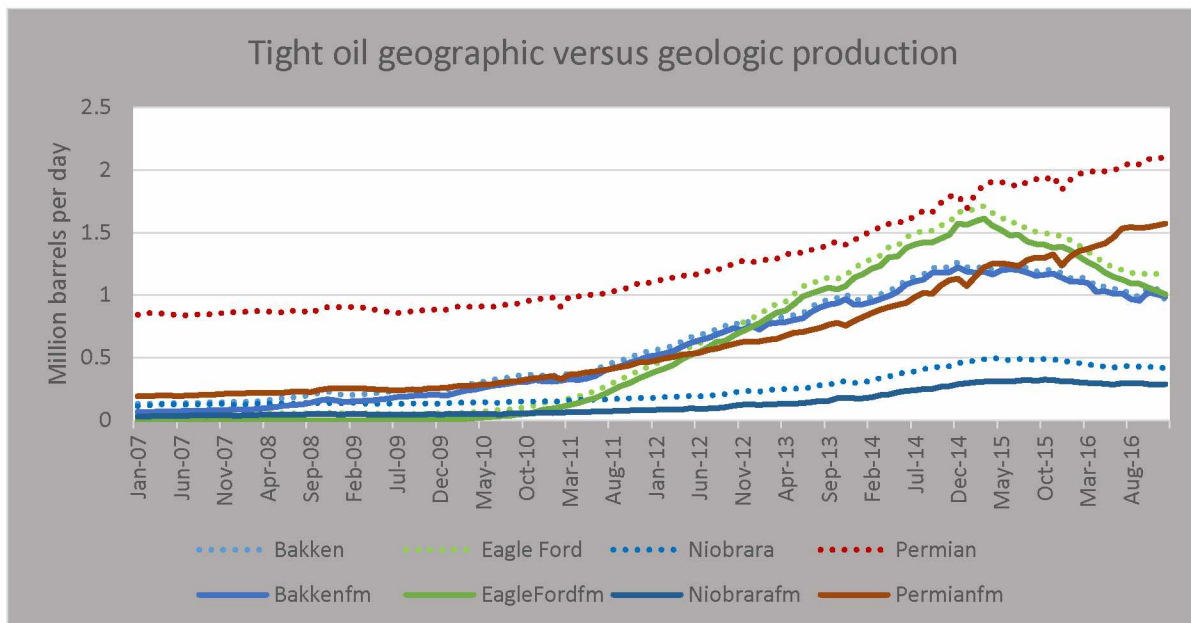
Figure 75. Oil production from tight oil regions compared to production from specific tight oil formations(fm) (EIA, 2017e; EIA, 2017t).

3) Rig Count Data

Rig count data was derived from the EIA drilling productivity reports (DPR). This report tallied rig counts based on whether those rigs are located in 'tight oil development counties' rather than whether they targeted just the tight oil zones in those counties. Because these counties are primarily producing tight oil, this rig count data is presented by the EIA as rig count for tight oil regions in the US. A natural log transform was applied to rig count data as well to honor the integrity of the model functional form meant to answer the question on elasticity of price on production and on rig counts.

The DPR report also observed that rig count is more closely correlated with production data with some lag estimated to run for months (EIA, 2015g).

The count of drilling rigs in a play highlights the pulse of the macroeconomic environment because of the ancillary services that relate to rig count. Since drilling always precedes oil production, rig count is a leading indicator of oil production and is expected to correlate with oil production with a lag. This lag is determined by the time it takes to drill, which depends on the requirements of a play and the selected well architecture. It is also influenced by the time it takes to hydraulically fracture the well, to put it on production and to report that data to the state agencies, at what time it becomes available to the EIA reporting system. Several other industry dynamics affect the relationship and lag between rig count and oil production.

Another phenomenon that has grown in significance in the last few years, which affects the relationship between rig count and oil production data is that of an artificial economic/strategic delay in producing a well due to a delay in hydraulically fracturing the well in times of low oil prices. This has led to a backlog of drilled but uncompleted wells in the major oil plays (EIA, 2016l). As a result of this phenomenon, a drilling rig leaves its location several months before production associated with that well is recorded. This situation creates a long lag time that could mask or even breakdown the relationship between rig count and oil production. For this reason, a six-month lag was imposed on all variables to increase the chance of capturing the relationships between oil price, production. and drilling.

4.1.2.2. Analysis Questions, Models and Methods

In order to determine the relationship among production, rig count and oil price variables, the ARDL model was used. An extra binary variable was applied to capture the atypical price plunge which started in the fourth quarter of 2014. An appropriate functional form had to be selected to best answer the study question, which is: how does changes in oil price affect oil production in the Bakken, Eagle Ford, Permian, and Niobrara plays? Since rig use is associated with oil production, rig count was also included as a second independent variable in the regression equation. The second question investigated is: what is the impact of oil price on drilling activity? Drilling rig count is used

as a proxy for drilling activity. Since all the research questions border on the elasticity of these variables with respect to one another, the log-log model form of equations was selected (Greene, 2008). As a result, the natural log of the dependent (explained) and independent (explanatory) variables was determined because using this form allows U.S. to understand the elasticity of the explained versus the explanatory variables, and to answer the following question: what percentage change occurs in the explained variable in the event of one percent change in an explanatory variable, controlling for other explanatory variables and other unknown factors (Greene, 2008). Below are the equations developed for the questions being investigated.

For the question on the impact of oil price and rig count on tight oil production in each play, the following model was postulated:

$$\ln pro_t = a + b \ln P_t + cRC_t + dDUM + \varepsilon_t \tag{22}$$

And for the question on the impact of oil price on rig count in each play, the next model postulated is as follows:

$$RC*_t = a + b \ln OP_t + cDM + U_t \tag{23}$$

where pro_t is the tight oil production in a U.S. play; P_t (OP_t) is crude oil price using the West Texas Intermediate price (WTI) as benchmark price, RC (RC*) represents rig count in a play and ε_t (U_t) is the error term, which represents all other factors affecting tight oil production (Equation 22) and rig count (Equation 23) that are not explicitly stated in the equations. DUM (DM) is a binary dummy variable that represents the impact of the massive price drop that occurred starting from the fourth quarter of year 2014. Months Oct 2014 through Dec 2016 carry a dummy variable of 1 and all other months carry a dummy variable of zero. Equation 22 investigates the effect of oil price (P_t) and rig count on tight oil production. Equation 23 investigates the impact of oil price (OP_t) on drilling activity levels using rig count as proxy. This equation also uses the oil price dummy (DM) to capture specific impacts on rig counts due to the oil price plunge that began in the fourth quarter of 2014.

If increasing oil prices lead to increases in oil production in a tight oil play, the oil price coefficient, b, in equation 22 will be positive, and if it leads to a drop in production, this coefficient will be negative. And if increasing oil prices lead to increase in the rig count in a tight oil play, the oil price coefficient, b, in equation 23 will be positive and if it leads to a drop in rig count, this coefficient will be negative. The magnitude of coefficient b in every play will provide a comparison for responsiveness of different plays to oil price within the study time frame.

Equations 22 and 23 are equations to determine long run responses of oil production to changes in the independent variables. In estimating using an Auto-regressive Distributed Lag (ARDL) approach, it is necessary to include the short-run adjustment process into both equations. This approach modifies the equation into an error correction format, which then yields both short run and long run effects of the independent variables on the dependent variable (Pesaran et al., 2001). When the short run components are added, Equation 22 and 23 now become:

$$\Delta \ln PRO_{i,t} = a + \sum_{k=1}^{n1} b_k \, \Delta \ln PRO_{i,t-k} + \sum_{k=0}^{n2} c_k \, \Delta \ln P_{t-k} + \sum_{k=0}^{n3} d_k \, \Delta \ln RC_{i,t-k} + eDUM_t$$

$$+ \, \theta_0 \ln PRO_{i,t-1} + \, \theta_1 \, lnP_{t-1} + \, \theta_2 \ln RC_{i,t-1} + \, \xi_t$$

$$(22^*)$$

$$\Delta \ln RC^*_{i,t} = a + \sum_{k=1}^{n1} b_k \, \Delta \ln RC^*_{i,t-k} + \sum_{k=0}^{n2} c_k \, \Delta \ln OP_{t-k} + dDM_t + \, \theta_0 \ln RC^*_{i,t-1}$$

$$+ \, \theta_1 \, lnOP_{t-1} + \, U_t$$

$$(23^*)$$

The equations 22* and 23* contain the first-differenced variables (Δln variables) and the short-run dynamics are captured by their coefficients b_k, c_k, and d_k. The long run effects are determined by the estimates of θ_0, θ_1, θ_2. The price variable in these equations is now represented by the notation P, and rig count is represented by RC.

Unless the model variables are cointegrated, whatever estimated coefficients derived are likely to be spurious (Greene, 2008). For this reason, Pesaran et al. (2001) recommended a two-step method in ascertaining that these coefficients are reliable. An F-test is used to test the joint significance of the lagged variables (t-i) and the test statistic from the F test is compared against two critical values, an upper bound and a lower bound value, depending on whether the model variables are stationary (I(0)) or nonstationary (I(1)). Since nonstationary variables must test above the upper critical value, while stationary variables need to yield an F-statistic above the lower bound, an F-statistic that is above the upper bound is a conservative test that ensures that whether the variables are stationary or not, the cointegration that is observed is valid (Umekwe & Baek, 2017b). Hence, if the F-statistic is greater than the upper critical value, we ascertain that the cointegration equation is valid, whether some of the variables are stationary or not.

Additionally, equation 22* (23*) was investigated for symmetric effects of oil price on tight oil production (rig count) following techniques established in the literature (Bahmani-Oskooee & Bahmani, 2015; Umekwe & Baek, 2017a; Umekwe & Baek, 2017b). Symmetric impact of oil price on production suggests that if a rise in price leads to an increase in production, a fall in price should lead to a proportionate drop in production. And symmetric impact of oil price on rig count suggests that if a rise in oil price increases rig count, a fall in oil price should lead to a symmetric fall in rig count. To test for symmetric effects, two more time series variables were created from the WTI oil price variable (lnP_t and $lnOP_t$; cumulative sum of negative and positive partial differences forming two separate series according to technique used by Shin et al (2014). To generate these series, first, we subtract oil price at time t-1 from oil price at time t to generate a series of negative and positive first difference values. Next, we sum the positive first differences separately from the negative first differences to construct cumulative partial sums of the positive and negative first difference values such that for positive series and negative series, lnP_n ($lnOP_n$) is largest (i.e the most positive) or smallest (i.e the most negative) respectively, as follows:

$$POS_t = \ln P_t^+ = \sum_{j=1}^{t} \Delta \ln P_j^+ = \sum_{j=1}^{t} \max(\Delta \ln P_j, 0) \qquad (24)$$

$$\text{NEG}_t = \ln P_t^- = \sum_{j=1}^{t} \Delta \ln P_j^- = \sum_{j=1}^{t} \min(\Delta \ln P_j, 0) \tag{25}$$

where $\ln P_t^+$ and $\ln P_t^-$ are the first differences in oil price while POS_t and NEG_t (PS_t and NG_t) are the partial sums of positive and negative changes in $\ln P_t$ ($\ln OP_t$). With these two variables, Eq. (22) then becomes:

$$\Delta \ln PRO_{i,t} = a' + \sum_{k=1}^{n1} b'_k \, \Delta \ln PRO_{i,t-k} + \sum_{k=0}^{n2} c'_k \, \Delta \ln POS_{t-k} + \sum_{k=0}^{n3} d'_k \, \Delta \ln NEG_{t-k}$$

$$+ \sum_{k=0}^{n3} e'_k \, \Delta \ln RC_{i,t-k} + f'DUM_t + \theta_0 \ln PRO_{i,t-1} + \theta_1 \ln POS_{t-1}$$

$$+ \theta_2 \ln NEG_{t-1} + \theta_3 \ln RC_{i,t-1} + \xi_t$$

$$\tag{22**}$$

and

$$\Delta \ln RC^*_{i,t} = a' + \sum_{k=1}^{n1} b'_k \, \Delta \ln RC^*_{i,t-k} + \sum_{k=0}^{n2} c'_k \, \Delta \ln PS_{t-k} + \sum_{k=0}^{n3} d'_k \, \Delta \ln NG_{t-k} + e'DM_t$$

$$+ \theta_0 \ln RC^*_{i,t-1} + \theta_1 \ln PS_{t-1} + \theta_2 \ln NG_{t-1} + U_t$$

$$\tag{23**}$$

The variables POS_t (PS_t) and NEG_t (NG_t) introduce nonlinearity into the short-run adjustment process making this ARDL model a nonlinear ARDL model (Umekwe & Baek, 2017b). We test whether the response of oil production to a rise or fall in oil price is symmetric or not, by comparing the coefficients of the variables POS_t (PS_t) and NEG_t (NG_t) for each play. If the coefficient of POS_t (PS_t) and NEG_t (NG_t) are different, we declare asymmetry; if not, we declare symmetry.

The nonlinear ARDL analysis was conducted using the IHS commercial software, Eviews version 9.0. This software also allows the analyst to conduct econometric analysis on time series data of

different frequencies using a variety of models which include the Ordinary Least Square (OLS), Autoregressive Integrated Moving Average (ARIMA), and Autoregressive Distributed Lag (ARDL) models among other models.

4.1.2.3. Results

A. Impact of Oil Price on Tight Oil Production

The results show the relationship among oil production, rig count and oil price over the period January 2007 through December 2016 using a nonlinear ARDL model. Six lags were imposed on the dependent and independent variables and the optimum model was selected using the Akaike Information Criterion (AIC). As part of the ARDL method, several equations are formed using different combinations of the level and lagged variables, and each of the equations yields an AIC value. The most optimal model selected is the model with the smallest AIC value (Eviews, 2016). Summary statistics from the tests conducted on this optimum model are presented and discussed in this section of the research.

Firstly, the effect of oil prices on U.S. tight oil production is assessed for the four plays: Permian, Bakken, Niobrara, and Eagle Ford, in the short run. And the effect of oil price changes on oil production is tested to establish if that effect is asymmetric or not. The estimated coefficients show that oil prices have significant short run impacts on oil production in all four plays except the Eagle Ford (Panel A, Table 26). For example, in the short run, a decrease in oil price leads to a significant fall in tight oil production in the Bakken. In addition to short run impacts of price on tight oil production, these effects were also tested to see if they hold true in the long run. For the long run, we observe that the variables POS and NEG show a significant coefficient for Bakken, Eagle Ford, and Permian plays, indicating that rise and fall of oil prices have a significant long run effect on tight oil production (Panel B, Table 26). In the Bakken play, for example, a rise (fall) in oil price has a positive (positive) effect on tight oil production. By comparing the significance and magnitude of the POS and NEG variables, we checked to see if the impact of oil price on tight oil production is symmetrical; if a decrease in price leads to a drop in production, does a rise in price lead to an equal rise in production? If the coefficients for oil price increases,

171

ΔPOS (POS) is equal to the coefficients of oil price decreases, ΔNEG (NEG), then we declare symmetry for the short run (long run) but if not, we declare asymmetry. In the short run, all the plays showed asymmetric effects of oil price on oil production. While short term rise in oil price showed a significant impact on oil production in just the Permian and Niobrara plays, this impact was not proportional when prices dropped, and except for the Bakken, in most cases the impact of a fall in prices was not even significant. This result was also similar in the long run; oil price impact on tight oil production was not symmetric. Generally, a rise in oil price showed an increase in oil production and a fall in oil prices did not show a significant decrease in oil production. For example, in the Bakken, a drop in oil prices showed just a slower increase in oil production.

Besides the impact of normal oil price fluctuations on oil production, the impact of the sudden fall in prices beginning from October 2014 was also investigated. The dummy variable for the oil price shock is not statistically significant for most cases in the short and long run, indicating that the recent collapse in prices of crude oil had little impact on tight oil production in all the plays, in both the short and long run, except for the Permian and the Eagle Ford plays. The price collapse shows a positive statistically significant impact on Permian oil production in the short run and long run, and a negative long run impact on oil production in the Eagle Ford play. This implies that oil production is observed to increase in the Permian play following the plunge in oil prices, while the impact of this price plunge was opposite for the Eagle Ford play.

Additionally, the effect of rig count on oil production was also investigated for the Bakken, Eagle Ford, Permian, and Niobrara tight oil plays. In the short run, rig count, RC is seen to have a positive and statistically significant impact in the Niobrara play. This implies that increasing rig count in the Niobrara play leads to an increase in oil production in the short run. And in the long run, rig count has a statistically significant impact on oil production in the Eagle Ford play. The long run coefficient is positive for the Eagle Ford, which implies that an increase in active rigs in the Eagle Ford play drives up tight oil production for this play in the long run.

Table 26. Full Information Estimates of Nonlinear ARDL Model describing the Impact of Oil Price on Tight Oil Production

	i = Permian	i = Eagle Ford	i = Bakken	i = Niobrara
Panel A: Short–Run Estimates				
$\Delta lnPRO_{i,t}$				
$\Delta lnPRO_{i,t-1}$	-0.34 (3.5)**	0.00 (0.05)		-0.38 (4.11)**
$\Delta lnPRO_{i,t-2}$	-0.30 (3.06)**	0.25 (2.97)**		-0.31 (3.24)*
$\Delta lnPRO_{i,t-3}$	-0.24 (2.54)**			-0.19 (2.02)
ΔPOS_t	0.00 (0.07)	-0.40 (0.64)	0.04 (0.71)	0.05 (0.56)
ΔPOS_{t-1}	-0.11 (2.20)**			-0.12 (1.42)
ΔPOS_{t-2}	-0.15 (2.87)**			-0.20 (2.26)**
ΔPOS_{t-3}	-0.12 (2.09)**			
ΔNEG_t	0.04 (1.2)	-0.03 (0.07)	-0.07 (1.80)*	0.02 (0.33)
ΔNEG_{t-1}				0.05 (0.73)
ΔNEG_{t-2}				0.14 (1.76)*
ΔNEG_{t-3}				-0.16 (2.39)**
$\Delta lnRC_{i,t}$	0.01 (0.18)	-0.51 (1.35)	0.06 (1.30)	0.09 (1.75)*
$\Delta lnRC_{i,t-1}$		0.87 (2.29)**	-0.11 (2.58)**	
DUM_t	0.05 (2.00)**	-0.15 (0.46)	-0.01 (0.33)	0.02 (0.48)
Panel B: Long-Run Estimates				
POS_t	1.09 (2.02)**	2.90 (3.23)**	1.61 (3.91)**	3.63 (0.71)
NEG_t	0.54 (1.07)	-0.45 (0.58)	0.75 (1.98)*	1.81 (0.48)
$lnRC_i$	0.33 (1.19)	0.78 (2.04)**	0.00 (0.03)	4.13 (0.84)
DUM_t	0.58 (2.29)**	-1.06 (1.89)*	-0.05 (0.22)	0.80 (0.7)
Constant	-2.87 (1.92)**	-13.41 (9.59)**	-2.75 (4.43)**	-21.15 (1.02)
Panel C: Diagnostic Statistics				
F	10.27	5.05	19.95	11.08
ECM_{t-1}	-0.04 (7.05)**	-0.27 (5.06)**	-0.07 (8.41)**	-0.01 (6.89)**
LM	0.05 [0.82]	0.03 [0.85]	0.10 [0.75]	0.10 [0.75]
AdjustedR^2	0.19	0.20	0.34	0.28
CS (CS^2)	S(S)	S(S)	S(US)	S(S)

Notes: Numbers in the parentheses are absolute values of t-statistics. ** and * indicate statistical significance at the 5% and 10% levels, respectively; The upper bound critical values of the F-test for cointegration at the 10% and 5% levels are 3.20 and 3.67, respectively; LM is the Breusch-Godfrey serial correlation test and is distributed as χ^2 with one degree of freedom. The critical value for the chi-squared distribution is 3.84 at the 5% level and 2.70 at the 10% level. Numbers in the brackets are p-values.

The validity of the above results rests on the assumption that our variables are cointegrated, that is, there is actually a long-term relationship between the variables. In the absence of such cointegration our results are likely spurious and the conclusions flawed. To test for this, the F-test or Bounds Test was conducted and the F-statistic compared against the upper bound limit for a 10% critical value (Umekwe & Baek, 2017b). At the 10% critical level, the lower bound critical level is 2.37 and the upper bound critical level is 3.2. Pesaran et al. (2001) showed that to

be safely above the higher bound proves cointegration whether or not some variables are I (1) or I (0). The F test statistics in Panel C (Table 26) provide evidence to show that these results are valid. The 10% critical value is 3.2 and for all the plays studied, we exceed this value (5.05 - 19.95). This shows that our variables are cointegrated, i.e. there is a long-term relationship between these variables.

The error correction term (ECt-1) is part of ARDL models that are classified as Error Correction Models (ECM), and this term indicates how fast our variables adjust towards a long run equilibrium (Greene, 2008; Umekwe & Baek, 2017b). This error correction term, to be effective at allowing our model variables to converge towards an equilibrium, needs to be negative and statistically significant (Greene, 2008). A positive term indicates that perturbations to this system lead these variables to diverge without returning to an equilibrium. The value of the coefficient measures the speed with which the model adjusts to equilibrium after any disturbance (Baek, 2015). For example, the ECt-1 coefficient for the Eagle Ford (Bakken), -0.27 (-0.07) indicates that adjustment toward long run equilibrium occurs at a speed of ~30% (7%) per month. This means, it takes approximately 3 (14) months (that is, $1/0.3 = ~3$ months; $1/0.07= ~14$ months) in order to erase the impact of any shocks in the Eagle Ford (Bakken) play.

Other statistics of note are derived from tests conducted to establish the absence of serial correlation, stability of the model and to judge goodness of fit (Umekwe & Baek, 2017b). The Lagrange Multiplier (LM) test tests for serial correlation or the validity of the standard error calculated, and by extension allows U.S. to validate the significance of the coefficients we have determined (IHCs Inc., 2015a). In performing this test, the null hypothesis is that the residuals in our model are not serially correlated. If the residuals are serially correlated, then the significance test of our coefficients is suspect and unreliable. The Lagrange Multiplier (LM) is shown to be distributed as χ^2 (chi-squared) with 1 degree of freedom. At 1 degree of freedom on the chi-squared distribution table, the 5% critical value is 3.84 and our LM statistics are statistically insignificant for all the plays. Since the LM statistics are not statistically significant, we cannot reject the null hypothesis, and our model is confirmed not to be serially correlated. Our estimated coefficients are also shown to be stable through the cumulative sum (CUSUM), and cumulative sum of squares (CUSUMSQ) tests (Table 26).

B. Impact of Oil Price on Rig Count

Next, we consider the effect of oil prices on drilling activities in the different plays. For the short run, the estimated coefficients show that a rise in oil prices, represented by ΔPS, and fall in prices, ΔNG impact rig counts in all the plays (Panel A: Table 27). And the differences between the coefficients of ΔPS and ΔNG show that there is short term asymmetry; rig counts do not rise in response to oil price increase and fall proportionately in response to falling oil price. In several plays, there is no significant response due to rise or fall in prices.

For the long run, we observe that oil price impacts all tight oil plays significantly except for the Niobrara, where that impact is not statistically significant (Panel B: Table 27). For example, in the Bakken play, controlling for other factors, a rise in oil prices leads to an increase in rig count and a fall in oil prices still leads to a rise in rig counts, albeit a smaller increase. This also answers the question on long run symmetry; the response of rig count to oil price is asymmetric because rig count does not decrease in response to a drop in oil prices. However, the impact of the drastic fall in oil prices, represented by the dummy variable, shows that although slight decreases in price had still kept rig counts rising in the Bakken, the price crash of Q4 in 2014, DM_t had a significant negative impact on rig count.

Table 27. Full Information Estimates of Nonlinear ARDL Model describing the impact of Oil Price on Rig Count

	i = Permian	i = Eagle Ford	i = Bakken	i = Niobrara
Panel A: Short–Run Estimates				
$\Delta lnRC_{i,\,t}$				
$\Delta lnRC_{i,\,t-1}$	0.40 (5.4)**	0.25 (2.85)**	0.40 (4.26)**	0.20 (2.18)**
$\Delta lnRC_{i,\,t-2}$		-0.04 (0.38)	-0.13 (1.30)	0.09 (0.97)
$\Delta lnRC_{i,\,t-3}$		0.00 (0.02)	0.20 (2.02)**	0.13 (1.42)
ΔPOS_t	0.05 (0.54)	0.11 (0.72)	-0.06 (0.44)	
ΔPOS_{t-1}			0.24 (1.87)*	0.12 (0.88)
ΔPOS_{t-2}			-0.19 (1.49)	0.00 (0.02)
ΔPOS_{t-3}				-0.47 (3.39)**
ΔNEG_t	-0.12 (2.01)**	-0.24 (2.02)**	-0.11 (1.29)	-0.11 (1.07)
ΔNEG_{t-1}	0.20 (2.81)**	0.23 (1.70)*	0.03 (0.33)	0.04 (0.38)
ΔNEG_{t-2}	0.21 (2.95)**	0.19 (1.38)	0.20 (1.93)*	0.55 (4.75)**
ΔNEG_{t-3}	0.06 (0.85)	0.21 (1.54)	0.04 (0.42)	0.08 (0.69)
DUM_t	-0.01 (0.21)	0.02 (0.31)	-0.04 (0.82)	0.05 (0.94)
Panel B: Long-Run Estimates				
POS_t	0.66 (1.86)*	1.69 (3.62)**	1.18 (1.92)*	-0.09 (0.08)
$NEG_{t,}$	0.31 (0.86)	1.08 (2.30)**	0.85 (1.45)	0.09 (0.09)
DUM_t	-0.47 (1.50)	-0.75 (1.55)	-1.30 (1.93)*	-0.40 (0.52)
Constant	5.35 (16.13)**	3.33 (8.11)**	4.18 (5.16)**	5.51 (4.35)**
Panel C: Diagnostic Statistics				
F	11.39	5.02	3.52	5.20
ECM_{t-1}	-0.06 (6.42)**	-0.07 (4.31)**	-0.05 (4.11)**	-0.05 (5.00)**
LM	0.03 [0.86]	2.53 [0.11]	0.10 [0.76]	0.45 [0.50]
$AdjustedR^2$	0.77	0.46	0.65	0.55
$CS\,(CS^2)$	S(S)	S(US)	S(S)	S(S)

Notes: Numbers in the parentheses are absolute value of t-statistics. ** and * indicate statistical significance at the 5% and 10% levels, respectively; The upper bound critical values of the F-test for cointegration at the 10% and 5% levels are 3.20 and 3.67, respectively; LM is the Breusch-Godfrey serial correlation test and is distributed as χ^2 with one degree of freedom. The critical value in the chi-squared distribution is 3.84 at the 5% level and 2.70 at the 10% level. Numbers in the brackets are p-values.

4.1.2.4. Discussions

Permian

The Permian play, with conventional and tight oil targets, is among the most prolific oil plays in the United States, and this play has a unique character in its response to oil price fluctuations. The impact of oil price change on this play is observed in the short run and long run. Results from our econometric analysis show that in the short run, controlling for other factors, a rise in oil prices has a negative impact on oil production. And in line with other tight oil plays, in the long run, a rise in oil price has a positive impact on Permian tight oil production. And a fall in oil prices shows an insignificant impact on tight oil production in this play. However, the oil price crash in Q4 2014 has a positive impact on oil production in the Permian play both in the short run and long run. Also, a rise in oil price is seen to have a positive effect on rig count in the long run.

These results point to one fundamental trait of the Permian play: its character as a 'backbone play' or fallback play for many operators. In the short run, our results suggest that in response to higher prices, operators move out of this play in preference for more profitable tight oil plays elsewhere, such as the Eagle Ford or the Bakken. This is also evidenced by the higher response (coefficients) in oil production for the Eagle Ford (2.90) and Bakken (1.61) plays to increasing oil prices compared to the Permian play (1.09). However, when oil prices crashed since the fourth quarter of 2014, as represented by the dummy variable, tight oil production in the Permian play increased. This could be for several reasons. The stacked plays of the Permian provide a mix of conventional and unconventional targets that attract investments from other plays to this play, and allows for well completion designs to target multiple zones. The increased focus on the conventional targets in this play, which require lower cost well stimulation operations, provide operators the opportunity to generate better returns while improving their understanding of the geology of the play, setting themselves up for even much better margins as prices rebound. Evidence to the pursuit of slightly more conventional formations within the Permian stacked formations is seen in the fact that, at the heart of the low oil price periods, the Permian play had most of the vertical wells operational within the US. Vertical well types are typically still found

profitable in conventional rock types while prohibitively marginal or uneconomic for unconventional tight oil development.

Another less obvious reason for this character of anchoring development and production on this play is the impact of leasing commercial arrangements and the impact of wells drilled in the Permian on proved and contingent reserves of operators. According to Toon (2016) leasing contracts in the Permian insist on operators actually producing from the acreages they wish to maintain ownership in, rather than just drilling wells. And tight oil production consumes disproportionately more capital in stimulating the wells prior to production than actually drilling. For this reason, depending on whether an operator is a new entrant in the basin or not, they had to prioritize capital spending into fulfilling the leasing contracts and bringing their acreages to production. And since the unconventional development in the Permian is more recent than other plays, e.g. the Bakken and the Eagle Ford, most operators who had assets in this play had to shift capital into investments here (Toon, 2016). Secondly, the presence of several rock formations that could be targeted is a major attraction for development and company potential future drilling activity. Unlike the Bakken and Eagle Ford that are less than 300ft thick each, the Permian formation gross thickness exceeds 3000ft. As a result, even when the cost of drilling a well in the Permian equals the same development in the Eagle Ford, the ability to book the petroleum reserves in adjacent horizons in this stacked play as potential future targets improves the valuation of operating companies (Toon, 2016). For this reason, operators would want to develop assets in the Permian play. While existing literature allude to this character of the Permian through observation of industry activity, this research presents evidence within a theoretically-sound framework of the character of this play and the behavior of operators in response to the geology of the play.

Eagle Ford

The Eagle Ford play is another major play in the state of Texas that has seen rising production through the last decade. The impact of oil price change on this play is observed in the short run and long run. Results from our estimated models show that in the short run and long run, oil prices have a significant impact on production in this play. The impact of oil price in the long run

in the Eagle Ford is not symmetric; while a rise in prices shows a strong positive response in production, a fall in prices shows a weaker negative response in oil production and this response is not statistically significant when we control for other factors. Controlling for the oil price crash and general trending in this play, the Eagle Ford play showed the strongest positive response of tight oil production to oil price, among all the plays studied (Panel B, Table 26). One percent increase in oil prices corresponds to almost three percent increase in production in this play. This result suggests that operator strategy in this play is nimble as producers seem to react to changes in the market environment more closely; oil production rises sharply with oil price increase and as oil prices plunge, rig addition slows down and oil production reduces.

Additionally, the Eagle Ford play also shows the biggest response in rig count due to increase in crude oil prices. Comparing the production and rig count response of this play to oil price increase against the same response in other plays studied, offers some insights into well productivity as well, and potentially on profitability. The Eagle Ford shows the biggest productivity gain per rig added. The geology of this play potentially offers further understanding into the behavior of operators here. Eagle Ford rocks are carbonate-rich and respond well to hydraulic fracturing leading to sharply rising production in response to new wells that are drilled and completed during high oil prices. In the absence of high prices to sustain the cost of expensive hydraulic fracturing of the wells, it is plausible that operators will back off expensive wells leading to a drop in production. Our results also show that the drastic fall in prices lead to a fall in production in the Eagle Ford (Table 26). Even when the drop in prices just reduces the number of rigs added in this play, the fall in production that results, suggests that low oil prices reduced the number of wells completed in this play significantly, thus impacting oil production. This implies that total cost of wells in this play is still high especially due to the cost incurred in well completions (stimulation through hydraulic fracturing).

The presence of a busy corridor of pipelines, pipeline infrastructure, and oil and gas expertise and servicing industry in the Texas area also has an impact on production levels in this play. With several producers, pipelines and refineries, Texas is the closest picture of a perfect market for oil and gas activities. It follows therefore that the reaction time for players in this part of the

world is quick enough to cash in on opportunities and withdraw from negative market signals ever more flexibly.

Bakken

The Bakken play is an example of a U.S. play born primarily from tight oil, horizontal wells, and hydraulic fracturing. The impact of increase and decrease in oil prices over the 2007 through 2016 timeframe on oil production was mild for this play. Our results show that oil production increased much slowly in response to a drop in oil prices in the long run (Panel B, Table 26). Since a rise in oil prices led to a rise in oil production and a fall in oil prices did not show a proportionate decrease in production, we conclude that the impact of oil price on oil production in the Bakken is asymmetric.

Unlike tight oil plays in Texas, the Bakken has more shale rocks with poorer quality than the thick Permian rocks with conventional pockets, and is more remote than the well-connected plays such as the Eagle Ford of Texas. Wells in this play require hydraulic fracturing and are drilled deeper and longer than most other tight oil wells, resulting in higher overall costs. This makes a stronger case for operators to react to negative market signals and decrease drilling activities as prices drop, leading to reduced production. But this was not observed in our analysis. Our results do not show a reduction in production in response to fall in oil prices but instead a reduction in oil production growth. Also, we observe a statistically significant reduction in well count in response to the oil price crash since Q4 of 2014 (Panel B, Table 26; Panel B, Table 27). Another characteristic that keeps this play productive is the high pressure observed at geologically deeper rocks as is observed in the Bakken. This over-pressure leads to higher oil production in Bakken wells for a longer period before gas production impedes further oil productivity.

Purdy et al. (2016) report that most operators in the Bakken held non-producing acreage at the time oil prices plunged in 2014 and were bound by lease terms to bring those leases to production. For the many producers who had hedged production at this time with oil prices over $90/bbl, such as Continental Resources, Inc. with vast acreage holdings in the Bakken, it was possible to continue drilling at contractually held oil prices (Continental Resources, Inc., 2014).

For example, Continental Resources, Inc. used fixed swap prices to ensure it received oil prices as high as it had hedged, paying out the swap seller if prices went higher, and used collar contracts to ensure prices didn't go lower than a floor price, its breakeven price for some projects (Continental Resources, Inc., 2014; EOG Resources, 2017a). In that way, it would receive make-up funds for oil prices that went below its projected price or make payments if prices were better than it had locked in. For operators who applied this strategy for reducing exposure to oil price fluctuations, it would be economical to spend in stimulating wells that were already drilled prior to the price plunge and bringing them to production, and drill wells in undrilled acreage to maintain ownership of those resources. But for other producers who had started developing in this play earlier and already had production in their acreages, they could deploy drilling capital in other plays they had to keep, such as the newer tight oil plays like the Permian (Toon, 2016). This is shown in the fact that rig count in the Bakken dropped significantly in response to the oil price plunge, while oil production loss was not significant. Since this play is among the most mature of U.S. tight oil plays, with less running room, drilling activities were more focused on other upcoming plays.

On the other hand, the statistically significant drop in rig count and the absence of a statistically significant reduction in oil production still points to potential mechanistic reasons tied to the longevity of this play as a tight oil producer. The Bakken play is a mature play and has undergone more cycles of oil price fluctuations than most other tight oil plays. A plausible reason contributing to the absence of a significant reduction in oil production in response to the price plunge is that, while similar oil price levels were experienced in the wake of the 2009 economic recession, that period was not a focus of the investigation of the impact of the oil price plunge. This is because the change in oil prices was in the context of a general recession in the U.S. and the global economy. The focus on the more recent price plunge (assignment of dummy variable of 1 to only that period) and neglect of a period with similar, albeit less drastic price plunge (2009 period maintaining the dummy variable of 0), in an oil play that experienced both periods more fully, could lead to the observed results. This research focused more on the recent price plunge and not the others because of the structural differences in the economy across both periods.

Niobrara

The Niobrara play, located in the DJ Basin in Colorado and Wyoming, contributes the least production among the four plays studied. Analysis of this play produced mixed results that, in most cases, were not found to be statistically significant. While there is a visible change in oil production in this play, this change was not found to be statistically significant in the long or short run periods. A plausible reason for this result is the mixed strategy of operators; oil and also significant gas targets are pursued for development in this play. This implies that oil price alone may not significantly explain development or behavior of operators in this play, in terms of how rigs are deployed or productivity of the play in general. Mixed development well results, lack of sufficient oil transportation infrastructure to improve the economics of development, and a comparatively high first year decline rate for Niobrara play wells may also be reflected in the undefined response of operator activity within this play (Crowe, 2013).

4.1.3. Summary: Oil Price and Tight Oil Development

This section has discussed the tight oil revolution in the U.S. with a focus on the impact of oil price on operator activity and tight oil production. By discussing development trends in key U.S. plays, as seen through the oil industry data, this work points to the potential impact of oil price on other non-US plays that are studied further in this research. Through a detailed look at the production, price, and rig count data, which are easily obtainable from public sources, this research has produced a framework for assessing other plays, using methods that are broader than those techniques available to the geoscientist, petroleum engineer or other subsurface scientists.

Building on the last chapter this section has also shown that interrelated segments of the crude oil system in the U.S. are important in understanding the impact of new technology or major shifts in the oil industry. Understanding, for example the link between the oil industry and financial system could enable the analyst see the impact of oil price hedges, the availability of midstream infrastructure on the presence or absence of observable production response to price swings.

This analysis has also shown that oil price affects oil production. And that impact of price on production is not always symmetric across or even within plays; some plays are more susceptible to price movements and shocks than others. Oftentimes, a rise in oil prices could lead to production responses that are not eroded even when prices fall. This is especially possible due to efficiencies that some plays develop which enables them to weather minor price shocks. Another reason is that, besides typically drilling a new well, there are several components of oil production sustenance or enhancement that could be justified at different price points, such as different scales of refracturing operations, partial recompletions or artificial lift projects which are outside the scope of this research. And where possible, those are the first steps taken to maintain productivity during low price environments before the move to drill new wells.

Drilling rig count constitutes an important metric in understanding price impact on production. This is shown in the pace at which rigs are added or taken out of plays in response to price movements. This relationship between rig count and price is also made more complex due to lags in production and production reporting. Also, the practice of delayed completion of wells dims the correlations between rig count and production. The reaction time of operators in different plays is reflective of the geology and productivity of the plays, and the impact of these properties on the breakeven prices of plays.

Key findings of this section are as follows:
- Oil and gas activity provides a trail of data that can yield insights into operator behavior and the valuation of assets in different plays, which is best appreciated within an interdisciplinary framework.
- Oil price is important to operator decisions and tight oil development activity levels within the US, and this holds true for upcoming tight oil plays in other places.
- Oil price impacts oil production in a different way for every play based on geological and above-ground (facilities infrastructure) dynamics.
- Commercial terms governing mineral leases and how they are developed are important in oil and gas development decisions.
- Even the same operators who own assets in different plays will react differently based on the unique characteristics of the plays in which they operate.

While this section has discussed the impact of oil prices, regulations set the rules and guidelines around which oil and gas operators operate. The next section will discuss the next two questions of this research. Firstly, what are some environmental legislations involved in oil and gas development in the U.S. and what are the environmental policy implications of tight oil development? After a review of the environmental implications surrounding tight oil development, the groundwork will be laid for delving into the next question: where else around the world could tight oil development lessons be applied? And what is the economic viability of developing similar resources in those other global locations?

Chapter 5. GOVERNMENT ENVIRONMENTAL REGULATIONS AND U.S. TIGHT OIL PRODUCTION: ENVIRONMENTAL PERSPECTIVE

5.1.   Introduction

Tight oil development in the U.S. has contributed significant benefits to local and state economies through employment, taxes, renewed manufacturing and service industries across the country. Of 15 active tight oil plays across the nation tracked by the EIA, the Eagle Ford and Bakken have contributed approximately 35% of total tight oil production from 2000 through 2016 (EIA, 2017e). In 2013, the oil and gas production from mainly the Williston basin was estimated to contribute $43 billion to the North Dakotan economy (North Dakota State University, 2014) and the impact of the Texas Eagle Ford shale to the economy of 20 counties was estimated at over $25 billion (UT San Antonio, 2012). The positive impact of the U.S. tight oil boom could also be seen in increased national oil production and decreasing reliance on oil imports. Despite these benefits, many have called to question the impact that tight resource development has on the environment because of the significant environmental footprint of hydraulic fracturing.

Pearce and Turner (1990) summarize these negative impacts of economic activity as external cost or negative externality, resulting in a loss of welfare to those who suffer from it, such as those who are impacted by the noise, dust or air pollution, or higher housing costs due to tight oil development. If external costs are valued and compensation granted for the harm suffered by society, they become internalized in the business and the economic benefits of projects become appropriately adjusted. To the extent that social costs are not included in the overall economics of a project, the net present value derived from the assessment of project profitability does not reflect the true net benefit of the activity. The social costs associated with a development also depend on the environmental policy in play and how much right to pollute it accords the polluter or those external to the market who suffer from pollution (Pearce & Turner, 1990). The pareto optimal production level is that level of production which yields the level of revenue sufficient to

attract investment in a venture, and appropriately compensate those who suffer from loss of welfare because of the same activity (Pearce & Turner, 1990).

Pareto optimal tight oil production levels could be achieved by elevated activity and oil production that will produce huge benefits that cover all costs related to the activity levels, or limited activity levels that will reduce the footprint of tight oil production while producing sufficient revenue to make the venture profitable. For example, this reduced level of production in tight oil development translates to less truck traffic, less water demands for fewer tight oil wells. A restriction of number of wells drilled or completed under the direction of such policy could mean reduced profitability for an asset and in some cases totally eradicate activity. For example, if the economies of scale benefits enjoyed by a seven well pad is reduced by a policy that leads to three wells drilled in that pad, the cost per well is increased, eroding profitability of the overall asset. For a small independent oil and gas firm, this loss in profitability could be the difference between sourcing high-interest capital to complete a project or missing out on options for financing the development of an asset.

Issues raised with respect to tight oil development include the following: (1) produced water management, (2) freshwater depletion, (3) fresh surface and underground water pollution, (4) methane gas pollution, and (5) traffic and noise pollution. This chapter is divided into four parts. The first part discusses the environmental issues involved in tight oil and gas development. The second part reviews a few U.S. environmental laws. The next part presents case studies on two tight oil development regions and local initiatives in place to address these environmental concerns with tight oil development. The fourth part is a cost assessment for different tight oil wastewater management options.

5.2. Environmental Externalities from U.S. Tight Oil Development

The United States experienced its largest oil production growth in a century in 2014 due, in large part, to a tight oil development boom across the country (EIA, 2015g). Tight oil production has shaped conversations around U.S. resource development and energy policy, oil industry job

creation and oil and gas outlook beyond the next decade. This new chapter of oil development is different from any other previous oil development cycle in that the resource being developed is mainly unconventional, which requires significant investment and environmental disturbance. This level of environmental disturbance is driven by the need for hydraulic fracturing. This section discusses some of the environmental issues experienced due to U.S. tight oil development.

5.2.1.   Freshwater Depletion

Water use in hydraulic fracturing is among the central environmental issues regarding tight resource and shale development operations. Tight oil wells in the Eagle Ford and Bakken shale plays use approximately 4 to 5 million gallons of water for hydraulic fracturing (Allen, 2013; Schmidt et al., 2015). The average shale gas well uses more water, estimated at 5 million gallons, for drilling and completion (Energy4me.org, n.d). Prior to the record years of shale oil drilling in 2013 and 2014, estimates of water used in hydraulic fracturing for 2012 ranged from 52 to 80 billion gallons of water, which constituted less than 1% of total water use in the U.S. (EPA, 2016a). Mostly freshwater is used for hydraulic fracturing due to the high cost of treating produced water of different chemistries, the negative impact of fine suspensions and the risk of spilling large volumes of stored produced water on site (Schmidt et al., 2015). As a result, just 5% of fracking water is reused, with some variation across oil plays, and far less water reuse noted in the Permian and Eagle Ford and other areas with many disposal wells (EPA, 2016c).

While stakeholders who are interested in water conservation do question this massive water use, others see tight oil and gas water consumption as quite small when compared to other uses, or when compared to the benefits resulting from oil and gas production. According to Energy4me.org (n.d), an educational initiative program by the society of petroleum engineers, this water use accounts for less than 1% of water demand in most shale regions and 5 million gallons of water used by a shale gas well constitutes water use within a 12-hour period in a typical coal-fired power plant. And compared to energy produced by other operations, shale gas produces 1 million BTU of energy for every 3 gallons of water use, compared to 11 gallons for nuclear power and 23 gallons for coal-fired power plants (Energy4me.org, n.d).

5.2.2.　　　Produced Water Handling

Produced water constitutes approximately 99% of oil and gas industry wastes (American Petroleum Institute, 1997). With an increase in hydraulic fracturing since the 2000s, flowback water after each hydraulic fracturing operation could constitute a significant portion of produced water, especially in the first days of production. The Permian basin produced over 330 million barrels of water every month for the first half of 2016 (Jacobs, 2016). According to Slutz et al. (2012), approximately 10-40% of hydraulic fracturing water is produced as flowback water. And as a result of this massive volume of water following hydraulic fracturing, approximately 30-40% of water production over the ten-year life of a well is produced in its first year (Jacobs, 2016). After the surge of water produced in the well's early life, the rest is produced later alongside oil and naturally existing compounds throughout the life of the well.

Over the low oil price period of 2014 through 2017, oil operators have accumulated thousands of drilled but uncompleted wells which, if brought to production quickly following a recovery in oil prices, would bring with it significant water management challenges (Jacobs, 2016). Jacobs (2016) added that the wider problem is already evident in maturing plays like the Permian play, where oil makes up just a sixth of all liquid production.

Besides the problem of reduced revenue due to the production of water instead of oil, which is more valuable, water handling after production is a major problem not experienced in the days of conventional oil production. Unlike developments in conventional plays, where produced water could be quickly reinjected for secondary recovery purposes, the low permeability in tight oil plays takes away this option for water handling, leaving operators with the costly option of trucking water to farther disposal wells or for treatment. According to Jacobs (2016), because of insufficient understanding of these new tight oil plays and a hasty chase for geologic sweet spots, tight oil development was not strategic in most fields and failed to properly consider water management challenges, as is done in conventional oil development programs. As a result, even in low oil price periods, with all the challenges in raising capital, operators are turning to options like water-reuse and water trucking for disposal at costs of $100 per truckload per hour, while

advancing more sustainable solutions through small-scale treatment, pipeline constructions (Jacobs, 2016).

Besides the cost and logistical inconvenience of produced water handling, the risk in massive produced water handling involves the potential for spills. The surge of water handled over a short period brings with it the risk of errors especially for new developers within an oil and gas play.

5.2.3. Process Safety and Ground Water Contamination

Some aspects of shale development have been a cause for concern from members of the public. Among these concerns are issues on health effects due to unconventional resource production operations such as the composition of hydraulic fracture and flow back fluid, the safety of underground freshwater sources, air pollution from volatile organic emissions and issues like the noise from drilling operations (Shonkoff et al., 2014). There is also the concern of potential health impacts of exposure to silica from huge sand quantities used during fracturing and the possible elevated levels of naturally occurring radioactive material (NORM) from post-fracturing flow back fluids (Finkel & Hays, 2015). In addition, a review of contents of hydraulic fracturing fluid shows that some compounds in fracturing fluids are hazardous.

The drilling and completion process uses several barriers to ensure that oil and gas is contained within the hydrocarbon-bearing zone typically located thousands of feet below groundwater zones. The oil well is drilled past these shallow water zones and the use of steel casings cemented in place keeps the produced petroleum within the casing until it is produced.

The EPA (2015a) estimates that 20,000-30,000 wells hydraulically fractured annually from 2011-2014 were mostly fractured less than a mile from 6,800 water sources which provided water to 8.6 million people. While the potential for contamination was high, the EPA found very few instances where contamination occurred, thanks to a combination of factors that ranged from well casing and cementing best practices to insufficient water baseline data collection (EPA, 2015a). Finkel & Hays (2015) also echoed the EPA's conclusion that the insufficiency of reputable published work that employed acceptable epidemiological study designs including baseline disease prevalence, exposed and control groups, clinical documentation of health

189

outcomes and exposure pathway, made it difficult to establish definitively the occurrence of health problems as a result of oil development activities.

5.2.4.   Water and Mineral Rights Disputes in Tight Oil Development

Land and water rights issues also bedevil tight oil development in the US. Examples of mineral right doctrines that guide common law issues surrounding mineral and surface estates include the implied easement of reasonable use, accommodation doctrine, and rule of capture (Allen, 2013). These doctrines are invoked in disputes involving oil mineral rights and the ownership of water rights (surface or underground) for use in tight oil activities. Often, ownership of surface rights is dissociated from ownership of mineral rights. The idea of implied easement of reasonable use affords the owner of a mineral right the associated surface right (including groundwater) except where stated explicitly in the oil and gas lease or mineral deed (Allen, 2013). Under this doctrine, the owner of surface rights could still sue for damages if surface use is excessive or wanton.

The doctrine of accommodation, simply put, ensures that both the surface rights and mineral rights owners accommodate each other and tolerate minor inconveniences that come with shared ownership (Allen, 2013). Allen (2013) argued that, while the mineral right owner has a right to the surface estate to develop his resource, this doctrine ensures that he acknowledges and accommodates the surface right owner's pre-existing uses, especially when less intrusive alternatives exist to the mineral rights owner. The accommodation doctrine also protects the mineral right owner from unnecessary liability charges by the surface right owner, for minor inconveniences that mineral development might cause (Allen, 2013). While the theory of these doctrines may be simple to understand, proving levels of inconvenience, the ease of pursuing alternatives to make the doctrine applicable may be challenging and result in controversies in tight oil development in the US.

Another concept often discussed is the rule of capture. The rule of capture allows the owner of a groundwater well the right to use this resource as he sees fit without recourse to its impact on the

groundwater available to his neighbor, whose well probably flows from the same resource (Allen, 2013). Key limitations of this rule exist when use is wasteful, negligent or malicious and under the local authorities.

Other mineral rights disputes in oil and gas development include spacing of wells within leases and across segments of leases held by different owners. Some states mandate spacing and unitization rules for oil and gas development. These rules help to minimize potential issues that may arise in resource development. The private land royalty owner has the incentive of desiring maximum development within their acreage while for a state player, there is the incentive to discourage warehousing of acreage or the holding of undrilled or undeveloped portions of the lease. Where conditions of drill-to-keep or produce-to-keep exist in lease clauses, there is a motivation for the operator to quickly develop the acreage. For example, the State of North Dakota requires horizontal wells shallower than the Mission Canyon formation to be at most 320 or 640 acres apart and not more, but wells deeper than the Mission Canyon formation to be 640-acre or more (IOGCC, 2015). States like Colorado do not prescribe a specific size but allow the quarter of a lease that is accessed by the well to be included in the developed acreage (IOGCC, 2015). This is the same for the state of Alaska (AAC, 2017).

Jacobs (2017) reports of interwell communication due to infill wells and wells drilled too close to older wells, thereby reducing the ultimate recovery of older wells. Since tight rocks often need wells drilled much closer to ensure the acreage is sufficiently drained, some jurisdictions could allow for closer well spacings since the risk of draining resources from adjacent wells at farther distances is less with tight oil wells. The oil and gas operator, EOG reports of well spacings as low as 650ft in its operations in the Bakken, 660 in its Permian operations with plans of going down to 500ft (EOG Resources, 2017b). And well spacings in tight oil development have reduced from 1000ft in 2010 to 250ft in some extreme cases (Jacobs, 2017). Some states maintain set back rules to ensure resources of one lease owner are not drained from a neighboring lease. The state of Utah maintains that wells stay 660 feet from unit boundaries, the state of Indiana requires that wells stay 330 feet from unit boundaries while in other states similar rules are set based on the depth of wells (IOGCC, 2015). Overall, these rules are meant to reduce the incidence of conflict between mineral interests.

5.2.5. Hydraulic Fracturing and Seismicity

There have been reports of increased seismic activity in some areas in the U.S. as a result of tight oil development operations. Sovacool (2014) reported that some regions have experienced a sevenfold increase in seismic activity partially attributed to the onset of shale development activities. Boak (2017) showed striking correlations between the number of earthquakes in Oklahoma and underground water injection in the Aubuckle formation (Figure 76).
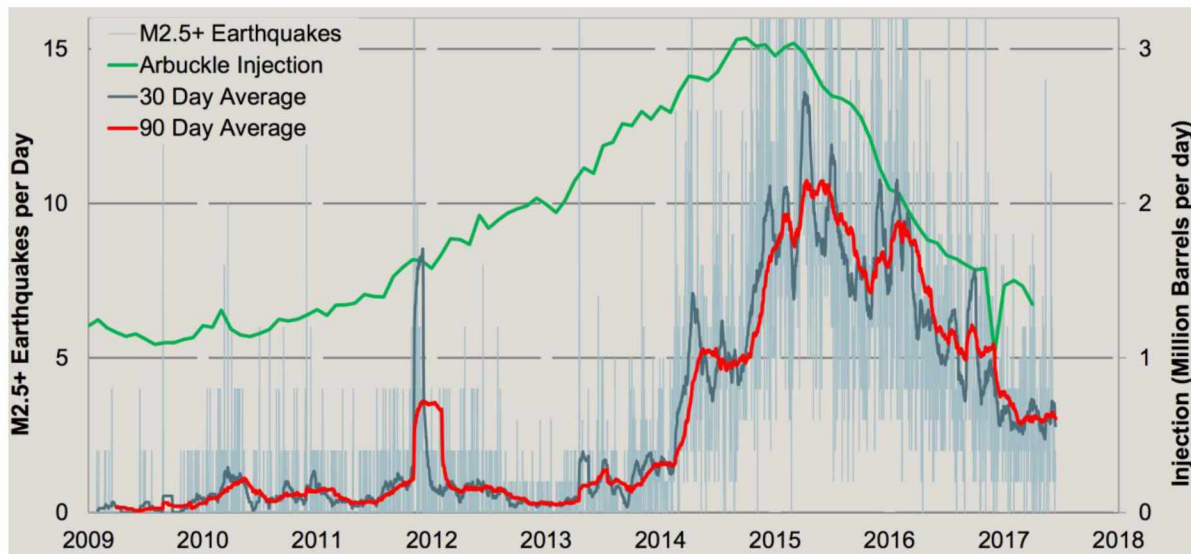
Figure 76. Seismicity and Underground Injection in Oklahoma (Boak, 2017)

In addition, diverse efforts have been made to understand the relationship between water injection and seismicity and to coordinate monitoring efforts. According to Rao (2014), for human activity to cause earth movements, underground injection of waste or produced water must introduce energy into an active fault, and the intensity of the movement depends on the length of such fault. He added that, except for very small faults, 3D seismic surveys conducted by oil exploration and production companies before drilling has helped oil operators identify and stay away from active faults.

Two types of industry development activity that often result in seismicity are during hydraulic fracturing and during water disposal. Rao (2014) noted that in the United Kingdom, microseismic surveys conducted to monitor seismicity during hydraulic fracturing operations

have shown mostly minor seismic events, with a few isolated events that recorded 2.5 on the Richter scale. Conversely, Rao (2014) noted that water disposal poses a greater concern on seismicity because it is more continuous. In addition to underground water disposal by operators who produce oil, some companies provide water disposal service only and collect water that is produced continuously from oil and gas wells from multiple operators. Several cases of increased seismicity in water disposal areas have been reported in the Oklahoma Mississippi Lime play (Jacobs, 2016).

The application of microseismic monitoring technology has enabled operators to determine and stay below threshold injection rates to prevent seismicity (Rao, 2014). And according to Rao (2014), the fact that few of the 150,000 disposal wells are related to seismic events shows that not all wells contribute to seismicity and that the dangers of seismic activities could be further reduced. Jacobs (2016) reported that it could take over a year of reduced injection activity to see a noticeable reduction in seismicity, and advised that wider disposal networks through pipelines or trucking water to locations outside the 10,000 sq mile Area of interest, where several seismic events have been recorded, would be required.

Boak (2017) observed that there is some reduction in seismicity already due to interventions through state regulations such as injection rate caps, cut back on injection, plug-in of wells located in more problematic locations followed by enforcement actions such as standing requests for daily injection reports. Boak (2017) also attributes some of the reduction in seismicity to reduced oil development activities and fracturing operations due to lower oil prices. Other actions by leaders in the state of Oklahoma besides reduced injection directives include funding for seismicity research projects, allocation of funds for response upon seismic events, and the introduction of tracking systems for earthquakes (Boak, 2017). While acknowledging that measures taken by executive and policymakers in the state have reduced the number of earthquakes resulting from underground water injection activities, Boak (2017) further recommended actions to improve recycle or re-use of frackwater, pipeline infrastructure to enable easy transfer across locations and consideration of other disposal mechanisms such as evaporation.

5.2.6. Hazardous Waste from Tight Oil Development Activity

Waste from oil development is mainly from produced water and drilling waste. Since produced water makes up over 90% of this waste (EPA, 2000), it is the focus of this section. With the onset of tight oil development, produced water could be classified into two segments: the portion of water produced as a result of hydraulic fracturing (i.e. flowback water) and generally produced water, which is part of the life of every well, even if not stimulated by hydraulic fracturing.

a) Produced Water Wastes from unstimulated Oil and Gas Wells

Not every waste from oil and gas production is related to hydraulic fracturing well stimulation. Some contents from water produced from unstimulated wells constitute hazardous waste. Compounds like benzene and toluene are present in oil and gas produced water from wells under primary recovery, that is, wells producing without the aid of nearby wells that inject any substance to provide pressure support, which could lead to changes in the content of the associated produced water (EPA, 2000). Compounds from produced water like benzene and toluene are known to possess carcinogenic properties, which increases public alarm as to the potential for harm from effluents of the oil and gas production process. Information about these compounds has increased the push by environmentalists to see the industry continue to seek better ways to handle produced water before disposal (FrackfreeColorado, 2016).

b) Produced Water Wastes from Wells due to Hydraulic Fracturing

Some components of wastewater result directly from hydraulic fracturing operations. These hydraulic fracturing waste components are in addition to the waste due to natural oil and gas produced water. Such waste components could be expected in significant quantities at the surface only during the flowback stage of production in stimulated wells. The fluid type and chemical waste from hydraulic fracturing vary widely across shale plays based on the objective of the hydraulic fracturing operation and the characteristics of the specific operation (Slutz et al., 2012; Table 28). The volume of cross-linkers, corrosion inhibitors and surfactants used may depend on

the size of fractures intended, the corrosion risks associated with an operation, and pressure required to pump the fluids into the wellbore. Water is often used as the base fluid. Sand or ceramic proppants are used together with gelling agents, cross-linkers, scale inhibitors, surfactants, pH control components, and stabilizers. Examples of these chemicals are methanol, aldehyde, isopropanol, potassium metaborate, potassium hydroxide, ethanol, naphthalene, and 1, 2, 4 Trimethylbenzene (Fracfocus, 2016). Table 29 shows chemical additives and their purposes in hydraulic fracture fluid and the website www.fracfocus.org, managed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission, is a forum by which oil and gas operators report the contents of hydraulic fracturing fluid used in their operations.

Table 28. Flowback Brine Analysis from Shale Plays across the U.S. (Slutz et al., 2012)

		Barnett	Eagle Ford	Fayetteville	Haynesville	Marcellus	Bakken
Sodium	(mg/L)	10,741	10,900	13,804	34,879	24,445	45,100
Potassium	(mg/L)	484	192	256	735	190	3,550
Magnesium	(mg/L)	316	111	293	828	263	720
Calcium	(mg/L)	2,916	1,270	1,046	7,052	2921	9020
Strontium	(mg/L)	505	203	267	1,354	347	
Barium	(mg/L)	15	10	18	1,121	679	13
Iron	(mg/L)	28	112	0	147	26	77
Chloride	(mg/L)	23,797	19,318	23,856	71,143	43,578	91,300
Sulphate	(mg/L)	309	163	13	0	4	440
Bicarbonate	(mg/L)	405	736	6161	382	261	126
Total Dissolved Solids	(mg/L)	39,516	33,015	45,715	11,7641	72,714	15,0346
Total Suspended Solids	(mg/L)	1,272	840	700	868	0	0

Table 29. Examples of chemicals used in designing hydraulic fracturing fluid * (Fracfocus, 2016)

Purpose of Additive	Ingredients of fracking fluids
Base Fluid (carrying medium for proppants)	Fresh, recycled or produced water
Proppant (to prevent fractures shutting in)	Silica or ceramic
Gelling agent (to keep proppants in suspension)	Guar Gum
PH Control (to provide conducive medium for other additives)	Sodium Hydroxide
Water Treatment Anti-bacterial	Glutaraldehyde, methanol
Corrosion Inhibitor	Aldehyde, Isopropanol, methanol
Cross-Linker (to improve density of carrying fluid)	Potassium Metaborate, Potassium Hydroxide
Non-Ionic Surfactant (to reduce system friction)	Ethanol, Naphthalene, 1,2,4 Trimethylbenzene
Solvent	Hydrochloric Acid
Similar functions as above	Proprietary additives by operators or service providers

*Naphthalene, methanol listed in 2015 Toxic Release Inventory chemical list (EPA, 2016d)

Through the Fracfocus website, the EPA (2016b) identified 1,606 chemicals associated with the hydraulic fracturing process, 11% of which posed a risk of cardio- and neuro-toxicity, change in blood chemistry, body weight, and immune system, liver and kidney toxicity if consumed in contaminated water. The EPA (2015a) also noted that 20 of the most soluble and mobile chemicals such as choline chloride and hydroxymethyl phosphonium were used in about 14% of the hydraulically fractured wells. While none of the above-listed chemicals were found in the 2015 Toxic Release Inventory (TRI) chemicals list, over 70% of chemical components of produced water from unstimulated wells are listed in the 2015 TRI chemical list (EPA, 2016c). Without publishing hydraulic fracturing chemicals in the TRI, the public is not made aware of the risk posed by potential release through protocols established by the EPA. Concerned members of the public have continued to push for fuller disclosure of chemicals, without any exceptions, and also for the industry to further its research into more benign chemical options to replace current additives to hydraulic fracture fluids.

Some of the issues in tight oil development are not ubiquitous but specific to a few tight oil plays. As a result, these environmental issues could be understood best within the context of the oil plays where they are argued. States like New York, New Jersey, Pennsylvania, Texas, and North Dakota have faced different issues based on the interests within these areas on both sides of the tight resource development debate. The New Jersey legislature banned the practice of hydraulic fracturing in 2011, while New York first increased the stringency of its permitting process, pushing for further study of the implications of the technology (Parlow, 2011), finally instituting a ban on fracking in 2015 (NY State, 2015). Supporters of hydraulic fracturing view restrictions to tight oil development as a loss to the regions that oppose the practice. Considine et al. (2011) studied the environmental impacts of shale development in Pennsylvania between 2008 and 2010 and concluded that there was a quantifiable loss in economic opportunities in New York caused by the state's moratorium on shale energy development. They found that the moratorium held back $11.4 billion in economic output, 15000 to 18000 jobs in the Southern Tier and Western New York and $1.4 billion in lost tax revenue. They compared the economic benefit of a typical shale well against its environmental impact and concluded that the economic benefit of the wells could very well compensate for environmental impacts of shale development.

The environmental issues raised with regards to hydraulic fracturing could be several and intractable given the different levels of interest on the issue across the US. While traditional oil and gas states may be more sympathetic to the practice, other states with significant non-oil economies may approach the issue differently. This chapter later crystallizes the issues by presenting two case studies on two states that have championed tight oil development. One of these states, Texas, is a more traditional oil development state in the U.S. and the other, North Dakota, has been transformed in the last decade from a mostly agricultural state to one that now ranks second in oil and gas production in the US. The two case studies discuss the management of environmental aspects of tight oil and gas development in the Bakken Play of North Dakota and the Eagle Ford Play of South Texas. Prior to the case studies, the next section discusses U.S. federal environmental regulations on waste management within which oil and gas development has occurred in states discussed in both case studies.

5.3.   U.S. Federal Laws Impacting Oil and Gas Industry Waste Management

Over the last century, laws and regulations have been promulgated at the federal and state levels to handle environmental issues related to oil and gas development. This section of the research discusses the federal laws involved in oil and gas waste management. The key issues faced by the tight oil development industry are assessed and the current state of solutions is also discussed. Through the lessons derived from the U.S. oil development, other tight oil provinces around the world could find templates around which individual solutions to environmental impacts of tight oil development could be derived.

Regulations in the United States concerning the protection of the environment are codified under Title 40 of the Code of Federal Regulations (CFR) which contains federal regulations governing all federal agencies. Hazardous waste regulation at the level of the states is mainly enforced by state authorities within the framework of regulations and guidelines by the federal agency called the Environmental Protection Agency (EPA). Parts of the CFR regulations concerned with hazardous waste management are parts 260 to 273 of Title 40.

There are different U.S. federal regulations governing onshore and offshore segments of the oil and gas industry, and the wastes generated from both segments are managed differently depending on the level of treatment and the intended use (EPA, 2000). Examples of regulations governing offshore operations include the Outer Continental Shelf Lands Act (OCSLA), Clean Air Act, Clean Water Act, Spill Prevention Control and Countermeasure Plans, and Oil Spill Contingency Plans. The onshore regulations are more pertinent to tight oil development because so far tight oil development occurs mainly onshore. Some of the laws regulating onshore oil and gas exploration and production are the following (EPA, 2000):
- Safe Drinking Water Act (SDWA)
- Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)
- Resource Conservation and Recovery Act (RCRA)
- Emergency Planning and Community Right to Know Act (EPCRA)
- Clean Water Act (CWA)

5.3.1.   Safe Drinking Water Act (SDWA)

This law was passed in 1974 with the main goal of securing public surface and underground portable water safety across the U.S. Through amendments in 1986 and 1996 the law has included more public information and training, upgrading water systems and securing water from source points to consumption points, and by 2004, was expanded to include the security of 170,000 water sources within the U.S. (EPA, 2004). Through a legal framework that allowed for states to apply for primacy and take charge of implementing and enforcing SDWA provisions, almost all U.S. states currently enforce standards on par or stricter than EPA's regulations on drinking water (EPA, 2004).

The SDWA also oversees the underground injection control programs ongoing in several states through class I to class VI wells. Of these wells, over 184,000 class II wells are concerned with oil and gas related injection, 20% of which are for disposal purposes (EPA, 2016c). The Energy Policy Act of 2005 made amendments to the SDWA. Critics of these amendments say it achieved two key desires of the oil and gas industry; firstly, that they exempted hydraulic fracturing operations from the control of the EPA and secondly, that they failed to ban the use of diesel as fracturing fluids even in the event of underground contaminations (Earthworks, 2007). This is because diesel fuels typically contain Benzene, Toluene, Ethylbenzene, and Xylene which are water-soluble and can easily contaminate and spread through water. However, the EPA requires that fracking operations that use diesel obtain an underground injection control (UIC) permit before commencing injection (EPA, 2014b).

Since more than 90% of hydraulic fracturing operations are done with water base fracturing fluids, the EPA is largely unable to regulate the bulk of the hydraulic fracturing and tight oil development industry. These operations are regulated at the state level and since state enforcement is empowered by the EPA, then it is expected that the state's enforcement of groundwater protection laws exceed or are on par with EPA strictness standards and the states can rein in potential excesses of the oil development industry. A full state enforcement of federal regulations would also be in line with findings by the EPA on drinking water protection published in 2016 which recommend the following (EPA, 2016a):

- That states ensure that water withdrawals for fracking is considerate of low water availability seasons and general abundance of water resource in the area.
- That states ensure that operators are mindful of impact on surrounding environment during chemical mixing in preparation for and during fracking operations.
- That high well integrity standards are in place to ensure ground water formations are protected.
- That states would prohibit the use of unlined pits and other unsafe flowback water storage and management practices.
- That in states or circumstances when surface discharge of water is part of water management strategy, states ensure that flowback water is properly treated.
- That states encourage recycling and reuse of frack flowback water so as to reduce the draw on portable water sources.

5.3.1.1. Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) was passed in 1980 to oversee the cleanup of hazardous sites that had been abandoned, intervene in hazardous waste pollution by industry to find and hold polluting parties liable, and to establish a fund to address these issues through tax on petroleum and chemical industries (EPA, n.d -a). It established a framework for both quick responses to harmful environmental releases and longer-term sustainable cleanup efforts. It also established a trust fund meant to finance projects purposed on cleaning up orphaned spill locations and other hazardous waste while creating provisions for getting payments from liable parties. The trust fund was funded through taxes, fines and penalties for violations from the oil and chemicals companies, collected over $1.5 billion for the first 5 years, although these taxes have been discontinued for the last decade (Earthworks, 2007). According to Earthworks (2007) this law allowed the federal government to hold liable parties individually and collectively, including hazardous waste generators, plant operators, past operators, and hazardous material transporters. It also enabled parties to sue

partner firms and get compensated if, through the individual and collectively liable philosophy of the law, a single liable party is made to pay for the entire cost of cleaning.

In 1986, the EPA's powers to enforce this program was expanded through provisions of the Superfund Amendment and Re-authorization Act (SARA). According to the EPA (n.d. -b) through the SARA, the government increased its ability and options for settlement of environmental liabilities, increased public participation in the program, created a prioritization scheme for hazardous sites across the country and increased the size of the trust fund to $8.5 billion.

According to the EPA (n.d. -a), the CERCLA has responded, contained, and controlled harmful releases into over 2,500 surface and underground locations and by 2015, the EPA had assessed approximately100,000 sites for remediation, completed short and long-term cleanup of over 1700 sites, and made over 700 sites ready for reuse. And since 2015, efforts to ensure that parties liable for pollution pay have also been ongoing. In 2015, the EPA secured a $2 billion commitment for cleaning liabilities, over half a billion in reimbursement for past EPA expenses in clean up and oversight, and in same year allocated close to half a billion dollars in funding for new projects (EPA, n.d. -a).

5.3.1.2. The Resource Conservation and Recovery Act (RCRA)

The Resource Conservation and Recovery Act (RCRA), passed in 1976, regulates the life of hazardous waste from generation through transport, treatment, all levels of management until final disposal as well as other non-hazardous solid waste (EPA, n.d. -c). RCRA regulations are found in parts 239 through 282 of Title 40 of the Code of Federal Regulations. The RCRA is divided into 10 subchapters of which the third (aka subtitle C) is concerned with management of hazardous waste from generation through transportation to disposal. According to Earthworks (2007), four years after the passing of the RCRA, the U.S. congress blocked the EPA's ability to enlist oil and gas wastes under Subtitle C by passing the Solids Waste Disposal Act (SWDA) which effectively defined oil industry waste away from the control of the EPA. As a result,

effectively, the oil and gas extraction industry is exempted from provisions of the RCRA Subtitle C on hazardous wastes (EPA, 2000).

With a few exemptions, this Act generally requires facilities that deal with hazardous waste to obtain RCRA permits. The EPA has authorized and maintains oversight on 47 state programs including Texas and North Dakota that implement RCRA programs (EPA, 2000). Among other methods of hazardous waste treatment and disposal, the RCRA permits the disposal of hazardous waste in 17% of class1 disposal wells located in 10 states in the nation (EPA, n.d. -d).

However, if the oil and gas extraction industry is included under the Resource Conservation and Recovery Act (RCRA) and hazardous waste is reported and listed under the Toxic Release Inventory under the Emergency Planning and Community Right-to-know Act, (EPCRA) there are a few potential outcomes.

Firstly, there is the business as usual scenario. If the state-run environmental protection programs are EPA-authorized, 'accredited', and enforcing laws that are at least as stringent as EPA laws, the manner in which these wastes are handled will not change. What could change is the public awareness and accountability that results from the fact that more facilities would report toxic releases under the EPCRA. However, a review of the stipulations of the Texas and North Dakota Administrative codes shows that these states prescribe EPA guidelines on hazardous waste management and largely draw definitions and guidelines from the Code of the Federal Republic which empowers the EPA. Another reason for this business as usual scenario is that the concentration of some reportable chemicals in hydraulic fracturing water may keep them below reportable thresholds.

On the other hand, including the oil and gas extraction industry under the RCRA could increase wastewater management burden from fracked wells, if flowback water exhibits hazardous characteristics. For example, in the Eagle Ford, Texas and other areas with several disposal wells, there could be increased cost in commercial injection in class 1 hazardous disposal wells. This burden will be greater in states with even fewer or no hazardous disposal wells such as

North Dakota. This may also generate interest in developing water recycle technologies that will reduce the overall footprint of hydraulic fracturing and the oil and gas industry.

5.3.1.3. Emergency Planning and Community Right to Know Act (EPCRA)

The Emergency Planning and Community Right-to-know Act (EPCRA) section 313 requires generators, transporters and users of hazardous chemicals above stipulated thresholds to submit annual toxic release reports to the Toxic Release Inventory (TRI) (EPA, 2000). These facilities must have 10 or more employees to fall under this regulation, be involved in specific industry sectors listed under this Act and use chemicals listed under a list developed by the EPA, above threshold limits (EPA, n.d. -e). The EPCRA section 313 exempts the oil and gas extraction industry from reporting its waste under the Toxic Release Inventory (EPA, 2000). This exemption implies the industry's facilities do not need to keep records of or report the chemicals and hazardous materials they manage, or coordinate with state and local emergency response and planning committees. An EPA response to a 2012 petition filed to include the oil and gas extraction industry under the TRI requirements of the EPCRA was partly rejected (EPA, 2015b). The gas sector was accepted for consideration but the oil sector was rejected stating, among other reasons, that the chemical release at the well level did not meet reporting thresholds and at the smallest units of measurement, well sites, hardly any facilities had 10 or more employees (EPA, 2015b).

5.3.1.4. Clean Water Act (CWA)

The Clean Water Act (CWA) passed in 1972, empowered the EPA to regulate the discharge of waste into U.S. waterways (EPA, n.d. -f). It also allowed the creation of a permitting system by which discharges into surface waters were required to meet set contaminant levels. Wastewater runoffs from oil and gas activity sites were exempted from the provisions of the CWA (EPA, n.d -g) but through a series of amendments, the EPA was empowered to regulate activities in sites larger than 5 acres (Earthworks, 2007).

The U.S. federal regulations discussed above do not constitute an exhaustive review of all laws that affect oil and gas operations. Rather, they show that the growth of industrial activities, the petroleum industry and tight oil development specifically have not been entirely unchecked. For these activities to have been sustained through several decades with the social license to operate within the communities in which they exist, environmental regulations played a major role. The review of the laws also show that in some cases the oil and gas industry was treated differently.

A major example of the unique treatment of the oil and gas industry stems from the regulatory and tax boost provided to specific operating well categories, for example, stripper wells. Stripper wells (wells producing less than 10bbls of oil per day) are largely exempted from most federal and state regulations due to potentially low emissions from them and the drive to incentivize their owners to keep them operational (EPA, 2000). However, these wells constitute a huge segment of operating oil wells in the US. From 1976 to 2007 stripper wells have constituted 71 to 85 % of all oil wells in the U.S. (Independent Petroleum Association of America, 2016). Environmentalist groups have argued that current laws have not gone far enough in restricting environmental violations perpetrated by the oil and gas activities (FrackfreeColorado, n.d.). The Colorado-based group, FrackfreeColorado (n. d.) argued that by design or inadvertently, the oil and gas industry was largely exempt from the strongest provisions of environmental laws. A major example, according to this group is the exemption of hydraulic fracturing from the regulation of other forms of underground injection under the Safe Drinking Water Act.

Given their impact on hazardous contaminants control and public involvement and transparency of waste records, two laws most critical to the discussion of oil and gas hazardous waste are the RCRA and EPCRA. The Environmental Protection Agency regulates waste handling in many industry sectors and reports wastes according to the provisions of the RCRA. The oil and gas extraction industry is exempted from the RCRA and from reporting its waste in Toxic Release Inventories (TRI) under the Emergency Planning and Community Right to know Act (EPCRA) (EPA, n.d. -h). This has led to discontent among environmental activists and skeptics of the oil and gas industry.

While a broad review of federal environmental regulations illustrates the coverage of existing laws and the treatment of the oil and gas industry, a narrower review of the interplay between environmental laws and the tight oil industry could be better understood within the context of specific oil provinces and oil plays. This review is provided next, with a focus on case studies in the Bakken play of North Dakota and the Eagle Ford play of South Texas.

5.4. Case Studies for Tight Oil Development and Environmental Issues

5.4.1. The State of North Dakota: The Environment and Tight Oil Development

The state of North Dakota has become the capital of the U.S. oil production comeback of the last decade, and ranks second among oil producing states next to the more traditional top oil producing state of Texas. Oil production in North Dakota has risen from under 100 thousand barrels per day in 2005 to approximately 1.2 million barrels per day in 2015 (EIA, 2017c). Sources of hydraulic fracturing water in North Dakota are both surface and underground. The main water source is the Missouri water system and underground water sources include potable water formations located at depths of 2000 ft, alongside less potable water supplies located at depths of 5000-6000 ft (ND State Water Commission, 2016).

The impact of oil production growth has been huge for the state of North Dakota (ND). According to Parlow (2011), oil production activities yielded the state of North Dakota approximately $700 million in tax revenues in 2011, increasing state funds for road repairs and construction of low cost housing, raised salaries within the state and pushed down unemployment rates to as low as 2.5%. The benefits of this development are also shared among the State's native populations. Through state-tribal collaborations, the state of North Dakota has secured oil development on reservation land, leading to the accrual of millions of dollars in state taxes, about a third of which is shared with the tribes (Parlow, 2011). However, alongside all the benefits of intense oil and gas development activities, environmental costs have been incurred.

Challenges in Tight Oil Resource Development

The following section discusses some issues that the State of North Dakota grapples with in its development of tight oil resources.

Natural Gas Flaring Concerns

The rapid production increase observed in the state of North Dakota brought along gas handling issues which have led to the disposal of natural gas by burning (gas flaring). Oil production in North Dakota grew by almost 400% from January 2010 through 2014, almost doubling gas production alongside, and gas gathering infrastructure has lagged this pace of development (EIA, 2014e; EIA, 2017d). This lag in the pace of infrastructure growth stems from the low economic attractiveness of investments in constructing gas gathering lines to address this issue, given the small volume of gas and the spread of development. Other issues contributing to flaring include (1) difficulties with aligning the interests of surface land owners for pipeline routing and facility constructions, (2) permitting delays, (3) county zoning regulations, (4) harsh weather conditions, (5) the right infrastructure to handle the pressure of new wells, (6) the repurposing of liquid pipelines for gas transportation, and (7) the high cost of getting the gas to pipeline quality (EIA, 2014f; Lee, 2017). North Dakota regulations also allowed new wells to flare the gas produced alongside oil early in the life of wells alongside other exemptions meant to accommodate gas handling difficulties, so as not to stifle oil production (NDAC, 2014). As a result, the share of natural gas production in the state that was flared exceeded 35% in the first quarter of 2014 (EIA, 2014f). Accidental release of natural gas during tight oil development activities introduce hazardous air pollutants into the atmosphere and violate provisions of the Clean Air Act (EPA, n.d -i)

Increased Traffic and Environmental Nuisance

Drilling and completion activities in the Williston area of North Dakota have increased truck traffic due to the transportation of drilling and well completion equipment. This traffic typically leads to more road accidents, noise, dust, overall poor air quality, and strain on public utilities. A good example of truck traffic issues is seen during well completions. According to Jacobs (2016)

a water truck hauls less than 150 barrels of water, and given that it could take over 95,000 barrels (4 million gallons) to frack a well, more than 600 truckloads of water would be required for a hydraulic fracturing operation. This implies severe traffic and road use in counties like the McKenzie in North Dakota which experience significant levels of drilling operations.

Housing Shortages and Social Stresses Due to a Transient Workforce

Tight oil development in North Dakota is supported by a both local and non-local work force. The movement of a new and temporary labor force through small communities amounts to some social stress on the local population. While influx of people could boost local businesses that cater to the needs of oil field workers, the fast movement of a population typically leads to a loss of culture and social strains on the resident population. The influx of oil and gas development workers has also led to higher rental prices, typically too expensive for local populations. The U.S. Housing and Urban Development (2014) noted trends pointing to housing shortages in North Dakota when data on falling rental vacancies, over 200% rise in rental prices in some counties and falling utilization rate of housing choice vouchers. Besides the issue of higher accommodation costs, higher paying oil and gas jobs also contribute to inflationary pressure on prices of goods sold. Higher prices increase the cost of living to the citizens of the state, especially those employed in lower paying jobs outside the oil and gas industry.

Pollution Concerns

The pace of development and the potential for water pollution is an aspect of concern to some interest groups within the State of North Dakota. Environmental groups have raised concerns with issues like the speed of the drilling permitting process within the state and pushed for more scrutiny for tight oil development projects (Parlow, 2011). For example, if wells are permitted too quickly, it is possible some steps could be missed in the due diligence required to safely execute new wells in high risk areas, such as in areas adjacent to older wells. Hasty permitting could also result in surface receptacles not built to specification so as to prevent pollution of surface water bodies. Millions of gallons of water are handled prior to and just after hydraulic fracturing operations in drilled wells. During the process of mixing water with chemicals prior to

fracturing or handling water that flows back from the well after hydraulic fracturing operations, it is possible some of this water could come in contact with surface freshwater bodies and so contaminate water sources used by nearby residents. Parlow (2011) advised on the need for baseline studies on water composition prior to fracking operations, more control on wastewater disposal, and for more rights for citizens to file environmental complaints.

Freshwater Access Concerns

Water is associated with oil and gas development in several ways ranging from the making of drilling mud, hydraulic fracturing, produced saltwater handling, and waterflooding (Beck, 2011). In tight oil development, hydraulic fracturing is the most significant use of water given the volume of water and logistics involved. Over 250 million barrels of water was used in North Dakota in 2014 for hydraulic fracturing operations (ND State Water Commission [ND SWC], 2016). Sources of hydraulic fracturing water in North Dakota are both surface and underground. The Missouri water system is the main source of surface water to the state while underground water sources are typically freshwater aquifers which lie 2000ft below the surface, and saline water sources which lie 5000-6000ft below the surface (ND SWC, 2016). Other surface water supplies in the state are not dependable as water volumes are seasonal and quite variable (University of North Dakota, 2013).

The North Dakota state water commission estimates that, with the projected pace of oil and gas development, demand for water is expected to grow to over 16 billion gallons per year by 2019 (Beck, 2011). Through 2020 the North Dakota state water commission projects a growth of water required for other uses such as domestic, rural and municipal, livestock, irrigational, and industrial use (Beck, 2011). And the projected rise of some sectors due to population increases raises the potential severity of water-stress within the state and probably furthers the competition for the resource by the sectors. Besides the uses of water use and access, some years have seen significant water stress within this state (Figure 77).
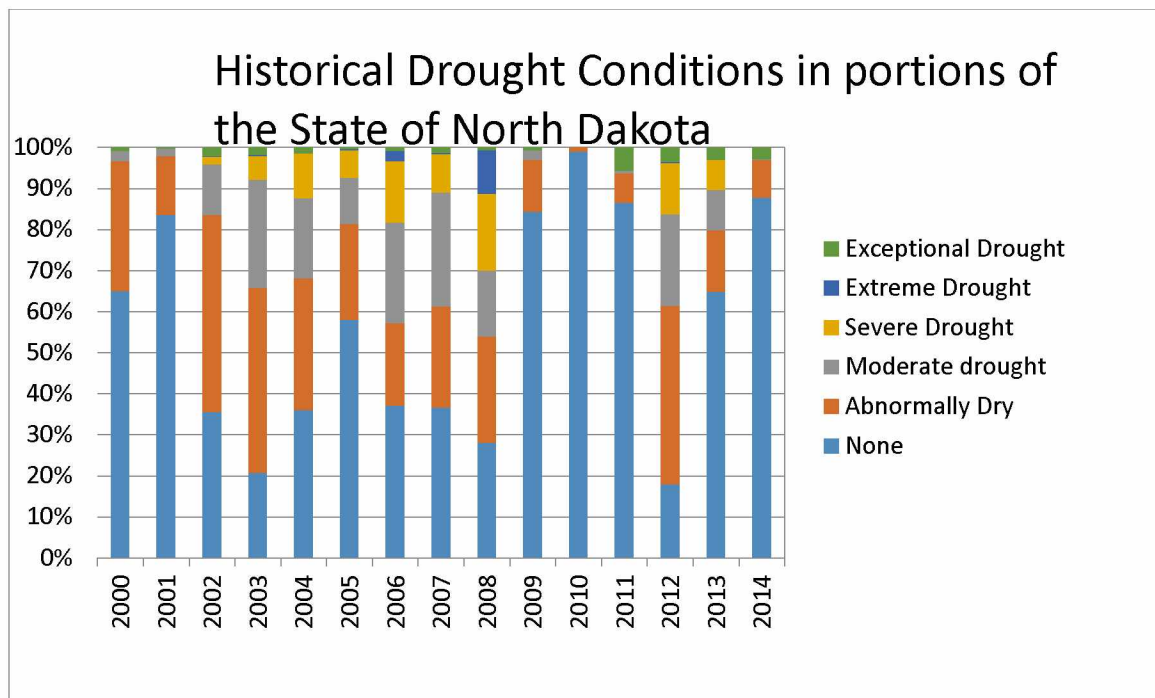
Figure 77. Historic Drought levels in the state of North Dakota (U.S. Drought Monitor, 2015)

Some popular resource access disputes highlight existing challenges in water rights to current water sources that threaten the future supply of water for the many industrial sectors in ND. Over 95% of ND's surface water is in the Missouri River mostly stored in lakes Sakakawea and Oahe which are both under the control of the U.S. Army Corps of Engineers (Beck, 2011). The Army Corps of Engineers placed restrictions on withdrawals from the Missouri River system within the boundaries of Lake Sakakawea and Oahe leading to challenges by the state (ND SWC, 2016). The Army Corps of Engineers (2013) affirmed that although the 1954 Garrison Dam project stretches over almost 0.5 million acres over 6 counties which include 45 of the 576 oil fields within the state, major water use for oil and gas development alone threatens other future uses. This has led to sharp challenges from the State of North Dakota, which sees its access to waters within its borders as threatened and in extension the vital revenue-generating development of oil and gas resources. Beck (2011) summarized water access issues that threaten stable supply of water for the state's industrial uses between the state of North Dakota and the states of Wyoming and Montana over water withdrawals from the Yellowstone River water, other water right disputes with the nation of Canada involving the Devils Lake projects, and issues of water rights with the Native tribes. A full or partial resolution of these issues that accommodates oil and gas

water demands will be central to the continued flourishing of tight oil development industry in the state of North Dakota.

Due to potential technological advances in recyclability of fracture water and advances in non-water fracturing, it is hard to say what will be the future of water demand for ND shale development. But there is general agreement on the idea that there ought to be protection of known supplies (Beck, 2011).

North Dakota State Level Solutions to Oil and Gas Development Issues

The previous section highlighted the key issues resulting from tight oil development in North Dakota ranging from social, to political, to water resource issues. These impacts on housing affordability, traffic, and water access and waste management are handled through free market solutions and by regulations. For example, the discussion of water resources within this state begins with the constitution of the state of North Dakota which assigned streams and natural water courses as property of the state for mining, irrigation, and manufacturing (Beck, 2011). North Dakota's constitution also assigns the administration of non-domestic uses of water to the North Dakota State Water Commission (Beck, 2011). The North Dakota Century Code (2017) clarifies that water use must be "consistent with the best interests of the people of the state" and such beneficial use as "the basis, the measure and the limit of the right to the use of water" (61-04-01.1 (2)). Solutions to the state's tight oil development issues are further discussed within this section.

North Dakota Gas Flaring Solutions

The problem of gas flaring in North Dakota is tackled in many fronts ranging from well permitting, gas gathering facility investments, and surface pipeline rights initiatives to the setting of flaring limits. The North Dakota Industrial Commission [NDIC] (2014) highlighted initiatives to include gas capture plans in operator development plans, keep the Department of Mineral Resources engaged in pipeline surface rights-of-way negotiations, encourage county-level solutions to zoning to allow for the citing and operation of gas gathering and processing

infrastructure. Some industry advocates have considered the extra requirement of gas capture plans as burdensome and potentially limiting the pace of development. The North Dakota Pipeline Authority (2014) noted that if wells are connected faster to gathering lines, 10% of flared volumes could be captured.

The EIA (2016k) highlighted a reduction of the share of natural gas production that was flared down to 10% in Q1 2016 from a 36% in Q1 2014 following flaring limit targets set by the ND industrial commission. While it is possible the reduction in oil prices have contributed to slower growth in new well count growth and associated gas production, there is evidence that regulations may have played a significant role in the reduction of flared gas. The North Dakota Century Code authorized the state to collect production taxes and mineral owners to receive royalty on gas that is flared after the first year of production (NDIC, 2017). The NDIC (2014) proposed crude oil production rate restrictions to wells that are not connected to gathering lines 60 days after being placed on production and presented potential impacts on the economics of projects. Restrictions have also been placed on the share of total statewide produced gas that could be flared not to exceed 9% by November 2020 (EIA, 2016k). With regulations in place and current plans for more investment in midstream activities ranging from processing plans and gathering lines, the state of North Dakota is positioned to potentially provide a template for gas flaring management for the nation and other tight oil development outside the US.

Housing Crises and High Rents Solutions
In 2014, due to the oil boom and shortage in housing, rental prices were at an all-time high in the city of Williston, ND, surpassing rental costs in some of the more traditionally expensive cities in the US, e.g. New York and San Francisco (NYT, 2014). Growth in number of permitted housing developments and houses in construction led to a reduction in rental costs by close to 20% (Reuters, 2015) and in some cases, up to 44% (Energy Media Group, 2016). This reduction in rent costs was partly due to increased housing and also due to the slump in oil and gas prices in late 2014 leading to reduced drilling and tight oil development activities.

The U.S. Housing Act authorizes the U.S. department of Housing and Urban Development (U.S. HUD) to assist families secure affordable housing at rental rates up to the 40th percentile of gross

rents and utilities costs in parts of the country (U.S. HUD, 2014). This act permits government agencies to provide extra assistance to parts of the country experiencing some emergency. Oil counties in North Dakota have received exemption status to make assistance payments that exceed to typical levels allowed by this housing program so as to react to the heated housing market due to tight oil development within this state (U.S. HUD, 2014).

In 2013, the ND legislature authorized increased funding for the construction of 1000 affordable housing units with 15-year fixed affordable rental rates to assist workers considered essential to state services such as workers in the school districts, counties and city services, and medical personnel (U.S. HUD, 2014). These efforts have especially helped lower income residents of the state who were facing increased pressure on rental cost and other fixed income individuals such as retirees.

Freshwater Access Solutions

The Office of the State Engineer manages water resources in North Dakota by allocating quotas for water use to permit holders, by monitoring water use, and also by collecting annual reports on actual water use by permit holders (ND SWC, 2016). This office also monitors and collects data on the state's water resources through over 4000 wells scattered across the state (ND SWC, 2016). In addition to the use of meters in locations where significant water use occurs, onsite telemetry systems are being introduced to enable real time monitoring of water use by industrial users, primarily those operators who engage in hydraulic fracturing operations (ND SWC, 2016). Water use information is published on the ND state water commission website for every permit holder and is made available to the public. In addition to being fined, violators of the water quotas face reduced quotas to make up for excess water use (ND SWC, 2016).

Water appropriation in North Dakota is according to hierarchy established by the water permitting system. Domestic uses of water require no permit unless such use impounds volumes of water above thresholds set in the North Dakota Century Code (ND Century Code, 2017). The North Dakota Century Code (2017) stipulates a hierarchy of water use priority that begins with (1) domestic, then (2) municipal, (3) livestock, (4) irrigation, (5) industrial, and (6) fish, wildlife and outdoor recreational uses. Oil and gas use falls under industrial use of water. This legislation

also accords priority of water use by the date on which water use begins for each beneficial user while allowing this date and the hierarchy of the user to be updated when the purpose of water use changes (ND Century Code, 2017). This implies that the first beneficial user has the right to full use in the case where water is limited, but his/her right falls at the back of the line when the purpose of his use of water changes. At such a time, his use is subordinate to that of a second beneficial user because only the date of the last change of use counts. This priority system mitigates disputes between different water uses.

Furthermore, water use in oil and gas operation is considered beneficial although questions exist as to the required quality of water needed and the possibility of treating more abundant non-portable water for such use. Some analysts also demand the diversification of water supply to ease the stress on other uses that require freshwater. It is also possible for an appeal to be brought before the North Dakota SWC to request that an unused water permit right be rescinded in favor of a subsequent beneficial water user (ND Century Code, 2017). This level of flexibility in transfer and adjustment of water rights contributes to mitigating the issue of access to the available water supply.

Drilling Waste and Produced Water Handling Solutions
The North Dakota Industrial Commission through the North Dakota Division of Oil and Gas regulates oil and gas operations, the disposal of salt water and oil field wastes, and the reclamation of land used for oil and gas development operations (ND Oil and Gas Rule Book, 2017). It also regulates drilling, casing and well operation conditions to prevent pollution of freshwater supplies. In regulating drilling and completion phase of operations, the commission requires that companies use freshwater in making drilling mud so as to prevent possible contamination of freshwater formations during drilling or disposal (Beck, 2011). The reason for this is that, upon contact with water bearing zones during drilling or during surface handling of drilling mud, environmental impact is minimized. According to the North Dakota Oil and Gas Rule Book (2017) surface pits and receptacles used for handling saltwater, drilling mud or waste must be lined and impermeable to prevent seepage into the surrounding environment.

Produced water from tight oil operations in the State of North Dakota is mostly disposed through wells that inject wastewater into deep underground formations in the State of North Dakota. The Inyan Kara formation is the primary target for underground wastewater disposal in North Dakota, taking injection fluids from 412 of the 435 saltwater disposal wells active in 2015 (Bader, 2016). This formation is suitably thick, permeable and laterally continuous, and sandwiched by the required bounding impermeable rock strata; the Pierre formation located above the Inyan Kara and the Swift formation located below. Bader (2016) estimated that over 1 billion barrels of water have been injected into the Inyan Kara formation in the last decade. Regulations on underground injection control in the state of North Dakota are found in the North Dakota Administrative Code (NDAC) Title 33, Article 25 chapter 1.

In addition to underground injection, another emerging solution to wastewater handling in North Dakota is by water treatment and reuse. North Dakota law permits infinite reuse or transfer of wastewater so long as the use is the same as is authorized by the water use permit (ND SWC, 2017). The North Dakota State Water Commission (2017) also allows the permit holder to use that treated water in any location until the water, upon proper treatment, is finally returned to "a natural watercourse" at which point it becomes the property of the state subject to permit restrictions in volume and use (ND SWC, 2017). This provision affords flexibility to operators by allowing them transfer water across different leases they own or enter commercial arrangements with others to facilitate wastewater reuse.

North Dakota state also has regulations that address hazardous waste management. These are found in the North Dakota Administrative Code (NDAC) Title 33, Article 24 chapter 2. ND state law prevents anyone from storing, treating, transporting, or offering any hazardous waste for transportation without obtaining an identification number and registration certificate from the ND Department of Health (NDAC, 1984). The law also requires transporters and treatment facilities to acquire hazardous waste transport and disposal permits. Prior to transportation of hazardous waste, the ND state law also requires the transporter to fill out an EPA waste manifest. North Dakota law designates any generator of hazardous waste above 1000kg per month as a storage facility, and requires further reporting requirements, unless they are permitted by the department of health to keep the waste for a period of up to 90 days.

5.4.2. The State of Texas: The Environment and Tight Oil Development

The state of Texas is among the oldest oil and gas development states in the US. As a result, Texas has had a long time to evolve in technology and legislation around its oil and gas issues. However, the development of tight oil still raises new issues while emphasizing age- old issues in oil and gas development within the state.

Tight oil development in Texas exists mainly in the Eagle Ford and the Permian basins. Since the Eagle Ford is more focused on tight oil and gas development, unlike the Permian with both tight oil and conventional oil, the environmental challenges in resource development discussed here will mainly focus on the Eagle Ford. The Eagle Ford oil boom started with a successful well in the LaSalle County of South Texas leading to a flurry of activities throughout the other 23 counties that make up the Eagle Ford play within the state (Allen, 2013). Drilling permits issued in the Eagle Ford rose from 94 in 2009 to over 5600 by 2014 (RRC, 2017). The Eagle Ford is unique because, unlike other plays, it offers opportunities for development of gas, wet gas and oil. The existence of multiple resource targets also increases the number of wells that could be drilled by operators whose business models focus on different resource types. This increase in drilling and development has also led to several environmental issues within this oil state.

Challenges to Tight Oil Resource Development
Most of the issues discussed for the state of North Dakota tight oil development hold true for the Eagle Ford in the state of Texas with more emphasis on specific issues like air pollution, truck traffic, and water availability amidst drought conditions in South Texas.

Severe Traffic Problems

The intensive nature of unconventional resource production is illustrated by the amount of resources pulled together for its development. Truck traffic in the Eagle Ford is a major symbol of this phenomenon. A report by an Eagle Ford Shale Task Force for the Texas Railroad Commission (RRC, 2013) stated that the building of bigger drilling pads to handle the broader

footprint of tight oil development, and the drilling of more wells, which require hydraulic fracturing, has led to thousands of heavy trucks using roads that were constructed for light road traffic. This level of traffic puts significant strain on roads that were constructed for the purpose of bringing farm produce to market and on communities that were inhabited by just a few hundred people (RRC, 2013). For example, the Eagle Ford Shale Task Force report estimated that over 1100 loaded trucks were required to put one gas well into production, with over 350 needed to service this well annually. The fact that over 5600 drilling permits were granted by the RRC in 2014 suggests that millions of truck trips were required to get these wells to production, leading to the huge risks in traffic incidents and pollution within major oil producing counties like Karnes, La Salle, and Dewitt. The Texas Department of Transportation (2014) noted increased levels oil and gas traffic in 2012 and 2013 and recorded over 3000 traffic incidents within the Eagle Ford region which led to over 230 fatalities.

Air Pollution Issues

Air pollution concerns have also been raised in the Eagle Ford Shale area of South Texas. According to the Alamo Area Council of Governments (AACOG) which houses some of the major Eagle Ford counties like Karnes, Dewitt, and others, ground-level ozone issues constitute a serious environmental concern in the area (AACOG, 2017). They report that this area has thrice failed to meet the Environmental Protection Agency's National Ambient Air Quality Standard due to three-year-average levels of ground-level ozone exceeding the current 70 parts per billion threshold. This is primarily due to nitrogen oxide from exhaust as a result of heavy day time truck traffic, together with volatile organic compounds which cause health problems for the young, elderly or those with breathing problems, and other adverse impacts to vegetation (AACOG, 2017; EPA, 2017a).

Air pollution is also contributed by the flaring and venting of gas associated with oil production. In the absence of gas gathering pipelines or during interruption of service of gas handling facilities, flaring and/or venting of gas is possible. Some flaring is allowed under current regulations, as is the case for almost every oil and gas province globally. Texas Statewide Rule 32 stipulates rules and exemptions around which gas flaring is permitted (RRC, n.d -a).

According to the RRC (n.d -a) since 2007, less than 1% of over 0.5 trillion cubic feet of total gas produced every month within the state of Texas is flared or vented.

Water Rights Issues in the State of Texas

Under Texas law, surface water bodies and subsurface streams are owned by the state; whereas, percolating water, such as aquifers accessible through water wells, are owned by holders of the surface estate (Allen, 2013). Since individuals can own mineral estate in the State of Texas, and also own the underground water sources that are required for mineral development, this shifts the pace and incentives for development towards the individual incentives and away from the state incentives, with obviously serious positive business implications. Non-state water resources, such as groundwater resources, are less regulated by the state but more by the 'rule of capture' doctrine (Allen, 2013). Allen (2013) noted that the rule of capture was adopted as a Texas state law in 1904 and allows anyone in momentary control of a migrant resource such as ground water, the right to ownership and use, and absolves them from liability towards claims of damages, except in situations of willful waste and negligence. This law limits state control over the ground water rights of private citizens in the state, whose rights are protected by the Texas state constitution.

The 'rule of capture' doctrine proposes no limit to groundwater use by its owner except when such use is not beneficial, is wasteful, or when shown to lead to subsidence of adjoining property (TWDB, n.d -a). Allowed such freedom to use water resources, a groundwater owner may choose to trade in water from his property for the fracturing of 100 wells outside that property without restriction, so long as the above-stated conditions are met. Under this doctrine of 'rule of capture' alone, the impact of such use to his neighbor's water well is not a factor to consider and his withdrawal during a state drought is unrestrained. In a tight oil province that goes by only such rule, this situation becomes a major issue if thousands of wells need to be drilled. The Texas solution to this is discussed later in this research.

Hydraulic Fracturing, Water Stress and Droughts in the State of Texas

The volume of water required for oil and gas development has raised some concerns among observers of oil industry activity in the state of Texas. An Eagle Ford well requires approximately 4.8 million gallons of water for drilling and completion, mostly drawn from the state's municipal water supplies, wastewater, ground water sources, or surface water bodies (Allen, 2013). Most of this water is used for hydraulic fracturing operations. The state of Texas is long known for water crises visible in severe droughts within the state (Allen, 2013). These droughts impact farmers and ranchers and increase worries about portable water supplies. In the absence of sufficient potable water, the consumptive use of close to 5 million gallons of water for oil and gas operations is an issue of concern for other water users.

The National Oceanic and Atmospheric Association (2011) declared the Texas 2011 summer as the hottest in the nation and the drought of that year as the worst in the last 220 years for the state. The summer of year 2011 was also the driest in Texas records with statewide precipitation averaging 2.44 inches of rain (NOAA, 2011). Droughts are not new in the state of Texas, as a report by the Texas A&M University (2011) numbered above 15 droughts in the history of the state since the 1800s, with some droughts running for as long as five consecutive years. According to EIA (2016a) 193 rigs were operating in the Eagle Ford in June of 2011 and a typical well drilled within a month. Assuming this was the case throughout the summer of 2011 (June-August), 579 wells were drilled and completed and used approximately 4 million gallons per well withdrawing some 2.3 billion gallons of water from the state's water supply during these driest months. Withdrawal of such a volume of water from aquifers in a state with known issues of drought is often the center of questions around the efficiency of water use by the industry, and the sustainability of tight oil resource development in drought locations prospective for tight oil development.

On the other hand, proponents of tight oil development still see the use of water as beneficial, given the huge returns of oil and gas to the state of Texas. Allen (2013) reported that in 2008, although over 68 billion gallons of water were used in South Texas, this use was not estimated to cause a major long-term risk to the source aquifer, the Carrizo aquifer, and that the volume of

water was reasonable when compared against the resulting economic return of oil development against the benefit of other uses.

Data compiled by the National Drought Mitigation Center shows significant changes in drought conditions across the US. Figure 78 shows that more than 6% of the U.S. experienced exceptional drought conditions in 2011. This trend extends into 2012 with approximately 70% of the U.S. experiencing abnormally dry conditions. Texas took the brunt of the drought as approximately 90% of the state experienced abnormally dry conditions (Figure 79). This same year saw major shale oil and gas development in the state suggesting further strain in the state's water resources.
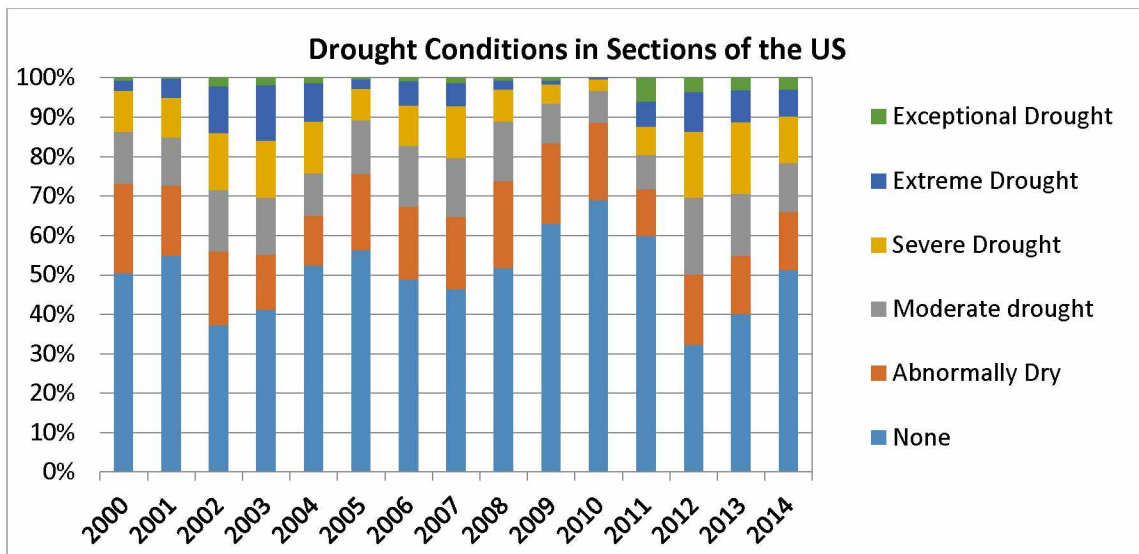
Figure 78. Historic Drought Levels in Sections within the U.S. (U.S. Drought Monitor, 2015)
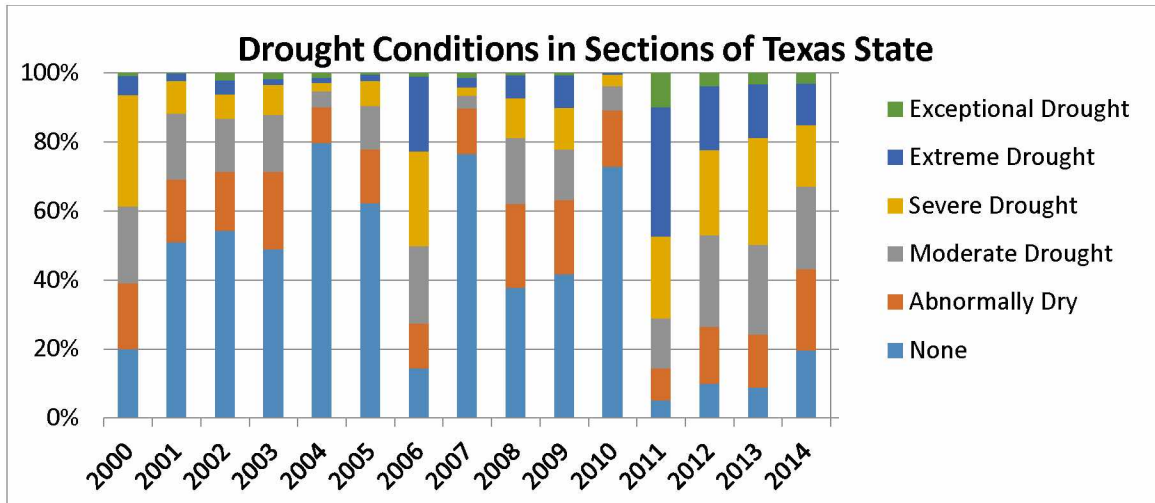
Figure 79. Historical Drought Levels in the State of Texas (U.S. Drought Monitor, 2015)

Figure 79 shows that in 2011 above 90% of the state of Texas experienced dry conditions, and from 2011 to 2014, at least 80% of the state experienced very dry conditions. The state of Texas saw a degradation in drought conditions from 2010 through 2011 (Figure 80). The Eagle Ford was among the 60% of the state that experienced extreme or exceptionally dry conditions and in late November 2011 through 2012 most of the 26 counties in the Eagle Ford enforced burn bans (Allen, 2013).
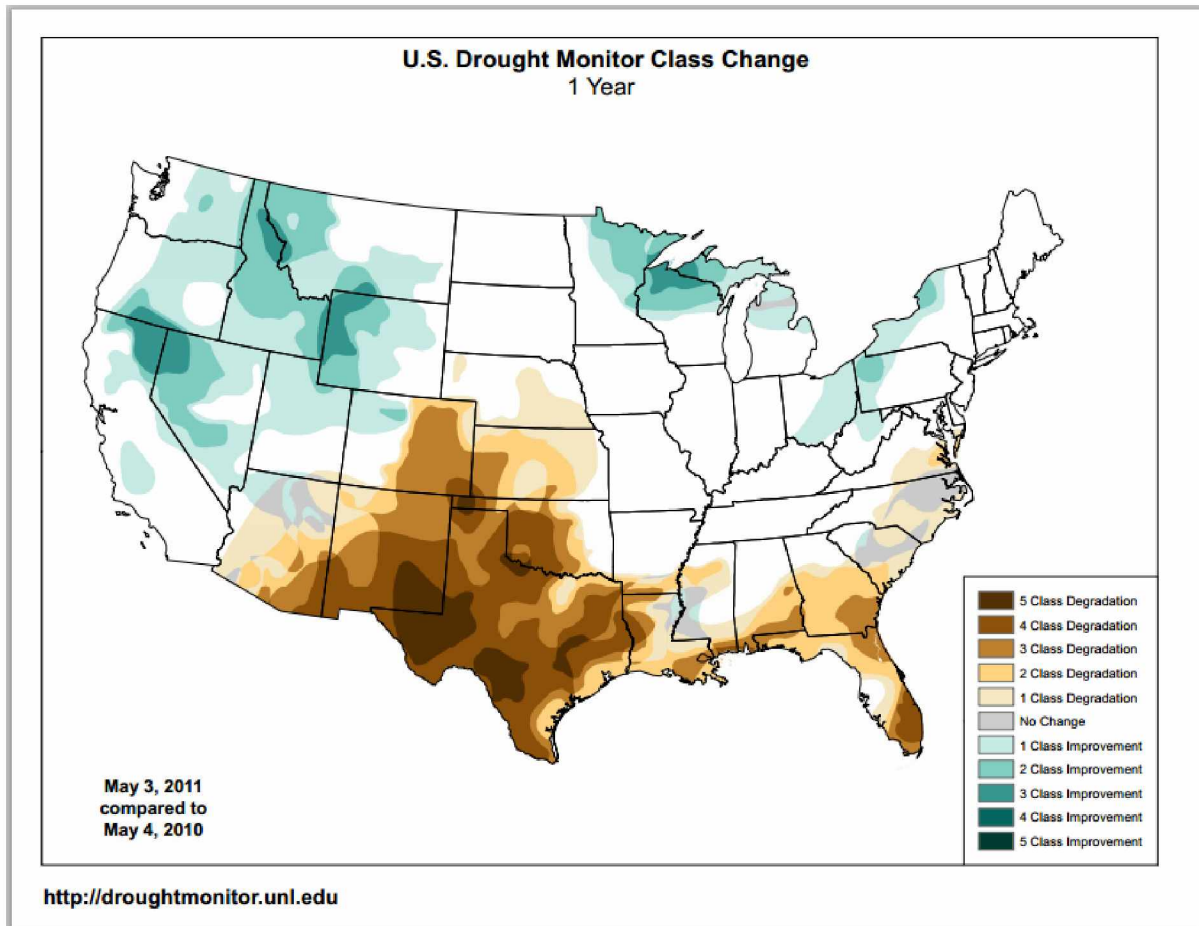
Figure 80. Map of drought conditions in the U.S. showing level of improvement/degradation of conditions from May 2011 compared to May 2010

Texas State Level Solutions to Oil and Gas Development Issues

Mitigating Truck Traffic

The state of Texas and oil and gas counties have approached the problem of severe road use and nuisance of truck traffic by generating more funding for road repairs while the oil and gas operators have generally made more efforts towards more construction of pipelines. Texas counties with disproportionately high oil and gas production are more involved with more road repair issues. These counties primarily get their funding through property taxes. According to Seeley (2014), the Dewitt County in Texas required over $400 million to upgrade its road network to handle impacts of tight oil development. This article also highlighted efforts to

increase state funding for roads through legislative allocations to the Texas Department of Transport, and by generating more property and other local tax revenue from a growing population and new businesses coming into oil development counties. Other ideas being discussed for increasing revenue to the county for road repairs include assessing ways of sharing in the royalty revenue collected by the royalty owners, and sharing in the severance tax revenue collected by the state (Seeley, 2014).

In addition to road maintenance, pipelines could be used to replace some of the services rendered by trucks. Trucks are used to transport pad and drilling equipment, crude oil, freshwater for well completion, saltwater for disposal, and sand used for hydraulic fracturing. According to the Eagle Ford Shale Task Force Report sponsored by the RRC (2013), pipelines could take off thousands of trucks and so reduce road traffic, air pollution, and traffic incidents. There are examples of produced water pipelines with a capacity of moving 150,000 bbl of water daily, estimated to reduce truck traffic by over 1000 while offering a safe, quiet and often cheaper way of water transportation (Jacobs, 2016). Water treatment solutions implemented by Apache Corporation have been reported to manage 10 million barrels of produced water leading to a reduction in truck traffic by 80,000 truckloads in 2014 (Boyd, 2015). While the upfront cost of constructing pipelines and the certainty of producible volumes is often a challenge towards capital deployment in long term projects, the experience in tight oil development in the major U.S. plays has shown that options for public-private collaborations that could put such infrastructure in place could be of significant benefit to local economies, safety of lives and longevity of oil and gas fields.

Air pollution Solutions
The problem of air pollution in the Eagle Ford shale is mostly handled through regulations. Air quality regulation in Texas is carried out by the Texas Commission on Environmental Quality (TCEQ). This commission ensures that economic development activities within the state of Texas occur without jeopardizing clean air and water and other natural resources. According to the Texas Clean Air Act of 1989, the TCEQ is authorized to enforce regulations on clean air to safeguard public health and welfare (State of Texas, 1989). TCEQ field inspectors visit operator sites to ensure compliance and also analyze flaring permits and well production reports which

show the volumes of oil, gas, and water produced (RRC, 2013). Texas Statewide Rule 32 regulates the flaring permit system while Rule 58 regulates the reporting of flared volumes to enable authorities keep track of how much is produced and flared and how industry efficiencies and development priorities affect air quality (RRC, 2013). The TCEQ also collects data from Ambient Monitoring Stations almost in real time, and its inspectors collect periodic air samples which is followed by laboratory analysis of potentially harmful compounds and publication of toxicology reports (TCEQ, n.d.). They also maintain an online Texas Air Monitoring Information System that allows users to query and generate reports of pollutant levels in different regions and counties. The presence of this data allows an evidence-based system through which the public could exert pressure on operators to rein in pollutants from their operations. Another method of air pollution control is by the federal government, EPA intervention, if air quality fails to meet the nationally-set standards.

Water Management Solutions in the State of Texas

The history of Texas Water law dates back to the 1600s (TWDB, n.d -a). This law has evolved from Spanish Water law to riparian laws, which governed water use around normal stream level water access without much structure, and then to an appropriation system through which state permits are required for major non-domestic water use, and finally to the current modern water licensing system (TWDB, n.d. -a). Since ground water typically belongs to landowners, through Texas Supreme court rulings, the power to regulate water use was accorded to the people of Texas and their representatives, the Texas legislature, to work out local solutions to groundwater management. In 1949, the Texas Ground Water Act created groundwater conservation districts to improve accountability and management of ground water resources (Allen, 2013; TWDB, n.d. -b).

Due to insufficient volume of surface water in south Texas, ground water is the main source of water for the purposes of hydraulic fracturing. Since this ground water is largely potable, its use introduces a strain on other competing water uses such as agriculture. Other non-potable water sources require costly treatments, for example, to desalinate and make them suitable for fracking. Examples of ground water sources include the Carrizo aquifer, the Edwards aquifer, and the Gulf Coast aquifer which are mainly accessed via wells drilled on surface property.

Texas law allots surface water such as streams, rivers, and lakes and subterranean streams to the state. Leases for surface water rights are regulated by the Texas Commission on Environmental Quality (TCEQ) while underground saline or brackish water below potable water zones is regulated by the Railroad Commission of Texas (Kurth et al., 2012). Oil and gas operations in Texas are also regulated by the Railroad Commission (RRC) of Texas. Besides air quality issues which are regulated by the Texas Commission on Environmental Quality (TCEQ), the RRC also regulates environmental issues related to oil and gas operations. Kurth et al. (2012) noted that, in the past, water use associated with well drilling operations were largely unrestricted. But the increased use of water for purposes of hydraulic fracturing has generally led to regulatory enforcement modifications meant to balance the water shortage in water-challenged Texas counties with the high water requirement for resource development (Kurth et al., 2012).

Waste Management Solutions in Texas State

Besides air quality issues that are regulated by the Texas Commission on Environmental Quality (TCEQ), oil and gas operations and related environmental issues in Texas are regulated by the Railroad Commission (RRC) of Texas. Rules governing the administration of oil and gas in the state of Texas are found in the Texas Administrative Code (TAC), Title 16, Part 1, chapter 3. Sections of the regulations involving waste management include water protection (3.8), disposal wells (3.9), hydraulic fracturing additional well guidelines (3.13-07), hydraulic fracturing chemical disclosure (3.29), cleanup of soil contaminated with oil and gas (3.91), and hazardous oil and gas waste (3.98).

Texas state regulations that protect water sources from oil and gas extraction waste prohibit disposal of drilling wastes in surface waters (TAC 16-1-3.8). The RRC has rules that specify dimensions for storage pits, lining and netting to protect wildlife and also prohibit the storage of petroleum products in pits (EPA, 2014a). The RRC is also involved with permitting and testing of underground disposal wells to ensure that the well architecture would not allow vertical migration of injected fluids. The RRC also oversees the plugging and abandonment of wells. According to the Texas Administrative Code (1977a) and Drilling Waste Management Information System [DWMIS] (2015a) the state of Texas RRC allows some disposals without

permits. Examples of these include the disposal of inert wastes in any manner other than in surface waters, shallow burial of fluids generated from completion workovers, and disposal of low chloride-content drilling fluids through landfarming (Texas Administrative Code, 1977a).

Regulations for managing hazardous waste in the state of Texas are more stringent when compared against regulations for non-hazardous waste handling and management. The Texas Administrative Code (TAC) (1977b) states that small quantity (<1000kg/month) and large quantity (>1000kg/month) generators of hazardous waste must notify the Texas Railroad Commission and also obtain EPA identification numbers within 10 days of generating such quantity of waste. This regulation also states that facilities that store hazardous wastes must comply with EPA standards of containment and labeling, training of personnel, and also develop adequate measures in preparedness and prevention of explosions or leaks. Texas law generally prohibits onsite treatment or disposal of hazardous waste and requires transportation of the waste to approved facilities. The TAC also provides specific exemptions to onsite treatment such as in neutralization units or totally enclosed facilities and in accordance with EPA guidelines (TAC, 1977b). Hazardous waste disposal is only possible in hazardous waste disposal wells and 23 of the 44 hazardous waste wells in the U.S. are found in Texas (EPA, 2015c). According to the EPA (2015c), these wells inject into formations that are proven to have sufficiently thick sealing layers and are expected to keep the injected fluids emplaced for a period of 10,000 years!

Water Management Organizations in the State of Texas

As a result of several historic droughts within the state of Texas, this state has a widely-developed organization around management of the state's water resources. Under the guidance of the state government through the Texas Water Development Board (TWDB), management of private water resources are handled through a system of sub-organizations referred to as water conservation districts. Some of the bodies charged with Texas state water resources are the Texas Division of Emergency Management, Texas Commission on Environmental Quality (TCEQ), Texas Drought Preparedness Council (TDPC), the Texas Water Development Board (TWDB), and the Drought Monitoring and Response Committee (DMRC) (Texas Water Code, 2016). The

key legislation that lays out the bodies involved in Texas water resource management is the Texas Water Code (Figure 81).
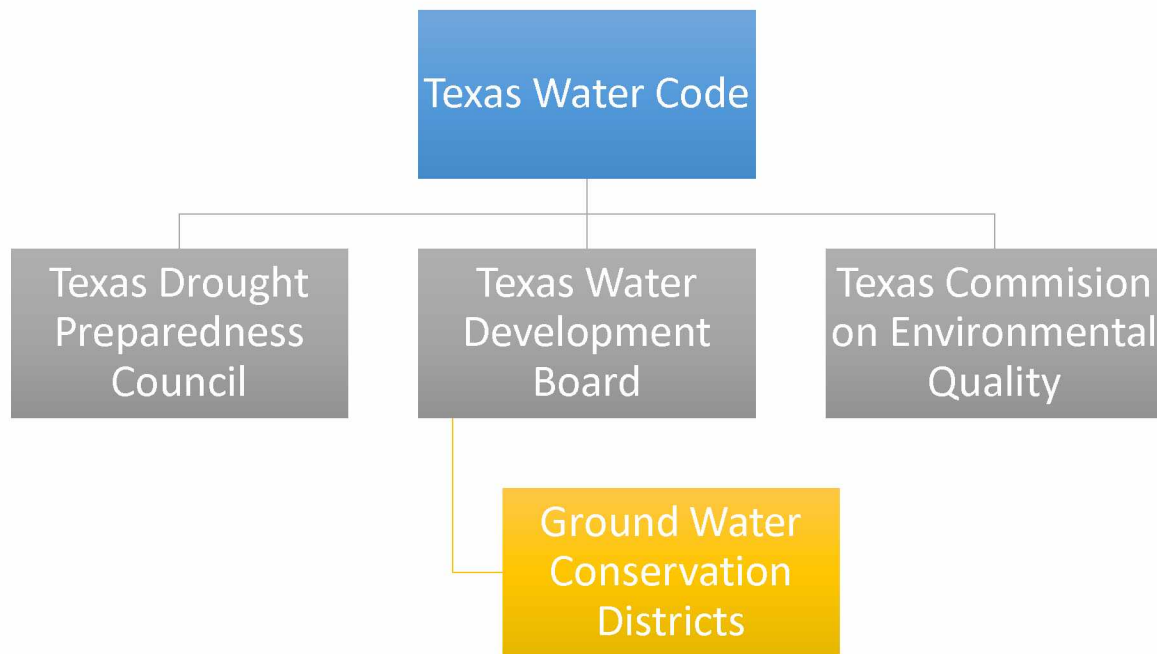
Figure 81. Organization of Water Management in the State of Texas, USA

The Texas State Water Code

The Texas state water code spells out the different bodies involved in management of Texas state water resources. It also puts forth a clear structure of information affecting the management of drought responses and water conservation (Texas Water Code, 2016). The code states that upon a county being highlighted by the conservation council as being at risk of a drought disaster, the county publishes the declaration in any widely-read newspaper (media), notifies the head of its parent regional planning board and each entity responsible for developing and activating a water management plan within the county. These entities are expected to take action immediately to implement the pre-designed drought contingency or water conservation plans (State of Texas, 1999).

Texas Drought Preparedness Council (TDPC)

The Texas Drought Preparedness Council (TDPC) was created in 1999, two years after the creation of the Drought Monitoring and Response Committee (DMRC). The council is headed by the chief of Texas Division of Emergency Management also known as the state's drought master (State of Texas, 1999). The council is comprised of representatives from several departments and divisions including agriculture, parks and wildlife services, emergency management, economic development, transportation, state soil and water conservation board, and an appointee of the governor. The mission of the council is in assessing drought conditions, coordinating responses of interested parties and advising the public and state leadership on drought related issues. Besides a monthly report to the public, every six months the council publishes a comprehensive report advising the legislature on drought conditions in the state (Allen, 2013). It develops and implements the state's drought preparedness plan and makes specific recommendations for drought disaster response (Allen, 2013). The council relies on expert information, studies and forecasts on state meteorology and hydrology, water demand and supply and potential economic, agricultural and public health impact of water shortage.

The Texas Water Development Board (TWDB)

The TWDB was instituted in 1957 with the aim of leading, informing, and providing financial and planning support for projects tied to Texas state water development. According to the TWDB (n.d.) this body provides loans and grants to support projects in water research, water quality enhancement and agricultural water conservation. It collects, maintains and disseminates data on state water resources, funds the creation of the state's water regional districts and administers the sale, transfer or leasing of water rights. The TWDB publishes annual reports on regional water plans prepared by ground water districts (Allen, 2013). Some funding and information organizations managed by the TWDB include the Texas Water Bank, the Texas Water Trust, the Texas Natural Resources Information System, Clean Water State Revolving Fund, and Drinking Water State Revolving Fund. Through the Texas Water Banks, the TWDB leases, transfers or sells water rights. A three member board appointed by the governor is charged with vetting the state water plan and also in the approval of applications for TWDB

grants and loans (TWDB, n.d.). The board also administers the system through which projects meant to alleviate water stress within the state's water plan could be funded at competitive interest rates (TWDB, n.d.).

Regional Ground Water Conservation Districts

There are 98 groundwater conservation districts (GCD) in the State of Texas (State of Texas, 2015b; TWDB, n.d.). These districts constitute the units of water management that are closest to the resource. The board of directors of GCD is made up of elected and appointed officials who are empowered to take actions to conserve water resources within their various districts (TWDB, n.d.). They are also referred to as groundwater conservation districts. Groundwater conservation districts have a constitutional authority to conserve, preserve, and regulate the use of ground water in their districts. They issue drilling permits for water wells, regulate spacing and prevent the waste of water resources. Owners of the wells are expected to submit logs, complete and plug water wells following regulations stipulated by the Texas Department of Licensing and Regulation (Kurth et al., 2012).

Water conservation districts are charged with developing regional groundwater management plans that clarify the regional water management goals and also to address issues of conservation, protection and recharging, and overall efficient management of the region's water resources (TWDB, 2012). These plans include detailed estimates of ground water volumes available, annual use, and water supply and demand within the district including forecasts (State of Texas, 2015b). The plans also put out measures taken by the district to address issues around drought and water supplies, how is tracks progress in attaining its water management goals (TWDB, 2012). Water management plans are expected to give estimates on financial assistance needed from the state to meet drought remediation goals and the impact in cost, safety and state economic development of not addressing them (Allen, 2013). These plans are expected at least every five years with updates encouraged when situations within the district make them necessary. The TWDB is charged with approval of the water development plans and also assists districts with meeting the requirements of their plans.

These conservation districts have often reacted to droughts in Texas by implementing some restrictions, which range from monitoring of water volume pumped from wells, to moving water across drill sites and considering a ban of fracking if water levels in aquifers drop too low (Allen, 2013). Allen (2013) further argues that the application of these laws through ground water districts or language in oil and gas leases could provide land owners the much-needed control over their water resources.

Texas Commission on Environmental Quality (TCEQ)

The TCEQ manages surface water rights. The director of the TCEQ is charged to manage water use during drought situations including interruption, suspension and modification of water rights, to maximize beneficial use of water within the state and to minimize waste. Under this authority, the TCEQ may allow more 'senior' water rights the access to water while restricting 'younger' water rights, but the TCEQ is not authorized to release water that was earlier stored by a water rights owner (Kurth et al., 2012). Kurth et al. (2012) noted that, under recommendations by the Sunset Advisory Commission (SAC), the TCEQ is also permitted to review records of water use by water right holders in reaching decisions during situations of water shortage or drought.

The structure of water management in the state of Texas provides a template for water-challenged tight oil development regions around the world, within a framework centered on individual rights and local control of the resource. In line with strong and sustained oil production in Texas amidst cycles of drought, one may argue that the reward of oil and gas development to the state of Texas supersedes the fear of water scarcity. And over the years, the state of Texas has managed its drought situations effectively by funding studies, passing necessary legislations empowering local control of water resources, and putting up controls to keep the state's leaders vigilant in water monitoring and sustainable water management. This shows that even water challenged regions can pursue tight oil development if regulations and guidelines exist on water use and if enforcement is strong.

The focus on water management in tight oil development stems from the consumptive use of water in hydraulic fracturing. Within the framework of regulations and laws around hydraulic

fracturing, tight oil development has thrived in the states of Texas and North Dakota. These states have also passed laws that work in conjunction with water management, oil and gas waste management and federal regulations to guide the practice of hydraulic fracturing. The state of hydraulic fracturing regulations in the states of Texas and North Dakota will be discussed in the next section.

5.4.3. Hydraulic Fracturing Regulations in Texas and North Dakota

Texas State Regulations on hydraulic Fracturing

The most significant concern about the hydraulic fracturing is the protection of ground water resources, which if contaminated is difficult to access or clean up. There are also major concerns about the handling of thousands of gallons of chemicals that are combined with water to form the fracturing fluid prior to fracking and the handling and disposal of this spent water after fracking. Other concerns also include the volume of freshwater consumed in this process, the process of redressing complaints of contamination, and the transparency of information to the public on the practice of hydraulic fracturing. Every tight oil development region handles these issues differently, and Texas and North Dakota, being the major tight oil producers in the US, provide a useful template to other jurisdictions in this regard.

Hydraulic fracturing in Texas is regulated alongside all oil and gas activities by the Railroad Commission (RRC) of Texas. Regulation of the hydraulic fracturing process begins with regulation of well mechanical integrity requirements, well operation requirements, and extends to regulation of the handling of flowback and produced water through pit construction (RRC, n.d. -b). As a result of these steps taken, the Railroad Commission of Texas notes that there has been no reported case of underground water contamination due to hydraulic fracturing in the 60-year history of the practice (RRC, n.d. -b). To address the public demand for transparency of hydraulic fracturing chemical disclosure, in February 2012, the State of Texas mandated operators to report chemicals used in hydraulic fracturing on the public website, fracfocus.org,

which is run and maintained by the ground water protection council in conjunction with the Interstate Oil and Gas Compact Commission (RRC, n.d. -b). The information required for disclosure on the website include the following:

1. The operator and date of the hydraulic fracturing operation
2. The well API number, county, longitude and latitude and well depth
3. The volume of water used in the operation
4. Trade name, supplier and function of each additive in the fluid
5. Names of each ingredient in the fluid added by the supplier and the operator and chemical details as shown in material safety data sheets
6. Actual or maximum concentration of each chemical ingredient named

According to Kurth et al. (2012) and TAC (n. d.) operators or service companies bear no responsibility for inaccurate information on chemicals from supplier companies, and suppliers bear no responsibility for inaccurate information or information that is undisclosed by product manufacturers. And the contact information of any party claiming protection under trade secret laws ought to be provided to the state by the operator.

North Dakota State Regulations on hydraulic Fracturing

Hydraulic fracturing in the state of North Dakota is regulated by the North Dakota Department of Mineral Resources through regulations in the state's oil and gas rulebook (NDDC, 2014). These rules guide the operation of hydraulic fracturing specifically. The rulebook also calls for the disclosure, within 60 days of carrying out a hydraulic fracturing operations, of every information "made viewable by the website" through the fracfocus.org.

Hydraulic fracturing regulations guide hydraulic fracturing activities, reporting guidelines and wastewater handling and disposal. These regulations provide safety guidelines to prevent nonstandard well casing practices, injection of fracturing fluid in unintended formations, or spills in the well vicinity. Regulations also mandate reporting of frack water chemical contents and the handling of information that is considered trade secrets. On these aspects, a few differences exist between regulations in these two states that have championed the U.S. shale oil boom, Texas and North Dakota (Table 30).

Table 30. Summarized Comparison between Hydraulic Fracturing Activities in Texas and North Dakota (Modified from Temple University, 2017; NDAC § 43-02-03-27; TAC § 16-01-03-29; TAC §16-01-03-8)

Criteria	North Dakota	Texas
Disclosure deadline for fracturing fluid chemical contents	31 to 60 days	Within 30 days
Disclosure guidelines for frack fluid contents	Not required to report volumes; just fluid contents on fracfocus.org platform	Required to report volume and contents of fluids on fracfocus.org platform
Trade secret information withholding	Can't withhold fracture fluid chemical content as trade secret	Can withhold. But must declare to health professionals in line with treatment when life or health risks exist.
Wastewater handling options	Surface tanks are permitted. Must be removed from location within a year after service. Impermeable material-lined dikes must be constructed around surface tanks/facilities. Dikes must be larger than the largest surface receptacle and one day's volume of production.	Commercial waste disposal facilities. Land treatment. Lined pits/Tanks. Treated fluid could be used for hydraulic fracturing without permit.
Fracking operation, well requirement guidelines to reduce chance of spills and loss of containment.	ND Administrative code 43-02-03-27.1. +Well casing thickness and cement integrity must be ascertained. Packer 100m standoff from treating interval is enforced. Treatment pressure during fracks must be at most 85% of pressure rating of casing. Casing must be pre-tested to pressures above treating pressure. + If casing yield pressure is not as high as required, an appropriate frack string must be used. + Relief valve must be used on treating lines to keep treating pressure at <85% of frack string/intermediate casing pressure rating. + Diversion lines must be in place to divert flow into pits if there is loss in containment. + Director must be notified if intermediate-surface casing annuli pressure exceeds 350psi.	Texas Administrative Code 16-01-03-3.13-7. (2017a) +Yield pressure of tubulars in well that will be fracked must be 110% of the maximum fracture treatment pressure. Casings (fracture tubing) must be tested to the maximum treating pressure. +Casing with pressure actuated valves must be tested to 80% of actuating pressure and shown to hold that pressure for at least 5 mins. A failed test means no fracturing is allowed and the division director notified within 24 hours. +Wells with minimum separation from portable water formations have stricter guidelines.
Hazardous waste treatment highlights	Treatment at designated facilities. Restrictions on storage.	Sent to authorized facility or treated on site in appropriate containers.

Criteria	North Dakota	Texas
Underground disposal	Class II wells allowed for injection. Underground Injection Control Law: ND administrative Code Title 33, Article 25 chapter 1. +Details the conditions for injection permit approvals and revocation Injection wells permit holders must prove that the wells have mechanical integrity and contain no leaks in any of the tubulars. +Rules on injecting hazardous waste underground revert to Federal rules in the Code of the Federal Republic. 40 CFR Part 144	Class II wells allowed for injection. Underground Injection Control Law: TX administrative Code Title 16, Part 1 chapter 3. +Rules on mechanical integrity tests, monitoring, periodic reporting for disposal wells, packer standoff from interval. Monitor all casing annuli during disposal. +Operator must obtain permit to inject and prove injection zone is protected from freshwater sources by bounding rock intervals. +Permit could be suspended if injection poses harm to the environment. +Operator of well must ascertain that wells a quarter mile from disposal well are properly plugged to ensure injection does not leak into freshwater sources.

Table 30 continued.

5.5.   Hydraulic Fracturing and Water Management: The U.S. Environmental Protection Agency Finding Review

In 2016, the EPA studied impacts of hydraulic fracturing on surface and underground water sources under a 5-stage cycle consisting of water acquisition, chemical mixing, well injection, produced water handling and wastewater disposal and reuse (Figure 82; EPA, 2016a). Through scientific papers and research into the processes involved in the hydraulic fracturing cycle, the EPA identified supporting factors and risks to drinking water associated with each portion of the cycle.

The EPA (2016a) concluded that water acquisition for hydraulic fracturing operations is a risk to freshwater availability when large quantities of water are withdrawn from water sources during

drought or other low flow seasons. Underground water sources are more at risk in areas where those were the main sources for water withdrawal, and surface water sources were more at risk in areas with little underground water available. The lack of sufficient Class II wells in some oil and gas plays and the high cost of transporting flowback water across long distances to disposal sites contribute to a growing reuse of hydraulic fracture water for new fracturing operations. Laws in some states also insist that water withdrawal from streams do not reduce the water flow below set levels, and that lower quality water, such as brackish water, be used in place of or alongside freshwater (EPA, 2016a). According to the EPA (2016a), these factors have helped mitigate surface and underground freshwater over use in most areas.

Additionally, additives to hydraulic fracture water also pose a risk to fresh surface and ground water sources in the event of spills (EPA, 2016a). Although water remains the main fluid used in hydraulic fracturing operations, the use of other conditioning chemicals is necessary to improve the effectiveness of hydraulic fractures. The EPA reported that over 1000 chemicals have been used in hydraulic fracturing operations from 2005 to 2013 and up to 28 could be used in a single well (EPA, 2016a). These chemicals are brought to site in concentrated form and through equipment or human error could leak into the environment. The EPA identified rock permeability and the adhesiveness and solubility of chemicals as contributing factors to the likelihood of contact with surface or underground water, as well as the impact or longevity of such impact.

Additionally, surface and underground sources can also become contaminated during the process of injecting hydraulic fracturing water down the wellbore (EPA, 2016a). This is made possible when a failure occurs in the metal casing lining the well or in the cased hole cement between casings or between the casing and the formation. Injection pressures during hydraulic fracturing operations could be as high as 12000 psi (800 times above atmospheric pressure) (EPA, 2016a). Failure in mechanical integrity of the well could happen for reasons ranging from the aging of well equipment, the pressure at which injection occurs, the distance of the fractured well from groundwater sources, fractures in rocks, and other poorly abandoned wells that easily connect to underground water sources (EPA, 2016a).

The EPA (2016a) also noted that depending on spill volume, soil type and solubility of spilled chemicals, large quantities of produced water from oil and gas operations, when poorly handled, also pose a risk to fresh surface and underground water sources. This is because produced water contains naturally existing ground chemicals and salts, radioactive materials and synthetic chemicals that were injected into the formation during the hydraulic fracturing process. The EPA (2016a) reported that salinity of produced water could be as high as 300,000 mg/l and noted situations where human and equipment failure had led to spills into surface water bodies resulting in increased salinity and conductivity of the contaminated water.

Finally, the EPA (2016a) observed that basic wastewater disposal practices could lead to contamination and pose a risk to surface and underground sources. Above ground produced water reuse or disposal methods applied in different areas across the U.S. depend on the quality of the water, laws and regulations in place, and the comparative economics of various water management options. According to the EPA (2016a), water management options available to many states across the U.S. include underground injection in class II wells, the use of evaporation ponds, percolation pits, treatment, and surface disposal through methods like irrigation. When improperly handled, spills do occur and do impact surface and subsurface sources. Even with these wide set of options available, it is worth noting that any selected option presents a different suite of water handling challenges between the point of flowback water generation to the point of use.

EPA-identified Risks of Hydraulic Fracturing on Drinking Water

| Water Sourcing in low water seasons | Chemical mixing and risk of surface water contamination | Well integrity and underground water contamination risk |
| Produced Water Handling | | Water Disposal Practices |
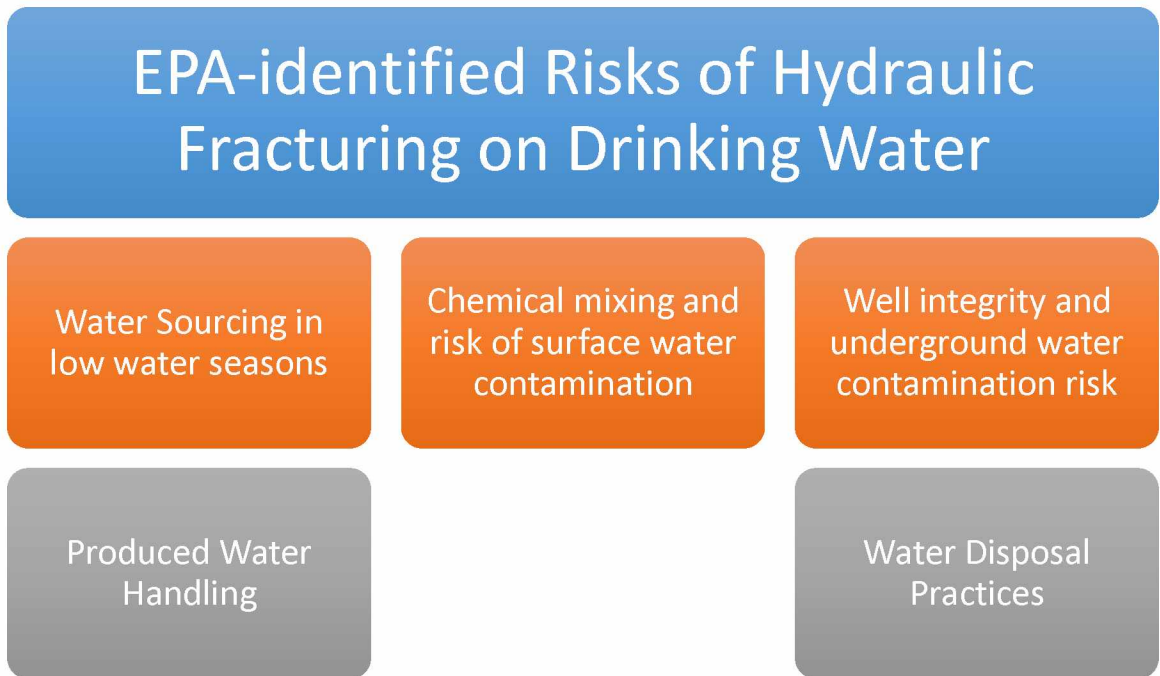
Figure 82. Summary of Risks to Drinking Water Identified by the EPA Hydraulic Fracturing Study (EPA, 2016a)

5.6.   Economics of Wastewater Management Options for Tight Oil Development

Slutz et al. (2012) categorized flow-back water management in shale development into the categories of re-use, recycle, and disposal. The application of these management categories could range widely depending on several factors. For conventional oil production operations, produced water reuse is typically the preferred option, since the benefits of reinjection are significant and because the rock quality allows copious volumes of water to be injected easily (Table 31). But for tight oil development, where direct reuse is not feasible, recycle or disposal are the main options available. Slutz et al. (2012) identified six factors that influence the chemistry of flowback water and the cost of flowback water handling as follows: (1) chemistry of source water, (2) the hydraulic fracturing program, (3) formation geochemistry, (4) communication with water-bearing formations, (5) blending flowback and other waters, and (6) the time the water stays on the surface. According to the RRC (n.d. -b) underground water injection is generally the preferred option for managing oil and gas produced wastewater.

Table 31. Management Options for Produced Water (EPA, 2000)

Method	Percent of Onshore Produced Water
Injected for Enhanced Recovery	57%
Injection for Disposal	36%
Beneficial Use	4%
Evaporation and Percolation Ponds	2%
Treat and Discharge	1%
Roadspreading	<1%

5.6.1. Total Disposal Scenario

One of the benefits of the exemption of the oil and gas industry waste from the RCRA regulation is that it allows operators to strive more towards finding cheaper disposal options (EPA, n.d. -b). Cost estimates for disposal of wastewater by commercial facilities vary widely. In 1997, operators quoted a total treatment and handling cost that ranges from $7.5 to $350/bbl, while commercial handling facilities quoted a range from 0.2 to 14.7/bbl for water-based or $1 - $57 for oil-based drilling waste (DWMIS, 2015b). Produced water disposal and water of different dirt levels are quoted to range between 0.01 to $8/bbl (Veil, 1997). Authorized facilities who receive the oil-field waste could treat or dispose them using EPA-authorized methods, including using one or more of the 44 class 1 wells in the country that handle hazardous wastes (EPA, n.d -j).

The American Petroleum Institute (1997) estimated that for each barrel of oil produced one barrel of water is also produced. Therefore, for a well that produces 1 million barrels of oil over a 20-year period, and disposes the entire produced water as hazardous wastewater using commercial waste disposers, at a cost of $10/bbl or non-hazardous water at $7/bbl, a simplified cost breakdown shows that the cost of water management for this well alone could range between $7.5 to $10 million in 1997 dollars (Table 32,

237

Table 33). Escalated to 2017 real dollars, at $13.7 and $19.5 per barrel for non-hazardous and hazardous water treatment, this cost grows to $13.0 and $18.3 million respectively (Federal Reserve Bank St Louis, 2017). Including the cost of transportation by trucks and labor, and under current water disposal practices, WaterWorld (2013) puts the cost of water disposal for the entire life of a well at $160 million.

Table 32. Cost breakdown for wastewater disposal for a fractured well assuming hazardous produced water

Parameter	Volume of water or Cost
Additional flowback water production shortly after frack (2 million gals; 50% of frack fluid volume of 4 million gals; 1bbl= 42 gals)	50,000 bbl
Total water production (if EUR = 1MMbbl)	1,000,000 bbl
Volume of hazardous water through authorized facilities	1,050,000 bbl
At $10/bbl disposal cost	**$10,500,000 over a period of ~20 years**

Table 33. Cost breakdown for wastewater disposal for a fractured well assuming only hazardous flowback water

Parameter	Cost
Cost of disposing 50,000bbl of hazardous flowback water at $10/bbl	$500,000
Cost of disposing non-hazardous 1,000,000bbl of water produced through the life of the well at $7/bbl	$7,000,000
Cost of disposing 1,050,000 bbl of hazardous and non-hazardous water through authorized facilities	**$7,500,000 over the well life of ~20 years**

5.6.2.   Water Treatment and Reuse Scenario

A typical hydraulic fracturing operation consumes approximately 4 to 5 million gallons of water. Sourcing and transporting this volume causes significant truck traffic and leads to increased accidents and road nuisance in the towns where tight oil development occurs. Besides these environmental impacts, the economics of water acquisition also puts pressure on the budgets of

asset managers. As a result, the industry and environmental activists alike are searching for ways to improve recycling and reduce the water requirement, and by so doing, the logistical burden of water procurement in shale development.

Economic and environmental pressures from water conservation regulations are promoting the use of recycled flowback water or brackish water in hydraulic fracturing operations. Full implementation of these efforts will reduce the freshwater demands on counties and communities in which hydraulic fracturing currently occurs. Examples of water conservation efforts are already happening, led by oil and gas operators' drive for operational efficiency and profitability. The Apache Corporation constructed a processing facility in Irion County, Texas, with an overall daily capacity of 40,000 barrels of produced water (Boyd, 2015).

The reusability of flowback water depends on water chemistry, and the logistical and cost challenges involved with water aggregation and treatment. The chemistry of flowback and produced water depends on the organic and inorganic materials present in the formation being developed, and the chemical additives to the fluid used in hydraulic fracturing. These materials constitute the levels of total dissolved solids (TDS) that are handled during water treatment.

The cost of water treatment is tied to the intended condition of the water planned for reuse. Hydraulic fracturing could be performed using three broad types of fluids: slickwater, linear gel fluids, and crosslinked gel fluids (Boschee, 2014). These fluids have different impacts on pump pressure requirements of the operation and have different proppant carrying capabilities. Minerals like calcium and boron are known to reduce the effectiveness of hydraulic fracturing fluids by reducing the ability of crosslinks to form, which in turn affects the ability of the fluid to transport proppants through the wellbore into the fractures (Boschee, 2014). According to Boschee (2014) the introduction of salt-tolerant fluid systems has improved the usability of flowback water containing high levels of dissolved salts. With the use of fluids that can crosslink in the presence of dissolved salts, operators can save costs in water treatment.

Transportation and treatment of flowback water also increases the logistical cost of recycling and water reuse. The distance between stimulated wells, over which flowback water needs to be

transported for treatment, affect the cost of recycling. When the flowback water is large enough, the presence of nearby already-stimulated wells that are producing water makes it easier and less expensive to stimulate new wells. If the wells are far apart, the cost of aggregating flowback water may erode much of the economies of scale benefit that significant amounts of flowback water would have provided to the operation.

Besides options for flowback water reuse, wastewater disposal through underground water injection has been the preferred option for several operators in oil plays within the U.S. (RRC, n.d. -b). The availability of commercial disposal wells facilitates the choice of water disposal over recycling. Most of the underground injection and disposal wells in the U.S. are located in the state of Texas (Propublica.org, 2012). The availability of large quantities of disposal wells makes the water disposal option attractive, while fewer disposal wells or stiffer regulations on wastewater handling increases the cost of disposal. The cost of different water management options and the unique characteristics of an asset guide the selection of the optimal water management option for that location. For example, for the Bakken, the total cost of water management which includes acquisition, transportation, recycling, and disposal is estimated to range between $6 and $15 per barrel and the portion of hydraulic fracturing fluid that returns as flowback water could average 27.5% (Boschee, 2014). Boschee (2014) also reports different flowback percentages for different tight oil plays (Table 34).

Table 34. Percentage Return Flowback Water in Major U.S. Shale Plays (Boschee, 2014).

Plays	Return water%	
	Low	high
Bakken	15%	40%
Permian	20%	40%
Niobrara	15%	30%
Eagle Ford	<15%	15%

Assuming the hydraulic fracturing operation for each well requires 4 million gallons of water, the difference between the cost of water management for a ten-well operation where flowback water is recycled and reused once before disposal, and another operation where flowback water

is disposed directly without any recycle or reuse, could be estimated across the four tight oil plays of Bakken, Eagle Ford, Permian, and Niobrara (Figure 83).
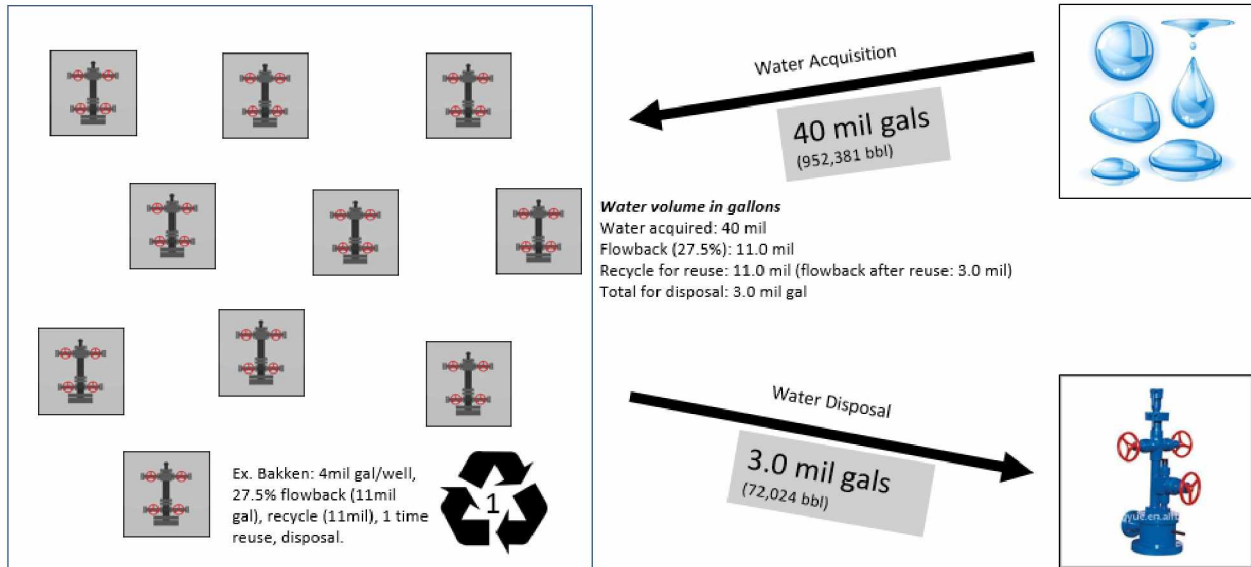
Figure 83. Water Management for a hypothetical 10-well asset in the Bakken Tight Oil Play

For the operation where 100% of the flowback water from every well is recycled and the cost of aggregating water across producing wells is small compared to actual recycling costs, it is possible to compare across two water management strategies. This is a simplifying assumption because it would take closely-sited wells and established facilities for an operation to run at such efficiency levels. Given that these facilities do exist and the total cost of water handling for the Bakken is $15 (Boschee, 2014), equally divided across the three processes of water acquisition and transportation, water recycling, and water disposal, each costing $5, the following is a cost breakdown for a hypothetical 10-well project for each of the four major tight oil plays (Figure 84 and Figure 85).
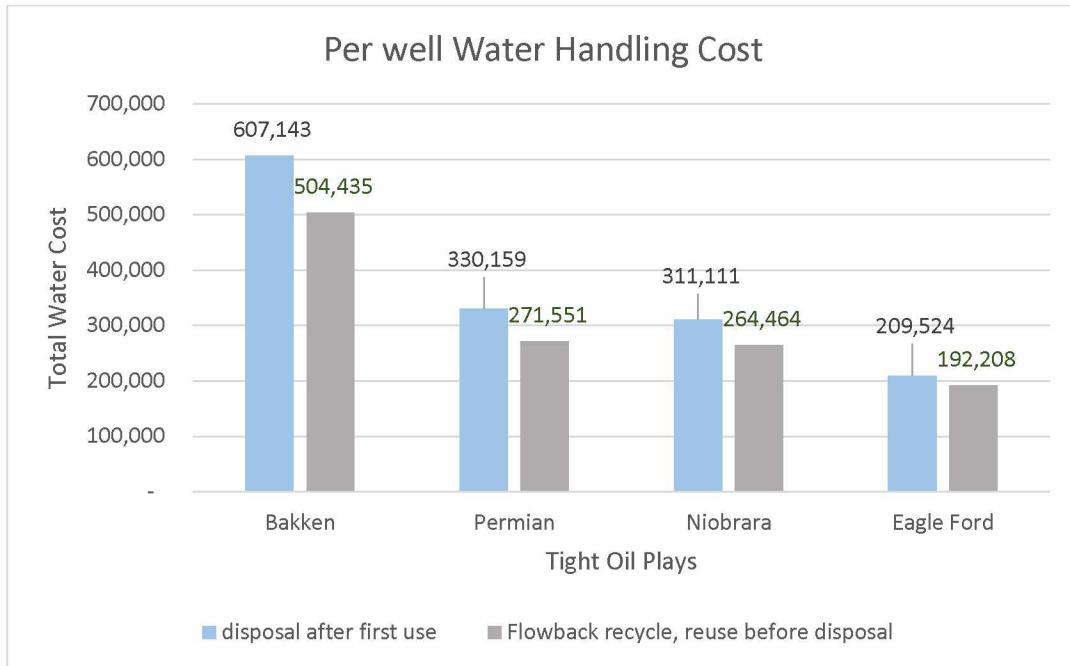
Figure 84. Comparing Water Management cost in Four U.S. Plays (Modified from Boschee, 2014)

Ex. Bakken	Cost/bbl		volume (bbl=gal/42)	Cost ($)		volume (gal/42)	Cost ($)
Initial wells fractured		10			10		
Water Acquisition cost	$ 5.0		952,381	4,761,905		952,381	4,761,905
Flowback %		*28%*			*28%*		
Flowback water recycle	$ 5.0		261,905	1,309,524		-	-
Disposal	$ 5.0		72,024	360,119		261,905	1,309,524
Total Water handling cost				6,431,548			6,071,429
Additional Wells fractured	*2.75*				*0*		
Total Number of wells fractured	*12.8*				*10*		
Per well water cost				504,435			607,143

Figure 85. Cost Comparison for Two Water Management Strategies (Adapted using Total Water Cost of Bakken Developments; Boschee, 2014)

The research into some water treatment options has not gone beyond pilot tests. Historically, high oil price periods have been associated with more investment in technology trials and oil field solutions including water management concepts. But lately, these advances are seen in low oil price times and since low oil prices from late 2014, operators are more motivated to finding creative ways of ensuring that costs incurred in water management do not erode the already-marginal economics of development in some plays.

Several trials are ongoing in finding more ways of handling the huge water management expense facing producers. Rassenfoss (2013) discussed pilot efforts to reduce the amount of water used in fracking by the use of nitrogen as fracturing fluid. The benefit of this new approach is due to the character of liquid nitrogen to return to the gaseous state under reservoir temperatures, leaving the formation undamaged and the rock permeability unimpaired. Schmidt et al. (2015) reported ongoing efforts in using solely produced water for hydraulic fracturing with several advantages. They estimated that the ~190 million gallons of water used annually could be entirely provided from potential supply from wells in place, hence saving freshwater and reducing truck traffic on roads. They also highlighted key challenges to using produced water for hydraulic fracturing as ranging from storage challenges, solids and salt content of flowback water, and the high cost of treating the water to a useable form.

Water management will remain a major issue in tight oil development with major implications for cost and the environment. Lunn et al. (2014) proffered a four-step water resource management guide that could be used by operators of assets and city planners. These steps consist of (1) data gathering on water use by any operation, (2) analysis of the data through metrics like withdrawal, percentage use and some measure of use efficiency, (3) risk assessment of the source of water supply and conditions of the environment, and (4) a risk management profile to continue to conserve the water source. Through this management framework, each water-use operation is encouraged to provide vigilant stewardship of its water use and continuously strive for a reduction in its water footprint. Other researchers and operators have studied the issue of water use and find no reason for alarm in most locations where precipitation levels were found sufficient to provide for competing water demands (Arthur et al., n.d). While stakeholders may differ on the existence of a water problem or the strategy of striving for water conservation by way of regulations, the impact of water management on profitability of oil and gas assets has won the attention of business leaders and may be the most compelling argument for water conservation.

5.7. Summary: Environmental Regulations and Tight Oil Development

In 2005, the U.S. congress removed the regulation of water-based hydraulic fracturing from the purview of the EPA under the Safe Drinking Water Act, contrary to a ruling by the Eleventh Circuit court of Appeal in 1997 (Beck, 2011). Many agree that this action is among the most relevant nationwide legislative protections of the tight resource development industry. Others argue that without this legislative protection, tight oil and gas development in the U.S. would have been stymied and the major economic benefits to the governments and public would have been lost.

The EPA in 2015, in a draft report on the impact of tight oil development on water sources, concluded that it could not rule out the potential of this industry's hydraulic fracturing activities to affect drinking water sources. While the EPA mentioned that in a review of the technique of hydraulic fracturing, the chemicals used and the nature of protection of wells showed clear pathways for pollution, it pointed out significant gaps in data and understanding that precluded a categorical implication of the tight oil industry in systemic widespread water pollution (EPA, 2016a). This leaves a key question unanswered: From the EPA's findings, should more laws be put in place or new guidance be put out on how to more closely regulate the tight oil and gas development industry?

The precautionary principle posits that when the consequence of damage posed by a hazard to a system is grave, the lack of settlement in the science or the absence of a convincing case that irrefutably establishes a causal link, is no excuse for inaction (United Nations, 1992). There is still room for cost benefit analysis to establish alternative options and to select cost effective measures of action (United Nations, 1992). Perkins (2010) further argues that if the severity of damage posed by the threat is irreversible and astronomical, in line with the pillars of severity and probability that define the concept of risk, only a zero probability can ensure that the risk is managed. This suggests that, in line with tight oil development, for example, if the threat of damage involves major aquifers, that will take, for example, hundreds of years to run off radioactive or highly soluble pollutants, the only way of managing such risk is not drilling the

well. This school of thought will suggest that wells planned for drilling around major aquifers around the country that service millions of people, ought not to be drilled because of the grave cost society will incur if contamination occurs.

The EPA (2016b) in studying the connection between hydraulic fracturing and drinking water concluded that it found circumstances in which fracking could impact drinking water but had data gaps in assessing both the severity of such impacts and frequency on a nationwide scale. The precautionary principle recommends that even the absence of strong ties or a preponderance of the evidence,on the scale the study set out to find, is no reason to do nothing or argument against rulemaking or enforceable guideline-setting for the tight oil industry. Opponents of this interpretation contend that it may lead to an endless stream of legislation in a thousand issues backed by, in some cases, pure speculation. And this practice could be a serious burden to businesses. It is easy to see how a business could free itself from a regulation that could be costly to follow by reducing its headcount just below the threshold above which it would otherwise fall into the class of businesses on which the regulation applies. Perkins (2010) weighed arguments on both sides of the precautionary principle theory and concluded that the decision maker cannot seek shelter in doing nothing when faced with the argument that the facts are not entirely established, and argued that undeniable certainty is almost never attained. The U.S. Army Corps of Engineers (2013) also agree that incomplete data and inconclusive scientific assessment only call for greater precaution in addressing potential impacts in a given situation.

Earthjustice (2011) petitioned the EPA to promulgate rules under the Toxic Substances Control Act sections 4 and 8, which would require operators to conduct toxicity tests on all the chemicals they employ in hydraulic fracturing and keep records of those. This, they argued would protect the public against potential harm from hydraulic fracturing chemicals. Because the states now enforce the disclosure of these chemicals to the public, and some states like North Dakota reject any arguments by operators to withhold information on chemicals as trade secrets, it is unarguable that the states themselves are taking the first step. This step sets the stage for more federal, state and private industry collaboration to continue to study the characteristics of chemicals and potentially find substitute chemicals with properties that are less harmful to the

environment, less lasting in the event of spills, and that could still be as effective as their more harmful classes of chemicals currently being used.

In addition to produced wastewater management issues, like proper disposal and protection of state surface water sources, the future of shale resource development still points to significant use of water and the potential for pollution. In 2014, over 240 million barrels of water were consumed for hydraulic fracturing in North Dakota (ND SWC, 2016) and 1 billion barrels is projected to require handling and disposal in the years between 2015 and 2018 (Bader, 2016). With more baseline studies on water quality, and improvements in technology to trace contaminations and their correlation to tight oil development activities, it is possible there could be a more evidence-based link between fracking and environmental impacts. While there is room for promulgation of guidelines to help the states better engage with the tight oil industry, the presence of a large body of data could bridge the gaps in current understanding and provide better authority to agencies, on the national and the state-level, to engage with the industry.

Safety of water resources can be assured if states and industry collaborate to maintain strict rules on well architecture and surface water handling to further reduce the probability of underground or surface contamination of freshwater bodies. For example, most states have laws against surface discharge of treated wastewater, even when that water is treated to distilled water status (TAC, 2017b). Supporters of the industry point to similar examples of laws currently enforced as evidence of sufficient state regulation on industry activity. Beyond the facts against or for hydraulic fracturing, there is need for some concerted effort to build trust between operators and the public. Initiatives like the Fracfocus website are helping in this regard. And unconditional disclosure of chemical content information by states like North Dakota show that even strong supporters of the industry could still be trusted to enforce laws that protect the lives of their populations.

5.8.   Conclusion

Environmental regulations have contributed in shaping the tight oil development experience in the US. Hand-in-hand with economic development is the presence and guidance provided by

regulations. This chapter has reviewed arguments about regulations from environmentalist and industry perspectives and has highlighted the resilience of laws that predate the tight oil industry. It has also discussed the adaptations of regulation to ensure safe and sustainable tight oil development. In so doing, we have shown through case studies on the busiest U.S. plays, the potential for disruption of industry activity to the lives of local inhabitants of resource development regions and the role of regulations, not as hurdles for economic activity, but as preservers of social license required for economic activity. The section provides different approaches applied in tight oil and gas development that could be adapted by other tight oil regions around the world to guide development of these resources. Since the collage of solutions taken by any province is based on its local laws and economic priorities, it is important that the U.S. solutions be seen as possible templates which could be built upon to provide every shale locale with a fit-for-purpose solution to address its own needs.

Chapter 6. SUMMARY AND CONCLUSIONS

6.1.   Research Summary

The United States oil and gas industry turned the corner in the last decade and reversed a 30-year decline in petroleum production. This phenomenon began with tight gas production. Prior to this, the U.S. was a natural gas importer and several businesses on the Gulf Coast were setting up to become import hubs for LNG from Middle Eastern, Australian producers, and other gas rich provinces. These same businesses, just a few years later are now working to become LNG exporters thanks to massive natural gas production from tight shale plays in the U.S. (EIA, 2016m). This was the impact of shale gas production, and a similar phenomenon is happening for oil production. Learnings in tight gas production were quickly transferred to liquid rich gas plays and later to tight oil plays. These plays have reversed the decline in U.S. oil production and relieved massive efforts at enhanced oil recovery in old and marginal fields. Tight plays like the Eagle Ford, Permian, Bakken, and Niobrara have been on the forefront of U.S. tight oil renaissance.

With huge national benefits in reduced oil import and accompanying international strategic benefits, low unemployment, and a broadening of the tax base of oil producing states, improvement in the lives of citizens and support industries, many experts within the U.S. and outside understand that tight oil development in the U.S. has been transformational. Besides this notional understanding, many have not assessed the many dimensions of this development in any detail beyond news articles, or academic conferences on select segments of the tight oil revolution. At that level of detail, the issues seem disparate and the insights don't lend themselves for comprehensive review for business leaders, or policy makers. And for non-U.S. plays with similar resource types, assessing the possibility of transferring lessons from tight oil development is challenging. In this research, a framework for such assessment has been provided.

This research evaluated the engineering, environmental, and economic dimensions of the U.S. tight oil phenomenon. It reviewed the key drivers that contributed to U.S. tight oil industry

successes as learnings for new and promising tight oil provinces around the world. The geological properties of non-U.S. plays, as provided by the U.S. Energy Information and Administration/Advanced Resources International (2013) report, were also used to draw comparisons between major U.S. plays and non-US frontier plays. It further developed preliminary economic assessments for non-U.S. plays, at the project level.

On the engineering front, this research produced a crude oil production forecast for seven tight oil regions; the Permian, Bakken, Eagle Ford, Niobrara, Haynesville, Marcellus, and Utica formations, under scenarios of high or low oil prices. We reviewed tight oil well production forecasting techniques, and by applying a hybrid technique of statistical type well derivation and the empirical modified Duong tight oil forecasting model, we developed 20-year well profiles for tight oil wells. This analysis used the commercially available software, Drillinginfo for type well derivation. The method developed for this analysis applied steady state well counts from historical low and high oil price periods to develop projections for crude oil production for high and low oil price scenarios. This result was shown to be comparable to production projections by the Energy Information Administration developed using the EIA's National Economic Modeling Software Tool.

On the environmental front, this research reviewed the role of U.S. federal and state environmental regulations in tight oil development. Our analysis of these regulations in relation to tight oil development showed the level of resilience of most laws that predated this development and the level of modifications that have enabled their enforcement. The need for a clean environment, in the midst of tight oil prosperity is highlighted by strong state enforcements and federal oversight through institutions like the EPA. We also assessed the environmental issues around tight oil development with the help of case studies within the busiest tight oil plays in the US: the Bakken and Eagle Ford. These case studies provided concrete circumstances where environmental regulations intersect with industry practices and the practice of hydraulic fracturing. We reviewed the regulations on hydraulic fracturing in these areas and highlighted ongoing efforts by state governments in preventing environmental contamination, ensuring transparency and public participation. Through the challenges and local solutions, these case studies also highlight the fact that regulations and smart enforcement, rather than stifling industry

could be key tools for preserving the social license to operate for oil firms, and ensuring the sustainability of the tight oil industry. I also conducted a quantitative evaluation of the potential economic impact of different solutions to the problem of water consumption and disposal in tight oil industry practice.

On the economic front, I applied an econometric technique in making sense of the impact of oil price and drilling activity levels on oil production. This assessment employed the Auto Regressive Distributed Lag (ARDL) model in highlighting the relationship among key variables within the tight oil development industry over the last decade. The framework used in this analysis, to the best of my knowledge, is the first time that insights from geological and play production and development characteristics were used within an econometric framework alongside the ARDL technique to understand the behavior of oil and gas operators in different oil plays. This analysis shows long run and short run behavior of oil production in response to oil price signals as different for different oil plays, based on the rock quality and commercial arrangements that operators have in these plays.

In addition, this research also reviewed the U.S. oil and gas industry to highlight key supporting factors for tight oil development. It also provides policy makers with a template from which to engage in capacity building and modification to support oil and gas development within their locales. This review, in addition to specific economic assessment of oil and gas projects in non-U.S. tight oil plays, provides business stakeholders interested in pursuing oil development opportunities, a framework for assessing projects. This work produced an easy way to compare qualities of tight oil plays and confirms that other locations where tight oil development projects could be economic. This research illustrates oil price and well cost as key determinants of play economics but also shows that projects are as economically attractive as fiscal systems will make them. The absence of good quality rock with high resource concentration is a major hurdle to development, but the profitability of the enterprise also depends on what share of the profit the operator is allowed to keep. Key elements within the tax system could be arranged to attract investment in frontier tight oil plays and ultimately upend the economic ranking of plays shown in this work.

251

6.2. Research Limitations and Major Exclusions

While this work evaluated the U.S. tight oil development phenomenon within an interdisciplinary framework, it is by no means exhaustive of every possible aspect of the issue. I acknowledge some limitations of the research that fall within and outside the defined scope.

Firstly, the economic assessment of tight oil development in non-U.S. plays has not looked into water and other operational logistics that enable tight oil development to occur. Peter Zeihan (2014) in *The Accidental Superpower* points out the importance of geography and the presence of water as a key factor in the development of nations. The availability of water has powered the tight oil and gas revolution in the US. The contiguous U.S. land has 2110 watersheds draining the U.S. mainland into thousands of streams and lakes (ND SWC, 2014). This work did not focus on an exhaustive review of the water-readiness of the non-US shale nations discussed in this work. Water requirements for hydraulic fracturing is a key issue excluded by this research. The U.S. mainland has waterways and bodies that enable operators to meet their water needs for hydraulic fracturing. This may not be the case for other countries or regions in which tight oil resources exist.

The Rails network constitutes a major portion of oil transportation within the US. The Bakken and Eagle Ford have growing networks of railroads and pipelines, to different degrees, taking crude out of oil fields. This is important because it affects the revenue of sovereign or royalty owners, as well as operators, even as the netback pricing scheme used by many regions protects the operator and reduces the royalty value of the resource by the cost of taking it to market. This makes development in some plays more attractive than others. Especially in nations without very good pipeline network, the cost and logistical challenges of development may be quite onerous and erode the profitability of some marginal producers. This work did not look into the availability of a viable transportation network by non-U.S. nations in this analysis.

6.3.   Recommendations for Future Work

This research built on the work of the EIA/ARI (2013) that provided a broad review of shale oil resources in 41 countries and evaluated over 137 shale formations. A potential for future study would be to further the search for new areas of tight resource development; this could build on the rapidly changing development techniques and exploration outcomes of some of these non-U.S. plays based on data from new exploration wells and pilot projects. Such work may use new recovery factors based on tested development pilots. In addition, the future work could apply the fiscal system specific to the location of the tight oil play to assess scenarios for economic viability that include the unique infrastructural, regulatory, and water availability conditions of the non-U.S. tight oil locations.

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