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NET ASSET VALUATION OF WHITING PETROLEUM'S ACQUISITION OF KODIAK OIL AND GAS

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NET ASSET VALUATION OF WHITING PETROLEUM'S ACQUISITION OF KODIAK OIL AND GAS

By

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A THESIS

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Abstract

In July 2014, it was announced that Whiting Petroleum would acquire Kodiak Oil & Gas in an all-stock deal valued at $6 billion. Both companies are headquartered in Denver and operate primarily in the Bakken but in a deal of this size it is possible for executives to hold ulterior motives for mergers such as higher compensation and golden parachutes. Acceptable motivating factors for engaging in a merger include cost savings through synergies and economies of scale, increased market power, asset diversification, and price volatility. A net asset valuation was used to help determine if shareholders should vote in favor of the merger. Through increased market share and cost savings, the merger can be deemed a success for Whiting Petroleum.

1. Introduction & Background

1.1 Introduction

On July 14, 2014, Whiting Petroleum announced they would acquire Kodiak Oil and Gas in a deal valued at $6 billion (Whiting Petroleum Corporation 2014e). The resulting company will become the largest producer in North Dakota, extracting over 100,000 barrels of oil per day.

Whiting Petroleum is an independent oil & gas company headquartered in Denver, Colorado and focuses primarily on exploration and production. The company was were founded in 1980, and went public on the New York Stock Exchange in November 2003 with a market capitalization of $284 million at the time. Current market capitalization of the company stands at $9.35 billion as of July 11, 2014 (Whiting Petroleum Corporation 2014d). The company currently operates mainly in the Rocky Mountains region, which accounted for 84% of its 2013 production. This region is broken down into two main locations, the Williston Basin of North Dakota and the Denver-Julesburg Basin of Colorado. Whiting also operates in the Permian Basin of west Texas, which accounted for 12% of its 2013 production. The remaining 4% of 2013 production came from properties in Arkansas, Louisiana, Michigan, Oklahoma and Texas (Whiting Petroleum Corporation 2014b).

Kodiak Oil and Gas is also an independent oil & gas company headquartered in Denver, Colorado. They operate almost entirely within the Williston Basin as well but also have acreage positions in Wyoming and Colorado. In 2013, they averaged daily sales volumes of 29,200 barrels of oil equivalent (BOE) per day. As of December 31, 2013 Kodiak had total proved reserves of 167 MMBOE all of which are located in North Dakota (Kodiak Oil and Gas Corporation 2014a).

In an oil & gas acquisition of this magnitude, many issues need to be taken into consideration. Why did Whiting Petroleum choose to acquire another company? Why did they choose Kodiak as opposed to another producer? To shareholders of Whiting Petroleum, the most important question is: will this acquisition add more value than the cost of the purchase? Another way to phrase this question could be: does purchasing Kodiak Oil & Gas increase or decrease the share price of Whiting Petroleum? A net asset valuation (NAV) model was used to help arrive at an answer to this question. A NAV model is commonly used to value oil & gas or natural resource companies.

Public oil & gas companies are required to report the size of their reserve base every year. This includes proved, probable, and possible reserves (Securities and Exchange Commission 2011). The NAV method makes an extraction forecast for these reserves while making predictions about commodity prices, variable costs, and fixed costs. Eventually this leads to a net present value of the company by using a discounted cash flow.

In addition to this quantitative analysis, a qualitative analysis will also be conducted to determine what other factors could positively or negatively contribute to this acquisition.

Both Whiting Petroleum and Kodiak Oil & Gas shareholders must vote to approve the merger before it can be completed (Whiting Petroleum Corporation 2014e). This analysis will be directed at these shareholders, providing them with all necessary information and a recommendation on whether they should vote for or against the merger. This analysis will also be relevant to anyone close to the decision making process for this acquisition. This could include the board of Whiting Petroleum, the board of Kodiak Oil & Gas, and any outside consultants. It would also be relevant to any individual or institutional investors who are deciding whether or not to make an investment in Whiting Petroleum as a result of this merger.

1.2 Background

On Friday July 11, 2014, Whiting Petroleum stock price closed at $78.54. On Sunday July 13, 2014, Whiting Petroleum issued a press release to announce a definitive agreement to acquire Kodiak Oil & Gas. As a result of this announcement, its share price jumped 7.7% to close at $84.58 on Monday, July 14, 2014. Since the announcement, the share price of Whiting has soared as high as $92.66 (Whiting Petroleum Corporation 2014d).

On July 11, 2014, the stock price of Kodiak Oil & Gas was $14.23 with a market capitalization of $3.8 billion. The details of the agreement stated Kodiak shareholders would receive .177 of a share of Whiting Petroleum for each share of Kodiak stock they owned (Whiting Petroleum Corporation 2014e). Based on Whiting Petroleum's July 11 closing price, this implies a purchase price of $13.90 per share for Kodiak Oil & Gas. Prior to the acquisition, Whiting Petroleum had 119,981,965 outstanding shares and they will issue 47,127,270 to fund the Kodiak purchase (Whiting Petroleum Corporation

2014b). Whiting shareholders will own 79% of the combined company while Kodiak shareholders will own the remaining 29% (Whiting Petroleum Corporation 2014e).

Whiting Petroleum was founded in 1980 in Denver, Colorado by Kenneth R. Whiting and Bert Ladd. Three years later the company became a public company after merging with Keba Oil & Gas. In 1992, it was acquired by Alliant Energy for $27.5 million or less than 1% of its market capitalization as of July 2014 Whiting Petroleum Corporation 2014d). Whiting again became a public company in 2003 with an IPO priced at $15.50 per share. Whiting first drilled into the Bakken formation in 2006. Whiting Petroleum continued to grow its position in the Rocky Mountains over the years and in the fourth quarter of 2013 hit the milestone production mark of 100,000 barrels of oil equivalent per day (Whiting Petroleum Corporation 2014d).

Many motivating factors exist as the driving force for a merger especially within the petroleum industry. Often times, executive compensation is directly tied to the stock price of a company. This can distract managers from the true goal of a company. A merger may be in the interest of the executives but not the shareholders of the same company. Other motivating factors for a merger include cost savings, economies of scale, increased market share, asset diversification, and price volatility. The following sections will help determine which of these variables possibly played a role in the Whiting Petroleum and Kodiak Oil & Gas merger.

The philosophy behind a merger of this type is that because of synergies, the combined company can accomplish more than what the two companies could accomplish individually. An example of this would be if Whiting and Kodiak each produced 50,000 bbls/day individually but the combined company was able to produce 125,000 bbls/day. This same logic could be applied to operating costs or general & administrative expenses.

Kodiak and Whiting operate primarily in the Bakken formation of Montana and North Dakota. To understand the true growth potential of these companies and this merger, it is first important to understand the magnitude of oil & gas production in the region. The Bakken play has become one of the largest oil producing regions in the United States. North Dakota is now the third largest oil producer in the United States behind only Texas and Alaska (Energy Information Administration 2014c). In June 2014, the Bakken averaged production of 1,027,957 barrels of oil per day. This is 200 times greater than what the field was producing in June 2006 (North Dakota Department of Mineral Resources 2014). Some of the biggest optimists like Harold Hamm, CEO of Continental Resources (largest producer in the Bakken before the Whiting Petroleum-Kodiak Oil & Gas merger) believe the Bakken will nearly double in production to two million barrels per day by 2020 (Helman 2014). Others believe the hype of the shale revolution is over blown. The biggest concern among skeptics is the rapid decline rate of shale wells when compared to conventional wells (Gronewold 2013).

Another reason to study this merger is because most mergers actually destroy rather than create value (Sirower, M. L. and O'Byrne, S. F. 1998). "So many mergers fail to deliver what they promise that there should be a presumption of failure. The burden of proof should be on showing that anything really good is likely to come out of one." (Sirower, M. L. and O'Byrne, S. F. 1998). This same study also suggests that any gains from a merger usually benefit the target company shareholders and the acquiring company shareholders are lucky to break even (Sirower, M. L. and O'Byrne, S. F. 1998). This would be a positive signal for Kodiak shareholders but a negative sign for Whiting shareholders. Therefore it is prudent for shareholders of both Whiting Petroleum to heavily scrutinize this purchase and this analysis should be helpful in that process.

The main goal of this paper is to determine if it was wise of Whiting Petroleum to acquire Kodiak Oil & Gas. Another goal of this paper is to learn what the process industry experts would use when evaluating the merger. The results of this analysis can be monitored over time to determine their accuracy. If the forecasts of this analysis coincide with the reality of post-merger Whiting Petroleum, it will signal the success of the framework of this paper. This evaluation process could then be used for future mergers and acquisitions in the United States. Any current or future shareholder of an oil & gas company should be interested in this analysis for the clarity and guidance it can provide on the issues surrounding a merger.

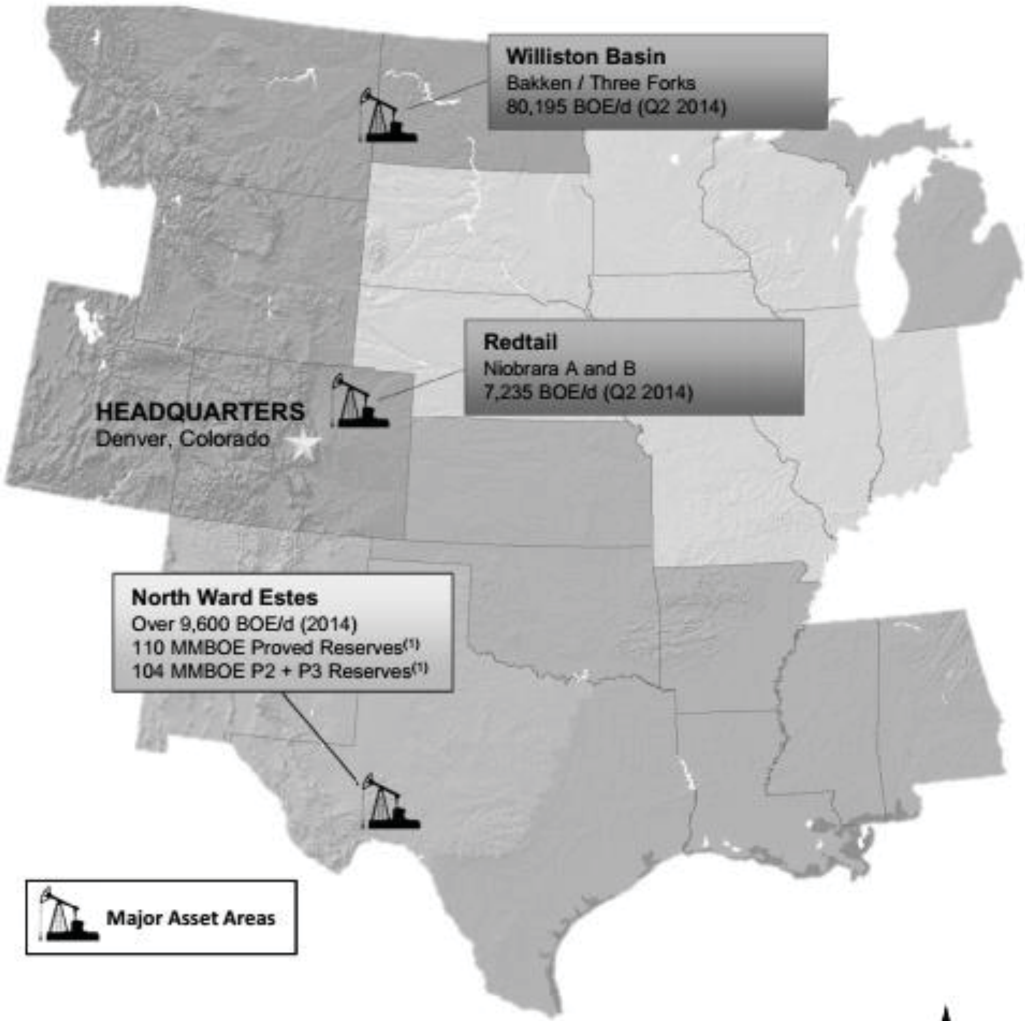

Figure 2.1: Map of Whiting Petroleum Operations

2. Research Methodology

2.1 Overview of the Analysis

To determine if Whiting Petroleum paid a fair price to acquire Kodiak Oil & Gas and to identify the value of the resulting company, a net asset valuation model was used. In general, this valuation method takes into account the reserves of a company and projects its supply forward into the future, using the discounted cash flow (DCF) method to arrive at the asset's current value. Many assumptions or estimations were needed to accurately construct the NAV model. This includes things like commodity price, well cost, well decline rate, and a drilling forecast. The following sections discuss how all numbers used in this model were calculated or estimated.

2.2 Data Collection

Whiting Petroleum and Kodiak Oil & Gas are both public companies and are required to file annual (10-K) and quarterly (10-Q) reports in accordance with Securities and Exchange Commission (SEC) regulations. The majority of these data required for the NAV model were found in these reports, which can be found on each company's website or the SEC website. Data was also collected from investor presentations on both company websites. These presentations are aimed at institutional or individual investors in the company and provide more detailed information than what is found in the 10-Ks or 10-Qs.

The initial data collected was Whiting Petroleum's developed and undeveloped acreage. This data is reported as both a gross and net number. The net figure is reported after taking into consideration Whiting Petroleum's working interest in a project. For example if Whiting entered into a joint venture with another company (each company owning 50%) in North Dakota for 10,000 acres, the gross acreage of the position would be 10,000 acres and the net acreage would be 5,000 acres. In this scenario, Whiting would be responsible for 50% of all costs involved and in return would receive 50% of the resulting revenue from the land (Breaking Into Wall Street 2014a). This data is also broken down by developed and undeveloped. Developed acreage is land that already has a well drilled and the necessary gathering pipelines in place. It can be either currently flowing or turned on with ease. Undeveloped acreage includes land that is owned or leased by Whiting Petroleum but has no completed well (Breaking Into Wall Street 2014a). The following tables show a breakdown of Whiting Petroleum's acreage positions by state (Whiting Petroleum Corporation 2014b).

Table 2.1: Whiting Petroleum's Developed Acreage by state as of December 31, 2013

	Developed Acreage		Implied Working Interest
Region	Gross	Net	
California	25,548	3,606	14.1%
Colorado	61,579	42,555	69.1%
Louisiana	40,074	11,691	29.2%
Michigan	139,351	61,064	43.8%
Montana	91,973	55,425	60.3%
New Mexico	16,665	5,427	32.6%
North Dakota	553,050	316,872	57.3%
Oklahoma	56,645	28,392	50.1%
Texas	260,935	147,963	56.7%
Utah	35,826	18,370	51.3%
Wyoming	95,725	55,835	58.3%
Other	9,810	4,503	45.9%
Total	1,387,181	751,703	54.2%

Table 2.2: Whiting Petroleum's Undeveloped Acreage by state as of December 31, 2013

Region	Undeveloped Acreage Gross	Net	Implied Working Interest
California	0	0	N/A
Colorado	179,242	116,629	65.1%
Louisiana	101,325	90,862	89.7%
Michigan	291,960	247,996	84.9%
Montana	136,964	81,730	59.7%
New Mexico	78,190	56,668	72.5%
North Dakota	365,538	261,008	71.4%
Oklahoma	406	68	16.7%
Texas	84,214	60,849	72.3%
Utah	406,522	240,108	59.1%
Wyoming	49,312	36,072	73.2%
Other	912	434	47.6%
Total	1,694,585	1,192,424	70.4%

As seen in the tables above, Whiting Petroleum's largest land position is in the Williston Basin of North Dakota. A detailed map of their acreage positions can be found in the figure below (Whiting Petroleum Corporation 2014e). Sixty-eight percent of Whiting Petroleum's proved reserves are located in the Rocky Mountain region. This includes both the Bakken/Three Forks formation and the Niobrara. Twenty-nine percent of their proved reserves are located in the North Ward Estes field of west Texas and the remaining 3% are located in Arkansas, Louisiana, Michigan, Oklahoma, and Texas (Whiting Petroleum Corporation 2014b). Historical reserves data for Whiting Petroleum can be found in Table 3.3 (Whiting Petroleum Corporation 2014b). An interesting observation is that their proved reserves have steadily increased over the past four years. This is significant because as an oil company produces oil & gas over the course of a year, it depletes its total proved reserve base. For this number to steadily increase, it means Whiting Petroleum has been discovering more oil than it has been producing each year. This is a positive sign for investors in the company.

Table 2.3: Historical Reserves Data of Whiting Petroleum

Reserves Data:	2011	2012	2013
Proved Developed Reserves			
Natural Gas (Mmcf)	211,297	160,893	183,129
Oil (MBbl)	203,084	190,845	198,204
NGL (MBbl)	0	24,204	23,721
Total Proved Developed Reserves (MBOE)	238,300	241,864	252,446
Proved Undeveloped Reserves			
Natural Gas (Mmcf)	73,678	63,371	94,385
Oil (MBbl)	94,669	110,440	149,217
NGL (MBbl)	0	15,894	21,148
Total Proved Undeveloped Reserves (MBOE)	106,949	136,896	186,096
Total Proved Reserves (MBOE)	345,249	378,760	438,542
Proved Reserves (MBOE)	345,249	378,760	438,542
Proved Undeveloped Reserves (MBOE)	106,949	136,896	186,096
Probable Reserves (MBOE)	105,979	115,168	176,191
Possible Reserves (MBOE)	195,255	171,178	189,127
Total PUD + PROB + POSS (MBOE)	408,183	423,242	551,414

Table 2.4: Whiting Petroleum Proved, Probable, and Possible Reserves as of December 31, 2013

	Oil (MMBbl)	NGL (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)
Rocky Mountains				
PDP	128.5	13.2	122.1	161.9
PDNP	0.5	0.1	1.2	0.8
PUD	107.6	12.4	85.5	134.3
Total Proved	236.6	25.7	208.8	297
Total Probable	90.8	17.4	215.3	144.1
Total Possible	59	8.4	136.2	90.1
Permian Basin				
PDP	49.6	5.9	11.8	57.4
PDNP	15.3	3.5	2.8	19.3
PUD	41.5	8.4	3	50.4
Total Proved	106.4	17.8	17.6	127.1
Total Probable	15.9	4.3	34.6	26
Total Possible	76.9	16.1	2.8	93.4
Other				
PDP	3.6	0.8	38.7	11
PDNP	0.7	0.3	6.6	2.1
PUD	0.1	0.3	5.8	1.3
Total Proved	4.4	1.4	51.1	14.4
Total Probable	2.6	0.6	17.7	6.1
Total Possible	1.3	0.1	24.8	5.6
Total Company				
PDP	181.7	19.9	172.6	230.3
PDNP	16.5	3.9	10.6	22.2
PUD	149.2	21.1	94.3	186
Total Proved	347.4	44.9	277.5	438.5
Total Probable	109.3	22.3	267.6	176.2
Total Possible	137.2	24.6	163.8	189.1

Table 2.4 shows the proved, probable, and possible reserves of Whiting Petroleum (Whiting Petroleum Corporation 2014b). This data is segmented by geographical region and by product. The products include oil, natural gas, and natural gas liquids. Oil and natural gas liquids are measured in barrels, while natural gas is measured in cubic feet. In an effort to easily compare these numbers, they are aggregated into one total column. Because cubic feet and barrels are different units, a conversion factor is needed. Based on heat content, it takes 6,000 cubic feet of natural gas to equal one barrel of oil (Breaking Into Wall Street 2014a). Using this conversion rate, the natural gas numbers were converted from billion cubic feet to million barrels of oil equivalent and the three products were added together.

Table 2.5: Percentage of Oil, Gas, and NGL by reserve type

Net Reserves	% Oil	% NGL	% Gas
PDP	78.90%	8.64%	12.49%
PDNP	74.32%	17.57%	0.05%
PUD	80.22%	11.34%	8.45%
Weighted Average:	79.22%	10.24%	10.54%

Using these data from Table 2.5, the average percentage of oil, natural gas, and natural gas liquids was calculated (Whiting Petroleum Corporation 2014b). In the future, it will be assumed the average well will follow this breakdown. This is important when calculating revenue because each product receives its own price. Therefore, a well that has high oil content could have very different economics than a well that has high gas content. It should be noted that Whiting Petroleum wells would have average oil content of almost 80%.

2.3 Well Data

In its most recent investor presentation, Whiting Petroleum reported an average estimated ultimate recovery (EUR) of 600 MBOE per well in North Dakota (Whiting Petroleum Corporation 2014a). In reality, each EUR per well varies from this number. For example, the geology of the sub-play, horizontal drilling length, well spacing, and number of fracing stages will all have considerable impact on the EUR of the well. Modeling the EUR at this level is beyond the scope of this paper. Just an average is needed to determine the number of new wells it would take to completely extract the remaining reserves. Whiting Petroleum segments its reserves in the following categories: Rocky Mountain, Permian Basin, and Other (Arkansas, Louisiana, Michigan, Oklahoma, Texas) (Whiting Petroleum Corporation 2014a). Ideally, the Rocky Mountain region would be broken down further between the Williston Basin of North Dakota and the Niobrara of Colorado. The EUR and well costs in these two regions are different and using assumptions for the Rocky Mountain region as a whole could result in an imperfect valuation of the assets (Whiting Petroleum Corporation 2014a).

Proved developed producing and proved developed non-producing reserves do not apply to future wells drilled. Using Table 2.5, the total proved undeveloped, probable, and possible reserves for the Rocky Mountain region are 368.5 MMBOE, 169.8 MMBOE for the Permian Basin and 13.0 MMBOE for the remaining regions (Whiting Petroleum Corporation 2014a). Using these numbers and an average EUR of 600 MBOE, the Rocky Mountain region will require 615 wells, Permian Basin will require 283 wells and the other region will require 157 wells in order to complete deplete the reserves base

(Breaking Into Wall Street 2014a). The table below shows historical drilling activity for Whiting Petroleum and the annualized oil price for that year (Whiting Petroleum Corporation 2014b).

Table 2.6: Whiting Petroleum Historical Drilling Activity and Oil Price

	2010		2011		2012		2013	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Wells Drilled	189	88	284	135	397	192.9	428	229.2
Oil Price	79.48	79.48	94.88	94.88	94.05	94.05	97.98	97.98
Wells Drilled by Oil Price	2.38	1.11	2.99	1.42	4.22	2.05	4.37	2.34

Many factors go into deciding the number of wells to drill in a given year but this table gives an idea of the upper and lower limits of wells drilled in the previous four years for Whiting Petroleum. This will be used to help forecast its drilling schedule going forward. It should be noted that according to their latest investor presentation, they have planned on drilling 328 gross wells for 2014 (Whiting Petroleum Corporation 2014a). It's also important to take into account the level of capital expenditure and rig allocation of Whiting Petroleum. In the same investor presentation, Whiting reports its 2014 Capital Expenditure to be $2.8 billion (Whiting Petroleum Corporation 2014a). Sixty percent or $1.68 billion of this money is planned for drilling wells in the Rocky Mountain region. $203 million is allocated for the Permian Basin region and only $44 million is going towards the "Other" region. The remaining amount of capital expenditure is for land acquisitions and miscellaneous expenses (Whiting Petroleum Corporation 2014a).

As of December 31, 2013 Whiting Petroleum has 23 drilling rigs in operation. 21 of these rigs were located in the Rocky Mountain region and the remaining two were located in the North Ward Estes field in the Permian Basin (Whiting Petroleum Corporation 2014b). The combination of rig allocation and capital expenditure allocation demonstrates the priorities of Whiting Petroleum. They are heavily focused in the Rocky Mountain region and the drilling forecast will accurately represent this situation.

2.4 Drilling Schedule

The wells calculated for each region in the previous section represent the net wells Whiting Petroleum would have to drill. The drilling schedule forecasts gross wells drilled, before taking into account their working interest. Their working interest was calculated by dividing future net wells by future gross wells from their 2012 Annual Report. The results were 47.9% working interest in the Rocky Mountains, 39.0% working interest in the Permian Basin, and 78.7% in the “Other” region (Whiting Petroleum Corporation 2013).

Table 2.7: Whiting Petroleum Drilling Schedule in High Price Scenario

	High Oil		
	Rocky Mountains	Permian Basin	Other
2014	319	9	0
2015	320	10	1
2016	320	10	1
2017	330	10	1
2018	0	320	5
2019	0	320	5
2020	0	330	5
2021	0	0	183

Table 2.8: Whiting Petroleum Drilling Schedule in Base Oil Scenario

	Base Oil		
	Rocky Mountains	Permian Basin	Other
2014	319	9	0
2015	270	5	1
2016	270	5	1
2017	270	5	1
2018	160	5	1
2019	0	270	5
2020	0	270	5
2021	0	270	5
2022	0	170	3
2023	0	0	180

Table 2.9: Whiting Petroleum Drilling Schedule in Low Oil Scenario

	Low Oil		
	Rocky Mountains	Permian Basin	Other
2014	319	9	0
2015	220	5	1
2016	220	5	1
2017	220	5	1
2018	220	5	1
2019	90	130	1
2020	0	220	1
2021	0	220	1
2022	0	220	1
2023	0	190	17
2024	0	0	175

Table 2.7 represents a maximum case scenario. If Whiting Petroleum drilled as much as they possibly could, they could not extract more oil than what is reported in their reserve numbers. In the base and low price case, they would still drill the same number of total wells but many of the wells would be pushed further in the future because there is less incentive to drill today with a lower oil price. This will affect the value of the company when calculating the discounted cash flow.

2.5 Price Information

A total of five price scenarios were used to quickly value Whiting Petroleum under a variety of oil & gas prices. All cases make a forecast for each year between 2014 and 2018. Beyond 2018, a long-term price is assumed. This is because it is difficult to make an accurate price forecast that far in the future and based on the time value of money concept it will have much less impact on the valuation than the prices from 2014 to 2018. The base case was determined using the futures market from the Chicago

Mercantile Exchange. This is a highly accurate scenario because these prices represent what price Whiting Petroleum could lock in today. In line with the drilling schedule, the next two scenarios are a high price case and low price case. The fourth price case assumes a stable price of $80 per barrel and $4.50 per Mcf from 2014 onward. The final price case mimics the SEC pricing technique. The SEC requires using a 12-month trailing price for calculating reserves (Securities and Exchange Commission 2011). At the valuation date of July 2014, this results in a price of $97.91 per barrel and $3.73 per Mcf. As of January 2015, these prices change to $89.12 and $4.22 respectively. The complete price list can be seen in the table below (Energy Information Administration 2014a) (Energy Information Administration 2014b)

Table 2.10: Various Price Scenarios (Chicago Mercantile Exchange 2014a)(Chicago Mercantile Exchange 2014b)

	Case 1: High Oil		Case 2: Base Oil		Case 3: Low Oil	
	Gas	Oil	Gas	Oil	Gas	Oil
Year	$ / Mcf	$ / Bbl	$ / Mcf	$ / Bbl	$ / Mcf	$ / Bbl
2014	4.85	93.00	4.04	93.00	3.23	93.00
2015	4.68	114.00	3.90	65.00	3.12	40.00
2016	4.56	108.00	3.80	70.00	3.04	45.00
2017	4.80	102.00	4.00	75.00	3.20	50.00
2018	5.04	96.00	4.20	80.00	3.36	55.00
LT	5.40	96.00	4.50	80.00	3.60	60.00

	Case 4: Stable		Case 5: SEC Prices	
	Gas	Oil	Gas	Oil
Year	$ / Mcf	$ / Bbl	$ / Mcf	$ / Bbl
2014	4.5	80	4.22	89.12
2015	4.5	80	4.22	89.12
2016	4.5	80	4.22	89.12
2017	4.5	80	4.22	89.12
2018	4.5	80	4.22	89.12
LT	4.5	80	4.22	89.12

Also, another price assumption that is needed is the difference between the market price and the price Whiting Petroleum actually receives for its product. The prices in the table above are quoted for West Texas Intermediate oil at Cushing, Oklahoma, the main hub for oil in the United States. Whiting Petroleum will most likely not receive this price for because of transportation costs. They will have to pay for transportation to Cushing or sell the oil to a third party locally who will demand a lower price because they will be incurring the transportation costs. In the first quarter of 2014, the average NYMEX price was $98.62 per barrel and $4.93 per Mcf (Whiting Petroleum Corporation 2014c). Whiting Petroleum actually received $88.85 per barrel and $6.50 per Mcf during the same time period (Whiting Petroleum Corporation 2014c). The price they received for natural gas was actually higher than the NYMEX price. Natural gas prices have considerable seasonal variation so it would be unwise to assume this pattern to continue throughout the year. Based on this information, it is assumed Whiting Petroleum will receive 90% of the NYMEX price for both oil and gas. Lastly, the average NGL price they received during this quarter was $52.95 per barrel (Whiting Petroleum Corporation 2014c). NGL prices are not quoted on the NYMEX so it is assumed the price Whiting Petroleum will receive will be 50% of the realized oil price at that time.

2.6 Reserve Cases

Reserves are the estimated amount of oil & gas in the ground under the land of which a company operates (Breaking Into Wall Street 2014a). A company's oil & gas reserves are updated on an annual basis by an independent engineering company. A team of expert geologists and petroleum engineers analyze geological data to estimate the quantity of oil & gas under the ground leased by that company. Because of technical limitations, it is impossible to completely extract every drop of oil that is believed to be in the ground. For this reason, reserves are further segmented into three smaller categories ranging from very high likelihood of extraction to very low likelihood of extraction. These three categories are known as proved, probable, and possible reserves.

It is commonly regarded that proved reserves have 100% chance of being extracted, probable has a 50% chance and possible has a 10% chance (Breaking Into Wall Street 2014a). In reality, these numbers may not be correct. A technological advancement in oil & gas extraction could imply the probable reserves have 75% of being successfully removed from the ground rather than 50%. The same idea can be applied to possible reserves. Just as multiple price scenarios were created to quickly value the company in different situations, multiple reserve credit cases were also created and can be seen in the table below. The first column shows the base case scenario of 100%, 50%, and 10% for proved, probable, and possible reserves respectively. This will be the base case used when doing the NAV calculations. Columns two through six will be used in the discussion of results section to see the impact technological advancements could have on the net asset valuation.

Table 2.11: Various Reserve Case Scenarios

Reserve Cases	1	2	3	4	5	6
Proved	100%	100%	100%	100%	100%	100%
Probable	50%	75%	50%	25%	75%	100%
Possible	10%	75%	50%	25%	50%	100%

2.7 Proved Developed Production Forecast

The production forecasts will be divided into four categories including proved developed, Rocky Mountains, Permian Basin, and Other. All proved developed producing (PDP) and proved developed non-producing (PDNP) reserves are included in the first category. The regional categories include proved undeveloped, probable, and possible reserves because these are the categories that require new wells to be drilled.

From Table 2.4, the total proved developed reserves can be calculated to be 252.5 MMBOE. It is important to remember these reserves are spread amongst the three regional categories. Whiting Petroleum produced 10.0 MMBOE in the first quarter of 2014 (Whiting Petroleum Corporation 2014c). Divided amongst the 91 days in the quarter, this results in 109.89 MBOE per day on average. As of December 31, 2013, Whiting Petroleum had 438.5 MMBOE of proved reserves (Whiting Petroleum Corporation 2014a). If they continued to produce 109.89 MBOE per day into the future, their proved reserves would last 10.93 years. At this same production level, their PDP and PDNP reserves would last for 6.30 years. These are important benchmarks for oil & gas producers because it gives an idea how fast their reserves are being depleted and how quickly they need to be replaced in order to maintain stable production into the future.

Because every oil well experiences a decline in production over the course of its life, it is assumed 109.89 MBOE/day is the maximum production level of these reserves. Annual production will continue to decline into the future until all 252.5 MMBOE are extracted. The tables below use a decline rate of 12.1% per year. Assuming a normally distributed start date of the currently producing wells, this number represents an average annual decline rate over the life of a well.

Table 2.12: PDP Reserves Production

	Beginning	Production		Ending
Year	Reserves	Daily	Annual	Reserves
2014	230,367	110	40,110	190,257
2015	190,257	97	35,257	155,000
2016	155,000	85	30,991	124,010
2017	124,010	75	27,241	96,769
2018	96,769	66	23,945	72,824
2019	72,824	58	21,047	51,777
2020	51,777	51	18,501	33,277
2021	33,277	45	16,262	17,015
2022	17,015	39	14,294	2,720
2023	2,720	34	2,720	0

Table 2.13: PDNP Reserves Production

	Beginning	Production		Ending
	Reserves	Daily	Period	Reserves
2014	22,167	11	0	22,167
2015	22,167	10	3,526	18,641
2016	18,641	8	3,099	15,542
2017	15,542	7	2,724	12,818
2018	12,818	7	2,394	10,423
2019	10,423	6	2,105	8,319
2020	8,319	5	1,850	6,469
2021	6,469	4	1,626	4,842
2022	4,842	4	1,429	3,413
2023	3,413	3	1,256	2,157
2024	2,157	3	1,104	1,052
2025	1,052	3	971	81
2026	81	2	81	-

Proved developed non-producing reserves include wells that have been completed and connected to the necessary pipelines but are not currently flowing. It is assumed these reserves will begin flowing in 2015.

2.8 Rocky Mountains

In the drilling schedule forecast, it was calculated that Whiting Petroleum would need to drill approximately 615 new net wells in the Rocky Mountains to adequately extract the remaining PUD, PROB, and POSS reserves in the region. Using a weighted average calculation, this means 224 net wells will be devoted to PUD reserves, 240 net wells for probable reserves and 150 net wells for possible reserves (Whiting Petroleum Corporation 2014b). Based on the likelihood of extraction, all PUD wells will be drilled first, followed by all PROB wells, and all POSS wells will be last.

Table 2.14: Rocky Mountains Drilling Locations and Risked Reserves

		Future Wells		Un-Risked Resources (MBOE)		Risked Resources (MBOE)	
Location Risking	Reserve Credit	Gross	Net	Gross	Net	Gross	Net
PUD	100%	467	224	280,524	134,482	280,524	134,482
PROB	50%	502	240	300,994	144,296	150,497	72,148
POSS	10%	314	150	188,199	90,222	18,820	9,022
Total:		1,283	615	769,716	369,000	449,840	215,652

The next step is to forecast the annual production of a single well in the Rocky Mountain region. This procedure is important because of the discounted cash flow and time value of money concept. If the annual production and revenue numbers in the NAV model do not accurately reflect reality, it will have a significant impact on the valuation of the company. Specifically, if the decline rate is too modest, it will result in an inflated valuation because more production will be occurring sooner and will not be discounted as heavily as production further into the future.

Based on the most recent Whiting Petroleum investor presentation, an initial production rate of 850 BOE/day was used. Over the course of the first year, it is expected this rate will decline by 67.0%, and the entire production profile can be seen in the table below (Whiting Petroleum Corporation 2014a).

Table 2.15: Production Profile of an Average Well in the Rocky Mountains

Period	Gas (Mmcf)	Oil (MBbl)	NGLs (MBbl)	(MBOE)	Rate
0	85.3	135.0	19.1	168.4	
1	38.8	61.4	8.7	76.6	54.5%
2	26.4	41.8	5.9	52.2	31.9%
3	19.4	30.7	4.3	38.3	26.6%
4	15.7	24.9	3.5	31.0	19.0%
5	13.3	21.1	3.0	26.3	15.3%
6	11.5	18.1	2.6	22.6	13.9%
7	9.9	15.7	2.2	19.6	13.4%
8	8.7	13.8	2.0	17.2	12.0%
9	8.0	12.7	1.8	15.8	8.5%
10	7.4	11.7	1.6	14.5	7.9%
11	6.8	10.8	1.5	13.5	7.4%
12	6.4	10.1	1.4	12.6	6.0%
13	6.1	9.6	1.4	12.0	5.0%
14	5.8	9.2	1.3	11.4	5.0%
15	5.5	8.7	1.2	10.8	5.0%
16	5.2	8.3	1.2	10.3	5.0%
17	5.0	7.9	1.1	9.8	5.0%
18	4.7	7.5	1.1	9.3	5.0%
19	4.5	7.1	1.0	8.8	5.0%
20	4.3	6.7	1.0	8.4	5.0%
21	4.0	6.4	0.9	8.0	5.0%
22	1.3	2.1	0.3	2.6	5.0%
Total				600.0	

The remaining assumptions needed for the Rocky Mountains are fixed costs and variable costs. Whiting Petroleum reports the fixed costs per well as drilling and completion costs. These costs include everything needed to drill a well. Within the Rocky Mountains, Whiting Petroleum reports the average D&C cost in the Williston Basin to be $8.0 million while the average D&C cost in the Niobrara is $5.48 million. Based on 2014-projected production, the Williston represents 91% of the Rocky Mountains production while the Niobrara represents the other 9% (Whiting Petroleum

Corporation 2014a). Using these numbers a weighted average of $7.77 million was calculated for the entire region.

2.9 Permian Basin

The tables below show the well break down by reserve type for the Permian Basin region and the Other region. Ideally, the Other category would be divided up by individual state or geological formation but Whiting does not report its reserves in that manner. Whiting Petroleum reports limited information on its Permian Basin activity. For this reason, an average well of Apache Corporation was chosen to represent Whiting. Apache is active in the Permian Basin and their well information should closely reflect that of Whiting Petroleum. Apache's most recent investor presentation reports a D&C cost of $6.3 million and a EUR of 600 MBOE (Apache Corporation). The full decline rate and annual production of the well can be seen in the table below.

Table 2.16: Production Profile of Average Well in Permian Basin

	Gross Type Curve				
Period	Gas (Mmcf)	Oil (MBbl)	NGLs (MBbl)	Total (MBOE)	Decline Rate
0	56.2	89.0	12.6	111.0	
1	27.7	43.9	6.2	54.7	50.7%
2	21.2	33.7	4.8	42.0	23.3%
3	16.6	26.4	3.7	32.9	21.7%
4	14.8	23.4	3.3	29.2	11.2%
5	13.3	21.1	3.0	26.3	10.0%
6	12.1	19.2	2.7	23.9	9.0%
7	11.1	17.6	2.5	22.0	8.0%
8	10.4	16.4	2.3	20.4	7.0%
9	9.7	15.4	2.2	19.2	6.0%
10	9.2	14.6	2.1	18.3	5.0%
11	8.8	13.9	2.0	17.3	5.0%
12	8.3	13.2	1.9	16.5	5.0%
13	7.9	12.6	1.8	15.7	5.0%
14	7.5	11.9	1.7	14.9	5.0%
15	7.2	11.3	1.6	14.1	5.0%
16	6.8	10.8	1.5	13.4	5.0%
17	6.5	10.2	1.4	12.8	5.0%
18	6.1	9.7	1.4	12.1	5.0%
19	5.8	9.2	1.3	11.5	5.0%
20	5.5	8.8	1.2	10.9	5.0%
21	5.3	8.3	1.2	10.4	5.0%
22	5.0	7.9	1.1	9.9	5.0%
23	4.8	7.5	1.1	9.4	5.0%
24	4.5	7.2	1.0	8.9	5.0%
25	4.3	6.8	1.0	8.5	5.0%
26	4.1	6.5	0.9	8.0	5.0%
27	3.0	4.8	0.7	5.9	5.0%
Total				600.0	

Table 2.17: Permian Basin Drilling Locations and Risked Reserves

		Potential Future Wells		Un-Risked Resources (MBOE)		Risked Resources (MBOE)	
Location Risking	Reserve Credit	Gross	Net	Gross	Net	Gross	Net
PUD	100%	215.1	84	129,081	50,400	129,081	50,400
PROB	50%	110.9	43	66,589	26,000	33,295	13,000
POSS	10%	398.6	156	239,209	93,400	23,921	9,340
Total:		724.8	283	434,879	169,800	186,296	72,740

2.10 Other Category

The Other reserves category includes acreage in Arkansas, Louisiana, Oklahoma, Michigan, and Texas. Of these properties, their most undeveloped acreage is in Michigan so an average well in the Antrim Shale was chosen to represent this category. The Antrim Shale in northern Michigan is known as a gas play, which is consistent with Whiting Petroleum's reported reserves for the Other category. Natural gas represents 62% of the reserves in this category, whereas it only represents 18% in the Rocky Mountains region. A report that was published by the Michigan Public Service Commission provides detailed information on the economics of wells drilled in the Antrim Shale. They report D&C costs of $300,000, a EUR of 500 MMcf (83.3 MBOE) and peak production of 150 Mcf per day (25 BOE/d) after 12 months of production (Michigan Public Service Commission 2010). After this peak, production declines at a rate of 7% per year. The complete well production can be seen in the table below.

Table 2.18: Production Profile for Average Well in "Other" category

	Gross Type Curve			Total	Decline
Period	Gas (Mmcf)	Oil (MBbl)	NGLs (MBbl)	(MBOE)	Rate
0	33.95	2.74	0.73	9.13	
1	31.57	2.55	0.68	8.49	7.0%
2	29.36	2.37	0.63	7.89	7.0%
3	27.30	2.20	0.59	7.34	7.0%
4	25.39	2.05	0.55	6.83	7.0%
5	23.62	1.90	0.51	6.35	7.0%
6	21.96	1.77	0.47	5.90	7.0%
7	20.42	1.65	0.44	5.49	7.0%
8	19.00	1.53	0.41	5.11	7.0%
9	17.67	1.42	0.38	4.75	7.0%
10	16.43	1.32	0.35	4.42	7.0%
11	15.28	1.23	0.33	4.11	7.0%
12	14.21	1.15	0.31	3.82	7.0%
13	13.21	1.07	0.28	3.55	7.0%
14	0.51	0.04	0.01	0.14	7.0%

Table 2.19: Drilling Locations and Risked Reserves for "Other" category

		Potential Future Wells		Un-Risked Resources (MBOE)		Risked Resources (MBOE)	
Reserve Type	Reserve Credit	Gross	Net	Gross	Net	Gross	Net
PUD	100%	4	3	1654	1302	1654	1302
PROB	50%	18	15	7761	6109	3880	3055
POSS	10%	17	13	7124	5609	712	561
Total:		39	31	16539	13020	6247	4918

2.11 Operating Costs

Whiting Petroleum will also incur costs associated with keeping a well in operation. These costs are expressed as a per barrel of oil equivalent produced. As of the second quarter of 2014, they had lease-operating expenses of $12.27 per BOE, production taxes of $6.78 per BOE, and G&A (general and administrative) expenses of $3.57 per BOE (Whiting Petroleum Corporation 2014c). They do not report an exact figure on royalty rates but do acknowledge it should be similar to other companies in the region. As will be seen in the following sections, Kodiak Oil & Gas average royalty rate is 18%, so this number will also be used for Whiting Petroleum.

2.12 Kodiak

Kodiak Oil & Gas operates entirely within the Rocky Mountain region of the United States. It holds lease positions in North Dakota (Williston Basin) in addition to Wyoming and Colorado (Green River Basin) (Kodiak Oil and Gas Corporation 2014a). Although they hold these two separate positions, they report 99.9% of their reserves are located in North Dakota (Kodiak Oil and Gas Corporation 2014a). For the purposes of this net asset valuation, it will be assumed their entire reserve base is located in North Dakota and it will be the site for all new wells drilled. A detailed map of their locations within the Williston Basin can be found in the figure below (Kodiak Oil and Gas Corporation 2014c).

Table 2.20: Kodiak Acreage Positions (Kodiak Oil and Gas Corporation 2014a)

	Total Acreage	
Williston Basin	Gross	Net
North Dakota	327,751	173,011
Green River Basin		
Wyoming	23,598	5,808
Colorado	11,001	4,319
	34,599	10,127
Acreage Totals	362,350	183,138

The same data collection and analysis methods were then applied to Kodiak Oil & Gas. Their reserve information can be found in the tables below. Total proved reserves of the company are 167.3 MMBOE. They did not report probable and possible reserves but instead reported the total to be 248.95 MBOE (Kodiak Oil and Gas Corporation 2014a). It was assumed to be a 50/50 split between these two categories. This may not be correct in reality and other scenarios will be examined during the valuation. \

Table 2.21: Kodiak PDP, PDNP, and PUD reserves

Net Reserves	Oil (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% Oil	% Gas
PDP	63.9	78.8	77.1	83.0%	17.0%
PDNP	0.0	0.0	0.0		
PUD	74.3	95.2	90.2	82.4%	17.6%
Average:			167.3	82.7%	17.3%

Table 2.22: Kodiak PUD, PROB, and POSS reserves

Proved Undeveloped Reserves (MBOE)	90,182
Probable Reserves (MBOE)	124,475
Possible Reserves (MBOE)	124,475
Total PUD + PROB + POSS (MBOE)	339,132

They averaged sales volumes of 29.2 MOBE per day throughout 2013, an increase from 3.9 MBOE per day in 2011 (Kodiak Oil and Gas Corporation 2014a). Their explosive production growth can be seen in the chart below. A total capital expenditure in of $940 million in 2014 was allocated for the drilling of 100 net wells (Kodiak Oil and Gas Corporation 2014c).

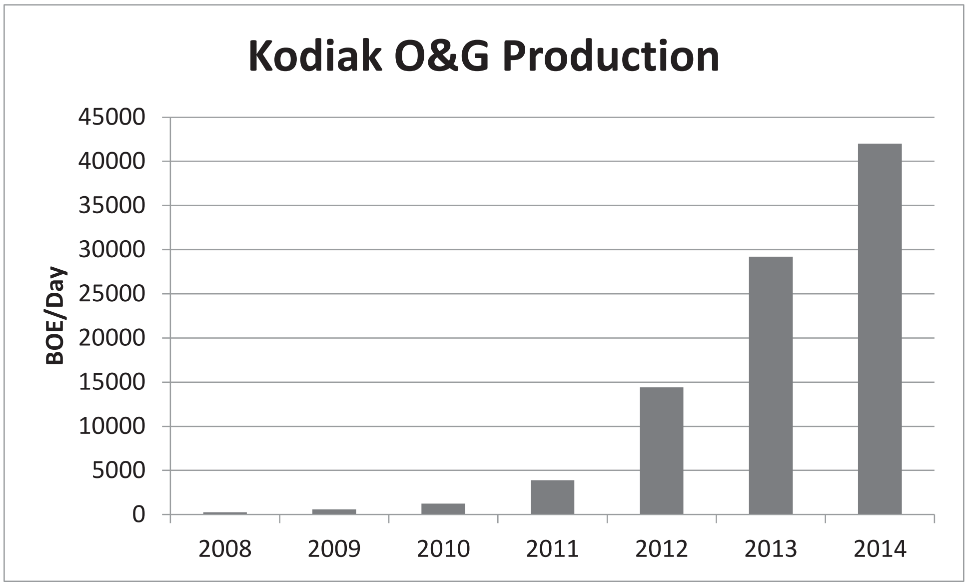

Figure 2.2: Kodiak Oil & Gas Historical Production

Kodiak Oil & Gas's June 2014 investor presentation offers very detailed information on the EUR per well by their location in the Williston Basin. In the Polar, Ursid, Koala, and Smokey sub-plays, they have disclosed EURs ranging from 600 to 950 MBOE (Kodiak Oil and Gas Corporation 2014c). There are 950 net potential drilling locations in these sub-plays. In Dunn County, they have recorded EURs of 800-950 MBOE and the Wildrose sub-play in the north recorded a more modest 350 MBOE per well (Kodiak Oil and Gas Corporation 2014c). To arrive at one single EUR, a weighted average of these numbers were used. This results in an average EUR per well of 760 MBOE.

Based on the same investor presentation, 2014 D&C costs were projected to be $9.0 million per well. This represents a substantial reduction from 2012 when their wells averaged $12.0 million (Kodiak Oil and Gas Corporation 2014c). The historical well costs can be seen in the figure below (Kodiak Oil and Gas Corporation 2014c). In addition to these fixed costs, Kodiak also has variable costs to keep a well in operation. For the second quarter of 2014, Kodiak reported a lease operating cost of $9.29 per BOE, production taxes of $9.07 per BOE, gathering, transporting, and marketing costs of $2.35 per BOE and G&A (General & Administrative) costs of $3.68 per BOE (Kodiak Oil and Gas Corporation 2014b). Kodiak Oil & Gas also has royalty obligations to pay to the landowner based on the amount of oil they produce. In their 2013 Annual Report, Kodiak stated its royalty rates range from 12.5% to 20% in most of the Williston Basin and are 18% for its leases in Dunn County, North Dakota (Kodiak Oil and Gas Corporation 2014a). An average of 18% was used for all of its acreage in North Dakota and will be accounted for when determining the value of Kodiak's assets.

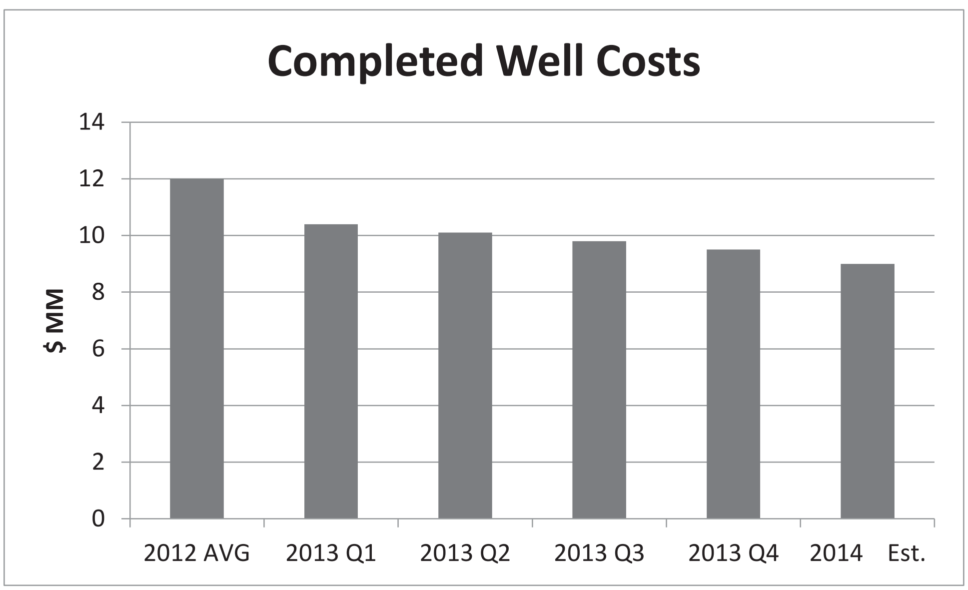

Figure 2.3: Completed Well Costs of Kodiak Oil & Gas

2.13 Kodiak Drilling Schedule

At an average EUR of 760 MBOE, it would take Kodiak Oil & Gas 543 net wells to fully extract its 416 MMBOE total reserves. Based on its acreage positions in the Williston Basin, its working interest is 52.8% (Kodiak Oil and Gas Corporation 2014c). This implies 1,028 gross wells must be drilled to equate 543 net wells for Kodiak. The forecasted drilling schedule in high, base, and low oil price scenarios can be found in the table below. Using a weighted average of reserve type, this translates to 145 proved wells, 199 probable wells, and 199 possible wells. As of December 31, 2013, Kodiak Oil & Gas budgeted $940 million capital expenditures for 2014, all of which were allocated to the Williston Basin. With seven operational drilling rigs, they planned to drill 100 net wells (223 gross wells) (Kodiak Oil and Gas Corporation 2014c).

Table 2.23: Drilling Scenarios for Kodiak Oil & Gas

	Drilling Scenario		
	High Oil	Base Oil	Low Oil
2014	223	223	223
2015	200	170	140
2016	200	170	140
2017	200	170	140
2018	205	170	140
2019	190	170	140
2020	0	140	140
2021	0	0	150

Table 2.24: Drilling Locations and Risked Reserves for Kodiak Oil & Gas

	Future Wells		Un-Risked Resources (MBOE)		Risked Resources (MBOE)	
Reserve Type	Gross	Net	Gross	Net	Gross	Net
PDP				77,033		77,033
PDNP				0		0
PUD	273	145	170,430	89,987	170,430	89,987
PROB	377	199	235,237	124,205	117,619	62,103
POSS	377	199	235,237	124,205	23,524	12,421
Total:	1,028	543	640,905	415,431	311,572	241,543

2.14 Kodiak Proved Developed Forecast

In the second quarter of 2014, Kodiak produced 3,482.67 MBOE or 38.27 MBOE per day (Kodiak Oil and Gas Corporation 2014b). If this production level remained constant into the future they would have a proved reserves to production ratio of 11.97 years. Their proved developed reserves to production ratio is 5.52 years. A PD decline rate of 8.6% was used based on the average decline rate of a single well for Kodiak Oil & Gas.

Kodiak Oil & Gas has various decline curve estimates based on the specific location within the Williston Basin and the drilling program used. A sample from the Polar/Koala sub-play shows an average production of 370 BOE per day throughout the first year. At the 12-month mark, the well would be expected to produce 217 BOE per day (Kodiak Oil and Gas Corporation 2014c).

Table 2.25: Production Profile of an Average Well for Kodiak Oil & Gas

	Gross Type Curve			
Period	Gas (Mmcf)	Oil (MBbl)	Total (MBOE)	Decline Rate:
0	137.8	112.1	135.1	N/A
1	62.1	50.6	60.9	54.9%
2	54.2	44.1	53.2	12.7%
3	48.1	39.1	47.2	11.3%
4	43.2	35.2	42.4	10.2%
5	38.9	31.6	38.1	10.0%
6	36.0	29.3	35.3	7.5%
7	34.2	27.8	33.5	5.0%
8	32.5	26.4	31.8	5.0%
9	30.8	25.1	30.2	5.0%
10	29.3	23.8	28.7	5.0%
11	27.8	22.7	27.3	5.0%
12	26.5	21.5	25.9	5.0%
13	25.1	20.4	24.6	5.0%
14	23.9	19.4	23.4	5.0%
15	22.7	18.5	22.2	5.0%
16	21.6	17.5	21.1	5.0%
17	20.5	16.7	20.1	5.0%
18	19.5	15.8	19.1	5.0%
19	18.5	15.0	18.1	5.0%
20	17.6	14.3	17.2	5.0%
21	4.6	3.8	4.5	5.0%
Total			760.0	

2.15 Hedging

Hedging is an important technique in protecting oil & gas companies from a sudden drop in commodity prices. It allows commodity-focused companies to fix their future revenue stream, which allows them to confidently invest in capital-intensive projects. The value of the hedges in place can have a significant impact on annual revenue depending on the size and weighted average price of the contracts. For this reason, the hedging values of Whiting Petroleum and Kodiak Oil & Gas are included in the net asset valuation. The value of the hedges in place is relative to the price scenarios in Table 2.10.

Some of the most common hedging strategies used are fixed price swaps, two way collars, and basis swaps. The fixed price swap establishes a quantity, length of time, and price. In essence, it is just an exchanging of cash flows because no physical oil is actually traded. Figure 3.5 depicts two examples of a fixed price swap. In both cases, the fixed price swap contract is for $100 per barrel. In the first example, the West Texas Intermediate price (also referred to as the spot/cash market) is $90. In this case, the producer would be $10 better off because they are still receiving $100 per barrel as stated in the contract. However, in the second example, the alternative is true. If the price of WTI were to rise to $110 per barrel, the producer would be $10 worse off because they are still receiving $100 per barrel.

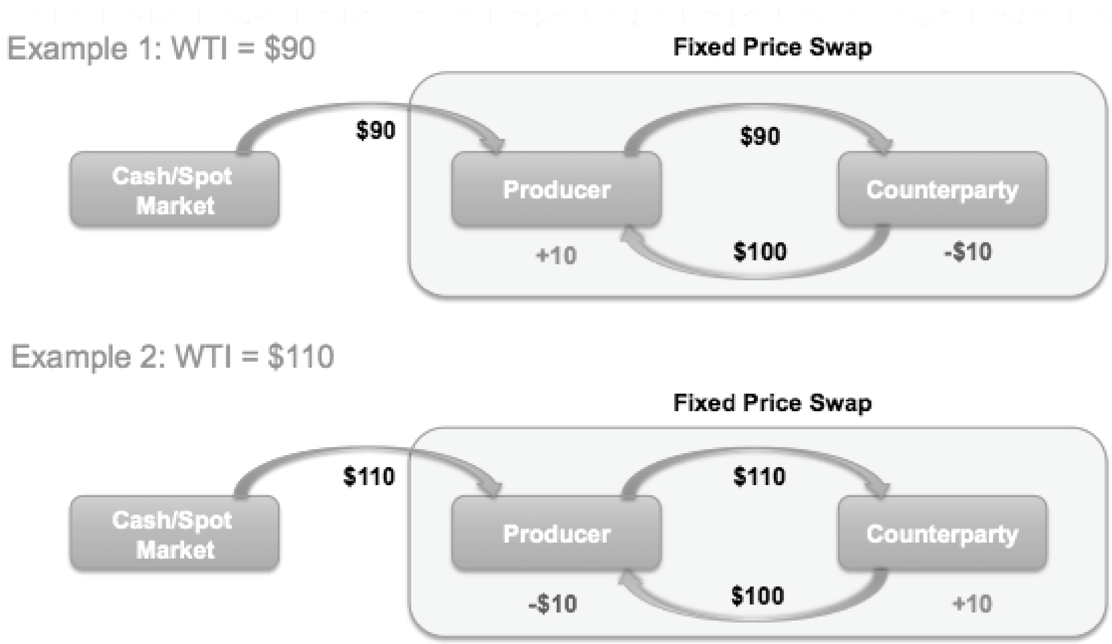

Figure 2.4: Fixed Price Swap Example

The basis swap is nearly identical to the fixed price swap but instead of exchanging the price of oil, only a differential is exchanged. The WTI price is for oil located at Cushing, Oklahoma, the main oil hub in the United States. Because the oil transportation network doesn't have unlimited capacity, regional supply gluts can occur. For example, if more oil is being produced in North Dakota than what can be sent to Cushing, there becomes an oversupply of oil in North Dakota. This will lower the price in North Dakota. The basis swap allows producers to get around these regional issues and fix themselves to a highly liquid market like the price in Cushing.

Figure 2.5: Two-Way and Three-Way Collar Examples

The third common hedging strategy used by oil and gas companies is the collar, which can be two-way, or three-way. In the two-way collar, the produce sells a call option and buys a put option. The call option is referred to as the ceiling price while the put option is referred to as the floor price. The put option costs money to purchase so the structure should be set up that the revenue generated from selling the call option, directly offsets the price of the put option. If this occurs, it can be called a costless collar. If the market price is between the ceiling and floor, the producer will receive that amount for their oil. However, if the market price falls below the floor price, the producer will receive the floor price and the opposite holds true for the ceiling price. The three-way collar is very similar to the two-way collar but it adds a sold put option below the floor price. The idea behind this action is to gain additional revenue from this sold put option and put it towards buying a put option at a higher price. In the example shown above, this is demonstrated by using a floor price of $80 in the two-way collar and a floor price of $81 in the three-way collar. The down side to the three-way collar is that is the market price falls below the sold put option, the producer is no longer protected. If the market price is in between the bought put option and the sold put option, the producer will receive the floor price or the price of the bought put option. However, if the market price drops below the sold option, the producer will receive the market price plus the difference between the bought put option and the sold put option. Using the example in above, if the market price falls to $50, the producer will receive $66 ($50 + ($81-$65)).

As of June 30, 2013, Whiting Petroleum had a number of oil & gas hedges in place. Complete details of these hedges can be seen in the following tables (Whiting Petroleum Corporation 2014c) (Kodiak Oil and Gas Corporation 2014b).

Table 2.26: Whiting Three-Way Collars as of June 30, 2013

Derivative Instrument	Period	Monthly Volume (Bbl)	Weighted Average Put/Floor/Ceiling
Three Way Collar	07/2014 to 09/2014	1,480,000	$71.82/$85.68/$103.85
Three Way Collar	10/2014 to 12/2014	1,480,000	$71.82/$85.68/$103.85
Three Way Collar	01/2015 to 03/2015	100,000	$70/$85/$107.9
Three Way Collar	04/2015 to 06/2015	100,000	$70/$85/$107.9
Three Way Collar	072015 to 09/2015	100,000	$70/$85/$107.9
Three Way Collar	10/2015 to 12/2015	100,000	$70/$85/$107.9

Table 2.27: Whiting Petroleum natural gas hedges as of June 30, 2013

Derivative Instrument	Period	Volume (Bbl per day)	Differential to WTI
Fixed-Differential	01/2015 to 12/2015	25,000	($4.75)
Fixed-Differential	01/2016 to 12/2016	30,000	($4.75)
Fixed-Differential	01/2017 to 12/2017	35,000	($4.75)
Fixed-Differential	01/2018 to 12/2018	40,000	($4.75)
Fixed-Differential	01/2019 to 12/2019	45,000	($4.75)

Table 2.28: Whiting natural gas hedges as of June 30, 2013

Derivative Instrument	Period	Volume (MMBtu per day)	Weighted Average Price per MMBTU
Fixed-Price	07/2014 to 09/2014	11,000	$5.49
Fixed-Price	10/2014 to 12/2014	11,000	$5.49

Table 2.29: Kodiak Oil & Gas hedges as of June 30, 2013

Derivative Instrument	Period	Volume (Bbl/day)	Price
Two Way Collar	07/2014 to 12/2015	300-350	$85/$102.75
Fixed Price Swap	07/2014 to 12/2014	25,800	$93.41
Fixed Price Swap	01/2015 to 06/2015	7,796	$93.08
Fixed Price Swap	01/2015 to 12/2015	3,291	$91.17

Based on its total production during the second quarter of 2014, Whiting Petroleum has approximately 47% of its production hedged for the remainder of 2014. This figure drops to 26% for 2015 and 28% for 2016 (Whiting Petroleum Corporation 2014c). Kodiak Oil & Gas has 68% of its 2014 and 29% of its 2015 production hedged (Kodiak Oil and Gas Corporation 2014b). Whiting Petroleum primarily uses three-way collars and basis swaps. The basis swaps they have in place should be very beneficial when taking into consideration their price received before hedging in relation to the NYMEX price. In a previous section, it was noted that in the first quarter of 2014, the average price per barrel Whiting Petroleum received was $88.85 while the average NYMEX price during the same period was $98.62 (Whiting Petroleum Corporation 2014c). This difference is a result of transportation costs, transportation bottlenecks, and regional supply gluts. With the fixed differential hedges of $4.75 in place, it would be the equivalent of Whiting Petroleum receiving $93.87 per barrel for the quantity hedged. This is a significant improvement from $88.85 per barrel.

The hedging strategy of Kodiak Oil & Gas is to use mainly fixed price swaps with a small volume of two-way collars. $93.41 represents a slight premium to the average sales price of $91.72 they received during the second quarter of 2014 (Kodiak Oil and Gas Corporation 2014b).

In the base case price scenario, the value of these hedges is $93.0 million. In the high and low price scenario the value changes to -$56.0 million and $183.0 million respectively.

2.16 Assumptions

A number of issues regarding the net asset valuation need to be addressed. The points listed in this section are assumptions that have been made in order to complete the NAV model but could lead to imperfect results. The first issue is the reporting format of Whiting Petroleum's reserves. They report their reserves in three separate categories including Rocky Mountains, Permian Basin, and Other. Within the Rocky Mountains, Whiting operates in the Bakken and Niobrara plays of North Dakota and Colorado respectively. These are two different geological formations and the typical EUR, D&C cost, well decline rate, and associated operating costs could be different for each region. The Whiting Petroleum investor presentation reports an average well in the Bakken to have a D&C cost of $8 million and average EUR of 600 MBOE. They also report an average well in the Niobrara to have a D&C cost of $5.5 million and average EUR of 420 MBOE. If the Rocky Mountain reserves were accurately divided amongst the Niobrara and Bakken, each play could be treated as its own category complete with its own future drilling schedule and well decline rate. Based on 2013 Bakken and Niobrara production, a weighted average was used for D&C and EUR. While this probably produces a reasonable aggregate production profile of the Rocky Mountain region, it may contain slight errors, which lead to an imperfect NAV per share calculation.

This same problem pertains to the Other category. Whiting Petroleum reports that the Other category contains reserves located in Arkansas, Louisiana, Michigan, Oklahoma, and Texas. Each state likely has its own well decline rate, EUR, D&C costs, and operating costs. Of these states, Whiting Petroleum leases the most acreage in

Michigan. Michigan is known for the Antrim Shale, which is located in the northern part of the Lower Peninsula. Based on this information, a typical well in the Antrim Shale was used to represent the entire Other category. Once again, this a good estimate with the information that is available but may be different from the true reserves and these differences could result in an imperfect calculation of the net asset value of Whiting Petroleum.

Another significant issue is the NAV calculation does not take into consideration future discoveries by Whiting Petroleum or Kodiak Oil & Gas. The valuation is based on a snapshot of Whiting and Kodiak reserves on the date the merger was announced. Oil production and estimated reserves in North Dakota have grown dramatically over the past few years and if this pace continues, Whiting Petroleum could end up producing more oil than what is currently reported in their reserve numbers. This would increase the net asset value of the company. In the discussion of results section, different reserve credit cases are examined. For example, if economic conditions improve and probable reserves were to have a 75% chance of being extracted as opposed to 50% chance in the base scenario. These situations are easy to account for but adding entirely new reserves to a company's asset base is difficult and highly speculative. With new reserves, information would need to be known on average EUR, D&C costs, operating costs, and probability of extraction. For this reason, new discoveries were omitted from the net asset valuation.

New discoveries could also affect the drilling schedule. The current drilling schedule prioritizes the regions by reserve size. The top priority is the Rocky Mountain region, followed by the Permian Basin, and the Other category is the lowest priority. This is also reflected by Whiting Petroleum's capital allocation and oilrig allocation. If new discoveries are made in the Bakken, it could push back the drilling of new wells in the Permian Basin. Alternatively, if significant reserves are discovered in the Permian Basin, the company could decide to shift priority to Texas and put drilling in the Rocky Mountains on hold.

The decline rate of proved developed producing and proved developed non-producing reserves is not known. The decline rate for this group depends on the age of each well. A typical well of Whiting Petroleum declines rapidly at first before slowing down after a few years. Annual production of a well in the Rocky Mountain region declines 54.5% between its first and second years. Annual production of the same well would only be expected to decline by 5% between the 20th and 21st year. In the second quarter of 2014, Whiting Petroleum produced 110 MBOE per day. To use an extreme example, if every producing well were less than a year old, production from these wells would be expected to be 50.05 MBOE per day in 2015 (a decline of 54.5%). Alternatively, if every well were 20 years old, production from these wells would be expected to be 104.5 MBOE per day (a decline of 5%). In the end, the same amount of reserves will be extracted but the year in which they are extracted will have significant impact on the company valuation because of the time value of money. A decline rate of 12.1% was used because it represents the average annual decline over the life of a well in the Rocky Mountains. If the true decline rate were significantly different, it would directly affect the valuation of Whiting Petroleum.

3. Results

The results in this section were determined using similar assumptions to make comparisons easier. The first was a discount rate of 10%. The second assumption was on commodity price. The total revenue category was calculated using the first price scenario. This was the scenario calculated from the Chicago Mercantile Exchange futures prices and can be seen in Table 2.10. Also, proved reserves were assumed to have 100% retrieval success rate, probable had 50% and possible had 10%. The high oil price-drilling schedule was used, which represents the most aggressive drilling scenario. Operating costs for Whiting Petroleum include a lease operating expense of $12.27 per barrel, production taxes of $6.78 per barrel and G&A expenses of $3.57 per barrel (Whiting Petroleum Corporation 2014b). Drilling and completion costs were set at $7.77 million in the Rocky Mountains, $6.3 million in the Permian Basin and $300,000 for the Other category. Estimated Ultimate Recovery of 600 MBOE was used for an average well in the Rocky Mountains and Permian Basin, while a EUR of 83 MBOE was used for the Other region (Apache Corporation 2014) (Michigan Public Service Commission 2010) (Whiting Petroleum Corporation 2014b). All of these assumptions were used consistently throughout this section. However, in the discussion of results section, other assumptions for these variables will be considered. It is important to understand how a change in each variable affects the overall valuation of Whiting Petroleum.

3.1 PDP and PDNP

The proved developed producing and proved developed non-producing results are found in the table below. This category includes wells that have already been drilled and connected to gathering pipelines. They could be located in North Dakota, Colorado, Texas, or anywhere else Whiting Petroleum has acreage. Proved undeveloped, probable, and possible reserve results will be addressed in the following sections.

This reserves category is fully depleted by 2026 when assuming a production decline rate of 12.1% per year. As seen at the bottom of the table, the total barrels of oil equivalent produced from this reserves category is approximately 252 MMBOE. Each quantity of oil, natural gas, and natural gas liquid was multiplied by the associated price received by Whiting Petroleum for each product in each year. These product revenues were then added together to arrive at total revenue per year. Operating expenditures were then calculated using the total production per year and $22.62 per barrel of oil equivalent in costs. This figure includes lease operating expenses, production taxes, and G&A costs. No capital expenses occur in the proved developed category because all wells have already been drilled and Whiting Petroleum has already incurred the drilling & completion costs. EBITDAX is calculated by subtracting the operating expenses from total revenue. This number is then discounted back to the valuation date of July 11, 2014. The discounted cash flow for 2014 takes into account that over six months of production have already occurred in the current year.

Summing the discounted cash flow in each year results in a total value of $6.8 billion for the proved developed reserves. This number does not take into consideration the taxes of Whiting Petroleum because they need to be calculated for the company as a whole, rather than by individual reserve type. However, this does accurately represent how much of the enterprise value of Whiting Petroleum is attributed to its proved developed reserves (Breaking Into Wall Street 2014b).

Table 3.1: Whiting Petroleum Proved Developed Results

Year	Total Production (MBOE)	Total Revenue ($ 000's)	Total OpEx ($ 000's)	EBITDAX ($ 000's)	DCF ($ 000's)
2014	40,110	2,899,152	764,093	2,135,059	1,044,189
2015	38,782	1,986,447	738,802	1,247,645	1,138,133
2016	34,090	1,871,507	649,407	1,222,100	1,013,482
2017	29,965	1,761,162	570,829	1,190,334	897,399
2018	26,339	1,650,120	501,758	1,148,362	787,051
2019	23,152	1,454,986	441,046	1,013,941	631,748
2020	20,351	1,278,933	387,679	891,254	504,824
2021	17,888	1,124,182	340,770	783,412	403,400
2022	15,724	988,156	299,537	688,619	322,354
2023	3,977	249,919	75,757	174,162	74,116
2024	1,104	69,408	21,039	48,369	18,713
2025	971	61,010	18,494	42,516	14,953
2026	81	5,110	1,549	3,561	1,139
Total	252,533	15,400,093	4,810,760	10,589,333	6,851,500

The Total Production column is calculated by multiplying 2013 production by 87.9%. This production is further broken down into oil, gas, and natural gas liquid production. Each product quantity is multiplied by the corresponding price from the price deck in table 2.10. These three values are summed together to create the Total Revenue column. The Total Operating Expenses column multiplies the total production by production taxes per barrel of oil equivalent, lease operating expense per barrel of oil equivalent, and other operating expenses per barrel of oil equivalent. Together, these numbers represent the total operating expenses of Whiting Petroleum in each year.

EBITDAX is the difference between total revenue and total operating expenses. Lastly, the DCF column uses a discount rate of 10% to find the value of the future annual cash flows at the merger announcement date of July, 14 2014.

3.2 Rocky Mountains

This section includes the proved undeveloped, probable, and possible reserves for the Rocky Mountain region of Whiting Petroleum. Because the Rocky Mountain region is the main focus of the company in 2014, all wells are drilled by 2017, which is the same year as the largest cash flow of $450 million. Production of these reserves peak in 2015 at 68,785 BOE per day and decline until 2039 when all 176 MMBOE are extracted. Because of the large capital expense of drilling 320 wells, the cash flow for 2014 is actually negative. However, the entire discounted cash flow value for these reserves is $1.8 billion. This is only one-third of the value of the PDP and PDNP reserves because of two main reasons. The first is that the risked reserves of the proved developed category contain 76 MMBOE more reserves than the Rocky Mountain region. The second is capital expenditure. The Rocky Mountain region must incur all drilling and completion costs required to retrieve oil from these reserves. For these reasons, the PDP/PDNP reserves are much more valuable to Whiting Petroleum than its Rocky Mountains PUD/PROB/POSS reserves.

Table 3.2: Whiting Petroleum Rocky Mountain's Results

Year	Total Production (MBOE)	Total Revenue ($ 000's)	Total OpEx ($ 000's)	Total CapEx ($ 000's)	EBITDAX ($ 000's)	DCF ($ 000's)
2014	21,101	1,555,722	490,202	1,188,249	1,065,520	-60,023
2015	25,097	1,305,572	583,040	872,635	722,532	-136,927
2016	24,172	1,349,795	561,560	595,987	788,235	159,430
2017	16,828	1,006,256	390,940	135,826	615,316	361,490
2018	11,788	751,536	273,861		477,675	327,383
2019	9,301	594,271	216,089		378,181	235,630
2020	7,751	495,207	180,068		315,139	178,501
2021	6,632	423,747	154,083		269,664	138,857
2022	5,761	368,094	133,847		234,247	109,655
2023	5,119	327,025	118,913		208,112	88,564
2024	4,636	296,218	107,711		188,507	72,928
2025	4,261	272,248	98,995		173,253	60,933
2026	3,962	253,119	92,039		161,079	51,502
2027	3,723	237,853	86,488		151,365	43,996
2028	3,523	225,110	81,855		143,255	37,854
2029	3,346	213,745	77,722		136,023	32,675
2030	3,179	203,076	73,843		129,233	28,222
2031	3,020	192,940	70,157		122,783	24,376
2032	2,869	183,309	66,655		116,654	21,054
2033	2,726	174,160	63,328		110,832	18,184
2034	2,590	165,467	60,167		105,300	15,706
2035	2,461	157,208	57,164		100,044	13,566
2036	1,756	112,214	40,803		71,410	8,803
2037	892	56,985	20,721		36,264	4,064
2038	299	19,097	6,944		12,153	1,238
2039	42	2,689	978		1,711	158.46262
Total	176,835	10,942,660	4,108,175	2,792,696	6,834,485	1,837,819

The method for arriving at the above table is very similar to table 3.1, the only differences are the Total Production column and the addition of the Capital Expenditure column. Table 2.8 forecasts how many wells Whiting will drill in the Rocky Mountains and in what year they will be drilled. Table 2.15 shows the average annual production of a Whiting Petroleum well in the Rocky Mountains. These two tables are combined to arrive at the total production per year for Whiting Petroleum in the Rocky Mountains region. For example, in 2014, Whiting will drill 152.9 wells after working interest is taken into consideration. Table 2.15 shows the average well in the Rocky Mountains region should produce 138 MBOE in its first year of operation after royalties are removed. As seen in Table 3.2, this will lead to total production of 21,101 MBOE in 2014 for Whiting Petroleum. Capital Expenditure is the summation of the total wells drilled in a given year, multiplied by the average cost of the wells. Tables 3.3, 3.4, and 3.7 follow this same calculation method for each corresponding region.

3.3 Permian Basin

Table The total value of the Permian Basin acreage is approximately $439 million. Production peaks in 2018 at 24.23 MBOE per day. This is the point where all necessary wells have been drilled in the Rocky Mountain region and Whiting Petroleum should shift its focus entirely on their next largest play, which is the Permian Basin. Despite being the year for record production in the Permian, Whiting Petroleum actually incurs a significant loss in 2018 due to large capital expenditure of $577 million. The reserves for the region take until 2047 to be completely depleted and total production is 59.6 MMBOE.

Table 3.3: Whiting Petroleum Permian Basin Results

Year	Total Production (MBOE)	Total Revenue ($ 000's)	Total OpEx ($ 000's)	Total CapEx ($ 000's)	EBITDAX ($ 000's)	DCF ($ 000's)
2014	320	23,574	7,428	22,139	16,146	-2,931
2015	513	26,681	11,915	24,599	14,766	-8,969
2016	651	36,370	15,131	24,599	21,239	-2,786
2017	759	45,410	17,642	24,599	27,768	2,389
2018	8,844	563,854	205,469	577,854	358,385	-150,417
2019	5,660	361,604	131,487	78,715	230,117	94,333
2020	4,230	270,280	98,280	11,266	172,000	91,043
2021	3,298	210,730	76,626		134,104	69,054
2022	2,882	184,141	66,957		117,183	54,855
2023	2,590	165,445	60,159		105,286	44,805
2024	2,359	150,703	54,799		95,904	37,103
2025	2,172	138,768	50,459		88,309	31,058
2026	2,021	129,109	46,947		82,162	26,270
2027	1,899	121,317	44,113		77,204	22,440
2028	1,801	115,086	41,848		73,238	19,352
2029	1,711	109,322	39,752		69,570	16,712
2030	1,626	103,865	37,768		66,098	14,434
2031	1,545	98,681	35,883		62,799	12,467
2032	1,467	93,756	34,092		59,664	10,768
2033	1,394	89,076	32,390		56,686	9,301
2034	1,325	84,630	30,773		53,857	8,033
2035	1,259	80,406	29,237		51,169	6,938
2036	1,196	76,393	27,778		48,615	5,993
2037	1,136	72,580	26,392		46,188	5,176
2038	1,079	68,957	25,074		43,883	4,471
2039	1,025	65,515	23,823		41,693	3,861
2040	974	62,245	22,634		39,612	3,335
2041	921	58,829	21,391		37,438	2,865
2042	853	54,506	19,819		34,686	2,414
2043	787	50,282	18,284		31,998	2,024
2044	724	46,269	16,824		29,445	1,693
2045	543	34,721	12,625		22,096	1,155
2046	73	4,658	1,694		2,964	141
Total	59,647	3,798,323	1,385,697	763,770	2,412,626	439,397

3.4 Other Region

New drilling for the other region begins slowly in 2015 when the focus of Whiting Petroleum is still in the Permian and Rocky Mountains. Because an average well in this region only costs $300,000, Whiting Petroleum would be able to drill all necessary wells for this region by 2021. Production peaks in this year at 1.21 MBOE per day and the reserves are fully extracted by 2035. Total production after royalties is 4.0 MMBOE and the reserves have a total value of $48 million. This is less than 2% of the value of the Rocky Mountains so it is clear why Whiting Petroleum would rather focus its time on the Rocky Mountains and Permian Basin.

Table 3.4: Whiting Petroleum Other Results

Year	Total Production (MBOE)	Total Revenue ($ 000's)	Total OpEx ($ 000's)	Total CapEx ($ 000's)	EBITDAX ($ 000's)	DCF ($ 000's)
2015	6	306	137	137	170	-61
2016	11	635	264	264	371	112
2017	16	984	382	382	602	276
2018	45	2,854	1,040	1,040	1,814	434
2019	71	4,541	1,651	1,651	2,890	1,065
2020	96	6,105	2,220	2,220	3,885	1,532
2021	427	27,251	9,909	9,909	17,342	1,959
2022	397	25,344	9,216	9,216	16,128	7,550
2023	369	23,570	8,570	8,570	14,999	6,383
2024	343	21,920	7,971	7,971	13,949	5,397
2025	319	20,385	7,413	7,413	12,973	4,563
2026	297	18,958	6,894	6,894	12,065	3,857
2027	276	17,631	6,411	6,411	11,220	3,261
2028	257	16,397	5,962	5,962	10,435	2,757
2029	237	15,119	5,498	5,498	9,621	2,311
2030	218	13,925	5,063	5,063	8,861	1,935
2031	201	12,814	4,659	4,659	8,155	1,619
2032	176	11,259	4,094	4,094	7,165	1,293
2033	153	9,792	3,560	3,560	6,231	1,022
2034	132	8,427	3,064	3,064	5,363	800
2035	5	326	119	119	207	28
Total	4,050	258,544	94,097	94,097	164,446	48,093

3.5 Discounted Cash Flow

In the discounted cash flow calculation, annual operating costs are subtracted from annual revenue to arrive at EBITDAX. The next step is to calculate depletion, depreciation and amortization. The first step in calculating depreciation is segmenting capital expenditures by tangible and intangible drilling costs. For this analysis, intangible drilling costs were assumed to be 80% of capital expenditures (Breaking Into Wall Street

2014c). This amount is expensed during the current year. The remaining 20% of capital expenditure is depreciated according to the 7-year MACRS schedule (Roberts M, Nelson P, Gale J 2011).

The remaining component of DD&A is unit of production depletion, which is calculated by multiplying beginning leasehold tax basis by the percent depletion of proved reserves in that year (Breaking Into Wall Street 2014c). The beginning leasehold tax basis in the first year of the discounted cash flow is the net property, plant & equipment (PP&E) value from the balance sheet (Breaking Into Wall Street 2014c). In each of the following years, the beginning leasehold tax basis is the beginning leasehold tax basis of the previous year minus the unit of production depletion of the previous year. The percent depletion is calculated by dividing annual production by the remaining proved reserves in the corresponding year (Breaking Into Wall Street 2014c).

DD&A is subtracted from EBITDAX to arrive at EBIT, which is used to calculate cash taxes. In 2013, Whiting Petroleum's cumulative tax rate was 36%, which includes state, local, and federal taxes (Whiting Petroleum Corporation 2014b). This tax rate was used throughout the discounted cash flow. After taxes are subtracted, DD&A is added back and capital expenditures are subtracted to arrive at After-Tax Free Cash Flow. The valuation date of July 14, 2014 is treated as time zero and this is reflected in the discount factors. Production for only the second half of 2014 is included in the After-Tax Cash Flow.

Table 3.5a: DCF of Whiting Petroleum after merger

Year	2014	2015	2016	2017
Production				
Gas (Mmcf)	58,327	65,294	61,442	51,265
Oil (MBbl)	63,646	70,693	66,338	54,431
NGLs (MBbl)	6,211	6,561	6,030	4,821
Annual Total(MBOE)	79,578	88,137	82,609	67,797
Daily Total (MBOE/d)	218	241	226	186
Revenue				
Gas	212,077	229,183	210,133	184,555
Oil	5,177,695	4,135,539	4,179,296	3,674,097
NGLs	252,619	191,920	189,960	162,722
Total Revenue:	5,642,391	4,556,642	4,579,389	4,021,374
Effect of Hedges:	29,411	96,809	-	-
Net Revenue:	5,671,802	4,653,452	4,579,389	4,021,374
Cash Expenses				
Production Taxes:	648,682	737,316	698,443	572,457
LOE Expense:	1,017,139	1,128,099	1,058,221	860,250
Other Operating Expenses:	132,718	174,568	174,168	148,751
Corporate Overhead / G&A:	284,094	314,648	294,914	242,034
Total Cash Expenses:	2,082,633	2,354,631	2,225,745	1,823,492
EBITDAX	3,589,169	2,298,820	2,353,644	2,197,882
Tax DD&A	2,892,989	2,562,464	2,065,992	1,299,963
EBIT	696,180	(263,644)	287,652	897,918
Cash Taxes	250,625	-	8,643	323,251
Net Income (Cash Tax Basis):	445,555	(263,644)	279,009	574,668
Plus: DD&A:	2,892,989	2,562,464	2,065,992	1,299,963
Less: CapEx:	1,862,748	1,340,241	1,016,876	353,285
After-Tax Free Cash Flow:	1,475,796	958,579	1,328,125	1,521,346
Discount Factor	0.978	0.912	0.829	0.754
After-Tax Cash Flow	721,764	874,440	1,101,408	1,146,951

Table 3.5b: DCF of Whiting Petroleum after merger

Year	2018	2019	2020	2021
Production				
Gas (Mmcf)	48,538	41,180	36,161	32,278
Oil (MBbl)	52,703	43,892	38,108	33,797
NGLs (MBbl)	4,828	3,888	3,288	2,861
Annual Total (MBOE)	65,621	54,642	47,423	42,037
Daily Total (MBOE/d)	180	150	130	115
Revenue				
Gas	183,473	166,778	146,452	130,724
Oil	3,794,597	3,160,189	2,743,779	2,433,362
NGLs	173,819	139,951	118,376	102,997
Total Revenue	4,151,889	3,466,919	3,008,607	2,667,084
Effect of Hedges	-	-	-	-
Net Revenue	4,151,889	3,466,919	3,008,607	2,667,084
Cash Expenses				
Production Taxes	555,327	463,304	403,698	359,470
LOE Expense	843,357	695,467	600,303	530,720
Other Operating Expenses	136,810	121,026	110,272	101,420
Corporate Overhead / G&A	234,266	195,073	169,300	150,073
Total Cash Expenses	1,769,759	1,474,871	1,283,573	1,141,684
EBITDAX	2,382,130	1,992,048	1,725,033	1,525,399
Tax DD&A	1,549,514	948,309	784,045	687,536
EBIT	832,616	1,043,739	940,988	837,863
Cash Taxes	299,742	375,746	338,756	301,631
Net Income (Cash Tax Basis)	532,875	667,993	602,232	536,232
Plus: DD&A	1,549,514	948,309	784,045	687,536
Less: CapEx	758,995	195,565	118,168	110,167
After-Tax Free Cash Flow	1,323,394	1,420,737	1,268,109	1,113,601
Discount Factor	0.685	0.623	0.566	0.515
After-Tax Cash Flow	907,012	885,207	718,283	573,424

Table 3.5c: DCF of Whiting Petroleum after merger

Year	2022	2023	2024	2025
Production				
Gas (Mmcf)	22,770	12,730	9,981	9,315
Oil (MBbl)	25,124	14,286	11,200	10,403
NGLs (MBbl)	2,508	1,291	937	857
Annual Total (MBOE)	31,426	17,698	13,800	12,813
Daily Total (MBOE/d)	86	48	38	35
Revenue				
Gas	92,218	51,558	40,423	37,724
Oil	1,808,903	1,028,565	806,370	748,995
NGLs	90,274	46,480	33,716	30,870
Total Revenue	1,991,395	1,126,603	880,510	817,589
Effect of Hedges	-	-	-	-
Net Revenue	1,991,395	1,126,603	880,510	817,589
Cash Expenses				
Production Taxes	255,045	156,181	127,416	118,707
LOE Expense	403,681	233,605	184,047	170,610
Other Operating Expenses	48,992	41,509	39,393	37,427
Corporate Overhead / G&A	112,192	63,183	49,265	45,741
Total Cash Expenses:	819,911	494,478	400,121	372,485
EBITDAX	1,171,484	632,124	480,388	445,104
Tax DD&A	445,416	250,040	189,361	166,887
EBIT	726,068	382,084	291,028	278,217
Cash Taxes	261,385	137,550	104,770	100,158
Net Income (Cash Tax Basis)	464,684	244,534	186,258	178,059
Plus: DD&A	445,416	250,040	189,361	166,887
Less CapEx	9,072	-	-	-
After-Tax Free Cash Flow	901,027	494,574	375,618	344,946
Discount Factor	0.468	0.426	0.387	0.352
After-Tax Cash Flow	421,785	210,471	145,316	121,318

Table 3.5d: DCF of Whiting Petroleum after merger

Year	2026	2027	2028	2029
Production				
Gas (Mmcf)	8,171	7,673	7,279	6,911
Oil (MBbl)	9,114	8,544	8,100	7,688
NGLs (MBbl)	720	669	633	600
Annual Total (MBOE)	11,196	10,492	9,946	9,440
Daily Total (MBOE/d)	31	29	27	26
Revenue				
Gas	33,094	31,075	29,479	27,989
Oil	656,230	615,168	583,196	553,538
NGLs	25,920	24,085	22,794	21,617
Total Revenue	715,244	670,329	635,469	603,143
Effect of Hedges	-	-	-	-
Net Revenue	715,244	670,329	635,469	603,143
Cash Expenses				
Production Taxes	105,957	99,580	94,428	89,636
LOE Expense	149,741	140,298	132,967	126,188
Other Operating Expenses	35,559	33,784	32,098	30,496
Corporate Overhead / G&A	39,970	37,456	35,508	33,702
Total Cash Expenses	331,227	311,118	295,001	280,022
EBITDAX	384,017	359,211	340,468	323,121
Tax DD&A	139,058	127,886	119,368	112,284
EBIT	244,959	231,324	221,099	210,838
Cash Taxes	88,185	83,277	79,596	75,902
Net Income (Cash Tax Basis)	156,774	148,048	141,504	134,936
Plus: DD&A	139,058	127,886	119,368	112,284
Less: CapEx	-	-	-	-
After-Tax Free Cash Flow	295,831	275,934	260,872	247,220
Discount Factor	0.320	0.291	0.264	0.240
After-Tax Cash Flow	94,586	80,204	68,933	59,386

Table 3.5e: DCF of Whiting Petroleum after merger

Year	2030	2031	2032	2033
Production				
Gas (Mmcf)	6,562	6,231	5,913	5,611
Oil (MBbl)	7,299	6,929	6,572	6,233
NGLs (MBbl)	570	541	512	485
Annual Total (MBOE)	8,962	8,508	8,069	7,652
Daily Total (MBOE/d)	25	23	22	21
Revenue				
Gas	26,577	25,238	23,948	22,724
Oil	525,511	498,906	473,176	448,741
NGLs	20,510	19,460	18,430	17,452
Total Revenue	572,598	543,603	515,555	488,917
Effect of Hedges	-	-	-	-
Net Revenue	572,598	543,603	515,555	488,917
Cash Expenses				
Production Taxes	85,105	80,804	76,652	72,709
LOE Expense	119,787	113,710	107,820	102,227
Other Operating Expenses	28,974	27,528	26,154	24,848
Corporate Overhead / G&A	31,995	30,375	28,808	27,319
Total Cash Expenses	265,861	252,416	239,434	227,103
EBITDAX	306,738	291,186	276,121	261,814
Tax DD&A	106,520	101,126	95,908	90,953
EBIT	200,218	190,061	180,213	170,861
Cash Taxes	72,078	68,422	64,877	61,510
Net Income (Cash Tax Basis)	128,140	121,639	115,336	109,351
Plus: DD&A	106,520	101,126	95,908	90,953
Less: CapEx	-	-	-	-
After-Tax Free Cash Flow	234,659	222,765	211,244	200,304
Discount Factor	0.218	0.199	0.180	0.164
After-Tax Cash Flow	51,245	44,225	38,125	32,864

Table 3.5f: DCF of Whiting Petroleum after merger

Year	2034	2035	2036	2037
Production				
Gas (Mmcf)	5,324	4,010	2,619	1,457
Oil (MBbl)	5,910	4,716	3,282	1,977
NGLs (MBbl)	459	422	335	230
Annual Total (MBOE)	7,257	5,807	4,054	2,449
Daily Total (MBOE/d)	20	16	11	7
Revenue				
Gas	21,562	16,242	10,606	5,901
Oil	425,551	339,554	236,331	142,308
NGLs	16,525	15,209	12,056	8,282
Total Revenue	463,638	371,006	258,993	156,491
Effect of Hedges	-	-	-	-
Net Revenue	463,638	371,006	258,993	156,491
Cash Expenses				
Production Taxes	68,967	53,830	36,594	21,429
LOE Expense	96,919	79,323	56,654	35,119
Other Operating Expenses	23,608	15,315	8,101	3,099
Corporate Overhead / G&A	25,907	20,731	14,472	8,744
Total Cash Expenses	215,400	169,198	115,821	68,392
EBITDAX	248,237	201,808	143,172	88,099
Tax DD&A	86,250	69,018	48,180	29,112
EBIT	161,987	132,790	94,992	58,987
Cash Taxes	58,315	47,804	34,197	21,235
Net Income (Cash Tax Basis)	103,672	84,985	60,795	37,752
Plus: DD&A	86,250	69,018	48,180	29,112
Less CapEx	-	-	-	-
After-Tax Free Cash Flow	189,922	154,003	108,975	66,864
Discount Factor	0.149	0.136	0.123	0.112
After-Tax Cash Flow	28,328	20,882	13,433	7,493

Table 3.5g: DCF of Whiting Petroleum after merger

Year	2038	2039	2040	2041
Production				
Gas (Mmcf)	846	570	493	466
Oil (MBbl)	1,226	880	782	739
NGLs (MBbl)	156	121	111	104
Annual Total (MBOE)	1,523	1,096	974	921
Daily Total (MBOE/d)	4	3	3	3
Revenue				
Gas	3,426	2,307	1,998	1,889
Oil	88,261	63,355	56,268	53,180
NGLs	5,628	4,360	3,979	3,760
Total Revenue	97,315	70,022	62,245	58,829
Effect of Hedges	-	-	-	-
Net Revenue	97,315	70,022	62,245	58,829
Cash Expenses				
Production Taxes	12,999	9,141	8,055	7,613
LOE Expense	22,265	16,296	14,578	13,778
Other Operating Expenses	1,066	209	-	-
Corporate Overhead / G&A	5,438	3,913	3,478	3,287
Total Cash Expenses	41,768	29,560	26,112	24,679
EBITDAX	55,548	40,463	36,134	34,150
Tax DD&A	18,104	13,026	11,580	10,944
EBIT	37,444	27,436	24,554	23,206
Cash Taxes	13,480	9,877	8,839	8,354
Net Income (Cash Tax Basis)	23,964	17,559	15,715	14,852
Plus DD&A	18,104	13,026	11,580	10,944
Less CapEx	-	-	-	-
After-Tax Free Cash Flow	42,068	30,586	27,294	25,796
Discount Factor	0.102	0.093	0.084	0.077
After-Tax Cash Flow	4,286	2,833	2,298	1,974

Table 3.5h: DCF of Whiting Petroleum after merger

Year	2042	2043	2044	2045
Production				
Gas (Mmcf)	432	399	367	275
Oil (MBbl)	684	631	581	436
NGLs (MBbl)	97	89	82	62
Annual Total (MBOE)	853	787	724	543
Daily Total (MBOE/d)	2	2	2	1
Revenue				
Gas	1,750	1,614	1,485	1,115
Oil	49,272	45,454	41,826	31,387
NGLs	3,484	3,214	2,958	2,219
Total Revenue	54,506	50,282	46,269	34,721
Effect of Hedges	-	-	-	-
Net Revenue	54,506	50,282	46,269	34,721
Cash Expenses				
Production Taxes	7,054	6,507	5,988	4,493
LOE Expense	12,766	11,776	10,837	8,132
Other Operating Expenses	-	-	-	-
Corporate Overhead / G&A	3,046	2,810	2,585	1,940
Total Cash Expenses	22,865	21,093	19,410	14,565
EBITDAX	31,641	29,189	26,859	20,156
Tax DD&A	10,140	9,354	8,607	6,459
EBIT	21,501	19,835	18,252	13,696
Cash Taxes	7,740	7,141	6,571	4,931
Net Income (Cash Tax Basis)	13,761	12,694	11,681	8,766
Plus DD&A	10,140	9,354	8,607	6,459
Less CapEx	-	-	-	-
After-Tax Free Cash Flow	23,900	22,048	20,289	15,225
Discount Factor	0.070	0.063	0.058	0.052
After-Tax Cash Flow	1,663	1,395	1,167	796

Table 3.5i: DCF of Whiting Petroleum after merger

Year	2046	2047	Total
Production			
Gas (Mmcf)	37	4	520,932
Oil (MBbl)	58	7	567,007
NGLs (MBbl)	8	1	51,089
Annual Total (MBOE)	73	9	704,918
Daily Total (MBOE/d)	0	0	1,931
Revenue			
Gas	150	18	1,975,485
Oil	4,211	505	39,623,319
NGLs	298	36	1,785,978
Total Revenue	4,658	559	43,384,782
Effect of Hedges	-	-	126,220
Net Revenue	4,658	559	43,511,002
Cash Expenses			
Production Taxes	603	72	6,044,265
LOE Expense	1,091	131	9,097,902
Other Operating Expenses	-	-	1,557,894
Corporate Overhead / G&A	260	31	2,516,558
Total Cash Expenses	1,954	234	19,216,619
EBITDAX	2,704	324	24,294,383
Tax DD&A	867	104	15,057,361
EBIT	1,837	220	9,237,022
Cash Taxes	661	79	3,325,328
Net Income (Cash Tax Basis)	1,176	141	5,911,694
Plus DD&A	867	104	15,057,361
Less CapEx	-	-	5,765,117
After-Tax Free Cash Flow	2,042	245	15,203,938
Discount Factor	0.048	0.043	
After-Tax Cash Flow	97	11	8,383,602

3.6 Pre-Merger NAV

As seen in the table below, the total enterprise value of Whiting Petroleum as of July 11, 2014, immediately before the purchase of Kodiak Oil & Gas was $7.294 billion. Over 70% of this value comes from is proved developed reserves. To arrive at net asset value, net debt must be subtracted and cash must be added to the enterprise value (Breaking Into Wall Street 2014e). Whiting Petroleum had $227 million in cash and $2.653 billion in net debt (Whiting Petroleum Corporation 2014c). This results in a net asset value of $4.867 billion. As of this same date, Whiting had 118,981,96 outstanding shares and 786,351 shares that could be executed as a result of options or warrants (Whiting Petroleum Corporation 2014c). This leads to a net asset value per share of $40.64. The share price of Whiting Petroleum on July 11, 2014 was $78.54, which represents a 48.9% premium to the net asset valuation (Whiting Petroleum Corporation 2014d).

Table 3.6: Calculation of Whiting Petroleum NAV Before Kodiak Oil & Gas Purchase

NAV by Reserve Type and Region (for PROB and POSS Reserves):	Risked (MBOE)	Base Case
PD	252,533	6,852
PUD	152,676	1,636
Rocky Mountains	66,559	528
Permian	18,319	129
Other	2,976	33
Pre-Tax Asset Value:		$9,177
Less: NPV of G&A:		(1,062)
+ / - NPV of Hedges:		93
Less: NPV of Cash Taxes:		(914)
After-Tax Asset Value:		$7,294
Less: Net Debt & Preferred:		$(2,426)
Net Asset Value:		$4,867
Diluted Shares Outstanding (Millions):		119.8
NAV / Share:		$40.64
Current Share Price:		$78.54
Current Share Price Premium / (Discount) to NAV:		93.3%

3.7 Kodiak

For this section, the valuation of Kodiak Oil & Gas's assets used the same assumptions regarding commodity prices, discount rate, and reserve retrieval percentages. The variables that were different for Kodiak include EUR, initial production rate, drilling & completion costs, operating costs, and percentage of oil. The EUR of an average well for Kodiak Oil & Gas was determined to be 760 MBOE with an initial production of 370 BOE per day for the first year. Current D&C costs for Kodiak are $9 million per well and each well should be 83% oil and 17% natural gas (Kodiak Oil and Gas Corporation

2014c). Operating costs include a lease operating expense of $9.29 per BOE, production taxes of $9.07, and miscellaneous expenses of $6.03 per barrel (Kodiak Oil and Gas Corporation 2014b). The total operating expenses per barrel are $24.39, which is $2.77 higher than Whiting Petroleum.

The production results for Kodiak Oil & Gas can be seen in the table below. Production for the entire company peaks in 2015 at 65.0 MBOE per day and the reserves are fully depleted by 2039. In total, Kodiak produces 211 MMBOE. The value of all Kodiak reserves is $2.037 billion. The majority of this comes from its proved reserves while only $377 million in value come from its probable or possible reserves.

Table 3.7: Kodiak Oil & Gas Production Results

Year	Total Production (MBOE)	Total Revenue ($ 000's)	Total OpEx ($ 000's)	Total CapEx ($ 000's)	EBITDAX ($ 000's)	DCF ($ 000's)
2014	18,048	1,320,743	536,816	789,996	783,927	-2,968
2015	23,739	1,237,635	706,089	543,849	531,546	-11,223
2016	23,684	1,321,083	704,469	465,088	616,614	125,660
2017	20,228	1,207,560	601,664	208,357	605,896	299,707
2018	18,604	1,183,525	553,365	179,959	630,160	308,553
2019	16,458	1,051,516	489,524	115,669	561,992	278,087
2020	14,996	958,082	446,027	105,721	512,055	230,156
2021	13,792	881,173	410,222	96,629	470,951	192,748
2022	6,662	425,660	198,163	9,072	227,498	102,249
2023	5,645	360,644	167,895		192,749	82,026
2024	5,357	342,261	159,337		182,925	70,768
2025	5,090	325,178	151,384		173,794	61,124
2026	4,836	308,948	143,828		165,120	52,794
2027	4,594	293,527	136,649		156,878	45,599
2028	4,365	278,877	129,829		149,048	39,384
2029	4,147	264,957	123,349		141,609	34,017
2030	3,940	251,733	117,192		134,541	29,381
2031	3,743	239,168	111,343		127,825	25,377
2032	3,557	227,230	105,785		121,445	21,918
2033	3,379	215,889	100,505		115,384	18,931
2034	3,210	205,113	95,489		109,625	16,351
2035	2,083	133,066	61,948		71,118	9,643
2036	1,102	70,386	32,768		37,619	4,637
2037	421	26,926	12,535		14,391	1,613
2038	145	9,262	4,312		4,950	504
2039	28	1,818	846		972	90
Total	211,853	13,141,961	6,301,331	2,514,340	6,840,630	2,037,126

3.8 Post-Merger NAV

After all Kodiak Oil & Gas reserves are included, the enterprise value of the combined company is $8.427 billion. In a press release regarding the purchase, Whiting Petroleum reported the enterprise value of the combined company to be $17.8 billion, a significant difference from this analysis (Whiting Petroleum Corporation 2014e). Whiting did not report the method they used to arrive at this calculation of enterprise value. Investors want to see the merger as accretive so Whiting has may overstate the cost savings or growth potential of the combined company. Also, it was not stated which price scenario was used in the calculation. This paper has no bias when calculating enterprise value so the difference in these two values should not be viewed as problematic. However, this difference should emphasize the importance of doing one's own due diligence when investing in a company. Every company wants to portray itself in a positive light and when possible may try to deceive investors in the true value of the company.

Kodiak Oil & Gas has net debt of $2.2 billion and total cash equivalents of $90,000 (Kodiak Oil and Gas Corporation 2014a). Therefore the net debt of the combined company is $4.626 billion, which is then subtracted from the enterprise value and results in a net asset value of $3.801 billion. To pay for the acquisition, Whiting Petroleum issued 47,127,270 shares, which brings the total shares of the combined company to 166,895,586 (Whiting Petroleum Corporation 2014e). This results in a net asset value per share of $22.77.

Table 3.8: Calculation of Whiting Petroleum NAV After Purchase of Kodiak Oil & Gas

NAV by Reserve Type and Region (for PROB and POSS Reserves):	Risked (MBOE)	Base Case
PD	329,567	7,771
PUD	226,422	2,516
Rocky Mountains	66,559	630
Permian	18,319	129
Other	2,976	33
Kodiak	61,073	364
Pre-Tax Asset Value:		11,443
Less: NPV of G&A:		-1,498
+ / - NPV of Hedges:		93
Less: NPV of Cash Taxes:		-1,610
After-Tax Asset Value:		$8,427
Less: Net Debt & Preferred:		$(4,626)
Net Asset Value:		$3,801
Diluted Shares Outstanding:		166.9
NAV / Share:		$22.77
Current Share Price:		$78.54
Current Share Price Premium / (Discount) to NAV:		244.9%

3.9 Reasons for Merger

The purchase of Kodiak Oil & Gas by Whiting Petroleum would be considered a horizontal merger as opposed to a vertical or conglomerate merger. It would be classified as a horizontal merger because Kodiak and Whiting produce the same product and both operate at the same phase of production (exploration and production) (Baye 2010). If Whiting were to purchase a pipeline company or a refinery, the transaction would be considered a vertical merger. On the other hand, if Whiting purchased a company outside of the petroleum industry, it would be a conglomerate merger. “The primary reasons to engage in horizontal integration are (1) to enjoy the cost savings of economies of scale or scope and (2) to enhance their market power." (Baye 2010) Whiting Petroleum was most likely motivated by both of these factors when they decided to purchase Kodiak Oil & Gas.

With this merger, Whiting Petroleum could benefit from many cost savings, most notably, the general and administrative operating costs. G&A expenses include everything from office space rent to legal fees to employee salaries. Before the merger, Whiting Petroleum reported G&A costs of $4.02 per BOE while Kodiak reported G&A costs of $4.44 (Whiting Petroleum Corporation 2014c) (Kodiak Oil and Gas Corporation2014b). It is likely that after the merger, repetitive jobs could be eliminated. For example, the combined company would only need one CEO. James Volker is the CEO of Whiting Petroleum and his duties and responsibilities should not increase in a significant manner as a result of the merger. One of the main responsibilities of a CEO is to define the strategy of a company. Because both Kodiak and Whiting operate primarily within the Williston Basin, this task should be the same whether the companies are together or separate. In 2013, the Kodiak CEO made $14 million, even after factoring in a healthy severance package and increase in Whiting CEO pay, this should still result in a direct cost savings to the G&A category (Morningstar 2014). This is just one of many examples as the Whiting CEO estimates the total cost savings to be one billion dollars, with most of it occurring over the next five years (Gelles 2014).

Market power would be another beneficial reason for acquiring Kodiak Oil & Gas. As mentioned previously, the combined company will become the largest producer in the Bakken play at over 100,000 BOE per day (Whiting Petroleum Corporation

2014e). They could use this gain in market share for their benefit in a number of ways. One of the biggest issues with producing in the Williston Basin is transportation. After oil has been removed from the ground, it must pass through a refinery to turn it into useable products. Unfortunately for producers, most of the refineries in the United States are located in the Gulf Coast region or on the East or West Coast. Kodiak reports that the cost of transportation via pipeline from North Dakota to Cushing, Oklahoma is $5 per BOE and as much as $17 per BOE to ship via train to the east coast (Kodiak Oil and Gas Corporation 2014c). These transportation costs reduce potential profits from producers in the region. If Whiting Petroleum will be the largest producer in the area, they could use it as a negotiating tactic when agreeing upon a sales price at a pipeline or rail origination location in North Dakota. To be the most profitable, a pipeline or train would want to be operating at full capacity all the time. Depending on their capacity, this may require signing contracts with dozens of producers in North Dakota. From the transportation company perspective it would be more convenient to deal with only one producer because of reduced administrative costs associated with dealing with many producers. Whiting Petroleum could use this as leverage to negotiate lower transportation costs or to receive a higher price in North Dakota.

Another benefit of increased market share could be to negotiate lower costs for drilling rigs. As the largest producer in North Dakota, Whiting Petroleum will likely lease the most drilling rigs in the region. Whiting Petroleum should also use this as a negotiating tactic to pay a lower cost per drilling rig.

Additional reasons for mergers in the petroleum industry include achieving synergies, diversifying assets, enhancing stock values, and responding to price volatility (United States General Accounting Office 2004). Synergies are “benefits from the combined strength of different companies” (United States General Accounting Office 2004). Whiting Petroleum is already a mature producer while Kodiak Oil & Gas is growing rapidly. Kodiak is projected to produce 40,000 BOE per day in 2014, which is nearly 150 times greater than its production of 270 BOE per day in 2008 (Kodiak Oil and Gas Corporation 2014c). Finding new assets and quickly developing them would be a strength of Kodiak. Whiting Petroleum production in the Bakken has only grown about five fold during the same time period (Whiting Petroleum Corporation 2013). Whiting Petroleum cannot offer the same level of growth as Kodiak, but it does achieve lower costs. Both D&C costs and total operating costs per BOE are lower than Kodiak. If these two strengths can be combined into one company, it could be mutually beneficial. Additionally, the Kodiak CEO said both companies have very similar culture and that it was a natural fit (Gelles 2014). The Whiting Petroleum CEO said “Our two acreage positions fit together hand in glove.” (Gelles 2014). These are all supporting reasons for why synergies will be achieved by the combined company. The discussion of results section examines whether or not these synergies can justify the purchase of Kodiak Oil & Gas and the $17.8 billion enterprise value.

Given that both producers operate primarily in the Bakken, diversifying assets would not be a reason for this merger. If Whiting Petroleum wanted to diversify its assets, they should have acquired an oil producer in Texas or a natural gas producer in

Pennsylvania. They could have even purchased a renewable energy company that focuses on wind or solar power.

Increasing the stock value of the company would be popular with all shareholders and especially top management whose compensation is directly affected by the stock price. Shareholders of Kodiak Oil & Gas should have been satisfied with the merger because the purchase price offered a 5% premium to the closing price of their stock on July 11, 2014 (Whiting Petroleum Corporation 2014e). After the purchase was announced, the stock price of Whiting Petroleum grew as high as $92.66 per share in August 2014 (Whiting Petroleum Corporation 2014d). This would indicate shareholders and market participants believe the future earnings potential of the combined company is stronger than the two companies operating individually. However, given the information presented previously in this section, the initial NAV per share of Whiting Petroleum actually decreases as a result of the merger.

Another reason for mergers in the petroleum industry is a response to price volatility. Commodity prices have a large impact on the value of a company and high price volatility can lead to uncertainty, which results in oil & gas companies that are undervalued. Companies that are undervalued are prime targets for mergers and acquisitions. Between June 2013 and June 2014, the price of oil ranged from $93.93 to $106.54 (Energy Information Administration 2014a). This is a relatively tight range when compared with historical oil price movements and would not be considered high volatility. Therefore, responding to price volatility would not be a motivating factor for Whiting Petroleum.

A common concern with mergers is that the market share of the resulting company will be too large and result in an oligopoly or reduced competition, which hurts the consumer (Baye 2010). If the social costs outweigh the social benefits of the merger, it may be prevented. An example of a social cost associated with this merger would be if Whiting Petroleum were able to control enough market share of the petroleum industry that they could purposely reduce production to increase the nationwide price of oil. This would translate to higher gasoline prices at the pump and higher prices for other byproducts of oil like plastics. If the government decides this is a legitimate concern, the Federal Trade Commission (FTC) or U.S. Department of Justice (DOJ) may intervene and prevent the merger (Baye 2010). In June 2014, production from the Bakken averaged just over one million barrels per day (North Dakota Department of Mineral Resources 2014). 100,000 barrels per day for the combined company would represent only 10% of total production in North Dakota. According to EIA data, production for the entire United States during the same time period averaged 8.6 million barrels per day (Energy Information Administration 2014d). According to the DCF tables in this section, total United States production for the resulting company will reach 241,000 BOE per day in 2015. This represents only 2.8% of United States production in June 2014. Given these numbers, it would be difficult to make the argument that the resulting company will control too much of the market.

The two main quantitative methods for determining if a merger will have negative repercussions are the four-firm concentration ratio and the Herfindahl-Hirschman index (Baye 2010). The four-firm concentration ratio adds the market share of the four largest firms in the industry. A score of zero would represent pure competition while a score of 100 would represent an oligopoly or monopoly. The following formula is used to calculate the Herfindahl-Hirschman index (Baye 2010).

$$H = \sum_{i=1}^{N} s_i^2$$

Where s_i is the market share of firm i in the market and N is the number of firms.

Scores on this index can range from 0 to 10,000 with 0 being perfect competition and 10,000 being a monopoly. An industry with a score lower than 1,000 is considered to be not concentrated while an industry with a score of greater than 1,800 is considered to be highly concentrated and mergers in this industry while likely be prevented (Baye 2010). When an industry falls within this range the government will take into consideration other factors like economies of scale and barriers to entry when deciding to approve a merger. Another determining factor is if industry HHI is greater than 1,000 and the merger increases the HHI by more than 100 points, it will require further analysis by the DOJ or FTC (Baye 2010). If the industry HHI is greater than 1,800 and the merger increases the HHI by more than 50 points, further analysis will be required (Baye 2010).

A May 2004 report by the United States General Accounting Office noted the HHI of the upstream segment of the oil & gas industry was 217 in 2000 (United States General Accounting Office 2004). This is down from 290 in 1990. This data is over a decade old, but it unlikely enough has changed since 2000 to push the HHI over the 1,000-point threshold.

3.10 Comparative Mergers

The largest ever oil & gas merger occurred in 1999 with the joining of Exxon and Mobil to for ExxonMobil. Exxon paid $81 billion to acquire Mobil but the Federal Trade Commission required Exxon to sell some of its assets in the process. At the finalization of the purchase, the combined company had 120,000 employees $138 billion in assets and produced 3.8% of the world's output (Oil & Gas Journal 1999). This merger was ten times larger than the Whiting-Kodiak deal so problems with the Department of Justice or Federal Trade Commission should not be a concern.

Denbury acquired Encore Acquisition Company in November 2009 for $4.5 billion and is much more comparable in terms of size to the Whiting-Kodiak merger. Both companies had operations in the Permian basin of west Texas and the CEO suggested two of the main reasons for the merger were future growth potential and more efficient development (Denbury Resources Inc. 2009b). Before the merger, Denbury was producing 46,343 boe/day and has lease operating expenses of $18.13 per boe (Denbury Resources Inc. 2009a). In 2013, over three years after the merger was completed, Denbury had production of 70,243 boe/day and lease operating expenses of $28.50 per boe (Denbury Resources Inc. 2014). Far more than just these two metrics should be used to determine the overall successfulness of the merger but they can be used to give an indication of the truthfulness of a CEO's comments at the onset of an acquisition. The Denbury CEO saved himself by not explicitly stating cost savings or cost reductions as a reason but more efficient development could be interpreted as cost savings by many investors. He also did not attempt to quantify the savings like the Whiting Petroleum CEO. Production did increase by 34% but operating expenses per barrel increased by an even greater percentage. This does not necessarily mean the merger was not successful but it does emphasize the need to scrutinize every detail stated by the executive team before accepting them as fact.

4. Discussion of Results

From a purely quantitative perspective, purchasing Kodiak Oil & Gas initially reduces the net asset value per share of Whiting Petroleum. This does not necessarily mean it was a reckless purchase. Many external factors could contribute to a higher NAV per share in the long run. These factors include economies of scale, increased market share, and cost savings. Under the correct management, the merger can be considered a success. If the proper cost savings are achieved, the post-merger NAV per share of Whiting Petroleum will be greater than the pre-merger NAV per share.

4.1 Price Effect

The net asset values from the results section were calculated using the strip pricing method which is also referred to as the base scenario. The remaining two price scenarios are a stable price of $80 per barrel and $4.50 per Mcf and the SEC 12-month trailing price. The SEC requires oil and gas reserves to be calculated according to a 12-month trailing average (Securities and Exchange Commission 2011). This can have a large impact on whether reserves are placed into the proved, probable or possible category. In January 2015, the 12-month trailing prices for oil and gas were $89.12 per barrel and $4.22 per Mcf respectively (Energy Information Administration 2014a) (Energy Information Administration 2014b). A complete list of the price scenarios can be seen in Table 2.10. The table below displays the NAV per share for Whiting Petroleum before and after the merger, for each price scenario. It is important to note that everything other than price is held constant in this table.

Table 4.1: Whiting NAV per Share in Various Price Scenarios

Price Scenario	Whiting NAV/share Pre-Merger ($)	Whiting NAV/share Post-Merger ($)
Base Oil	40.64	22.77
High Oil	71.92	54.48
Low Oil	10.51	(6.21)
Stable	46.70	28.59
SEC Pricing	56.39	38.62

The share price of Whiting Petroleum at the time of the announcement was $78.54 (Whiting Petroleum Corporation 2014d). Even in the high oil price scenario, the net asset value per share is significantly lower. This table also captures the loss of NAV/share as a result of the merger. In almost every price scenario the NAV per share is reduced by up to $20. To reach a NAV per share of $78.54 for Whiting Petroleum before the merger, it would require a constant price of $130 per barrel for oil and $5.50 per Mcf for natural gas. To reach a NAV per share of $78.54 for the combined company, it would require a constant price of $165 per barrel for oil and $6 per Mcf for natural gas. This would represent a record high price of oil (Energy Information Administration 2014a). This suggests that even in the most optimistic commodity price scenarios, Whiting Petroleum is overvalued before the merger and even more overvalued after the merger.

4.2 Reserve Cases

The likelihood of extracting each reserves category can also have serious impact on the net asset value of the company. The standard reserves case used for the initial results assumed proved reserves had 100% chance of being extracted, probable had a 50% chance of being extracted, and possible had a 10% chance. The likelihood of extracting reserves can change as a result of technology improvements or price changes. The table below illustrates the NAV per share of Whiting Petroleum before and after the merger in various reserve extraction scenarios. For the results in this table, everything other than reserve extraction probability is held constant.

Table 4.2: Whiting NAV per Share in Various Reserve Extraction Scenarios

Reserves Scenario (Proved %, Prob %, Poss %)	Whiting NAV/share Pre-Merger ($)	Whiting NAV/share Post-Merger ($)
(100,50,10)	40.64	22.77
(100,100,100)	46.77	30.18
(100,50,50)	42.47	24.95
(100,75,50)	43.43	26.16
(100,25,25)	40.40	22.39

If all three reserve categories are fully extracted, it yields a NAV per share of $61.26 for Whiting Petroleum. Even in the most optimistic reserve extraction scenario, the NAV per share is significantly lower than the stock price. This evidence supports the claim that Whiting Petroleum is overvalued before and after the merger.

4.3 Initial Production

Initial production of a well is important because determines the amount of oil that is produced and in what time period it occurs. In the end, the same amount of oil & gas is extracted but because of the time value of money, it can have an impact on the company's valuation. The sooner the oil can be recovered, the better it is for Whiting Petroleum. The table below shows the NAV per share of Whiting Petroleum in various initial production rate scenarios, holding all else constant.

Table 4.3: Whiting Petroleum NAV per Share in Various IP Rate Scenarios

Percent Change in IP Rate	Whiting NAV/share Pre-Merger ($)	Whiting NAV/share Post-Merger ($)
0%	40.64	22.77
-25%	33.40	17.93
+25%	45.36	25.91
+50%	47.82	27.53
+100%	49.37	28.53

Doubling the initial production is probably not achievable but this table does show the importance of what year the reserves are extracted. The same amount of oil is extracted in each scenario in this table, but depending on how quickly it is extracted, it can have a significant impact on the company valuation.

4.4 Market Share

The royalty rate used for the initial valuation was 18% for both Whiting Petroleum and Kodiak Oil & Gas. Actual lease royalty rates varied between 12.5% and 20% for Kodiak but their 2013 Annual Report suggested 18% was a fair assumption to use for the company as a whole (Kodiak Oil and Gas Corporation 2014a). One of the motivating factors for the merger that was mentioned earlier was increased market share. A benefit from increased market share could be the ability to negotiate lower royalty rates with landowners. Competition decreases in the region as a result of fewer companies. Reduced competition gives landowners fewer options when leasing their land. This gives more power to the petroleum companies to negotiate more favorable royalty rates. As mentioned previously, after the merger Whiting Petroleum will control about 10% of North Dakota production. This may not be enough market share to make a meaningful impact on royalty rate negotiations. The NAV per share of various royalty rate scenarios are presented in the table below. Everything other than royalty rate is held constant.

Table 4.4: Whiting Petroleum NAV per Share in Various Royalty Rate Scenarios

Royalty Rate	Whiting NAV/share Pre-Merger ($)	Whiting NAV/share Post-Merger ($)
20%	39.50	21.42
18%	40.64	22.77
12.5%	43.78	26.44
10%	45.20	28.09
0%	50.87	34.58

A 0% royalty rate is unrealistic but if it were completely removed it would have a more positive impact on NAV per share than the most optimistic price or extraction scenarios. This demonstrates the importance of market share for an oil & gas producer. It also provides insight into the possible thought process of Whiting and Kodiak executives for agreeing to this merger.

Another factor of increased market share is the possibility of negotiating more favorable sales prices in North Dakota or reduced transportation costs to oil hubs like Cushing, Oklahoma. For the initial analysis, it was assumed Whiting would receive 90% of the West Texas Intermediate price. If as a result of increased market share, this figure were to increase to 95%, it would increase the NAV per share of the combined company to $27.96 from $22.77. This has almost the same effect as reducing the royalty rate to 10% from 18%. This also shows the upside potential to increased market share and why it was likely a motivating factor for this merger.

4.5 Cost Savings

Another motivating factor for the merger is the possibility of achieving cost reductions through synergies. The main costs involved are the drilling & completion costs, operating costs (lease operating expense, production taxes, other costs), and the general & administrative costs.

Whiting Petroleum drilling & completion costs in the Bakken were $8.0 million in 2013, while Kodiak Oil & Gas's were $9.0 million (Whiting Petroleum Corporation 2014a) (Kodiak Oil and Gas Corporation 2014c). In just three years, Kodiak had reduced their D&C costs by $3 million (Kodiak Oil and Gas Corporation 2014c). With the access to Whiting Petroleum's cost savings techniques, it is entirely plausible they could reduce them even further to $8.0 million for the combined company. In 2013, total operating expenses were $19.05 per BOE for Whiting Petroleum and $24.39 per BOE for Kodiak. During the same time period, general & administrative costs were $3.57 per BOE for Whiting and $4.44 per BOE for Kodiak (Kodiak Oil and Gas Corporation 2014a) (Whiting Petroleum Corporation 2014b).

Kodiak is higher in all three cost categories. As mentioned in the previous section, cost reductions are a major motivating factor for mergers. The differences in costs between Whiting and Kodiak show that cost reductions were likely a motivating factor for this merger. In addition to reducing Kodiak costs to the level of Whiting, the combined company should be able to reduce costs per BOE even further by being a larger producer. The table below shows the effect these cost savings would have on the NAV per share.

Table 4.5: Whiting Petroleum NAV per Share in Various Cost Savings Scenarios

D&C Cost (Bakken)	Operating Cost per BOE	G&A Cost per BOE	Whiting NAV/share Post-Merger ($)
$8.0 M	$19.05	$3.57	$21.23
$7.5	$18.00	$3.25	$27.52
$7.0	$16.00	$3.00	$32.41
$6.5	$14.00	$2.75	$37.23

Even modest cost reductions can have a significant impact on the NAV per share of the combined company. In the initial valuation scenario, the NAV per share of Whiting Petroleum was $40.64 before the merger and $22.77 after the merger. The most optimistic cost savings scenario almost completely erases this difference and nearly justifies the Kodiak acquisition on its own.

4.6 Best Case Merger Scenario

Thus far, many components of the net asset valuation have been examined individually. This section will study the combined effects of the potential benefits of the merger. The two most influential motivating factors were likely achieving cost reductions through synergies and increased market share. Increased market share could lead to more power in negotiating more favorable royalty rights and sales prices. Cost reductions have obvious implications of increasing profits and the net asset value of the company. These are items that neither company would be able to achieve on their own. For this section, price effect, reserve extraction probability and initial production rates were held constant because these variables are not directly related to the merger. They would have the same effect on Whiting Petroleum whether or not they acquired Kodiak. The most optimistic scenario assumes an average royalty rate of 12.5%, a sales price that is 95% of WTI, D&C costs in the Bakken of $7.0 million, operating costs of $16.00 per BOE, and G&A costs of $3.00 per BOE.

Table 4.6: Whiting Petroleum NAV per Share in Various Merger Scenarios

Merger Scenario	Whiting NAV/share Post-Merger ($)
No Change	$22.77
Some Benefits	$32.65
Maximum Benefits	$46.06

Before the merger, the NAV per share of Whiting Petroleum was $40.64. After the merger it was $22.77. After the first glance of this acquisition, it looks like a terrible transaction and destroyed nearly $20 per share in firm value. Once the key merger catalysts were taken into consideration, the reason for the merger becomes clearer. In the best-case merger scenario, Whiting Petroleum will add $5.42 in NAV per share. This only represents an upside potential of about 11.7%. This is a less than ideal profit, but the key take-away from this section is the importance of factors like cost reductions and increased market share and the impact they can have on a merger of this magnitude. After the merger, the company can increase its NAV per share by 50.5% to $46.06 from $22.77 by focusing on cost reductions as a result of synergies and more negotiating power through increased market share.

With the high oil price scenario, 50% increase in initial production rate, 100% chance of extracting proved reserves, 75% chance of extracting probable reserves, and 50% chance of extracting possible reserves, the NAV per share would be $109.25. Many variables including some out of Whiting Petroleum's control would all have to move in their favor for this valuation to occur. On the other hand, if these variables moved against Whiting Petroleum and if the variables directly associated with the merger did not change, the NAV per share could actually become negative. This means the company would be better off not drilling and waiting for market conditions to recover before resuming normal operations.

5. Conclusion

Mergers within the upstream segment of the petroleum industry are quite common, as producers must consistently replace their depleting reserves base. Although, acquiring another company is not always in the best interest of the shareholders. Ulterior motives like executive compensation and golden parachutes can cloud the judgment of managers making these decisions. Asset diversification, increased market power, cost reductions, synergies, price volatility, and enhanced stock values are all considered good motivating factors for a merger. In the case of Whiting Petroleum, increased market share and cost reductions through economies of scale were likely the points that initiated talks between the two companies.

Whiting Petroleum can use increased market share to negotiate more favorable royalty rates and local sales prices. Greater market share can also lead to cost savings. For example, lease-operating costs per BOE should be lower as Whiting Petroleum rents more drilling rigs. Cost savings should also occur in the general & administrative category. The Kodiak CEO received $14 million in total compensation in 2013 but the combined company will only require one CEO. Even taking into consideration raising the Whiting CEO pay and a large severance package given to the departing Kodiak CEO, this should still result in a cost savings in the long run. This is just one of many examples as total cost savings are predicted to be one billion dollars by the Whiting Petroleum CEO.

Acquiring Kodiak Oil & Gas initially lowers the NAV per share of Whiting Petroleum but these losses can be overcome so long as the new management team correctly implements the previously mentioned value added techniques. Therefore, both

Kodiak and Whiting shareholders should vote in favor of the merger. While the merger can be beneficial to Whiting Petroleum, the upside is only around 3% in an optimistic scenario. Whiting Petroleum should have used this analysis to negotiate a better purchase price. This would require issuing fewer shares to acquire Kodiak, but it may be difficult because Kodiak shareholders would probably not approve anything less than the current share price of the company.

This analysis demonstrates the importance of heavily scrutinizing a merger of this magnitude within the petroleum industry. In line with the goal of this paper, it also provides a framework for forecasting the future success of an oil & gas merger.

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