HASKAYNE
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The Student's Guide to Analyzing Oil & Gas Producers

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Introduction

The oil & gas industry is driven by more than just the underlying commodity pricing. Buying an oil & gas producer's stock goes beyond taking a view on the commodity, it brings with it a deeper level of factors – management, asset quality, operational efficiencies, to name a few – that provide an opportunity for greater returns on capital, and increased learning potential than the underlying commodity. The industry differs in many ways from business models that students are generally familiar with and seems intimidating on the surface, but as you'll hopefully see by the end of this guide, the basics really aren't that complicated.

We'll start by looking at the oil & gas industry from a macro level – highlighting the structure of the value chain and understanding the underlying commodity. Then we'll look at understanding the key asset held by oil & gas producers – their reserves – and how they go about extracting it. Finally we'll summarize these unique business models and present different ways of valuing them. To provide deeper insights, we'll use examples from Canadian producers where possible.

Industry Overview

What are the different segments in the industry?

In order to analyze an oil & gas company it is important to understand the different roles companies play along the supply chain. This chain can be divided into three different 'streams' which explain how crude oil and natural gas become a commercial product. These 'streams' are upstream, midstream and downstream.

Upstream

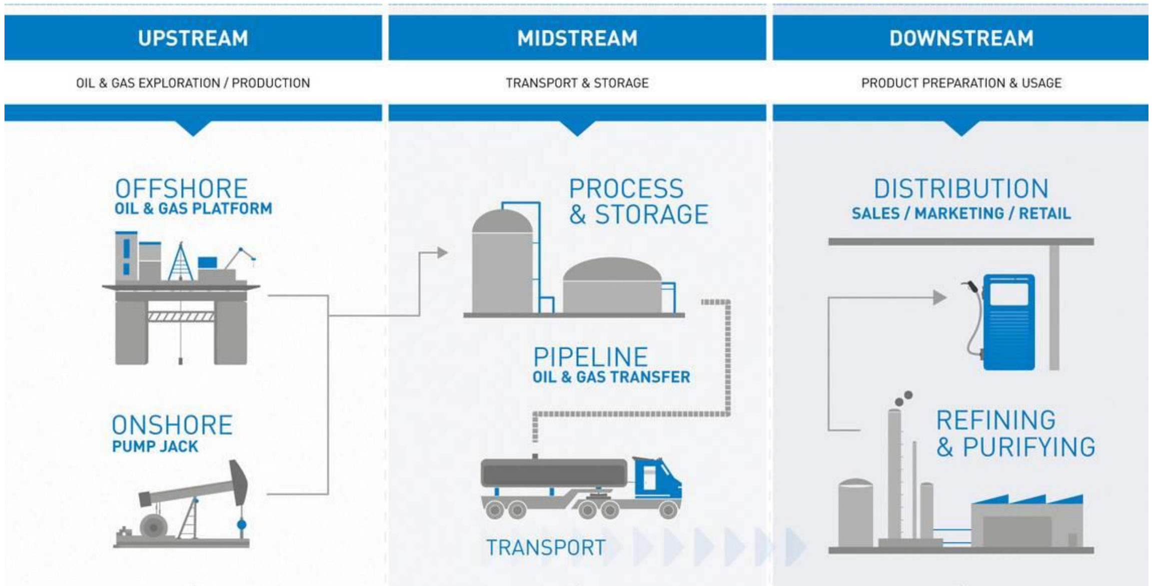
Consists of companies that find and extract crude oil and natural gas also referred to as Exploration and Production (E&P) companies. In other words, the same way the Bow River flows from the Bow Glacier located upstream, oil & gas "flows" from a source (E&P company) located upstream in the value chain. Examples of Canadian E&P companies include ARC Resources, Canadian Natural Resources, and Raging River Exploration. Also included within the upstream classification are companies which provide services in the form of engineering and geological services, as well as industry tools and equipment used to extract the commodity. Examples of these include Calfrac Well Services, Secure Energy, and Schlumberger.

Midstream

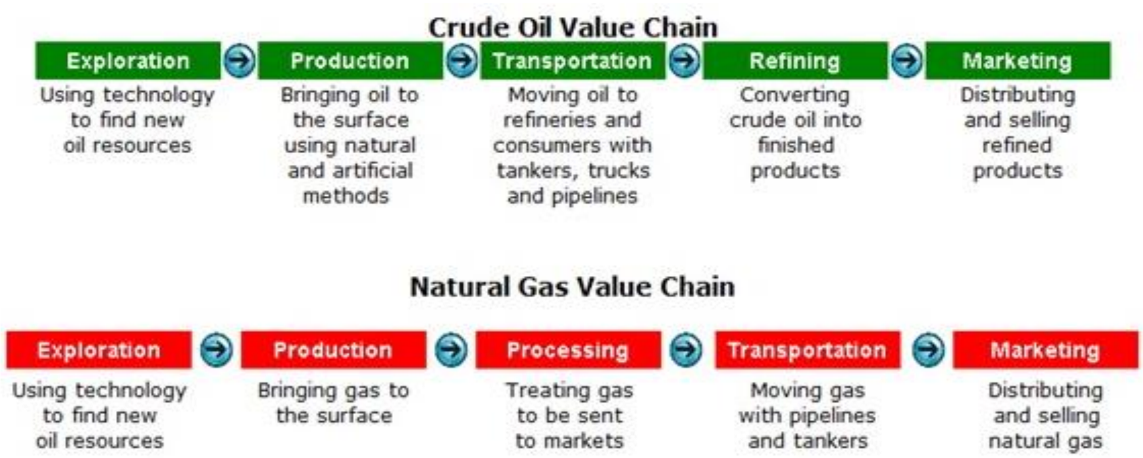
Focuses on the transportation of Oil & gas products from the oilfield to the downstream refiners and retailers. Pipelines are a large part of the midstream industry as well as other transportation methods such as rail or tankers. This industry also consists of storage facilities and various processing facilities. If the Bow Glacier is upstream, think of midstream companies as the Bow River as it travels down the valley and through cities, collecting in pools and peripheral reservoirs along the way. Enbridge, Keyera, and Gibson Energy are all examples of Canadian midstream companies.

Downstream

To continue the analogy, as the Bow River flows downstream, for our purposes, it reaches a water treatment plant where it is then treated, tested, and distributed. This is, in essence, the same role downstream oil & gas companies play. Using various extracted forms of oil & gas, they refine/process, market, and distribute the end product to consumers in many different forms, for example gasoline, heating oil, and fertilizers. The products produced vary and are largely dependent on the type of oil/gas as well as the refining process. Examples of downstream oil & gas companies are Bitumar, North Atlantic Refining, and Tidal Energy Marketing.



In addition to companies that specialize in a specific supply chain role, companies such as Husky Energy, Imperial Oil, and Shell are integrated energy companies. They participate in upstream production, midstream transportation, and downstream refining/marketing. Hence why you are likely already familiar with them because of their downstream presence in the form of gas stations.[1]



What are the differences between crude oil and natural gas?

Most E&P companies extract both liquids and gas – liquids referring to different grades of crude oil along with other liquid products, and gas varying from Methane to Pentane. Some pure play companies may be heavily liquids focused (Granite Oil Corp, production is ~100% oil) or gas focused (Advantage, only ~4% oil)[2], but generally speaking, most

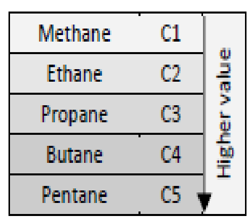
[1] Source: ecom Instruments, oil & gas Journal
[2] Note: Data as of 2016

companies produce a mix of both commodities. The following tables provide a general breakdown of the different commodities:

Crude Oil

Types	Description	Characteristics	Benchmarks	End Use
Light Oil	• Flows easily through pipelines • Holding all else equal, sold at a premium to heavy oil	• High API Gravity (ranging from ~30-45). Higher number means heavier, which = better quality • Low viscosity • Higher sulphur content = "sour" = lower quality	• West Texas Intermediate (WTI) • Brent Crude oil (Brent)	• Gasoline • Diesel • Jet fuel *Yields a higher percentage of fuel than heavy*
Heavy Oil	• Requires pumping to flow through pipelines • More difficult to extract than lighter oils • Typically sells at discount to light oil	• Low API Gravity (ranging from ~0.1-22) • High viscosity • Higher sulphur content = "sour" = lower quality	• Western Canada Select (WCS) • Mexican Maya Crude	• Asphalt • Gasoline/Diesel *Yields a lower proportion of fuels, more complex refining required*

Natural Gas

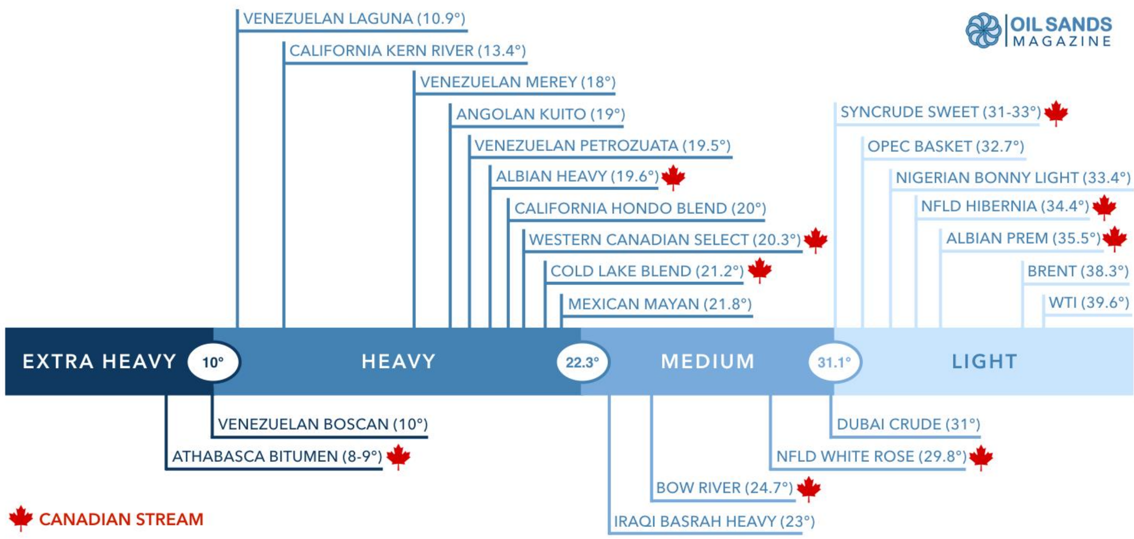
Types	Description	Relative Value[1]	Benchmarks	End Use
Natural Gas (Dry)	• Methane, found with various amounts of other heavier hydrocarbons		• AECO (Alberta) • Henry Hub	• Power generation • Cooking, heating, transportation • Oil production
Natural Gas Liquids (NGLs)	• Stripped from dry natural gas (methane) • More valuable than dry gas		• Varies by grade (C2-C5)	• Heating, fuels for vehicles • Petrochemical/crude refining feedstock

More on natural gas and an in-depth overview of the global natural gas environment is provided in a previous HFC report "Challenges Facing Canadian Natural Gas".

[1] Source: RBC Energy Made Simple 2.0

How are crude oil & natural gas priced?

Crude oil prices are set according to various quality benchmarks. Fundamentally, these benchmarks are groupings of crude oils with similar features, largely based on location and quality. Benchmark grades are used as a standard for pricing throughout the global oil industry. Characteristics of effective benchmarks include consistent quality, high trading liquidity, a safe supply and a diversified market consisting of a multitude of sellers and buyers of the crude stream.[1]



Brent & WTI

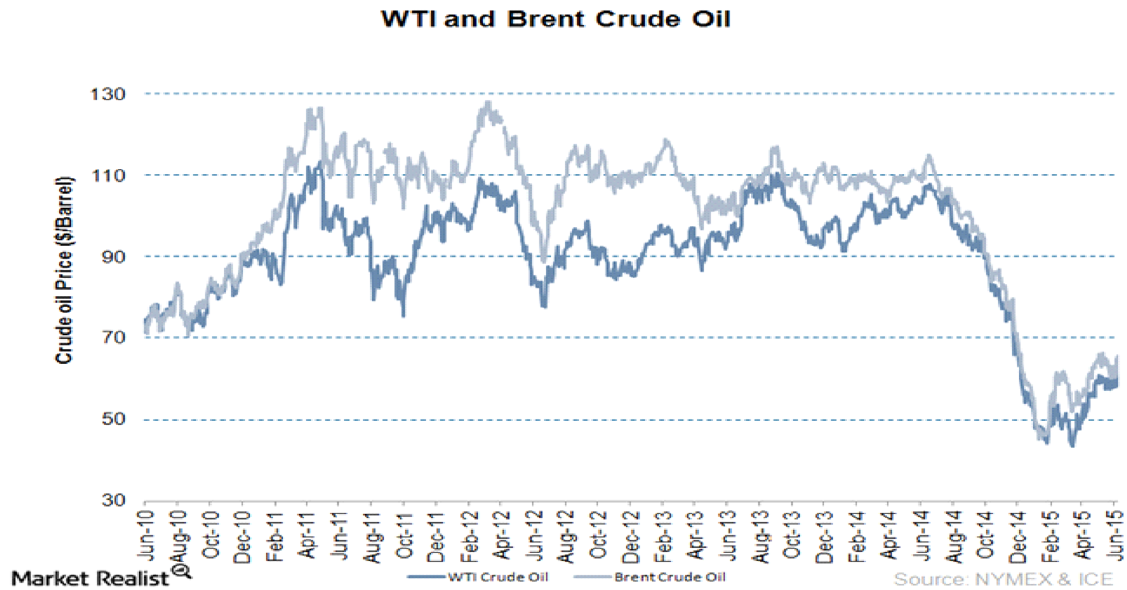
The two most recognized crude oil benchmark grades are Brent crude oil, and the U.S.–based West Texas Intermediate (WTI). WTI crude oil production is derived from West Texas and New Mexico, blended with comparable quality crude streams from central Texas, Kansas, and Oklahoma. The popularity and success of the WTI benchmark stems from its strong liquidity. WTI is used as the main reference grade for the most heavily traded oil futures contract in the world, and is the benchmark typically used for North American crude.

The Brent benchmark is a blend of numerous crude oils produced in the North Sea region of the United Kingdom and Norway. Brent has strong physical liquidity and is the leading European benchmark. Additionally, African-based crude oils from countries including Nigeria and Libya are also priced off the Brent benchmark.

Due to the cost of transport along with several other reasons, Brent typically trades at a premium to WTI, as shown in the graph below.[2]

[1] Source: Oil Sands Magazine

[2] Source: Market Realist



Canadian Crude Oil Benchmarks

*Mixed Sweet Blend (MS*W), more commonly known as "Edmonton Par" serves as the primary benchmark for light crude oil produced in Western Canada. Mixed Sweet Blend is similar to WTI in that they both are a high-quality, low-Sulphur content crudes.

Western Canadian Select (WCS) is a blend of Western Canadian conventional heavy and bitumen crude oil streams, mixed with sweet synthetic and condensate diluents to provide an appropriate feedstock for U.S. Midwest refineries. WCS is mainly marketed toward U.S. Gulf Coast refiners and competes with Mexican and Venezuelan heavy crudes. Although the spread varies, WCS has recently traded at a ~$15 discount to WTI.

NYMEX & AECO

In North America, the predominant natural gas benchmark trades on the NYMEX and is referred to as Henry Hub – a natural gas distribution pipeline system located in Louisiana. The Western Canadian natural gas benchmark is known as the AECO Hub.

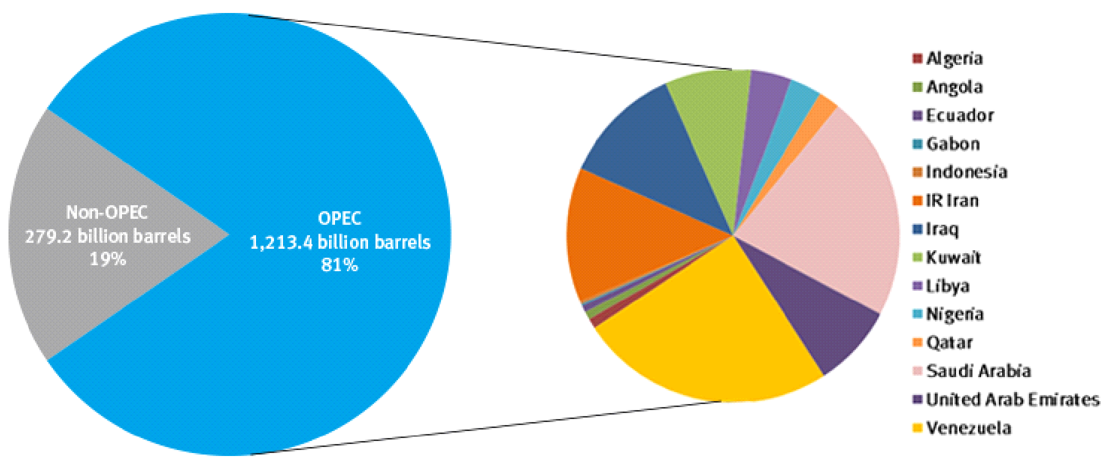
Realized prices

It's important to note that the tangible selling price realized by crude oil producers is not necessarily equal to the benchmark price. What often occurs is that volumes are sold at a variance from the quoted benchmark, this being a discount or a premium depending on the quality of commodity sold and the particular benchmark used. As mentioned previously, the processing required for refining heavy oil such as bitumen into a finished product results in refiners paying less compared to light crude oil such as WTI. For example the producer could sell their oil for a premium such as 120% or a 1.2x multiple of WTI as it is of higher grade. These pricing differentials are important when projecting future revenues - we ignore this in our example NAV model later in this report, but it is typically an important part of the assumptions.

What is OPEC?

Created in 1960, The Organization of Petroleum Exporting Countries (OPEC) is a perpetual, intergovernmental organization consisting of 13 member nations including: Iraq, Kuwait, Iran, Saudi Arabia, Venezuela, Algeria, Ecuador, Gabon, Libya, Nigeria, Qatar, United Arab Emirates and Angola. OPEC's objective is to unite and synchronize petroleum policies among member countries to assure steady and fair prices for petroleum producers; an efficient, economic and consistent supply of petroleum to consuming nations; and a reasonable return on capital for those investing in the industry.

OPEC share of world crude oil reserves, 2015



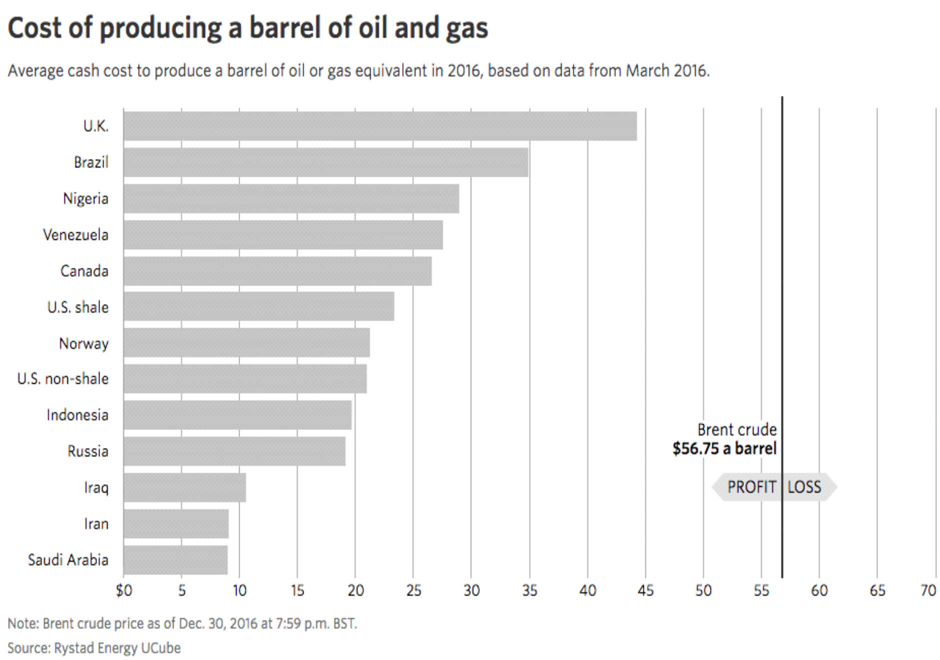
OPEC proven crude oil reserves , at end 2015 *(billion barrels, OPEC share)*

Venezuela	300.88	24.8%	Kuwait	101.50	8.4%	Qatar	25.24	2.1%	Indonesia	3.23	0.3%
Saudi Arabia	266.46	22.0%	United Arab Emirates	97.80	8.1%	Algeria	12.20	1.0%	Gabon	2.00	0.2%
IR Iran	158.40	13.1%	Libya	48.36	4.0%	Angola	9.52	0.8%			
Iraq	142.50	11.7%	Nigeria	37.06	3.1%	Ecuador	8.27	0.7%			

Source: OPEC Annual Statistical Bulletin 2016.

Why is OPEC important?

As seen above the majority of the world's proven crude oil reserves are located in OPEC Member Countries (more than 80%). Along with accounting for a substantial part of the world's oil reserves, OPEC member countries' cost of producing is generally lower per barrel of oil than non-member countries (as seen in the chart below). These attributes lead to OPEC having the ability to influence global oil prices, although it has decreased in recent years due to growing non-OPEC oil production (particularly in the United States).

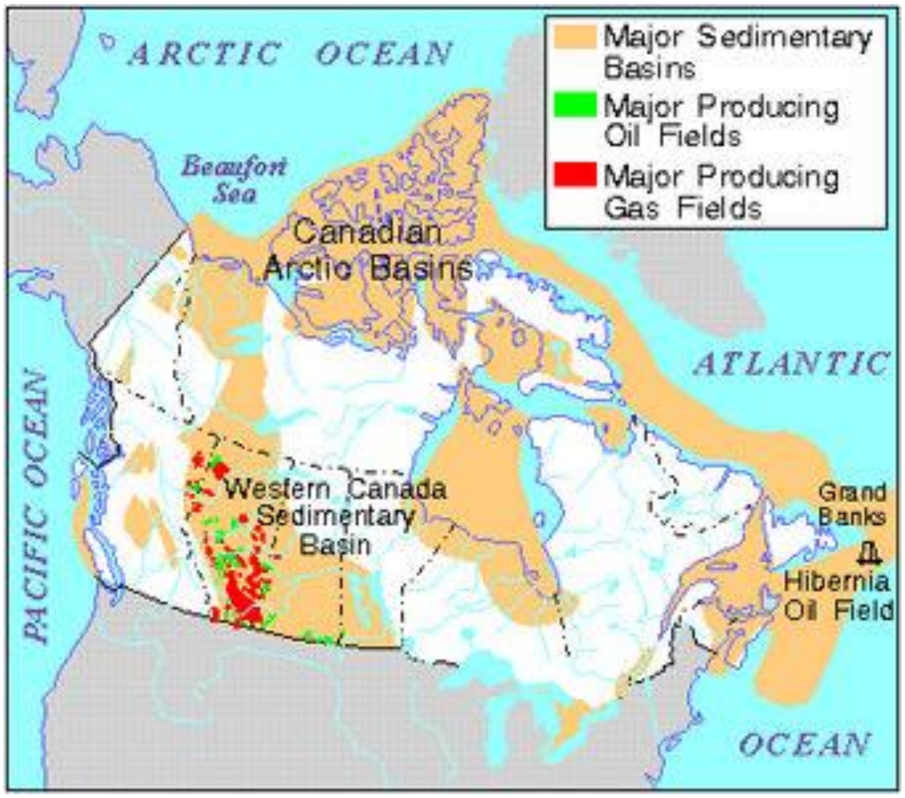


After the substantial decrease in crude oil pricing in 2014, OPEC was under pressure to cut production. In late 2016/early 2017, OPEC nations agreed to cut production, which ultimately led to an approximately 20% increase in the price of WTI.

Reserves & Production

The value of an E&P company, for obvious reasons, derives predominantly from the quality and quantity of their reserves. When analyzing E&P companies, it is important to understand the types of "plays" or reservoirs they extract from. This provides insight into the composition/grade and size of their reserves, among other unique characteristics.

Where is the oil & gas located in Canada?



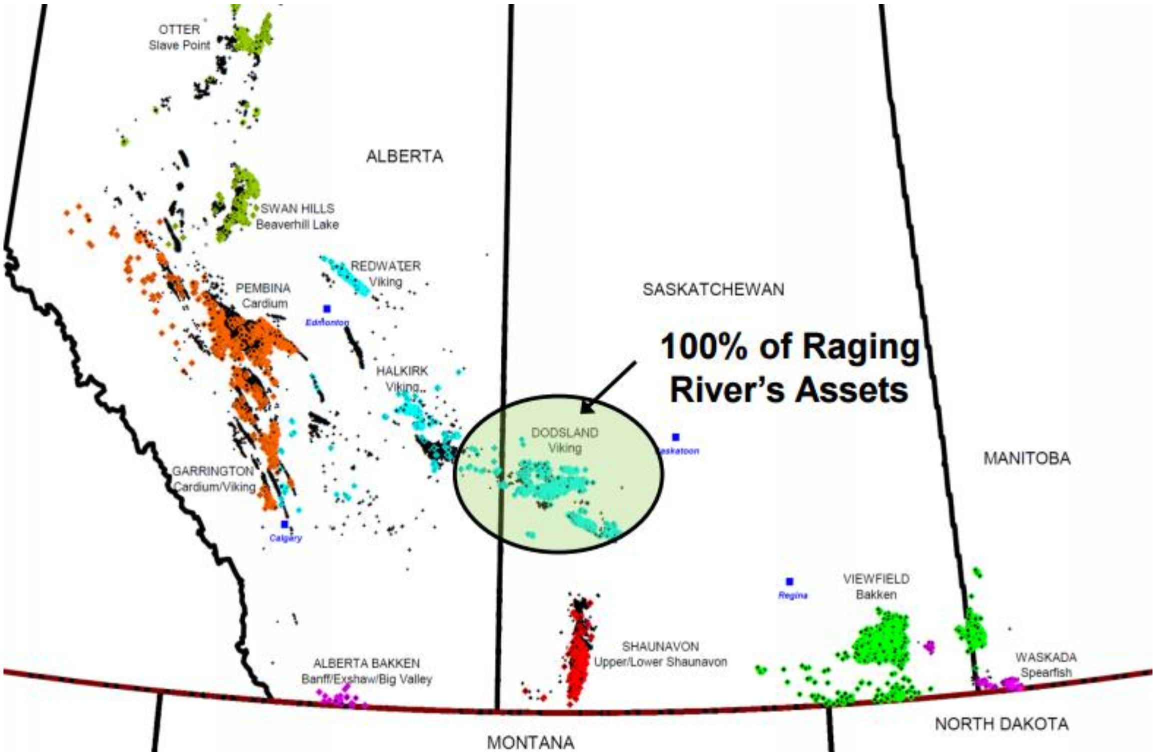
The Western Canada Sedimentary Basin is an important hydrocarbon reservoir stretching from north eastern British Columbia to southern Manitoba. This basin is home to light & heavy oil, as well as natural gas. Examples of formations include[1]:

Name	Type	Producers
Cardium	light oil/gas	CNRL, Husky, Whitecap
Duvernay	oil/liquids rich gas	Encana, Shell, Chevron
Montney	liquids rich gas	Encana, Arc, Seven Generations
Viking	light oil	Raging River, Teine, Crescent Point

[1] Source: Canadian Encyclopedia

How do E&P companies classify reserves?

In practice, companies typically include a geographical breakdown of their assets in investor presentations.[1]



E&P companies express the oil or gas available for extraction from their underground reservoirs as reserves. They are estimated and classified by geologists into three main categories: proved, probable, and possible. The focus is on the likelihood of economic recovery. In other words, given crude/gas pricing and production costs, how likely is it that the company will be able to extract profitably?

Type of Reserve	Certainty of Commercial Extraction
Proved (1P)	90%
Probable (2P)	50%
Possible (3P)	10%

[1] Source: Raging River Exploration Investor Presentation, 2017

It's important to note that whenever you see "2P Reserves", the number includes both 1P *and* 2P reserves. So in the example to the left, 856 mmbbls (million barrels) is the amount of reserves with a 50% or greater chance of being economically extracted.[1]

Reserves Summary

	Oil	Gas	NGLs	Total	% Liquids	RLI
	mbbl	mmcf	mbbl	mboe	%	yrs
PDP	32,852	35,354	2,115	40,859	86%	5.7
Total Proved	50,646	62,642	3,286	64,372	84%	9.0
P+P	77,719	100,753	5,063	99,574	83%	13.9
PDP/Total Proved				63%		
PDP/P+P				41%		
Proven/P+P				65%		

The life of these reserves is called their Reserve Life Index (RLI). This is a measure of how long a reserve is expected to last given the average amount in boe a company produces per day. To calculate the RLI, simply divide the resource base (mmboe) by the annual production (boe/d x 365). The number will approximate the *amount of years* the reserve is expected to last.

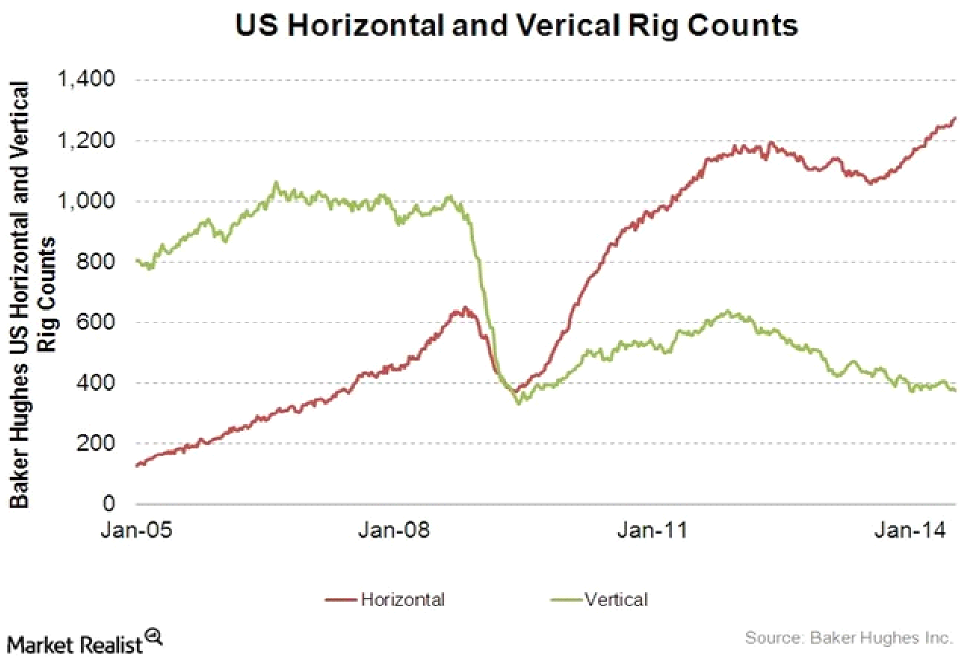
How is oil & gas extracted?

The methods used by producers to extract oil & gas vary depending on the unique characteristics of their reserves. A company might use horizontal drilling techniques in the Bakken Shale, while a producer in the Alberta Oil Sands may employ traditional mining, or newer SAGD technologies. Recent innovation has resulted in advanced recovery methods that are increasingly changing the industry landscape. The US Shale Boom, for example, can largely be attributed to innovation in unconventional methods such as horizontal drilling.

Vertical drilling is a conventional technique that provides access to a well where extraction can only occur straight below the well head. As a result, this makes them less costly to develop, but relatively less productive because of their limited range. Due to recent developments highlighting the superior efficiency of horizontal drilling, vertical drilling is quickly becoming outdated.

[1] Source: Torc Oil & Gas Corporate Presentation, 2016

Horizontal drilling is a drilling process in which the well is turned horizontally at depth. It is able to penetrate a greater length of the reservoir and can offer significant production improvements over a vertical well. A drilling company using the horizontal technique can reach more of their resource with fewer wells. Additionally, horizontal drills come online quicker than vertical, providing further explanation to the increased use of horizontal rigs (see below).



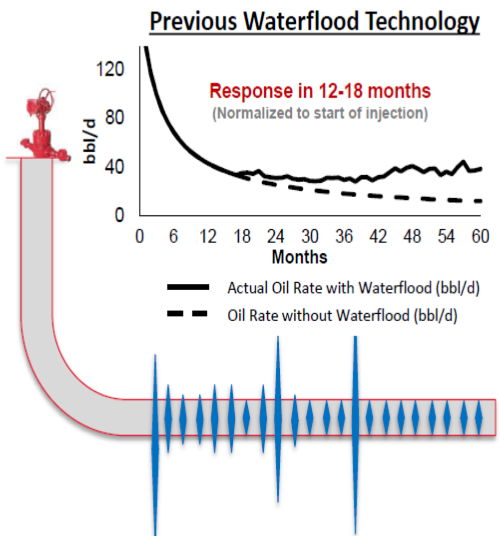
For bitumen (very heavy oil) recovery producers use two methods: mining and in-situ. Both of these methods are used extensively in the Alberta oil sands.

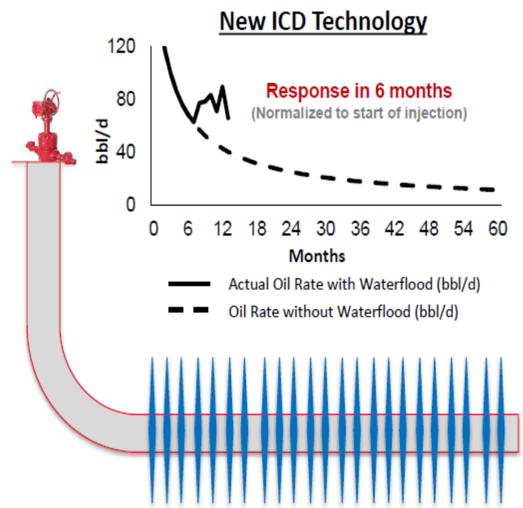
Mining is used to develop bitumen deposits of depths up to 70 meters. The upfront capital and operational requirements are higher for this mature technology than those of in-situ projects. Despite this, surface mining is a simple and effective technique that normally produces recovery factors of approximately 95%. It is a mature technology and is dramatically more expensive than in-situ projects.

In-situ is a relatively new method used to develop bitumen deposits of depths 100 meters or greater. Cyclical Steam Stimulation (CSS) and Steam Assisted Gravity Drainage (SAGD) are two commercially utilized in-situ technologies, and there are a vast number of experimental technologies currently in the testing phases.

After the primary and secondary recovery stages comes the final phase of production, called Enhanced Oil Recovery (EOR). EOR is the process of stimulating the flow of oil to the well bore through various methods such as waterflooding, heat, or steam injection as a means to increase the recoverable reserves of a producing well.

Companies are continuously looking for ways to innovate and improve their recovery techniques, as this can provide a competitive advantage and increase profitability.[1]





How do E&P companies measure production?

We've seen where reserves are located, and the ways in which companies extract from them. Once a company is producing, they follow several industry conventions to quantify ongoing production.[2]

Acronym	Term	Measure
BOE	Barrel of Oil Equivalent	The amount of energy in a barrel of crude oil (42 gallons)
MBOE/MMBOE	Thousand/Million Boe	Used to quantify oil. Note that M expresses *thousand* not million
MCF/MMCF	Thousand/Million Cubic Feet	Used to quantify natural gas, commonly used

2017 Average Production	172,000 boe/d (~89% liquids)
2017 Exit Production	183,000 boe/d (~89% liquids)

[1,2] Source: Crescent Point Corporate Presentation, 2017

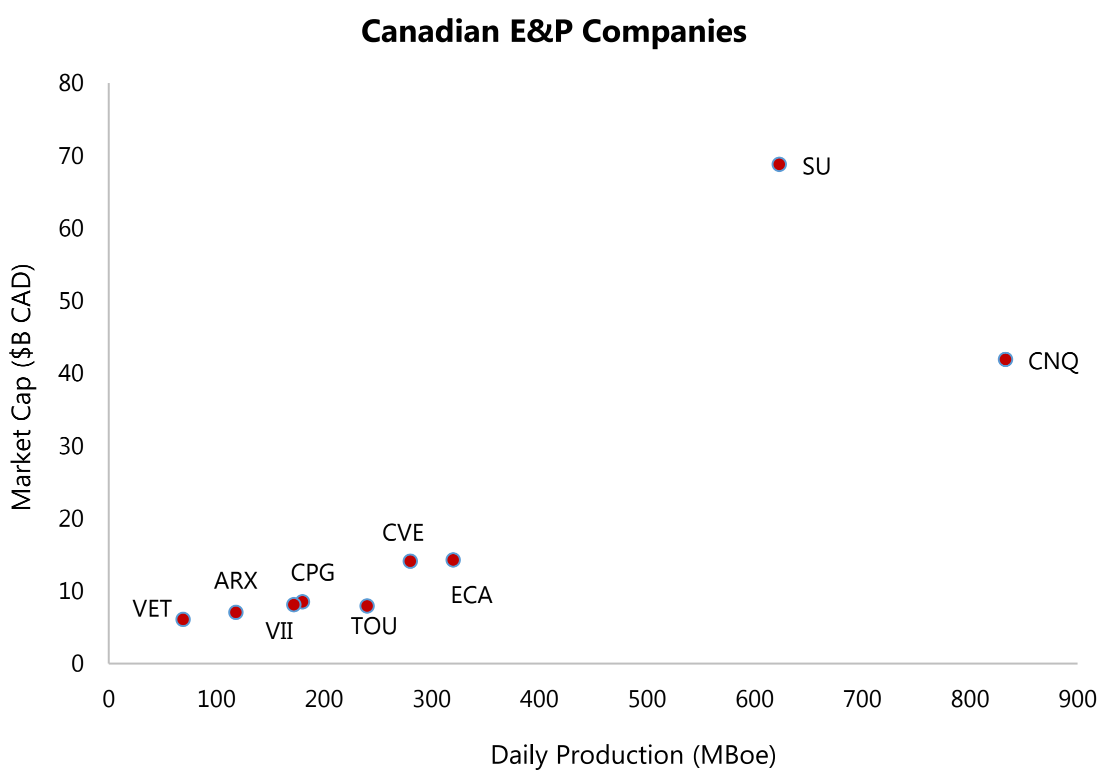
The example above communicates that taking into consideration all daily production (oil & gas) over the year, on average the company expects to produce 172,000 barrels of oil equivalent per day. Note that this *does not necessarily mean* that the company is producing that many barrels of crude oil - the industry converts gas production to "barrel of oil equivalent" (the same amount of energy) to make measurement easier and consistent. In this case, they approximate that 89% of production will be liquids, the remainder will be gas (despite being expressed as barrel of oil equivalent).

To convert gas to the same metric as oil, convert mcf to boe. One mcf contains approximately one-sixth of the energy of one boe, therefore to equalize:

1 BOE = 6 MCF

How much do Canadian E&P companies typically produce?

Companies with higher production tend to have a higher market capitalization. The graph below shows where the currently ten largest (by market cap) E&P companies in Canada rank.[1]



[1] Source: Bloomberg, as of February 2017

Given the decline rates of a company's reserves, it is important for E&Ps to be consistently drilling new wells and/or acquiring reserves to sustain production. Companies with a strong record of acquiring quality assets while managing decline rates with innovative recovery techniques are typically rewarded by the market.

Valuation

Now that we've seen the structure of the oil & gas Industry and the ways in which E&P companies participate, we can better understand the unique approaches required to value them. In simplest terms, the three main factors that determine the financial health of an E&P company are: the amount it costs them to produce a boe, the amount of boe they own/produce, and the market price for that boe (given the composition breakdown of gas & liquids).

Key differences

Unlike many sectors, E&Ps are "price-takers" in the sense that they don't set the price their commodity sells for – the price is determined by the market. Additionally, because mineral rights in most Canadian jurisdictions are owned by the government, companies must pay royalties – this perpetual cash flow obligation makes them an important consideration for valuation.

An E&P company's value is derived directly from their reserves (current and future production), which means that if they are not finding/acquiring more reserves, holding all else equal, their value is depleting. This is the fundamental reason why the industry is *especially* capital intensive – massive amounts of investment is required to maintain and grow a company's asset base. In other words, a significant amount of continuous capital expenditure is required to consistently create value.

The capital intensive nature of the business is why producers are typically – relative to most industries – highly levered. Projects generally require a large up-front cost (particularly in the Oil Sands) in order to generate future cash flow, hence why debt financing is commonly used.

Implications for valuation

These unique characteristics lead to a shift in focus from earnings to *cash flow*. The cash flow statement is prioritized for a couple key reasons. As we mentioned, E&Ps are "price-takers", therefore revenue doesn't tell us much. Additionally, higher leverage means higher interest expense, leading to an earnings number that doesn't paint the full picture. Finally, the nature of projects (high up-front costs) means that companies record significant initial losses and carry them forward as deferred tax shields, adding another layer of complexity to earnings.

The price-taking characteristic of revenue and the distorted earnings number render comparable multiples such as price to sales or price to earnings largely irrelevant for E&Ps.

The three overarching valuation techniques, however, still generally apply: discounted cash flow (DCF), comparables, and precedent transactions. For the purposes of this report we will focus on the first two.

Intrinsic valuation (DCF/NAV)

Given that value for an E&P company is ultimately derived from reserves, intrinsic valuation naturally takes the form of a Net Asset Value (NAV) Approach. The NAV approach is not fundamentally different – it involves forecasting and discounting future cash flows - but it does differ in several key ways from a traditional DCF.

- **Terminal Value**: Unlike a DCF, a NAV model seeks to value a *finite* cash-flow stream (reserve) so instead of forecasting 5/10 years and then assuming a perpetuity, a NAV model typically forecasts cash-flows until the reserve is depleted, and therefore has no terminal value.
- **Discount Rate:** DCF models use a Weighted Average Cost of Capital to discount a company's free cash flows, while a NAV model typically uses an industry standard 10% discount rate.
- **Assumptions:** Unique to E&P companies, factors such as decline rates, liquids/gas weighting (expected composition of oil vs. gas), and WTI/NYMEX price projections are key value drivers in a NAV model.

How do you build a NAV model?

Without going into extensive detail, we'll summarize the key steps in building a simple NAV model, by using a fictional company (ticker: HFC) with one well in production.

Step #1 - *Assumptions*

We must start by making some necessary assumptions, which fall under two general categories: production/reserve assumptions and "netback" assumptions (netback explained later). This list is not comprehensive but covers some of the key factors.

Production & Reserve	Netback
• *Estimated Ultimate Recoveries (EUR):* The expected amount of production over the life of the well • *Initial Production Rate*: The initial boe/d production level • *Decline Rates*; Expected decline in resource level (changes year to year) • Gas Weighting: Because crude & natural gas sell at different prices, composition of the resource is important	• *Pricing:* Expected prices for crude oil and natural gas over the forecast period • *Royalty Rate;* The percentage of revenue that is due to the government (or another entity) • *Costs:* Operating, transportation, and G&A expense

Production & Reserve		Netback Assumptions	
EUR (mboe)	1000	*WTI Price* (/bbl)	$70.00
IP Rate (boe/d)	500	*Royalty Rate*	10%
Gas Weighting	0%	*Operating Costs* (/boe)	$5.00
		Transportation Costs (/boe)	$2.00
		G&A (/boe)	$1.00

In our model, we kept our assumptions simple – these are not meant to be in line with "real-life" numbers.

Step #2 – *Production Schedule*

		2017	2018	2019	2020	2021	2022
Beginning Production	(boe/d)	500	175	114	85	68	58
Annual Decline	(%)	65%	35%	25%	20%	15%	10%
Average Production	(boe/d)	175	114	85	68	58	52
Daily Production	(boe/d)	175	114	85	68	58	52
Days		365	365	365	365	365	365
Annual Production	(mboe)	**64**	**42**	**31**	**25**	**21**	**19**

Next, using production/reserve assumptions we forecast annual production. To keep it simple we assumed 100% crude weighting and took "average" yearly production numbers and declined rather than using beginning and exit production (typically done in practice).

Step #3 – *Cash Flow Schedule*

		2017	**2018**	**2019**	**2020**	**2021**	**2022**
Revenue	(mm)	$4.5	$2.9	$2.2	$1.7	$1.5	$1.3
Royalty Expense	(mm)	$0.4	$0.3	$0.2	$0.2	$0.1	$0.1
Operating Costs	(mm)	$0.3	$0.2	$0.2	$0.1	$0.1	$0.1
Transportation Costs	(mm)	$0.1	$0.1	$0.1	$0.0	$0.0	$0.0
Field Netback	**(mm)**	$3.6	$2.3	$1.7	$1.4	$1.2	$1.1
	(mm)						
G&A Expense	(mm)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0
Cash Flow Netback	**(mm)**	$3.5	$2.3	$1.7	$1.4	$1.2	$1.0
	(mm)						
Cash Flow from Operations	(mm)	$3.5	$2.3	$1.7	$1.4	$1.2	$1.0
Capital Expenditures	(mm)	$4.0	-	-	-	-	-
Free Cash Flow	(mm)	$(0.5)	$2.3	$1.7	$1.4	$1.2	$1.0
PV @ 10%	**(mm)**	**$5.5**					
	(mm)						
Enterprise Value	(mm)	$5.5					
Less: Net Debt	(mm)	$0.0					
Equity Value	**(mm)**	**$5.5**					

After projecting production, to get the top line of the cash flow schedule (revenue), multiply by the expected price listed in the assumptions.

Netbacks

A simple way of understanding netback is as a profitability metric. "Field netback" refers to per barrel cash flow after royalties, operating costs, and transportation costs, and "cash flow netback" refers to cash flow after general & administrative expenses. From there, subtract away capital expenditures to get free cash flow, and then discount back at 10% to get the enterprise value. Finally, subtract net debt (no debt or cash in this case) to get equity value, or for a public company market capitalization.

Comparable valuation

To better analyze public E&Ps, it's useful to compare them to their peers using oil & gas specific multiples. We'll categorize them as "cash flow ratios" - adjusting financial health and comparing with peers - and "production/reserve ratios" - considering the variance in value relative to the underlying asset. Keep in mind that to conduct comparable analysis in any meaningful way, the first step is to ensure that the companies are *comparable*. This entails checking for factors such as size (daily production), reserves (grade of commodity), and liquids weighting (% of oil vs. gas in production).

Cash Flow

Both of the cash flow ratios that we consider are very useful in E&P valuation, as they reflect a number of cash flow characteristics: sustainability, growth, capital efficiency, etc. The down-side is that cash flow metrics measure short-term performance created by currently producing assets, without (explicitly) accounting for the value of assets that may generate future cash flows. They are most useful for comparing established companies, but we must remember to look at them in the context of factors such as reserve quality.

Enterprise Value / Debt Adjusted Cash Flow

Intuition: *How much are investors paying per dollar of cash flow generated by day-to-day operations?*

The components of this financial ratio are Enterprise Value (EV) and Debt-Adjusted Cash Flow (DACF). It can be interpreted as the oil & gas equivalent of EV/EBITDA, and in cases where a company doesn't pay tax (for various reasons, including deferred losses), the two ratios are equivalent.

Enterprise Value is measured the same as usual (Market Cap + Debt - Cash), while DACF:

$$DACF = Operating\ Cash\ Flow + Interest * (1 - Tax\ Rate)$$

Like EV/EBITDA, the multiple is "capital structure neutral" meaning it adjusts for the effect of debt (interest expense) when analyzing cash flow – useful considering the highly leveraged nature of most E&Ps. That being said, the ratio ignores differing tax rates which is important to keep in mind, particularly if companies operate in different jurisdictions. **The ratio is widely used in practice, and is an important tool for E&P valuation.**

Price / Cash Flow Per Share

Intuition: *How much are equity investors paying per dollar of cash flow generated by day-to-day operations?*

In this case price (P) simply signifies the current trading price of the stock. Cash flow per share (CFPS) signifies the company's operating cash flow (per share). Differing from EV/DACF because it *does not add back interest expense*, in other words, the cash flow is "levered". The reason for this is because if the numerator is equity value, the denominator must only include cash flow that flows to equity holders (hence why it is net of debt, because interest expense is paid before dividends). The example below shows how some Canadian E&Ps compared to one another in late 2016.[1]

	Ticker	P/CF		EV/DACF	
		2016e (x)	2017e (x)	2016e (x)	2017e (x)
Intermediate Yield (> 25,000 boe/d)					
ARC Resources	ARX	11.9x	9.3x	12.4x	9.8x
Bonavista Energy	BNP	3.8x	2.8x	4.5x	4.5x
Crescent Point Energy	CPG	5.2x	5.0x	6.9x	6.6x
Enerplus Corporation	ERF	UR	UR	UR	UR
Peyto Exploration	PEY	10.1x	7.3x	11.3x	8.4x
Vermilion Energy	VET	12.2x	10.1x	13.3x	11.1x
Whitecap Resources	WCP	10.8x	7.3x	12.0x	8.2x

Production/Reserve

The following ratios do a good job of summarizing a company's current production/reserve profile relative to its peers, but it's important to keep in mind that they do not directly reflect cash flow/profitability factors, which are crucial indicators of the company's ability to capitalize on reserves. Additionally, external factors such as current/future commodity prices have a significant influence on the materialization of profitable production. Ultimately, the ratios presented here are useful only in the context of all relevant factors, and serve as a useful starting point in analysis.

[1] Source: National Bank Daily Bulletin, 2016

Enterprise Value / Flowing Barrel (Boe/d)

Intuition: *How much are investors paying per barrel of current production? Or how expensive is the company relative to current production?*

The Enterprise Value per Flowing Barrel ratio is useful for getting a sense of how "expensive" a company currently is, but is most relevant for established, producing companies. It's important to remember that it doesn't (explicitly) take into account future production, but if investors foresee future growth (amongst other reasons) the company may trade at a "premium". Context is important as otherwise it may seem that a company is "expensive" when in reality they may have high expected growth in production, or even just higher profitability per barrel.

Enterprise Value / 2P Reserves

Intuition: *How much are investors paying per barrel of 2P reserves (>50% chance of economic recovery)*

Rather than current production like EV/Flowing barrel, EV/2P considers how much a company is worth per barrel of *reserves*. The ratio essentially captures the value of a company's asset base, with variance present in the form of commodity grade (eg. heavy vs. light oil), liquids weighting, along with a company's ability to profitably produce into the future. Looking at the example below, it may seem that Peyto is cheap relative to Whitecap, but the difference is largely due to reserve composition (gas heavy vs. light oil).[1]

	Ticker	EV/boe/d		EV/boe
		2016e ($/boed)	2017e ($/boed)	($/boe)
Intermediate Yield (> 25,000 boe/d)				
ARC Resources	ARX	$85,666	$81,875	$12.38
Bonavista Energy	BNP	$50,827	$47,745	$16.72
Crescent Point Energy	CPG	$65,356	$62,544	$10.30
Enerplus Corporation	ERF	$38,578	$39,081	$4.89
Peyto Exploration	PEY	$55,440	$51,880	$8.92
Vermilion Energy	VET	$90,715	$83,915	$17.43
Whitecap Resources	WCP			

[1]Source: National Bank Daily Bulletin, 2016