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United States Oil Industry and Liquid Supply/Demand to 2022
UNITED STATES OIL INDUSTRY AND LIQUID SUPPLY/DEMAND TO 2022
# Table of Contents

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>LIST OF FIGURES</td>
<td>v</td>
</tr>
<tr>
<td>LIST OF TABLES</td>
<td>vi</td>
</tr>
<tr>
<td>EXECUTIVE SUMMARY</td>
<td>ix</td>
</tr>
<tr>
<td>CHAPTER 1 INTRODUCTION</td>
<td>1</td>
</tr>
<tr>
<td>CHAPTER 2 PADD 1: EAST COAST</td>
<td>5</td>
</tr>
<tr>
<td>CHAPTER 3 PADD 2: MID-CONTINENT AREA</td>
<td>7</td>
</tr>
<tr>
<td>The Bakken Shale, Williston Basin, North Dakota and Montana</td>
<td>7</td>
</tr>
<tr>
<td>Geology and Basin Metrics</td>
<td>8</td>
</tr>
<tr>
<td>E&amp;P Players and Recent M&amp;A Activity</td>
<td>13</td>
</tr>
<tr>
<td>CHAPTER 4 PADD 3: SOUTHERN STATES</td>
<td>29</td>
</tr>
<tr>
<td>The Eagle Ford Shale, Maverick Basin, Texas</td>
<td>29</td>
</tr>
<tr>
<td>Geology and Basin Metrics</td>
<td>30</td>
</tr>
<tr>
<td>E&amp;P Players and Recent M&amp;A Activity</td>
<td>35</td>
</tr>
<tr>
<td>CHAPTER 5 PADD 4: ROCKY MOUNTAIN STATES</td>
<td>45</td>
</tr>
<tr>
<td>The Niobrara Shale, Colorado/New Mexico/Nebraska</td>
<td>45</td>
</tr>
<tr>
<td>Geology and Basin Metrics</td>
<td>46</td>
</tr>
<tr>
<td>E&amp;P Players and Recent M&amp;A Activity</td>
<td>53</td>
</tr>
<tr>
<td>CHAPTER 6 PADD 5: WEST COAST</td>
<td>65</td>
</tr>
<tr>
<td>CHAPTER 7 UNITED STATES LIQUIDS SUPPLY AND DEMAND</td>
<td>67</td>
</tr>
</tbody>
</table>
List of Figures

E.1 United States Crude Oil Imports from OPEC Countries ........................................... x
E.2 United States Crude Oil Imports from non-OPEC Countries ................................ xi
E.3 United States Liquids Supply/Demand Balance..................................................... xii
1.1 Petroleum Administration for Defense Districts ...................................................... 2
2.1 PADD 1 State Production of Crude Oil ................................................................. 5
3.1 PADD 2 State Production of Crude Oil ................................................................. 7
3.2 The Bakken Formation ......................................................................................... 8
3.3 Producing Wells in the Bakken Shale Play ......................................................... 9
3.4 Bakken-Lodgepole Shale Play ......................................................................... 10
3.5 Map of Bakken Shale and the Three Forks Formation ........................................ 11
3.6 Stratigraphic Cross-section of the Bakken Formation ....................................... 12
3.7 North Dakota Annual Oil Production from 1993 to 2012 ................................ 14
3.8 North Dakota Monthly Oil Production between 2008 and 2012 ..................... 15
3.9 North Dakota Monthly Oil Production ............................................................ 16
3.10 Montana Monthly Oil Production between 2008 and 2012 ............................ 17
3.11 Oilfield Activity in the Bakken Shale Play ....................................................... 18
3.12 Continental Resources 2012 Proved Reserves .................................................. 20
3.13 Continental Resources 2012 Net Acreage ....................................................... 20
3.14 Continental Resources 4Q2012 Production .......................................................... 21
3.15 Three Forks Isopach Map ................................................................................. 22
3.16 Whiting’s Lease Holdings in the Bakken Shale .............................................. 23
3.17 EOG Acreage in the Bakken/Three Forks ..................................................... 25
3.18 PADD 2 Unconventional Crude Oil Forecast .................................................. 27
4.1 PADD 3 State Production of Crude Oil ................................................................. 29
4.2 Eagle Ford Shale Map ......................................................................................... 30
4.3 Eagle Ford Shale Play – Wells Permitted and Completed .................................. 31
4.4 Eagle Ford Shale Play .......................................................................................... 32
4.5 Schematic Geology of the Eagle Ford Shale ..................................................... 33
4.6 Eagle Ford Shale Oil Production between 2008 and 2012 ................................. 36
4.7 EOG’s Lease Holdings in the Eagle Ford Shale .................................................. 38
4.8 Chesapeake’s Lease Holdings in the Eagle Ford Shale ..................................... 40
4.9 ConocoPhillips Acreage in the Eagle Ford Shale ............................................. 42
4.10 PADD 3 Unconventional Crude Oil Forecast .................................................. 43
5.1 PADD 4 State Production of Crude Oil ................................................................. 45
5.2 The Niobrara Shale and Area Map .................................................................. 46
5.3 The Niobrara Shale Map ..................................................................................... 47
5.4 Niobrara Shale Stratigraphy .............................................................................. 48
5.5 Stratigraphic Cross-section of the Niobrara Formation ................................... 49
5.6 Target Formations within the Wattenberg Field .............................................. 50
5.7 The Denver Basin Province ............................................ 52
5.8 Colorado Oil Production, 1952-2012 .................................. 54
5.9 Colorado Natural Gas Production, 1952-2012 ....................... 55
5.10 Noble Energy’s Lease Holdings in the Niobrara Shale .............. 56
5.11 Noble Energy’s DJ Basin Net Production ............................ 57
5.12 Noble Energy’s Horizontal Wells in the Niobrara Shale ............ 58
5.13 Capital Allocation by Area ............................................ 59
5.14 Anadarko’s Niobrara Lease Holdings ................................ 60
5.15 Wattenberg <5,000 ft Lateral Cycle Time & Cost .................... 61
5.16 Wattenberg HZ’s Net Production .................................... 62
5.17 PADD 4 Unconventional Crude Oil Forecast ......................... 63
6.1 PADD 5 State Production of Crude Oil ................................. 65
7.1 United States Crude Oil Imports from OPEC Countries .......... 67
7.2 United State Crude Oil Imports from non-OPEC Countries ...... 68
7.3 Western Canadian Conventional Oil Production Forecast ........ 69
7.4 Canadian Conventional, Unconventional and Oil Sands
  Export Potential ......................................................... 69
7.5 United States Crude Oil Production by PADD ......................... 70
7.6 United States Liquids Supply/Demand Balance ....................... 70
List of Tables

1.1 2012 Facts about US Liquids Fuel ................................................................. 3
3.1 Bakken Shale Geological Characteristics ......................................................... 12
4.1 Eagle Ford Shale Geological Characteristics ...................................................... 34
4.2 Eagle Ford Shale Reservoir Characteristics ........................................................ 34
5.1 Niobrara Shale Geological Characteristics ....................................................... 51
5.2 Niobrara Shale DJ Basin Geological Characteristics ......................................... 51
Executive Summary

Crude oil production in the United States has started to grow again, closing in on 7 million barrels per day (MMbpd), while oil imports are retreating from a high of 10 million barrels per day in 2005, to its current position of 8.3 MMbpd. The political buzz in Washington is “oil self-sufficiency within the next 10 years”. Is this possible and if it does happen what could this mean for Canadian production? The objective of this report is to investigate the development trends for domestic shale oil production within the United States and couple that with a forecast of Canadian and Mexican imports to establish the level of foreign crude oil imports, if any, out to the year 2022. It is important to have a clear understanding of the US supply potential in order to establish the level of crude oil imports that would be required by the United States and by extension the potential for Canadian crude oil and bitumen to fulfill part of that deficiency. For Canada, the potential for expanded exports to the United States is of significant interest to industry and governments based on the difficulties pipelines are having in accessing global markets for Canadian energy.

Energy conservation (improved fuel standards) and conversion to natural gas fuels within the transportation sector could offer a savings of 1-2 million barrels per day; however, the rate of adoption within the transportation sector is slow and in all likelihood will not be achievable until well into the next decade. The Bakken play in North Dakota, the Eagle Ford play in Texas, the Niobrara play in Colorado and the Utica play in Ohio might have the potential to bring on 2-4 million barrels of new crude oil production by the end of the decade. However, conventional production and Gulf of Mexico offshore production are in decline resulting in a potential loss of 1.5 million barrels per day, also by the end of the decade. Canada currently delivers in excess of 2.3 million barrels per day of crude oil, bitumen and synthetic crude oil to the US. Oil sands production growth plus conventional oil production potential from Western Canada could result in 1-2 million “new” barrels of oil looking for a market, possibly the United States.

As the next 5 years will be pivotal in the future of the Canadian oil industry, the key question is:

“Looking out to the year 2022, in the face of rising domestic tight oil entering the market, and accounting for the potential of oil use conservation in the transportation sector, what does the North American oil market look like and of more importance, what role does Canada play in this picture?”
Figure E.1 illustrates the historical US imports of crude oil from OPEC member countries. In 2012, the United States imported, on average, 4,030,000 bbls per day with 34 percent originating from Saudi Arabia, 23 percent from Venezuela and 12 percent from Iraq.

**Figure E.1: United States Crude Oil Imports from OPEC Countries**

![Graph showing crude oil imports from OPEC countries](image)

Source: Energy Information Administration (EIA)

Figure E.2 illustrates the historical imports of crude oil from non-OPEC member countries. In 2012, the United States imported, on average, 4,488,000 bbls per day with 54 percent originating from Canada, 22 percent from Mexico and 9 percent from Colombia.
Figure E.2: United States Crude Oil Imports from non-OPEC Countries

Source: Energy Information Administration (EIA)

Figure E.3 illustrates the potential growth in US domestic production, growth in Canadian imports and a decline in imports from sources, other than Canada, against the Energy Information Administration (EIA) estimate of liquids fuel consumption for the United States going out to 2022. Total liquids fuel consumption (dashed line on Figure E.3) accounts for imports of refined petroleum products, domestic biofuels and other liquid fuels. In this analysis, it is assumed that the usage level of these fuels will remain constant over the time frame and the analysis will be focused on the ability to increase US domestic crude oil.

Imports of crude oil from countries other than Canada decline from 6,100,000 bbls per day in 2012 to 3,100,000 bbls per day by 2022. In addition, Figure E.3 also indicates that Canadian imports will grow from 2,344,000 bbls per day to 4,050,000 bbls per day by 2022. Mexico is assumed to export approximately 1,000,000 bbls per day to the United States.

One conclusion that can be drawn from examination of Figure E.3 is that oil independence from foreign imports is not achievable either in the continental United States context or the North American context. In the North American context, after accounting for Mexican and Canadian import volumes, the United States still requires 2,000,000 bbls per day of crude imports to meet demand which would be sourced from OPEC and non-OPEC sources.

This analysis assumes that pipeline and rail assets will be added when needed to allow crude to flow from sources to markets unimpeded. Thus, the Keystone XL pipeline will
be constructed and will operate at its full capacity as well as proposed enhancements to the Enbridge mainline. Rail will be added on the supply side in areas where pipeline connectivity is not available, or on the demand side where optionality of accessing different markets (east and west coasts) is desirable.

**Figure E.3: United States Liquids Supply/Demand Balance**

![United States Liquids Supply/Demand Balance](image)

Source: EIA Historical data, Hart Energy Unconventional forecast to 2016, CERI trend analysis to 2022
Chapter 1
Introduction

Technological advances are having a profound effect on North America’s energy landscape. Advances in horizontal drilling, 3-D seismic technology and hydraulic fracturing (frac’ing) are opening up new resources, previously determined as non-productive or not feasible to produce.

Several years ago, the United States and Canada experienced a shale gas boom. Amidst conventional natural gas production declines, the success of East Texas’ Barnett Shale created a sense of excitement for E&Ps and the energy sector as a whole. E&Ps utilized horizontal drilling and advances in frac’ing and other forms of stimulation to turn the Barnett Shale into the most prolific shale gas play in the US. The techniques learned in the Barnett Shale were soon utilized to release shale gas in other shale gas plays across North America. Economically- and technically-feasible shale gas on a large-scale arrived and shale plays were ‘discovered’ by the dozen. This development was facilitated by not only technology advancement but also higher natural gas prices at that time. Unfortunately for natural gas producers, that would not last.

While increasing natural gas production was nothing short of stunning, the price of natural gas began to fall in mid-2008 and has never truly recovered. Low, lingering natural gas prices have forced many producers to make the transition from producing natural gas (dry) to liquids production – either crude oil or natural gas liquids (NGLs). While natural gas prices plunged a couple of years ago, the price of oil was surging. Numerous E&Ps turned their attention to oil-bearing shales, or tight oil plays.

Tight oil plays have oil – medium to light in viscosity – embedded into limestone, sandstone and carbonate, in a low-permeable reservoir.\(^1\) While shale formations have unique properties, in terms of porosity, thickness, and brittleness, they are generally characterized by having low permeability. By utilizing advances in horizontal drilling and frac’ing, E&Ps are able to produce crude oil and NGLs from these shale formations.

The shale boom continues, except that operators are currently finding crude oil and NGLs more lucrative than natural gas.

Growth in several oil-bearing shales has been impressive, particularly in the Eagle Ford Shale in Texas and the Bakken Shale in North Dakota and Montana. The impact on US crude oil production is visible. Currently, US oil production, expected to exceed 8 million

\(^1\) Understanding Tight Oil, Canadian Society for Unconventional Resources, pp. 2.
bpd by end-2014, is scheduled to surpass crude oil imports for the first time in two decades.2

The following chapters will examine the shale oil potential across the United States by focusing in on the leading shale oil play in each PADD area (see Figure 1.1). The three leading oil-bearing shale, or tight oil, plays in the United States are: the Eagle Ford Shale, the Bakken Shale and the Niobrara Shale. Each part is further divided into two sections: geology and basin metrics, and E&P players and recent activity. It is important to understand their unique geological characteristics and the players involved. While the number of players in these plays is increasing or changing seemingly every quarter, it is prudent to discuss only the major players.

Figure 1.1: Petroleum Administration for Defense Districts

Table 1.1: 2012 Facts about US Liquids Fuel
2012 Average Day Volumes

<table>
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<tr>
<th>Domestic Crude Production (incl. condensate)</th>
<th>6,335,000 bbls/day</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross Imports of Crude Oil</td>
<td>8,555,000 bbls/day</td>
</tr>
<tr>
<td>Other Petroleum Supply:</td>
<td></td>
</tr>
<tr>
<td>Gas Plant Liquids</td>
<td>2,364,000 bbls/day</td>
</tr>
<tr>
<td>Refined Product Imports</td>
<td>736,000 bbls/day</td>
</tr>
<tr>
<td>Blending Components, etc.</td>
<td>536,000 bbls/day</td>
</tr>
<tr>
<td>Refined Product Exports</td>
<td>2,837,000 bbls/day</td>
</tr>
<tr>
<td>Liquids Fuel Consumption:</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>18,646,000 bbls/day</td>
</tr>
<tr>
<td>Motor Gasoline</td>
<td>8,731,000 bbls/day (46%)</td>
</tr>
<tr>
<td>Jet Fuel</td>
<td>1,413,000 bbls/day (7%)</td>
</tr>
<tr>
<td>Diesel</td>
<td>3,400,000 bbls/day (18%)</td>
</tr>
<tr>
<td>Liquefied Petroleum Gases</td>
<td>2,293,000 bbls/day (12%)</td>
</tr>
<tr>
<td>Other (resid., etc.)</td>
<td>2,809,000 bbls/day (15%)</td>
</tr>
</tbody>
</table>

Source: Energy Information Administration (EIA)
Chapter 2
PADD 1: East Coast

The East Coast region as displayed in Figure 2.1 makes up PADD 1 of the Petroleum Administration for Defense Districts of the United States. Included in this PADD area are the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont, Delaware, District of Columbia, Maryland, New Jersey, New York, Pennsylvania, Florida, Georgia, North Carolina, South Carolina, Virginia, and West Virginia. Pennsylvania is considered the birth place of the United States oil industry with the first oil well being drilled in 1859. The US Energy Information Administration (EIA) data indicates that oil production from this area has continuously declined from 120,000 barrels per day (bbls/day) in 1981 to a low of 15,000 bbls/day in 2009. Production increases in the form of condensate from the high liquids rich areas of the Marcellus play has grown in recent years and averaged 3,200 bbls/day/year over the past three years. Production in 2012 averaged 24,650 bbls/day. Maintaining this rate of growth would suggest that production from PADD 1 could reach the 50,000 bbls/day level by 2022.

Figure 2.1: PADD 1 State Production of Crude Oil

Source: Energy Information Administration (EIA)
Chapter 3
PADD 2: Mid-Continent Area

The PADD 2 region includes the states of Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Tennessee, Kansas, Kentucky and Wisconsin. This area has both conventional and unconventional crude oil production with conventional crude production expected to decline over the coming years. The growth in crude oil for this area will come from the unconventional oil plays of the Bakken in North Dakota, the Woodford in Oklahoma, and the Utica in Ohio. Of these, the Bakken oil play in North Dakota has led the field and by all indications will be a significant source of crude oil in the future. The following describes the historic production (see Figure 3.1) followed by a description of the Bakken Shale play and a trend analysis for the PADD.

Figure 3.1: PADD 2 State Production of Crude Oil

Source: Energy Information Administration (EIA)

The Bakken Shale, Williston Basin, North Dakota and Montana
Geologists have known about the Bakken Shale since the 1950s, but only in the past few years has the play attracted attention. Like the Eagle Ford Shale, it is currently one of
the hottest shale plays in the US, and has turned North Dakota into the second-largest oil-producing state in the US.¹

**Geology and Basin Metrics**

The Bakken Shale makes up an area of approximately 200,000 square miles of the Williston Basin, the largest sedimentary basin in the continental US. The Bakken Shale stretches across southern Saskatchewan, northeastern Montana, northwestern North Dakota, and into the southeastern corner of Manitoba. A new oil pool was discovered in 2011 in north-central Montana that extends into natural resource-rich Alberta; this portion is referred to as the Alberta Bakken Shale.² It is important to note that this section discusses the US-side of the Bakken Formation.

Figure 3.2 shows where the late Devonian to early Mississippian Bakken is embedded within the larger Williston Basin.

**Figure 3.2: The Bakken Formation**

![Map of the Bakken Formation](http://www.sheridancountyonline.com/bakken_formation.html)

The Bakken takes its name from Henry Bakken, a farmer from Tioga, North Dakota, under whose land the Bakken Formation was discovered.³ The namesake of the Williston Basin, on the other hand, is from the city of Williston, North Dakota. The name of the Williston describes the Phanerozoic succession, or a geologic feature, as illustrated in Figure 3.2.⁴ The Williston Basin is circular and its depression is centered roughly near the city of Williston. The area is rich with oil, coal and potash. The largest

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¹ EIA website, Petroleum & Other Liquids, Crude Oil Production, [http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_m.htm](http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_m.htm) (accessed on March 27, 2013)
known potash deposits are located in Saskatchewan, and are controlled by the Potash Corporation of Saskatchewan. Other important cities in the Bakken include Sidney, Terry and Parshall. The first two are located in Montana while Parshall is located in North Dakota.

The 8,000 active oil wells are spread across 15 counties in Montana and North Dakota: Williams, Divide, McKenzie, Mountrail, Dunn, Mercer, Billings, Stark, Morton, Burke, Richland, Dawson, Wilbaux, Roosevelt and Prairie. Ten counties are located in North Dakota and five are located in northeastern Montana. As shown in Figure 3.3, green identifies the counties where the emerging shale is primarily located and red indicates natural gas-related producing cells, while the blue represents mixed oil and gas producing cells. It is evident that the Bakken Shale is predominantly an oil play. The graphic also illustrates six anticlines in the Williston Basin, as well as the Williston Basin’s boundary, as defined by the United States Geological Survey (USGC). They are the Nesson, Antelope, Cedar Creek, Billings, Little Knife and the Poplar. The anticlines are considered “sweet spots” in the play.

Figure 3.3: Producing Wells in the Bakken Shale Play

![Map showing producing wells in the Bakken Shale Play]

Source: USGC


Figure 3.4 illustrates the Williston Basin and the Bakken-Lodgepole Total Petroleum System (TPS). The former’s boundary is outlined in red (as identified also in Figure 2.3); the Bakken Shale’s boundary is indicated by a blue line. The graphic outlines the aforementioned anticlines.

**Figure 3.4: Bakken-Lodgepole Shale Play**

Source: USGC

The Bakken Formation dates from the Late Devonian to the Early Mississippian. The rock unit overlies the Devonian-aged Three Forks Formation and underlies the Mississippian-aged Madison Limestone and the Lodgepole Limestone. The Bakken Formation, made up of bituminous shale, is a subdivision of the Three Forks Group. Other subdivisions include the Lyleton Formation (silty shale), Big Valley Formation (mudstone) and the Torquay Formation (brown dolomite and shale). The play is often referred to as the Bakken/Three Forks.

Figure 3.5 illustrates a map of the Williston Basin, Bakken Formation and the Three Forks Formation. The graphic also illustrates the Nesson Anticline, as well as the highly

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productive Elm Coulee Field. The Nesson Anticline Field is positioned in the midst of the Three Forks, an oil area below the upper part of the Bakken oil shale formation located in various North Dakota counties.

**Figure 3.5: Map of Bakken Shale and the Three Forks Formation**

![](image)

Source: EPRINC

The Bakken Formation is comprised of three layers: an upper layer of black shale, a middle silty-dolomite and a lower layer of black shale. The light, sweet crude is trapped within the shale rock in the Bakken. These geological characteristics of the Bakken Formation are illustrated in Figure 3.6.

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Table 3.1 provides a summary of Bakken’s key geological characteristics.

### Table 3.1: Bakken Shale Geological Characteristics

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Bakken Shale</th>
</tr>
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<tbody>
<tr>
<td>Geological age</td>
<td>Late Devonian/Early Mississippian</td>
</tr>
<tr>
<td>Area (sq. miles)</td>
<td>6,522</td>
</tr>
<tr>
<td>EUR (MBO/well)</td>
<td>550</td>
</tr>
<tr>
<td>Well Spacing (wells/sq. mile)</td>
<td>1</td>
</tr>
<tr>
<td>TRR (BBO)</td>
<td>3.59</td>
</tr>
<tr>
<td>Depth range (ft)</td>
<td>6,000</td>
</tr>
<tr>
<td>Shale thickness (ft)</td>
<td>22</td>
</tr>
<tr>
<td>Porosity</td>
<td>8%</td>
</tr>
<tr>
<td>Pressure gradient (psi/ft)</td>
<td>0.6</td>
</tr>
</tbody>
</table>

Source: EIA\textsuperscript{11}


\textsuperscript{11} ibid
The Bakken is roughly 6,522 square miles in area. The estimated ultimate recovery (EUR) is estimated at 550 MBO per well and the technically recoverable resources (TRR) are approximately 3.59 billion barrels of oil (BBO). The Bakken lies at an average depth of 6,000 ft., which is comparable to East Texas’ prolific Barnett Shale which is at 6,500-9,000 ft. This depth is considered ideal in that the shale is more likely to be over pressured and easier to extract. Like the Eagle Ford Shale, the Bakken Shale is a source rock and is ideal for frac’ing. In terms of thickness, the Bakken averages 22 ft. The Bakken has a porosity of 8 percent, comparable to the Eagle Ford, which ranges between 4 and 15 percent. The average pressure gradient is 0.6 psi/ft.

Initial reports in 1995, by the USGS, estimated the discovery of 151 million barrels of technically recoverable oil shale in the region. However, with new innovations in geological exploration and advances in drilling technology, the number increased to between 3.0 and 4.3 billion barrels of recoverable oil in 2008. The estimated mean value is 3.65 billion barrels of oil, approximately 25-fold higher than the USGC’s 1995 estimate. With its latest resource assessment, the USGS calls the Bakken the largest “continuous” unconventional oil accumulation it has ever assessed. The area also is estimated to contain 3.7 Tcf of associated/dissolved natural gas and 0.2 billion barrels of NGLs. North Dakota state officials estimate, completed in January 2011, suggest that resources are 11 billion barrels of recoverable oil in North Dakota alone. Continental Resources, a large player in the Bakken, estimates that the Bakken will yield between 24 and 40 billion barrels.

**E&P Players and Recent M&A Activity**

While geologists have known about Bakken’s Shale for decades, it was not economically feasible to produce. Oil was first discovered along the Cedar Creek Anticline in the 1920s and 1930s, and many of the core producing fields in the Bakken Shale in the 1950s. The nine largest oil fields and their discovery year are: Elm Coulee (2000), Beaver Lodge (1951), Pine (1952), Pennel (1952), Cabin Creek (1953), Little Knife (1977), Tioga (1952), Blue Buttes (1955) and Charlson (1952). Of the top nine largest fields, seven were discovered in the early to mid-1950s. It is also interesting to note that four of the top five fields are located in Montana, including the prolific Elm Coulee, located in Richland.

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17 http://bakkenshale.com/ (accessed on March 27, 2013)
County. The Elm Coulee is estimated to hold 270 million barrels of oil. The Beaver Lodge holds an estimated 130 million barrels of oil and an estimated 115 Bcf of natural gas, as well as an estimated 47 million barrels of NGLs. Montana’s Pine field holds an estimated 127 million barrels of oil and 20 Bcf of natural gas.

The Bakken Shale has come a long way since the #1 H.O. Bakken, drilled by Amerada Petroleum Corp., began producing in 1953. In 1999, North Dakota was tied with Kansas as the United States 7th largest oil producing state. Currently, it is second only to Texas. Advancements in frac’ing and horizontal drilling have been a game changer for the Bakken. And this is best illustrated by the oil production statistics.

Figure 3.7 illustrates the annual oil production in North Dakota between 1993 and 2012. Production is measured in thousand barrels. This graphic shows the dramatic growth in oil production from 1993 to 2012, with production more than doubling from 2008 to the end of 2012. As of end-2012, the total barrels of oil produced in 2012 are 242 million barrels, up from 153 million barrels produced in 2011 and up from 113 million barrels in 2010.

Figure 3.7: North Dakota Annual Oil Production from 1993 to 2012 (thousand barrels)

Source: EIA

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20 EIA website, Petroleum & Other Liquids, Crude Oil Production, http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mmbbl_m.htm (accessed on March 27, 2013)
According to the EIA, North Dakota oil production in December 2012 set a record-high, at 23.8 million barrels, up from 22 million barrels in November 2012 and 23.2 million barrels in October 2012. Oil production is up from 16.5 million barrels in December 2011 and 10.6 million barrels in December 2010.

Figure 3.8 illustrates North Dakota’s monthly oil production, in thousand barrels per day, between 2008 and 2012. According to the EIA, North Dakota oil production in December 2012 set a record-high, at 769,000 bpd, up from 735,000 bpd in November 2012 and 749,000 bpd in October 2012. Oil production is up from 535,000 bpd in December 2011 and 344,000 bpd in December 2010. The decrease in November 2012 broke a string of 18-months of increasing production, most likely due to a decreasing rig count. The average rig count decreased consistently from 213 in June to 186 in November. It is, however, interesting to note that wells producing have, over the same time period, increased from 7,375 in June to 8,122 in November. There were a record-high 8,227 wells producing in December 2012, a dramatic increase from 6,479 year-over-year.

Figure 3.8: North Dakota Monthly Oil Production between 2008 and 2012 (thousand bpd)

Source: EIA

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21 ibid
23 Industrial Commission of North Dakota Oil & Gas Division, 2012 Monthly Statistical Update
24 ibid
It is important to note that nearly 90 percent of the state’s oil production comes from the Bakken and Three Forks Formations. North Dakota’s state regulator reports that 21.8 million barrels were produced in December 2012 from the Bakken Shale, or approximately 704,360 bpd. Figure 3.9 illustrates North Dakota’s oil production (between January 2005 and May 2012), but divides the production from the Bakken Shale and Three Forks Formation from the rest of North Dakota.

Figure 3.9: North Dakota Monthly Oil Production (thousand bpd)

Between 1953 and 2008, 135 million barrels of oil were produced from the Bakken. Conversely, nearly 35 million barrels of oil were produced in 2008, and the number has grown consistently. According to North Dakota’s state regulator, the Bakken produced 28 million barrels of oil in 2008, 50 million barrels of oil in 2009 and 86 million barrels of oil in 2010. The increase in production is dramatic.

Figure 3.10 illustrates Montana’s monthly oil production, in thousand barrels per day, between 2008 and 2012. According to the EIA, Montana’s oil production in January 2008 was 90,000 bpd. In December 2012 it was 75,000 bpd, down from 78,000 bpd in November 2012, but up from 67,000 bpd in December 2011 and 68,000 bpd in December 2010. The monthly oil production is increasing – albeit slowly. The decrease and subsequent gradual increase in oil production is most likely due to the decreasing production of the Elm Coulee oil field after 2006 and its gradual recent revival.

28 ibid
Currently, Elm Coulee (Montana), Parshall field (North Dakota), Nesson Anticline (North Dakota) and Viewfield (Saskatchewan) are the areas that have witnessed major development in the Bakken.\textsuperscript{31} The majority of activity remains on the US-side of the Bakken. Figure 3.11 shows oilfield activity in the aforementioned fields.

\textsuperscript{30} EIA website, Petroleum & Other Liquids, Montana Field Production of Crude Oil, http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPMT2&f=M (accessed on March 27, 2013)

Figure 3.11: Oilfield Activity in the Bakken Shale Play

Source: EPRINC

It is no surprise that the Bakken has attracted some of the energy industries largest and most experienced players. These include Anglo Canadian Oil Corp., Concho Resources Inc., Abraxas Petroleum Corporation, EOG Resources Inc., Continental Resources Inc., Whiting Oil & Gas Inc., Marathon Oil Corporation, QEP Resources, Brigham Exploration (bought by Statoil in 2011), Hess Corporation, Samson Oil and Gas Ltd., Statoil, ConocoPhillips and Exxon Mobil Corp.

The following are the top 10 largest producers, by gross operated production, in the Bakken in December 2012. Whiting Petroleum is the top producer at 66,155.7 bpd, followed by Continental Resources which produced 65,141.2 bpd and Hess Corporation which produced 64,656.7 bpd. Brigham Oil & Gas (Statoil) is the fourth largest producer in December 2012 at 50,324.5 bpd and EOG Resources at 46,090.9 bpd. Rounding out

the top 10 is: XTO Energy (ExxonMobil) (33,148.2 bpd), Marathon Oil (31,194.4 bpd), Petro-Hunt (25,743 bpd), Slawson Exploration (21,058.4 bpd) and Kodiak Oil & Gas (20,423 bpd). It is interesting to note that in terms of cumulative oil production, as of mid-January 2013, the top five oil producers in North Dakota are: Hess Corporation (327,465,899 bbl), Whiting Petroleum (173,796,212 bbl), Denbury Onshore (140,381,459 bbl), Continental Resources (130,205,244 bbl) and Petro-Hunt (123,800,580 bbl). EOG is quickly catching up with 76,871,597 bbl of oil produced to date. These production numbers go back to 1951, reflecting Hess’ historical roots in the Bakken, dating back to 1951.

While the number of operators is increasing by the month, the following will discuss the major players: Continental Resources, Whiting Petroleum and EOG Resources. These three are often regarded as the “Big 3”.

Continental Resources is the largest lease holder and the largest producer in the Bakken Shale. The Oklahoma City-based company has amassed a net acreage exceeding 1,100,000 acres in the Bakken/Three Forks Formation. It is also the first company to complete a horizontal well in the Three Forks zone in 2008, as well as completing a 1,280 foot-long lateral multi-stage frac in 2007. It is not a coincidence that shortly afterwards, the Bakken took off, attracting E&Ps from all over the world.

Continental has major operations in not only the Bakken, but also the neighbouring Red River Units (south of the Bakken, extending down to eastern Montana, the southwest corner of North Dakota and the northeast corner of South Dakota), Niobrara (Wyoming and Colorado), Anadarko Woodford and Arkoma Woodford. The latter two plays are located in Oklahoma. The majority of its proved reserves, however, lie within the Bakken.

As of end-December 2012, Continental proved reserves were 785 MMBoe, up from its estimate of 508 MMBoe in 2011. Figure 3.12 illustrates the share of proved reserves across its various aforementioned assets. Their Bakken acreages account for 71.8 percent – 66 percent in North Dakota and 5.8 percent in Montana. Red River Units account for 10 percent of proved reserves.

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34 Top 20 operators in oil production over the years, http://www.minotdailynews.com/page/content.detail/id/572552/Top-20-operators-in-oil-production-over-the-years.html?nav=5010 (accessed on March 27, 2013)
Figure 3.12: Continental Resources 2012 Proved Reserves

Source: http://www.clr.com/operations/charts#chart182

Figure 3.13 is a map of Continental’s massive net acreage in the heart of the Bakken shale play, as of November 2012. The yellow-coloured regions show the company’s acreage, red-coloured shows acreage acquired and the green-coloured areas illustrate Continental’s held-by-production (HBP) acreage.

Figure 3.13: Continental Resources 2012 Net Acreage

Source: Bakkenshale.com

37 Bakken Shale Play, Continental Resources Bakken Shale Map http://bakkenshale.com/companies/continental-resources/attachment/continental-resources-bakken-shale-map/ (accessed on March 27, 2013)
Figure 3.14 shows Continental’s 4Q2012 production, of which approximately 70 percent is oil and 30 percent is natural gas. The Bakken dominates production, with 63 percent of total production. North Dakota Bakken accounts for 55 percent while Montana Bakken properties account for 8 percent. Red River Units account for 14 percent of 4Q2012 production. Total crude oil produced in the last three months of 2012 was 76,449 bpd while total natural gas produced in 4Q2012 was 182,289 Mcfpe. Continental is one of the leaders in the Bakken, producing 59,019 Boepd in the North Dakota side of the Bakken and 8,503 Boepd on the Montana side of the Bakken in 4Q2012. Both are up from 55,918 Boepd in the North Dakota Bakken and 6,535 Boepd in the Montana Bakken in 4Q2011. In 4Q2011, Continental produced 35,565 Boepd from the North Dakota Bakken and 5,678 Boepd in the Montana Bakken.

As of early March 2013, Continental is operating 21 rigs in its Bakken properties.

Continental’s capital expenditure in 2012 was US$3.5 billion, of which US$2.2 billion were allocated to the Bakken. And the trend is expected to continue. Continental’s CAPEX budget for 2013 is US$3.4 billion. Drilling allocation for 2013 include: Bakken (66 percent), South Central Oklahoma Oil Province (SCOOP) (15 percent), exploratory

Source: http://www.clr.com/operations/charts#chart182

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39 ibid
41 ibid
(15 percent) and other development (4 percent). The Oklahoma City-based company plans to average 35 operating rigs in 2013, up from 33 in 2012, as well as drilling 738 gross wells and 300 net wells in 2013.

Included in the company’s Bakken expansion is the Three Forks (TF) initiative, in which 20 wells are planned, building on the success to the Charlotte 2-22H and 3-22H wells. The former has produced 108 MBoe in just over a year while the latter has produced 35 MBoe in the first three months. The company plans a 320 acre spacing pilot and a 160 acre spacing pilot. Both developments are illustrated in Figure 3.15. The 310 acre development is expected to cost US$161 million while the 160-acre spacing pilot is expected to cost US$36 million.

![Figure 3.15: Three Forks Isopach Map](image)

Source: Continental Resources

Whiting Petroleum is one of the top producers in the Bakken Shale, and in December 2012, was the Bakken’s top producer – albeit barely. The large independent oil and gas producer is also a player in the Rocky Mountain, Permian Basin, and mid-Continent and Gulf Coast regions of the US. As of end-December 2012, the companies proved

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43 ibid
44 ibid
46 ibid
48 ibid (accessed on March 27, 2013)
reserves totaled 378.8 MMBoe while production totaled a record high 32.2 MMBoe, or 82,540 Boepd.\textsuperscript{50} Whiting’s largest projects are, however, in the Bakken and Three Forks plays in North Dakota.

According to the North Dakota State Industrial Commission, the Denver-based company holds over 700,000 net acres in the Bakken/Three Forks Formations.\textsuperscript{51} Figure 3.16 illustrates Whiting’s vast land holdings in the Bakken and the Three Forks Formations. Whiting’s net acreage is divided into three parts: Southern Williston (Lewis & Clark and Pronghorn), Western Williston (Cassandra, Hidden Bench, Tarpon and Missouri Breaks) and Sanish (Sanish and Parshall). As of end-September 2012, their largest net acreage is in the Lewis & Clark (137,808 net acres), followed by Pronghorn (130,269 net acres) and Big Island (121,982 net acres).

**Figure 3.16: Whiting’s Lease Holdings in the Bakken Shale**

![Whiting’s Lease Holdings in the Bakken Shale](source)

Source: Bakkenshale.com\textsuperscript{52}

Whiting completed 192 net wells in 2012, above its projected 160 net wells.\textsuperscript{53} Not surprisingly, Whiting spent approximately US$2.1 billion in 2012, exceeding its capital

\textsuperscript{50} Whiting Petroleum Corporation, Reserves and Production, http://www.whiting.com/about-whiting-petroleum/reserves-and-production/ (accessed on March 27, 2013)
expenditure budget by US$212 million.\textsuperscript{54} With a CAPEX of US$574 million in 4Q2012, Whiting drilled 67 net wells in the productive quarter.\textsuperscript{55} In 2012, the company produced 23,139 MBbl of oil, 2,766 MBbl of NGLs and 25,827 MMcf of natural gas, mostly in Northern Rockies properties.\textsuperscript{56} In 4Q2012, Whiting averaged 5,120 Boepd in the Western Williston area. Its net acreage is approximately 115,000 in the area.\textsuperscript{57} Over the same quarter, Whiting produced 13,430 Boepd in the Southern Williston Basin. Its net acreage on the Pronghorn and Lewis & Clark areas is approximately 263,000 net acres, combined.\textsuperscript{58} Whiting’s net production in the Sanish averaged 32,590 Boepd in 4Q2012.\textsuperscript{59}

Whiting’s aggressive capital spending, a CAPEX of $2.2 billion, will continue through 2013. Whiting plans to spend US$1.142 billion in the Northern Rockies and US$136 million in the Central Rockies, more specifically the Niobrara Shale play.\textsuperscript{60} The annual CAPEX includes US$108 million for land and US$178 million for facilities. With regard to the Northern Rockies, Whiting’s plans in 2013 include:\textsuperscript{61}

- Planning six wells per 1,280 acre spacing unit in the Pronghorn Prospect
- Drilling three well pads in the Tarpon Prospect
- Testing the “Middle Bakken Silt” in the Hidden Bench Prospect in 2013
- Continue to de-risk acreage in the Missouri Breaks Prospect in 2013
- Planning a tighter spacing test in early 2013 and re-frac’ing wells within the Sanish Field

EOG Resources are a significant player in the oil shale-rich Bakken Shale. They are also major players in several of the hottest shale plays in North America. Bringing in their experience into the Bakken solidifies their status in the “Big 3”. The company has operations in Canada, Trinidad & Tobago, the United Kingdom and China. Other operations in the US include central Texas, East Texas, northern Louisiana and the Rocky Mountains.

The company increased its development activity in the Williston Basin and Eagle Ford Shale; the latter in 2009 and 2010, particularly on the North Dakota side of the border. Led by the Bakken Shale and the Eagle Ford Shale, 53 percent of North American revenues came from liquids production in 2010.\textsuperscript{62} This is up from 24 percent from a few years earlier, indicating the company’s transition from natural gas production to crude

\textsuperscript{54} ibid
\textsuperscript{55} ibid
\textsuperscript{56} ibid
\textsuperscript{57} ibid
\textsuperscript{58} ibid
\textsuperscript{59} ibid
\textsuperscript{60} ibid
\textsuperscript{62} EOG Resources, Company History, http://www.eogresources.com/about/company_history.html (accessed on March 27, 2013)
oil and NGLs. The Houston-based company also increased its presence in other oil shale or tight oil plays, such as the Fort Worth Barnett Shale Combo, the Permian Basin and Niobrara Shale (Denver-Julesburg Basin).

EOG, as of end-December 2012, is one of the largest land holders in the Bakken, holding approximately 600,000 net acres, of which 100,000 net acres are located in the Bakken Core. Most of EOG’s activity is centered in the counties of McKenzie, Dunn, Mountrail, Williams and Burke.

Figure 3.17 illustrates EOG’s acreage in the Bakken and Three Forks Formation.

Figure 3.17: EOG Acreage in the Bakken/Three Forks

Source: http://bakkenshale.com/tag/parshall-field/

EOG is also one of the top oil producers in the Bakken, over 62,100 bpd at year-end 2012. EOG was the largest oil producer in North Dakota at end-2011, producing 56,400 bpd.

Notable wells inside of Parshall include the Fertile 51-0410H, the Wayzetta 022-1509H and the 149-1509H. The Fertile had a maximum IP rate 1,800 Boepd, with 850,000

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64 EOG Resources, Investor Relations Presentation, March 13, 2013, pp. 28
Mcfpd of natural gas.\textsuperscript{67} The Wayzetta 022-1509H and the 149-1509H had IP rates of 1,185 and 1,265 Boepd, respectively.\textsuperscript{68}

Southwest of the Bakken Core in the Antelope Extension, the Hawkeye 01-2501H and 102-2501H were completed to sales in early January 2013. These McKenzie County wells, in which EOG has 75 percent working interest, were turned to sales at 2,445 and 2,945 Boepd, respectively.\textsuperscript{69} In the Stateline area near the North Dakota-Montana border, the Garden Coulee 001-1410H had an IP rate of 1,415 Boepd.\textsuperscript{70} The latter also produced 1,260 Mcfpd of natural gas.

According to EOG’s stakeholder meetings in mid-February 2013, the company is planning to drill 53 net wells in 2013, mostly in the Core and Antelope areas.\textsuperscript{71} At that rate the company maintains a 7-year drilling inventory – based on current technology. EOG also confirmed in February 2013 that a 320 acre well spacing is economically feasible in its Bakken Core acreage, using new frac’ing techniques and technology.

EOG’s 2013 CAPEX budget is between US$7-7.2 billion, with much of the focus on the Eagle Ford and the Bakken.\textsuperscript{72} Approximately 83 percent of the 2013 CAPEX is allocated to exploration and development.\textsuperscript{73} Due to low natural gas prices, the company plans to maintain its focus on crude oil production.

Within the PADD 2 area there are three primary unconventional oil plays, the Bakken/Three Forks as described above which contains the largest potential, and the Utica and Woodford which are in the early stages of development. Figure 3.18 shows three possible development tracts for PADD 2. The solid line utilizes the EIA historical data to 2011 followed by the development forecast from Hart Energy (red line) for the years 2011 to 2016 and an extrapolation to the year 2022. In this case, a log-based numeric function was used to extend the forecast. The dashed line starts with the EIA historical data to 2012, appends the actual production rate for the first quarter of 2013 (725,000 bbls/day) and extrapolates to the end of the forecast. In this case, a power-based numeric function was used to extend the forecast. This curve represents a continuing growth situation. The dotted line follows the EIA data and the Hart Energy forecast to 2016 followed by a polynomial numeric function to extend the forecast to 2022. This curve mimics the situation where drilling activity falls off significantly. In the context of this report, the “growth” curve is utilized to develop the medium-term forecast of US domestic oil supply.

\textsuperscript{67} ibid  
\textsuperscript{68} ibid  
\textsuperscript{69} ibid  
\textsuperscript{70} ibid  
\textsuperscript{73} EOG Resources, Investor Relations Presentation, March 13, 2013, pp. 14
Figure 3.18: PADD 2 Unconventional Crude Oil Forecast


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Chapter 4  
PADD 3: Southern States

The PADD 3 region includes the states of Alabama, Arkansas, Louisiana, Mississippi, New Mexico, and Texas. This area has both conventional and unconventional onshore as well as some offshore crude oil production with conventional crude production expected to decline over the coming years. The growth in crude oil for this area will come from the unconventional oil plays of the Eagle Ford in Texas, and the Permian, also in Texas. The following describes the historic production (see Figure 4.1) followed by a description of the Eagle Ford Shale play and a trend analysis for the PADD.

![Figure 4.1: PADD 3 State Production of Crude Oil](chart)

Source: Energy Information Administration (EIA)

**The Eagle Ford Shale, Maverick Basin, Texas**

Since 2010, E&Ps have been very active in the Eagle Ford Shale, and they have not showed any signs of letting up. The growth of this play is dramatic. It truly illustrates the ever-changing nature of shale in the US. Even half a dozen years ago many maps identifying major shale plays in the US did not even show the Eagle Ford, and only a few showed the Pearsall Shale in southwestern Texas.
While its shale gas potential initially attracted the attention of E&Ps, it is now its oil shale that is in the spotlight – in part due to low, lingering natural gas prices. The Eagle Ford Shale is currently one of the hottest shale plays in the US.

**Geology and Basin Metrics**

The Eagle Ford Shale is situated in the state of Texas, south and east of Houston and adjacent to the Gulf of Mexico. The heart of the play is located in the Maverick Basin and extends from the southwest corner of Texas and the US-Mexican border towards Houston. Figure 4.2 illustrates the location of the Eagle Ford Shale.

![Eagle Ford Shale Map](http://www.aei-ideas.org/wp-content/uploads/2012/12/EagleFord_map1.jpg)

The Cretaceous-aged Eagle Ford takes its name from the town of Eagle Ford where the outcrops peak through to the surface. The town is now a suburb of Dallas. The play is roughly 80 kilometres wide and nearly 650 kilometres long. The play begins near the Texas-Mexico border in the counties of Webb and Maverick and extends northeast to the county of Leon. According to the Railroad Commission of Texas, oil and gas activities in the play encompass 23 counties. Figure 4.3 shows oil and natural gas wells permitted and completed in the Eagle Ford, as of February 4, 2013.

Figure 4.3: Eagle Ford Shale Play – Wells Permitted and Completed

Source: http://www.rrc.state.tx.us/eagleford/index.php

The highlighted blue areas identify the counties where the Eagle Ford is primarily located. The green dots indicate oil-related wells, while the red dots show the location of natural gas wells. Oil can be found in the counties of Atascosa, Wilson, Gonzales, Karnes, De Witt, McMullen and Live Oak. Natural gas, on the other hand, can be found in the aforementioned counties, plus Frio, La Salle, Duval, Zavala, Maverick, Dimmit, Webb and Zapata. The number of counties is expected to increase as the number of players increase and companies test more wells in the outer edges of the play.

The Eagle Ford Shale is primarily located within the Maverick Basin and is generally divided into three zones: gas, gas-carbonates and oil. It is the latter that is currently growing dramatically and attracting the most attention from E&Ps. Figure 4.4 demonstrates the three zones, the location of oil and gas producing wells and the geological depth of the shale.

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3 ibid
The large play is divided into a lower transgressive layer and an upper regressive layer. The former holds oil potential while the latter upper regressive layers are gas prone. The Eagle Ford is most shallow in the Maverick and Zapata counties, near the Mexico border, and tends to get deeper in the dry gas zone, adjacent to the Gulf of Mexico. Depths of the shale can reach 15,000 ft in the dry gas zone.

Figure 4.5 shows the geology of the Eagle Ford Shale.
The Eagle Ford lies below the Cretaceous-aged Austin Chalk, which stretches across Texas, Louisiana and Mississippi. The Austin Chalk, drilled since the 1920s, is currently producing natural gas and oil. The advent of horizontal drilling is enhancing productivity of the Austin Chalk reservoirs. By 2008, over 150,000 wells have been completed in the Austin Chalk, with a cumulative production of over 2.5 billion barrels of oil equivalent.

The lesser known shale – the Pearsall Shale – is located in the Maverick Basin. The Pearsall Shale is located in southwest Texas, located on the Rio Grande River in the counties of Maverick, Dimmit and Webb, adjacent to the Mexican border. The Jurassic to Cretaceous-aged shale has both oil and gas reserves. While smaller than its Eagle Ford counterpart, the Pearsall attracted several large and experienced companies – including TXCO Resources, Anadarko and Encana. While the coalbed methane (CBM) and shale gas potential is raising eyebrows in the Pearsall Shale, many E&Ps are, however, waiting until gas prices increase. It is interesting to note that TXCO Resources, one of the early shale players, declared bankruptcy and sold its assets to Anadarko Petroleum and Newfield Exploration.

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6 ibid
10 ibid
While geologists have known about Eagle Ford’s shale for decades, it was not economically feasible to produce. Prior to 2008, the Eagle Ford Shale was non-productive. E&P’s targeted the overlying Austin Chalk, until the Petrohawk STS #1 in October 2008.\(^{12}\) While this spurred interest, it was not until 2010 that the organic-rich black Eagle Ford Shale really gained momentum. This is mostly attributed to advancements in drilling technology and hydraulic fracturing. The Eagle Ford Shale is a source rock where oil and gas are trapped in the low permeability shale. The low clay content and high calcite levels of the Eagle Ford Shale make it brittle and easy to frac.\(^{13}\)

Table 4.1 provides a summary of Eagle Ford’s key geological characteristics of the three zones: dry gas, condensate and oil. The average EUR for the oil zone is 300 MBO/well, and the TRR is 3.35 BBO. The Eagle Ford has approximately 20.81 Tcf of technically recoverable of natural gas.

### Table 4.1: Eagle Ford Shale Geological Characteristics

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Dry Gas Zone</th>
<th>Condensate Zone</th>
<th>Oil Zone</th>
</tr>
</thead>
<tbody>
<tr>
<td>Area (sq. miles)</td>
<td>200</td>
<td>890</td>
<td>2,233</td>
</tr>
<tr>
<td>EUR (Bcf/well)</td>
<td>5.5</td>
<td>4.5</td>
<td>n/a</td>
</tr>
<tr>
<td>EUR (MBO/well)</td>
<td>n/a</td>
<td>n/a</td>
<td>300</td>
</tr>
<tr>
<td>Well Spacing (wells/sq. mile)</td>
<td>4</td>
<td>8</td>
<td>5</td>
</tr>
<tr>
<td>TRR (BBO)</td>
<td>n/a</td>
<td>n/a</td>
<td>3.35</td>
</tr>
<tr>
<td>TRR (Tcf)</td>
<td>4.38</td>
<td>16.43</td>
<td>n/a</td>
</tr>
</tbody>
</table>

Source: EIA\(^{14}\)

Table 4.2 provides a summary of Eagle Ford’s key geological characteristics.

### Table 4.2: Eagle Ford Shale Reservoir Characteristics

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Eagle Ford Shale</th>
</tr>
</thead>
<tbody>
<tr>
<td>Geological age</td>
<td>Cretaceous</td>
</tr>
<tr>
<td>Depth range (ft)</td>
<td>4,000-14,000</td>
</tr>
<tr>
<td>Shale thickness (ft)</td>
<td>100-330</td>
</tr>
<tr>
<td>Permeability</td>
<td>up to 0.13 md</td>
</tr>
<tr>
<td>Porosity</td>
<td>4-15%</td>
</tr>
<tr>
<td>Pressure gradient (psi/ft)</td>
<td>0.6</td>
</tr>
</tbody>
</table>

Source: EIA\(^{15}\)

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\(^{12}\) Eagle Ford Overview, Ramona Hovey, SVP Analysis and Consulting, February 23, 2011, pp. 3.


\(^{15}\) ibid
The Eagle Ford lies at a depth range of 4,000-14,000 ft., which is comparable to East Texas' prolific Barnett Shale which is at 6,500-9,000 ft. This depth is considered ideal in that the shale is more likely to be over pressured and easier to extract, rather than at normal pressure. In addition, the Eagle Ford Shale is brittle and fracs easily. In terms of thickness, the Eagle Ford is 100-330 ft. The Barnett Shale’s thickness is 200-1,000 ft. in the Core/Tier 1 and 100-250 ft. in the South/Western. The Eagle Ford has a porosity of 4 to 15 percent and permeability up to 0.13 md. The average Total Organic Content (TOC) is 4.25 percent wt, while the pressure gradient is 0.6 psi/ft. Some suggest that the TOC ranges between 4.5 and 5.5 percent.\(^{16}\)

EOG Resources, the largest lease holder and top producer in the shale play, increased its estimates on its 664,000 net acreage in the oil zone, from 900 million barrels of oil equivalent (MMboe) to 1,600 MMboe in February 2012.\(^{17}\) And in February 2013, EOG increased its estimate again, to 2,200 MMboe, a 38 percent increase.\(^{18}\) Halliburton suggests that early core analysis shows that the Eagle Ford Shale may have the potential to be one of the highest quality shale reservoirs in the US while ConocoPhillips believes that the Eagle Ford could be as big as the Haynesville Shale.\(^{19}\)

**E&P Players and Recent M&A Activity**

The Eagle Ford Shale has come a long way since October 2008 when the Petrohawk discovered the Hawkville Field in Las Salle County. The well flowed at a rate 7.6 MMcfpd and was drilled to a total vertical depth of 11,141 ft. and 3,200 ft. laterally.\(^{20}\)

According to the Railroad Commission of Texas (RRC), there were 1,262 producing oil leases on schedule in 2012. This is up dramatically from 368 producing oil leases on schedule in 2011, 72 producing oil leases in 2010 and 40 producing oil leases in 2009.\(^{21}\) Despite the low price of natural gas, there were 875 producing gas wells on schedule in 2012; up from 550 gas wells in 2011, 158 gas wells in 2010 and 67 gas wells in 2009.\(^{22}\) In total, there were 4,145 drilling permits issued in 2012, up from 2,826 in 2011 and 1,010 from 2010.\(^{23}\)

Figure 4.6 shows the dramatic growth in oil production in the Eagle Ford Shale between 2008 and November 2012. Oil production from the shale play has more than doubled.

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\(^{16}\) Eagle Ford Overview, Ramona Hovey, SVP Analysis and Consulting, February 23, 2011, pp. 8.


\(^{20}\) ibid


\(^{22}\) ibid

from 2011, with one month remaining in 2012. By year end, the total barrels of oil produced in 2012 could reach 360,000 bpd.\(^{24}\)

**Figure 4.6: Eagle Ford Shale Oil Production between 2008 and 2012**

![Eagle Ford Shale Oil Production between 2008 and 2012](image)

Source: RRC\(^{25}\)

It is also important to note that natural gas production was 964 MMcf between January and November 2012, up dramatically from 659 MMcf in 2011 and up from 216 MMcf in 2010 and 47 MMcf in 2009.\(^{26}\) Condensate production, on the other hand, was 72,126 bpd between January and November 2012, up slightly from 70,934 bpd in 2011 and up significantly from 13,708 bpd in 2010.\(^{27}\) Both condensate and natural gas production have leveled off in the past couple of years, while oil production has surged.

While early activity focused on the shale gas in the Eagle Ford, with low gas prices, the focus has shifted to the Eagle Ford’s oil-bearing shale. And with approximately US$30 billion being planned by operators in the shale play in 2013, Eagle Ford is turning the energy spotlight on South Texas.\(^{28}\) Today the Eagle Ford is creating ripples for its significant oil shales and is now considered one of the most prolific in the US. Some

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analysts suggest that the Eagle Ford ranks as one of the most important oil and gas
developments in the history of Texas and the US. Other analysts suggest that the Eagle
Ford could add 420,000 bpd to US oil production.

It is no surprise that the Eagle Ford has attracted some of the energy industries largest
and most experienced players.

The following are the top 10 largest oil producers in the Eagle Ford in 2012, through
November 2012. EOG Resources is the top producer, at 29,503,410 bbls and has 171
producing leases. The company also produced 38,338,935 Mcf of natural gas. ConocoPhillips (Burlington Resources) produced 16,091,354 bbls and has 262 producing
leases. It also produced 42,248,658 Mcf of natural gas. Chesapeake Energy produced
15,354,886 bbls and has 261 producing leases. Anadarko Petroleum produced 7,077,478
bbls and has 220 producing leases. It is also a large natural gas producer, at 53,580,600
Mcf. Geosouthern Energy produced 11,701,430 bbls and has 111 producing leases.
Companies to round out the top 10 are Plains Exploration (6,625,356 bbls and 50
producing leases), Marathon Oil (5,312,048 bbls and 87 producing leases), El Paso
Corporation (5,300,228 bbls and 21 producing leases), Murphy E&P (4,590,476 bbls and
53 producing leases) and Pioneer Natural Resources Exploration (3,441,928 bbls and 63
producing leases).

While the number of operators is increasing by the month, the following will discuss
three major players: EOG Resources, Chesapeake Energy and ConocoPhillips.

Houston-based EOG Resources is the Eagle Ford’s largest producer and has amassed the
largest net acreage. With almost 650,000 net acres in the Eagle Ford, the company is the
largest player in the shale play, and one of the largest independent oil and natural gas
companies in the US. EOG’s acreage breakdown in the three zones are 569,000 net
acres in the oil window, 21,000 net acres in the condensate window and 49,000 net
acres in the natural gas window.

Figure 4.7 illustrates EOG’s land holdings (in yellow) in the Eagle Ford. The company’s
presence extends from Gonzales County, down to Las Salle and Webb counties.

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29 ibid
30 Reuters Website, Analysis: 100 years after boom, shale makes Texas oil hot again,
http://www.reuters.com/article/2011/05/03/us-pipeline-eagle-ford-idUSTRE7426A220110503 (accessed on March 27, 2013)
31 Largest oil producers in the Eagle Ford Shale, San Antonio Business Journal, February 7, 2013,
Already a significant player in the Barnett Shale and the oil shale-rich Bakken Shale in North Dakota and Montana, EOG increased its presence in the Eagle Ford in 2010, securing 520,000 net acres. At the time of the purchase, EOG estimated that, on its own acreage, the reserve potential was 900 MMboe. As previously mentioned, this estimate was later increased to 1,600 MMboe and, as of this year, 2,200 MMboe. With current drilling activity, the company suggests that it has a 12-year drilling inventory.

The company drilled 305 wells and operated an average of 23 drilling rigs in 2012. As of February 15, 2013, EOG’s rig count is 24, up a single rig from the previous week.

As of December 31, 2012, EOG’s net production in the Eagle Ford was 106 MBoepd and averaged 109 MBoepd in the 3Q2012. The company’s 2012 average net production was 94.4 MBoepd.

Source: http://eaglefordshale.com/companies/eog-resources/attachment/eog-acreage-map-600x-v2/

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Thus, EOG’s most productive wells are located in the Gonzales Country, including the Burrows Unit #2H. The Burrows initial production (IP) rate was 6,330 bpd, with 713 bpd of NGLs and 4.1 MMcfpd of natural gas.\textsuperscript{39} The Burrows Unit #1H has an IP rate of 5,424 bpd of oil, along with 600 bpd of NGLs and 3.5 MMcfpd.\textsuperscript{40} Both wells were completed in January 2013. Other highly productive wells in the county include the Boothe Unit #1H and #2H, whose IP was 5,380 and 3,810 Bpd, with 625 and 525 Bpd of NGLs and 3.6 and 3.0 MMcfpd of natural gas, respectively.\textsuperscript{41} Wells in the McMullen County include the Naylor Jones Unit 59 East #1H and West #4H. Both of their initial production rates were 1,670 and 1,150 bpd, respectively.\textsuperscript{42} In 2013, EOG plans to focus on the Eagle Ford Shale, as well as their properties in the Bakken Shale and the Permian Basin. According to EOG’s stakeholder meetings in mid-February 2013, the company is planning to drill 400 net wells, with approximately 26 rigs, in 2013.\textsuperscript{43} EOG’s 2013 CAPEX budget is US$7.2 billion, with much of the focus on the Eagle Ford and the Bakken.\textsuperscript{44} Approximately 83 percent of the CAPEX is allocated to exploration and development.\textsuperscript{45} EOG’s 2012 CAPEX budget was US$7.5 billion.\textsuperscript{46} The company also has operations in Canada, Trinidad & Tobago, the United Kingdom and China. Other operations in the US include central Texas, East Texas, northern Louisiana and the Rocky Mountains. EOG is also one of the largest crude oil producers in the Bakken/Three Forks in North Dakota. It is interesting to note that, during 2011, nearly 85 percent of the company’s production is from North America.\textsuperscript{47} Soon after Petrohawk’s results were revealed, other companies began to acquire land in the shale play. The largest – at least initially – was Chesapeake Energy. It is still, however, a major player in the Eagle Ford Shale. The Oklahoma City-based company currently holds approximately 485,000 net acres in the Eagle Ford Shale. The assets are located in the counties of Webb, Dimmit, La Salle, Zavala, Frio and McMullen; mostly in the oil zone.\textsuperscript{48} At one point, the company had approximately 600,000 net acres, but has sold a 33 percent stake to the China National

\textsuperscript{37} EOG Resources, Investor Relations Presentation, March 13, 2013, pp. 22.
\textsuperscript{38} ibid
\textsuperscript{39} Eagle Ford Shale Play, EOG Resources Adds Reserves & Reports Record Well, February 14, 2013 http://eaglefordshale.com/news/EOG-resources-adds-reserves-reports-record-well/ (accessed on March 27, 2013)
\textsuperscript{40} ibid
\textsuperscript{42} ibid
\textsuperscript{44} ibid
\textsuperscript{47} ibid
\textsuperscript{48} ibid
Offshore Oil Corporation (CNOOC).\textsuperscript{49} CNOOC paid Chesapeake US$1.08 billion.\textsuperscript{50} In addition to the cash, CNOOC will fund 75 percent of Chesapeake’s drilling costs for up to a second US$1.08 billion.\textsuperscript{51}

Figure 4.8 illustrates Chesapeake’s lease holding in the Eagle Ford Shale.

\textbf{Figure 4.8: Chesapeake’s Lease Holdings in the Eagle Ford Shale}

\begin{figure}
\centering
\includegraphics[width=\textwidth]{figure4_8}
\caption{Chesapeake’s Lease Holdings in the Eagle Ford Shale}
\end{figure}

Source: http://alleagleford.com/eagle_ford_shale_maps.htm

As of 4Q2012, Chesapeake had 534 gross operated producing wells, of which 402 reached first production.\textsuperscript{52} The company is currently operating 17 rigs (February 15, 2013), up six from the prior week.\textsuperscript{53} The company peaked with 34 rigs in April 2012.

In 4Q2012, Chesapeake’s net production averaged 62,500 Boepd, up 266 percent year-over-year.\textsuperscript{54} The 4Q2012 production mix in the Eagle Ford Shale is 66 percent oil, 19


\textsuperscript{51} ibid

\textsuperscript{52} Chesapeake Energy, Chesapeake Energy Corporation Reports Financial and Operational Results for the 2012 Fourth Quarter and Full Year, 2/21/2013, http://www.chk.com/News/Articles/Pages/1787352.aspx (accessed on March 27, 2013)


percent natural gas and 15 percent NGLs.\textsuperscript{55} Chesapeake’s most notable wells completed yielded the following results during the 4Q2012:\textsuperscript{56}

- The Hahn Dew 1H in DeWitt County, TX achieved a peak rate of approximately 1,985 Boepd, which included 550 bbls of oil, 360 bbls of NGLs and 6.4 MMcf of natural gas per day;
- The Flat Creek Unit A Dim 2H in Dimmit County, TX achieved a peak rate of approximately 1,470 Boepd which included 1,210 bbls of oil, 160 bbls of NGLs and 0.6 MMcf of natural gas per day; and
- The JJ Henry IX M 1H in McMullen County, TX achieved a peak rate of approximately 1,275 Boepd, which included 1,160 bbls of oil, 55 bbls of NGLs and 0.4 MMcf of natural gas per day.

Despite the fact that Chesapeake’s CAPEX budget is US$6.4 billion, down from US$10.5 billion, the company is planning to allocate 35 percent of their drilling and completion CAPEX on the Eagle Ford Shale.\textsuperscript{57} Due to low natural gas prices, the company is focusing 85 percent of the 2013 drilling and completion on liquids plays – a dramatic change in philosophy for a company that is the second-largest producer of natural gas in the US.\textsuperscript{58} Other unconventional liquids plays that Chesapeake is a major player include the Utica Shale, Anadarko Basin, Granite Wash, Mississippi Lime and the Niobrara Shale. In terms of shale gas, they are major players in the Marcellus, Haynesville and the Barnett Shale.\textsuperscript{59}

ConocoPhillips (Burlington Resources) is also one of the major players in the Eagle Ford Shale. Burlington Resources was one of the early players in the Eagle Ford Shale until it was purchased by ConocoPhillips in 2006. The Houston-based ConocoPhillips purchased Burlington and its assets for US$35.6 billion. It is now operated as a division of the giant multinational ConocoPhillips. The company has worldwide operations in Alaska, Canada, Lower-48, Europe, Asia Pacific and the Middle East. As of May 2012, ConocoPhillips employs more than 16,000 people across 30 countries.\textsuperscript{60}

ConocoPhillips has over 223,000 net acres in the Eagle Ford, focusing on the liquids and condensate windows of the shale play.\textsuperscript{61} Figure 4.9 shows ConocoPhillips’s lease holdings

\begin{itemize}
\item \textsuperscript{55} ibid
\item \textsuperscript{56} Chesapeake Energy, Chesapeake Energy Corporation Reports Financial and Operational Results for the 2012 Fourth Quarter and Full Year, 2/21/2013, http://www.chk.com/News/Articles/Pages/1787352.aspx (accessed on March 27, 2013)
\item \textsuperscript{58} ibid
\item \textsuperscript{60} ConocoPhillips website, Worldwide Operations, http://www.conocophilips.com/EN/about/worldwide_ops/Pages/index.aspx (accessed on March 27, 2013)
\item \textsuperscript{61} Eagle Ford Shale, ConocoPhillips – Burlington Resources, http://eaglefordshale.com/companies/conocophillips-burlington-resources/ (accessed on March 27, 2013)
\end{itemize}
in the Eagle Ford Shale. Most of the drilling activities are in the counties of DeWitt, Live Oak, Karnes and Gonzales—along the liquids-rich portion of the Eagle Ford Shale.

**Figure 4.9: ConocoPhillips Acreage in the Eagle Ford Shale**

![Map of ConocoPhillips Acreage in the Eagle Ford Shale](image)

Source: ConocoPhillips’s website

In the 4Q2012, the Eagle Ford averaged 89,000 Boepd, achieving a daily peak of 103,000 Boepd. The company operated 11 rigs in 4Q2012. At end 2011, ConocoPhillips had 16 rigs active, with a net production of over 50 MBoepd. At the end of 3Q2012, production exceeded 86 MBoepd, up from 54 MBoepd at the end of the 1Q2012. The increase in production from 2011 to 2012 is 144 percent in the Eagle Ford.

ConocoPhillips plans to spend US$15.8 billion in 2013, including more than US$4 billion in its US Lower-48 assets. These include: Eagle Ford Shale, Bakken Shale, Niobrara and Permian Basin.

Within the PADD 3 area there are two primary unconventional oil plays, the Eagle Ford and the Permian. Figure 4.10 shows three possible development tracts for PADD 3. The

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64 Ibid
solid line utilizes the EIA historical data to 2011 followed by the development forecast from Hart Energy (red line) for the years 2011 to 2016 and an extrapolation to the year 2022. In this case, a log-based numeric function was used to extend the forecast. The dashed line starts with the EIA historical data to 2012, and the Hart Energy forecast to 2016 (red line) and extrapolates to the end of the forecast. In this case, a power-based numeric function was used to extend the forecast. This curve represents a continuing growth situation. The dotted line follows the EIA data and the Hart Energy forecast to 2016 followed by a polynomial numeric function to extend the forecast to 2022. This curve mimics the situation where drilling activity falls off significantly. In the context of this report, the “growth” curve is utilized to develop the medium-term forecast of US domestic oil supply.

Figure 4.10: PADD 3 Unconventional Crude Oil Forecast


Refining Unconventional Oil, Hart Energy Research Group, 2012
Chapter 5
PADD 4: Rocky Mountain States

The PADD 4 region includes the states of Montana, Idaho, Wyoming, Utah, and Colorado. This area has both conventional and unconventional crude oil production with conventional production expected to decline over the coming years. The growth in crude oil for this area will come from the unconventional oil plays of the Niobrara which is found in Colorado, Nebraska and Wyoming. The following describes the historic production (see Figure 5.1) followed by a description of the Niobrara Shale play and a trend analysis for the PADD.

Figure 5.1: PADD 4 State Production of Crude Oil

Source: Energy Information Administration (EIA)

The Niobrara Shale, Colorado/New Mexico/Nebraska
Despite the fact that E&Ps have been active in the Niobrara Shale since 2010, it is only now truly emerging. Its geological characteristics are unique and this shale/tight oil play is garnering attention. With company’s making the transition from natural gas to liquids, the Niobrara Shale, and the Denver-Julesburg Basin, is quite attractive, with many dubbing it the “neo-Bakken”.
Geology and Basin Metrics

The Niobrara Shale is located in Wyoming, Colorado and Nebraska. While the play is also attracting a lot of attention for its oil shale potential, leading some industry pundits to compare it to the Bakken Shale, it is also rich in natural gas.

The location of the Niobrara Shale is illustrated in Figure 5.2. It is important to note that the Niobrara Formation, of which the Niobrara Shale is a part, is a large geological formation that extends from Western Canada to New Mexico. As such, the organic-rich Niobrara Formation occurs in several basins, including the Powder River Basin, the Niobrara Shale and the Park Basin. The location of all three is shown in Figure 5.2. The Powder River Basin lies mostly in Wyoming but extends into Montana; it is occasionally referred to as the Mowry-Niobrara or Niobrara-PRB. The smaller Park Basin is located west of the Niobrara Shale, entirely in the state of Colorado. This section, however, focuses on the Niobrara Shale, as indicated on the map below. It is interesting to note the graphic also shows the locations of the Uinta Basin and the Piceance Basins located in Utah and Colorado, respectively.

![Figure 5.2: The Niobrara Shale and Area Map](http://www.ugcenter.com/resources/images/niobrara_shale.gif)

Source: UGcenter

Figure 5.3 shows a more detailed view of the Niobrara Shale, down to the county level. The core of the Niobrara shale lies within Colorado and Wyoming. The core is in the

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counties of Adams, Larimer, Logan and Weld in the former and the counties of Platte, Goshen, Laramie and Converse in the latter.²

**Figure 5.3: The Niobrara Shale Map**

Most of the focus currently in the Niobrara is in the Denver-Julesburg Basin (DJ Basin). The name Julesburg stems from the town, located in heart of the basin. The large basin is sometimes simply referred to as the Denver Basin. This is where the ‘sweet spot’ Wattenberg and Silo fields are located. The former is in the heart of Weld County, Colorado, while the latter is in the southeastern corner of Wyoming.⁴ E&Ps in the Wattenberg field are experiencing positive results, despite the challenging geological characteristics. It is important to note that the Wattenberg is both an oil and natural gas field, while the Silo is an oil field.

While rich in oil and natural gas, the geology of the Niobrara Shale is complex. Biogenic natural gas is usually found at a depth of 3,000 ft, oil is generally located between depths of 7,000 to 8,000 ft. Figure 5.4 shows the complex geology of the Niobrara Formation.

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Figure 5.4: Niobrara Shale Stratigraphy

The Cretaceous-aged formation is made up of thin layers, or chalk zones (Niobrara A, B and C). The Niobrara Shale underlies the Pierre Shale and overlies the Fort Hays Limestone. Source rock lies between the various Niobrara Shale layers, made up of inter-bedded marls and shale. These complex layers date back to the Cretaceous Age (145.5-54.5 million years ago), when this area was the eastern edge of the Western Interior Seaway. The giant body of water divided the North American continent, from the Arctic Ocean all the way down to the Gulf of Mexico.

The Codell Sandstone, the thin layer underlying Fort Hays Limestone, is an important natural gas field. This is sometimes referred to as the Codell-Niobrara Interval, and is the

Source: http://www.niobraranews.net/niobrara-formation- genesis/

5 The Niobrara News, Niobrara Formation Genesis/http://www.niobrarane w.net/niobrara-formation- genesis/ (accessed on March 27, 2013)

6 ibid

7 ibid
8\textsuperscript{th} in gas reserves in the US, including Alaska and the Gulf of Mexico.\textsuperscript{8} The Codell Sandstone is clay-rich, marine sandstone. The organic-rich Greenhorn Limestone underlies the Codell Sandstone; it is also gas-bearing in the Wattenberg area.\textsuperscript{9} The Dakota Sandstone (D-Sand) is Late Cretaceous-aged and lies at an average depth of 7,800 ft and consists of marine deposits; the Dakota Formation extends across the northern Great Plains, across several mid-western states.

The complex and unique geological characteristics of the Niobrara Formation are illustrated in Figure 5.5. This graphic shows a cross-section of the Niobrara Formation across Utah, Colorado, Nebraska, Kansas and Iowa (from left to right). The oil-rich limestone and chalk is shown by the thin black-coloured bands. They are surrounded by bands of fine-grained continental deposits and marine shale. The latter provides a plethora of fossils of flora, invertebrate and vertebrate life. Areas near the bottom of the basin are rich in thermal natural gas.

\textbf{Figure 5.5: Stratigraphic Cross-section of the Niobrara Formation}

\begin{center}
\includegraphics[width=\textwidth]{niobrara_cross_section.png}
\end{center}

Source: http://c1wsolutions.wordpress.com/2013/01/28/the-niobrara-shale-play-the-next-bakken/

While geologically challenging, the rewards are high. Advances in drilling technology and seismic have made this region attractive for E&Ps. Horizontal drilling and advances in frac’ing techniques are making it easier for operators to target natural fractures and


thicker shale seams. This, combined with decreasing drilling costs, has made this area economically feasible. This was not the case even a dozen years ago.

Figure 5.6 shows the target formations within the Wattenberg field. This area has attracted some of the biggest players, including Noble Energy, Anadarko Petroleum, Chesapeake Energy and EOG Resources. While a simplified graphic, the strategy is to extend laterals along the seams and to increase spacing units on the surface.\(^\text{10}\) Laterals can reach 4,000 ft, along with 80-acre spacing.\(^\text{11}\)

**Figure 5.6: Target Formations within the Wattenberg Field**

![Target Formations within the Wattenberg Field](http://www.niobraranews.net/exploration/niobrara-premier-oil-resource-play/)

Table 5.1 provides a summary of the Niobrara’s key geological characteristics and metrics. The following table also includes estimates for F&D, D&C and royalty percentage. The Niobrara Shale lies at a depth range of 6,000-10,000 ft., comparable to the Barnett Shale which lies at a depth range of 6,500-9,000 ft. In terms of thickness and porosity, the Niobrara is 150-500 ft. and has a TOC content of 1-8 percent. The EUR is also greater than 200 MBoe while the IP is greater than 400 Boepd.

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\(^\text{11}\) ibid
Table 5.1: Niobrara Shale Geological Characteristics

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Niobrara Shale</th>
</tr>
</thead>
<tbody>
<tr>
<td>Geological age</td>
<td>Cretaceous</td>
</tr>
<tr>
<td>Depth range (ft)</td>
<td>6,000-10,000</td>
</tr>
<tr>
<td>Shale thickness (ft), gross</td>
<td>150-500</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>8-10</td>
</tr>
<tr>
<td>Total organic carbon (%)</td>
<td>1-8</td>
</tr>
<tr>
<td>In-Place MMBoe/mile(^2)</td>
<td>20-50</td>
</tr>
<tr>
<td>IP (Boepd)</td>
<td>400 +</td>
</tr>
<tr>
<td>EUR (MBoe)</td>
<td>200 +</td>
</tr>
<tr>
<td>F&amp;D Cost ($/Boe)</td>
<td>15-30</td>
</tr>
<tr>
<td>D&amp;C ($MM)</td>
<td>3.5-6.5</td>
</tr>
<tr>
<td>Royalty (%)</td>
<td>17</td>
</tr>
</tbody>
</table>

Source: Niobrara Tudor & Pickering\(^{12}\) IHS Energy and Rose Exploration\(^{13}\)

Table 5.2 provides a summary of the Cretaceous-aged DJ Basins geological characteristics – considered the heart of the Niobrara Shale. They are similar to the Niobrara as a whole but there are unique differences in the shale.

Table 5.2: Niobrara Shale DJ Basin Geological Characteristics

<table>
<thead>
<tr>
<th>Parameter</th>
<th>DJ Basin</th>
</tr>
</thead>
<tbody>
<tr>
<td>Geological age</td>
<td>Cretaceous</td>
</tr>
<tr>
<td>Depth range (ft)</td>
<td>4,000-9,000</td>
</tr>
<tr>
<td>Shale thickness (ft), gross</td>
<td>250-600</td>
</tr>
<tr>
<td>In-Place MMBoe/mile(^2)</td>
<td>20-50</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>4-18</td>
</tr>
<tr>
<td>Ave Well Cost (US$M)</td>
<td>4</td>
</tr>
<tr>
<td>Ave Lateral (ft)</td>
<td>6,000</td>
</tr>
<tr>
<td>Ave EUR (MBoe)</td>
<td>280</td>
</tr>
<tr>
<td>OOIP (MMBo)</td>
<td>20-40</td>
</tr>
</tbody>
</table>

Source: http://www.shaleexperts.com/plays/niobrara-shale/Overview

The average EUR is 280 MBoe per well and the original-oil-in-place (OOIP) is approximately 20-40 MMBoe per square mile. The DJ Basin lies at between 4,000 ft. to 6,000 ft. This depth is considered ideal in that the shale is more likely to be over pressured and easier to extract. In terms of thickness, the DJ Basin is between 250 and 600 ft, with a porosity of 4-18 percent. It is important to note that the average lateral in the DJ Basin is 6,000 ft.

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In 2002, the USGC assessed the oil and natural gas resources of the Denver Basin Province (DJ Basin). Figure 5.7 shows a map of the Denver Basin Province (red line). The area in the top left corner of the map is the Powder River Basin, lying just outside the Denver Basin Province. The bulk of the Denver Basin is located in Colorado, but it extends into the states of Kansas, Nebraska, South Dakota and Wyoming. Oil is shown by green, natural gas by red and a mix between the two in yellow. Black indicates non-productive wells. The U.S. Geological Survey mean estimates of petroleum potential in the Denver Basin Province are 104.23 million barrels of oil, 2,519 billion cubic feet of gas, and 51.81 million barrels of NGLs.

**Figure 5.7: The Denver Basin Province**

![Map of the Denver Basin Province](image)

Source: USGC\(^{14}\)

While the geology may be tricky, the pay-offs are large. More current resource estimates show that the Denver Basin holds more oil and natural gas than previously

\(^{14}\) ibid
thought. Anadarko Petroleum, one the major players in the Niobrara, suggests that the DJ Basin alone may hold approximately 3.1 to 3.6 billion barrels of oil.\textsuperscript{15} At end-November 2011, Anadarko estimated a net resource of 500-1.5 billion barrels. Noble Energy, another major player, mirrors these sentiments. The Houston-based company estimates 2.1 billion barrels of oil on its land holdings within the DJ Basin.\textsuperscript{16} This estimate is up from 1.3 billion Boe in 2011.

New innovations in geological exploration and advances in drilling technology, as well as improving economics, are increasing the amount of technically recoverable oil in the Niobrara Shale.

\textbf{E&P Players and Recent M&A Activity}

Similar to the Bakken Shale’s impact on North Dakota oil production, the Niobrara is having a dramatic impact on Colorado’s total oil production. While not as prolific as thrusting North Dakota to the second-highest oil producing state in the US, Colorado’s oil production hit a 57-year high in 2012.\textsuperscript{17} According to the Colorado Oil & Gas Conservation Commission (COGCC), 48,866,402 barrels of oil were produced in 2012. This is up from 39,124,879 barrels in 2011 and 32,747,992 barrels in 2010.\textsuperscript{18} The Niobrara is an important part of the high production figures. Interestingly, 2012 is not a record-high, but second only to 1956, when Colorado produced 58,564,000 barrels of oil.\textsuperscript{19}

Figure 5.8 shows oil production in millions of barrels from 1952 to 2012. The Wattenberg field is in the Niobrara Shale, and it dominates oil production in the state. The annual production in Weld County – the heart of the core of the Wattenberg field – was 36,372,128 bbl in 2012.\textsuperscript{20} Nearly 75 percent of total oil production in the state of Colorado was produced in Weld County. Niobrara oil production is up from nearly 30,000,000 barrels in 2011 and up from 24,000,000 barrels in 2010.


\textsuperscript{16} ibid


\textsuperscript{18} Colorado Oil and Gas Conservation Commission, COGCC Reports Portal, Monthly Oil Produced by County, http://cogcc.state.co.us/COGCCReports/production.aspx?id=MonthlyOilProdByCounty (accessed on March 27, 2013)

\textsuperscript{19} ibid

\textsuperscript{20} Colorado Oil and Gas Conservation Commission, COGCC Reports Portal, Monthly Oil Produced by County, http://cogcc.state.co.us/COGCCReports/production.aspx?id=MonthlyOilProdByCounty (accessed on March 27, 2013)
In addition to its oil production, Weld County also produced 268,808,564 Mcf in 2012, up from 239,589,973 Mcf in 2011 and 218,911,782 Mcf in 2010. The county is only third in natural gas production behind Garfield County (701,431,865 Mcf) and La Plata (393,172,677 Mcf). Garfield County is located in western Colorado, around the fast-growing communities of Glenwood Springs and Parachute, near the heart of the Piceance Basin. La Plata, on the other hand, is located in Colorado’s southwestern corner.

Figure 5.9 show Colorado’s natural gas production between 1952 and 2012. Natural gas production in the Wattenberg field is increasing – albeit not as dramatically as its oil production.

Source: COGC

21 Colorado Oil & Gas Commission, March 2012 Update to Oil Production
22 Colorado Oil and Gas Conservation Commission, COGCC Reports Portal, Monthly Oil Produced by County, http://cogcc.state.co.us/COGCCReports/production.aspx?id=MonthlyOilProdByCounty (accessed on March 27, 2013)
The rig count in Weld County was 33 rigs as of week-ending March 22, 2013, down two from the previous week and down five from the same time last year. Eighteen rigs are oil-targeted while the remaining 15 are natural gas-directed, as of March 22, 2013. The number of oil-directed rigs is unchanged from the previous week and is up from 15 rigs year-over-year. Natural gas-directed wells, on the other hand, have decreased two from the previous week and eight from this time last year. Thirty-one of the 33 total rigs in Weld County are horizontal in nature.

The Niobrara Shale play has attracted some of the energy industries largest and most experienced E&P oil and gas players. Although the situation is dynamic, the top four land holders in acres are Anadarko Petroleum, Noble Energy, Chesapeake, and EOG Resources. Other large E&Ps with smaller acreages include CNOOC, WPX Energy, Quicksilver Resources, Marathon Oil and Whiting Petroleum.

The following will discuss Noble Energy and Anadarko Petroleum, the two most active and largest players in the Niobrara.

Noble Energy is a major player in the burgeoning Niobrara Shale, particularly in the DJ Basin. The independent oil and gas producer is also a player in the Marcellus Shale, Deepwater Gulf of Mexico, Eastern Mediterranean and West Africa. Non-core areas include China and the North Sea. The company’s mainstays are the DJ Basin and

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23 Colorado Oil & Gas Commission, March 2012 Update to Oil Production
25 ibid
Marcellus Shale. The latter includes positions in southwest Pennsylvania and northwest West Virginia.\(^{27}\)

The Houston-based company holds 640,000 net acres in the Niobrara, 80 percent are located in the oil window.\(^{28}\) Noble has 410,000 net acres in the Greater Wattenberg Area (GWA) in the core area of the shale play. Of their GWA land holdings, 290,000 net acres are in the oil window and 120,000 net acres are in the natural gas window.\(^{29}\) They hold an additional 230,000 net acres in Northern Colorado, including the East Pony area. This area has yielded positive drilling results. The East Pony 3 pilot program is producing oil at an average 24-hour rate of 780 Boepd and a 30-day average rate of 620 Boepd.\(^{30}\)

Figure 5.10 shows a map of Noble Energy’s large acreage in the Colorado-portion of the Niobrara. The natural gas window is shown in red while the oil window is shown in green. Noble’s acreages are shown in dark blue. Denver city limits are shown in the bottom left corner.

**Figure 5.10: Noble Energy’s Lease Holdings in the Niobrara Shale**

![Map of Noble Energy’s Lease Holdings in the Niobrara Shale](http://www.niobraranews.net/drilling/noble-energy-accelerate-niobrara-operations/)

Source: http://www.niobraranews.net/drilling/noble-energy-accelerate-niobrara-operations/

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\(^{27}\) ibid

\(^{28}\) Noble Energy, DJ Basin, Analyst Conference, December 6, 2012, pp. 50

\(^{29}\) ibid

Noble estimates that it can produce approximately 2.1 billion barrels of oil equivalent from its land holdings in the Niobrara. This is nearly 60 percent higher than its previous production estimates from the DJ Basin. The Houston-based company estimates 9,500 horizontal drilling locations on its acreage and targets increasing average EURs to 335 MBoe.

Total company 4Q2012 liquids produced were a record-high 120 MBblpd, up 40 percent year-over-year. Production in crude oil and other liquids in the DJ Basin averaged 51 MBblpd, up 34 percent year-over-year. Figure 5.11 illustrates the net production in the DJ Basin over the past five quarters. Production in the DJ Basin averaged 86 MBoepd in 4Q2012, up 15 percent from 3Q2012 and up 34 percent over the previous year. The net daily production was 62 MBoepd in 2011. It is interesting to note that the horizontal drilling program accounted for 39 MBoepd of production in the DJ Basin.

Figure 5.11: Noble Energy’s DJ Basin Net Production

Source: Noble Energy

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33 Noble Energy, Fourth Quarter 2012 Supplemental Information, pp. 5.
34 Ibid
38 Noble Energy, Credit Suisse Energy Summit, Charles Davidson, February 4-8, 2013, Pp. 9
Noble drilled 53 wells and completed another 63 wells in 4Q2012.\textsuperscript{39} This increases the 2012 total to 200 wells drilled and 193 wells completed.\textsuperscript{40} The company operated eight rigs in the DJ Basin and two in Northern Colorado. The company plans to drill approximately 300 horizontal wells in 2013, up from about 200 wells in 2012 and 85 in 2011.\textsuperscript{41} An estimated 500 wells are planned to be drilled by 2016.\textsuperscript{42} This is a part of Noble Energy’s DJ Basin Development Program, in which they plan to double drilling activity in two years. Figure 5.12 shows the number of horizontal wells and cumulative wells expected in the Greater Wattenberg Area and Northern Colorado up to 2017. The GWA is in green and the Northern Colorado regions in blue.

\textbf{Figure 5.12: Noble Energy’s Horizontal Wells in the Niobrara Shale}

![Figure 5.12: Noble Energy’s Horizontal Wells in the Niobrara Shale](image)

Source: Noble Energy\textsuperscript{43}

Noble’s capital program for 2013 is US$3.9 billion, including a 25 percent increase in spending in the DJ Basin. The Marcellus properties are expected to see an 80 percent year-over-year increase.\textsuperscript{44} Between 2013 and 2017, Noble plans to spend approximately US$10 billion in the Niobrara.\textsuperscript{45} Figure 5.13 shows the breakdown of Noble capital program expenditures.

\begin{itemize}
\item 40 ibid
\item 43 Noble Energy, Howard Weil 41\textsuperscript{st} Annual Energy Conference, March 2013, Charles Davidson, pp. 11.
\item 44 Noble Energy, Credit Suisse Energy Summit, February 4-8, 2013, pp. 7
\item 45 ibid
\end{itemize}
Anadarko is not only one of the largest players in the Niobrara, but it is among the largest global independent E&Ps. The company also has operations in the Eagle Ford Shale, Marcellus Shale, Greater Natural Buttes, Deepwater Gulf of Mexico, New Zealand and across various parts of Africa. In addition to E&P activities, its midstream activities include 28 natural gas systems and 12,620 miles of gathering pipelines.

Anadarko holds a net acreage of 350,000 net acres in the core of the Wattenberg field, and an additional 550,000 net acres in the periphery of the GWA. Figure 5.14 illustrates Anadarko’s massive net acreage in the heart of the Niobrara shale play – the Wattenberg field – as of end-2012. The yellow-coloured regions show the company’s acreage and the purple-coloured lines show Anadarko’s pipeline infrastructure. The graphic also illustrates the White Cliffs Oil Pipeline and four processing plants, as well as the Anadarko’s future Lancaster Cryo processing plant. The former is a 527-mile, 12-inch diameter crude oil pipeline that moves crude from the DJ Basin to Cushing, Oklahoma. The Lancaster Cryo Plant has a planned capacity of 300 MMcfpd and is expected to be online in 1Q2014. The Woodford Texas-based company owns acreage on the periphery of the Wattenberg that extends north and southeast of the map shown.

Source: Noble Energy

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In 2012, Anadarko had more than 5,500 wells in the liquids-rich Wattenberg field. As the name of the program suggests – Wattenberg HZ – Anadarko employs primarily horizontal drilling and frac’ing. In 2012, Anadarko drilled 136 vertical or directional wells and 176 horizontal wells. In 4Q2012 the company drilled 62 horizontal wells in the Niobrara and Codell formations. Anadarko added a tenth horizontal rig to the Wattenberg and released a record-high 24 wells in December 2012.

In addition to drilling rig increases, Anadarko is reporting improved drilling efficiencies as well. Figure 5.15 illustrates Anadarko’s drilling efficiencies in the Wattenberg. Spud-to-rig release has decreased from an average of 16.8 days in 1Q2011 to an average of 12.3 days in 4Q2012.

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54 ibid
56 ibid
57 ibid
Anadarko reached a milestone in 3Q2012 in the Wattenberg field as sales volumes surpassed the 100,000 Boepd level. As of 4Q2012, sales volumes averaged 103,400 Boepd.\textsuperscript{59} Sales volumes in the Wattenberg in the fourth quarter were 40 MBblpd of oil, 16 MBblpd of NGLs and 287 MMcfpd of natural gas.\textsuperscript{60} This is up from 3Q2012, in which sales volumes were 34 MBblpd of oil, 13 MBblpd of NGLs and 262 MMcfpd of natural gas.\textsuperscript{61} Sales volumes in the Wattenberg in 4Q2011 were 23 MBblpd of oil, 16 MBblpd of NGLs and 222 MMcfpd of natural gas.\textsuperscript{62} Average sales volumes in 2012 were 91 MBoepd, up from an average of 73 MBoepd in 2011 and an average of 61 MBoepd in 2010. Anadarko expects sales volumes to increase in the range of 120 to 125 MBoepd.\textsuperscript{63}

As of 4Q2012, the Wattenberg HZ is producing slightly more than 45,000 Boepd, gross, from 176 horizontal wells.\textsuperscript{64} This is up from 3Q2012, where 115 horizontal wells produced 37,000 Boepd.\textsuperscript{65} Figure 5.16 illustrates the rapid growth of net production in the Wattenberg over the past couple of years.
Anadarko estimates that, on their land holdings alone, the liquids-rich reservoir holds between 1 billion to 1.5 billion Boe. The EUR is approximately 350 MBoe per well. It is interesting to note that the company has identified approximately 4,000 potential drillings sites, up from between 1,200 and 2,700 potential drilling sites in early 2012.

The company invested approximately US$1 billion in capital into its Colorado operations in 2012, and spent US$306 million in the Wattenberg alone in 4Q2012. Anadarko’s CAPEX budget for 2013 is between US$7.2-7.6 billion, and the US onshore operations are expecting an allocation of 60 percent.

Within the PADD 4 area the Niobrara is the predominate unconventional oil play. Figure 5.17 shows three possible development tracts for PADD 4. The solid line utilizes the EIA historical data to 2011 followed by the development forecast from Hart Energy (red line).

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66 ibid
72 Anadarko Petroleum Corporation, Howard Weil 41st Annual Energy Conference, March 2013, Al Walker President and CEO, pp. 5.
for the years 2011 to 2016 and an extrapolation to the year 2022. In this case, a log-based numeric function was used to extend the forecast. The dashed line starts with the EIA historical data to 2012, and the Hart Energy forecast to 2016 (red line) and extrapolates to the end of the forecast. In this case, a power-based numeric function was used to extend the forecast. This curve represents a continuing growth situation. The dotted line follows the EIA data and the Hart Energy forecast to 2016 followed by a polynomial numeric function to extend the forecast to 2022. This curve mimics the situation where drilling activity falls off significantly. In the context of this report, the “growth” curve is utilized to develop the medium-term forecast of US domestic oil supply.

**Figure 5.17: PADD 4 Unconventional Crude Oil Forecast**

![Graph showing PADD 4 Unconventional Crude Oil Forecast](image)


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73 Refining Unconventional Oil, Hart Energy Research Group, 2012
Chapter 6
PADD 5: West Coast

The PADD 5 region includes the states of Washington, Oregon, Nevada, Arizona, California, Hawaii, and Alaska. Future production from the area is expected to continue declining at the recent history decline of 4 percent per year. Figure 6.1 details the historical production from the PADD 5 area. There is potential for development of the Monterey shale oil play in California but at these early stages the level of production is unknown. The Monterey shale formation is believed to hold one of the world’s largest onshore reserves of shale oil. The US government estimates that 15.4 billion barrels of oil could be locked within the Monterey shale. To put this into context, the Bakken play in North Dakota and Montana is approximately 50 percent of this value and the Eagle Ford play in Texas is 20 percent. However, the Monterey runs beneath significant tracks of wildlife habitat and underlies the San Joaquin Basin in the Central Valley where farmland produces one-quarter of the nation’s food and crops. The oil industry and the farming sector are about to run into a significant challenge – that of weighing a new potential source of income against competition for water allotments, increased truck traffic, issues around the potential for ground water contamination, and the potential of induced seismic activity. Assuming that the environmental movement focuses its attention on stopping this development, the general public will eventually be drawn into the discussion. The future of the Monterey shale development is unknown and thus is not included as a future growth in PADD 5.

Figure 6.1: PADD 5 State Production of Crude Oil

Source: Energy Information Administration (EIA)
Chapter 7
United States Liquids Supply and Demand

In 2012 the United States consumed, on average, 18,646,000 barrels of crude oil and crude oil equivalent liquids per day to produce motor gasoline (47 percent), diesel fuel (18 percent), jet fuel (7 percent), liquefied petroleum gases (12 percent), and other residual products (16 percent). The supply to meet this demand came from domestic sources (34 percent), imports (46 percent) other liquid fluids from gas plants (13 percent), and other product imports and blending components (7 percent). Imports averaged 8,518,000 barrels per day with, 28 percent sourced from Canada, 16 percent from Saudi Arabia, 11 percent from Venezuela, 11 percent from Mexico, and 34 percent from other sources including Iraq, Nigeria, Colombia and others. Refer to Figures 7.1 and 7.2 for a list of all suppliers. It is interesting to note that Venezuela, Saudi Arabia, Kuwait, Colombia, and Canada have increased their exports to the United States since the recession of 2009, whereas, Nigeria, Mexico and the United Kingdom (North Sea) have reduced their exports. In total, US imports have decreased by 500,000 bbls per day over the period 2009 to 2012.

Figure 7.1: United States Crude Oil Imports from OPEC Countries

Source: Energy Information Administration (EIA)
CERI estimates that Canada’s production of conventional light and heavy crude will increase by 225,000 barrels per day by 2020 (Figure 7.3) over the 2012 production level. Production of conventional crude from Western Canada has been in a steady decline since the 1970s but the advent of horizontal well drilling and hydraulic fracturing technology has resulted in this decline being reversed in 2010 and has been growing ever since.

Canada’s oil sands production in 2012, both upgraded and non-upgraded, reached the 1,800,000 barrel per day mark. Figure 7.4 details CERI’s forecast of conventional crude oil and oil sands production that could be delivered to the United States if pipeline and rail connectivity is developed. This forecast is net after accounting for local demand. In this forecast, CERI has accounted for the expansion of the Enbridge Clipper pipeline (Phase I and II), the construction of the Keystone XL pipeline and the development of rail transport to the 600,000 barrels per day level. These developments would deliver 1.4 million new barrels per day of crude oil and bitumen to the US market by 2018.

In their Annual Energy Outlook (AEO2013: reference case), the US Energy Information Administration indicates that the US consumption of hydrocarbon based liquids will not grow significantly from its current level. Their forecast shows US consumption reaching 19.8 million barrels per day by 2022 which in effect is a total growth of 6 percent between 2012 and 2022.

The results of the trend analysis of unconventional shale oil growth on a PADD basis (Figure 2.18, Figure 3.10, Figure 4.17 and the PADD I and PADD V discussion) indicates that US domestic supply could reach 8.9 million barrels per day by 2022 (see Figure 7.5).
Figure 7.6 details the forecast of US crude oil supply, including domestic production, imports from Canada and imports from other nations against the EIA forecast of US consumption of liquid fuels.

**Figure 7.3: Western Canadian Conventional Oil Production Forecast**

![Western Canadian Conventional Oil Production Forecast](image)

Source: CERI

**Figure 7.4: Canadian Conventional, Unconventional and Oil Sands Export Potential**

![Canadian Conventional, Unconventional and Oil Sands Export Potential](image)

Source: CERI
**Figure 7.5: United States Crude Oil Forecast by PADD**

Source: EIA Historical data, Hart Energy Unconventional forecast to 2016, CERI trend analysis to 2022

**Figure 7.6: United States Liquids Supply/Demand Balance**

Source: EIA Historical data, Hart Energy Unconventional forecast to 2016, CERI trend analysis to 2022