Duvernay vs. Eagle Ford
Is the Duvernay catching up to the prolific south Texas shale play?

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Overview of Study

This study compares the early stage development of the Duvernay shale play in Alberta with the later stage development of the Eagle Ford shale play in Texas, looking for similarities and differences between the two plays. It looks at the geology of both plays, activity in each play since its inception, and how productivity has improved. It examines the technological development in the plays with a focus on:

1. Drilling productivity
2. Completions productivity
3. Capex/Estimated Ultimate Recovery
4. Breakeven prices

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Introduction

The early-stage development Duvernay shale play is often compared to the prolific Eagle Ford shale play in Texas in terms of its geology, product mix and potential for future development.

Since 2010, over 19,780 horizontal wells have been drilled in the Eagle Ford. Around 2.5 billion barrels of oil and 10 trillion cubic feet of natural gas have been produced out of the play.

Production in the Eagle Ford averaged around 1.2 million barrels of oil per day in January 2018, with around 5.8 billion cubic feet of gas per day generated during the same time frame.

The Duvernay shale play is in a much earlier stage of development, with approximately 550 horizontal wells brought on stream since 2011. Current production is around 70,000 barrels of oil equivalent per day.

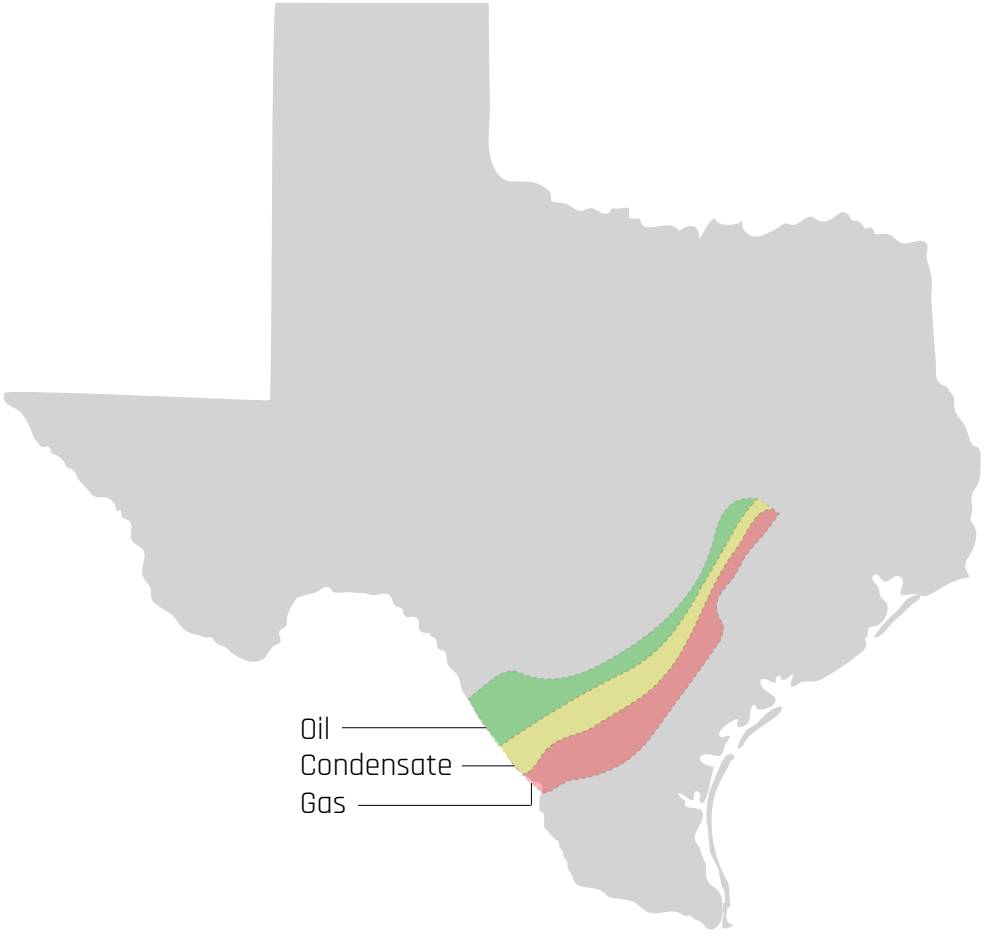
But with a number of companies, including multinationals Chevron and Shell, moving into full-scale commercial development in the Duvernay, production from the play is expected to begin climbing throughout 2018-2019 and beyond.

This report compares the resource potential of each play and reviews their development from 2014 to 2017. It examines current developments through the window of productivity improvements driven by technological change. It also looks at what lessons have been learned in the Eagle Ford and how they are being applied in the Duvernay to drive development forward.

And finally, it compares economic factors at work in both plays that will influence future development trajectories.

Eagle Ford Review

Eagle Ford Review



Source: University of Texas

The Eagle Ford shale play covers around 20,000 square miles in East Texas at depths ranging from 1,200 to 3,700 metres. Dry gas is produced in the deeper areas of the play, with condensate and natural gas liquids in the middle depths, and oil at shallower depths. With the shale formation consisting of a high percentage of carbonate making it brittle and easy to fracture, and low clay content, the Eagle Ford was one of the earliest shale gas developments.

Eagle Ford Play Characteristics	
Estimated Area (sq. miles)	20,000
Depth (metres)	3,050-3,960
Net Thickness (metres)	40-110
Carbonate Content (%)	40-90
Mineralogy (% non-clay)	75-85
Total Organic Content (%)	3.0-7
Average Porosity (%)	8.0-12
Permeability (nD)	50-1200

Eagle Ford Review

PetroHawk Energy Ltd. drilled the first well targeting the Eagle Ford in 2008, but development didn't take off until 2011 when almost 3,000 wells were drilled in the play.

Since then, the Eagle Ford has seen almost 20,000 horizontal wells drilled, and has produced around 2.5 billion barrels of oil and 10 trillion cubic feet of natural gas. A study by DrillingInfo estimates the play could produce another 2.1 billion barrels of oil and five trillion cubic feet of natural gas as operators move into its second half of development activity.

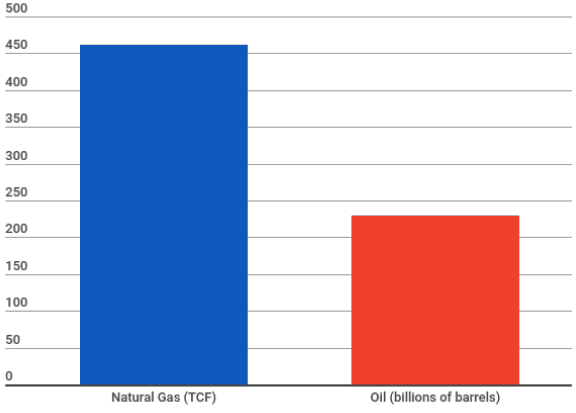
Drilling in the core areas are in late stage development, with around 90 per cent of the best rock developed, said DrillingInfo. Median peak production rates in these core areas averaged about 920 boe/d.

Only 30 per cent of the much larger mid-quality areas have been developed, however, where median top peak production rates per well come in at 370 boe/d.

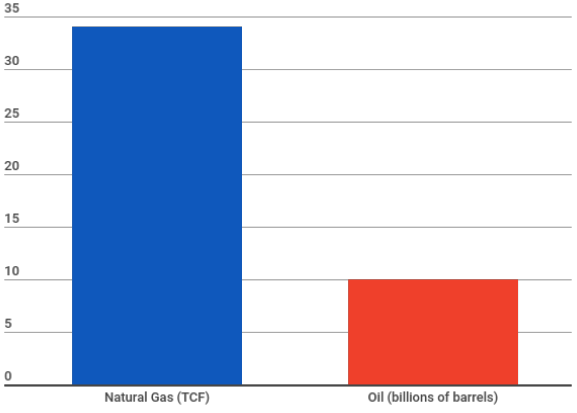
In total, DrillingInfo estimates that around one-sixth to one-third of the Eagle Ford has been developed.

A recent study by the University of Texas at Austin expects around 100,000 wells to ultimately be drilled in the Eagle Ford, with 80,000 remaining locations.

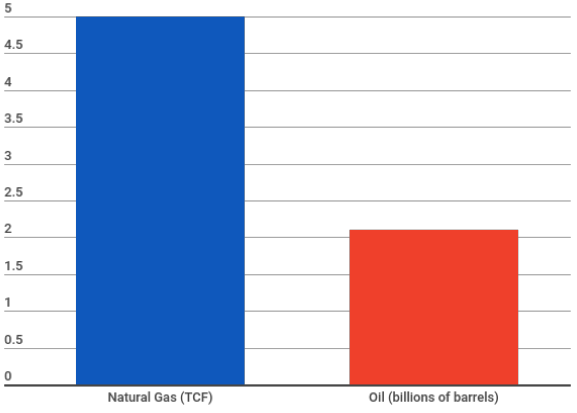
Original Petroleum in Place



Estimated Technically Recoverable Resources

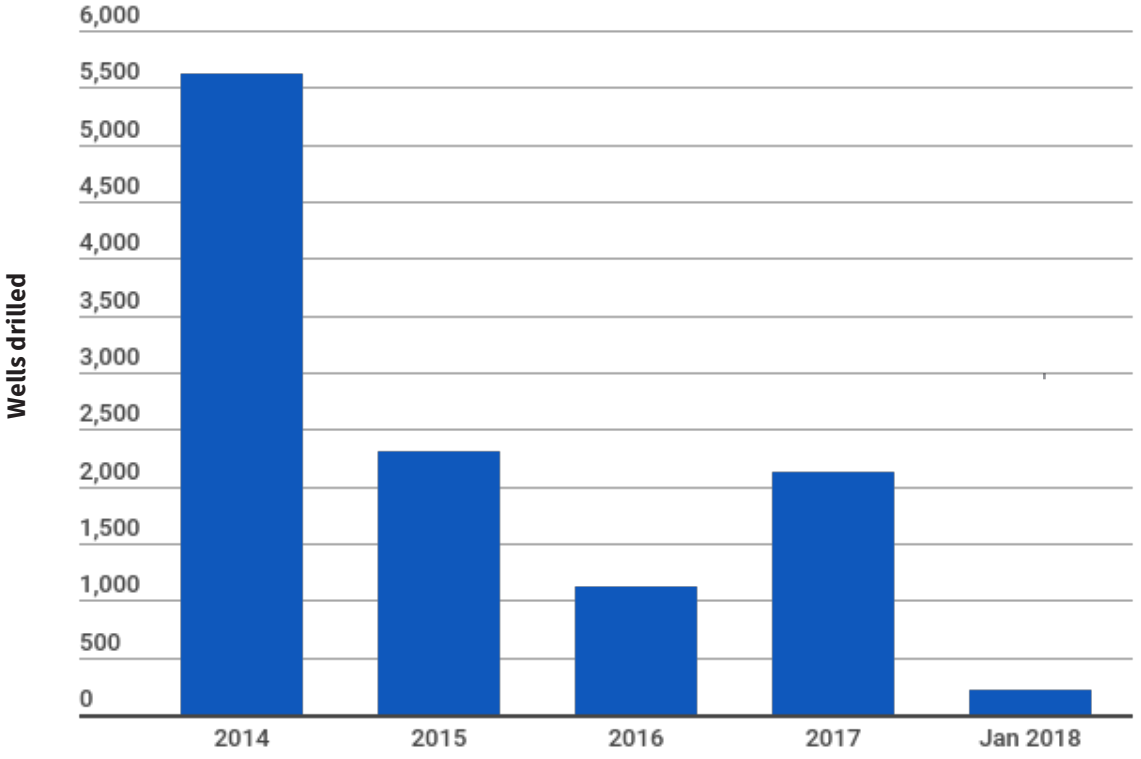


Estimated Marketable Resources



Source: University of Texas

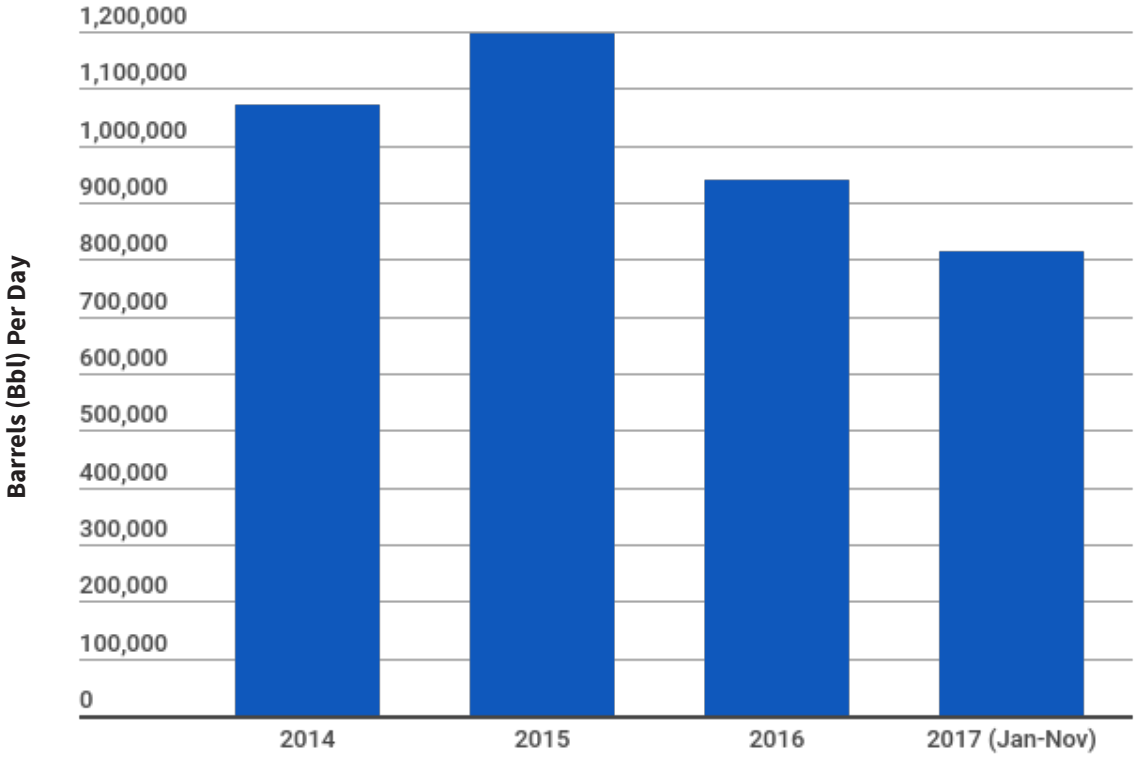
Eagle Ford drilling took off with rising prices



Source: Texas Railroad Commission Drilling Permit Query

Drilling permits in the Eagle Ford took off in 2011, with 2,826 wells drilled. By 2014, that number had almost doubled to 5,613 wells before crashing with oil and gas prices in 2015.

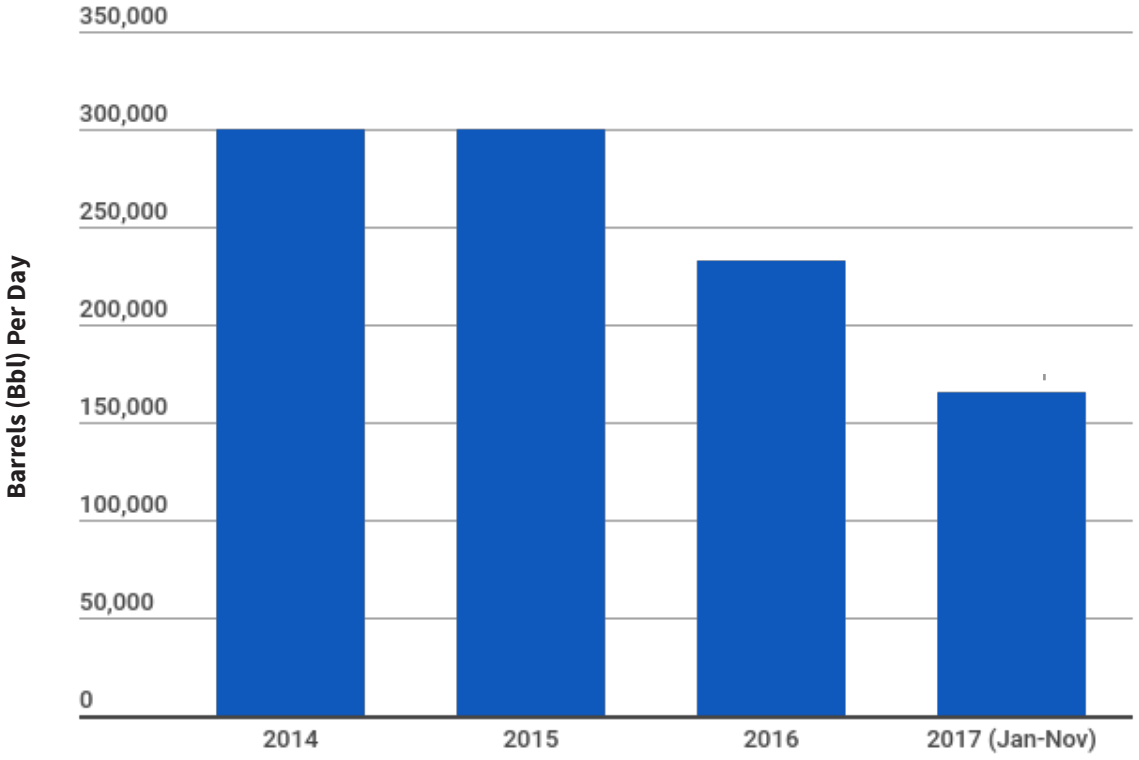
Oil production drops with well count



Source: Railroad Commission of Texas Production Data Query System (PDQ)

Oil production followed drilling permits, with production rising almost 760 per cent between 2010 and 2011. By 2014, oil production had crossed the 1 million barrel per day threshold. A decline in the number of rigs operating in the oil window of the Eagle Ford has resulted in significant declines since 2015.

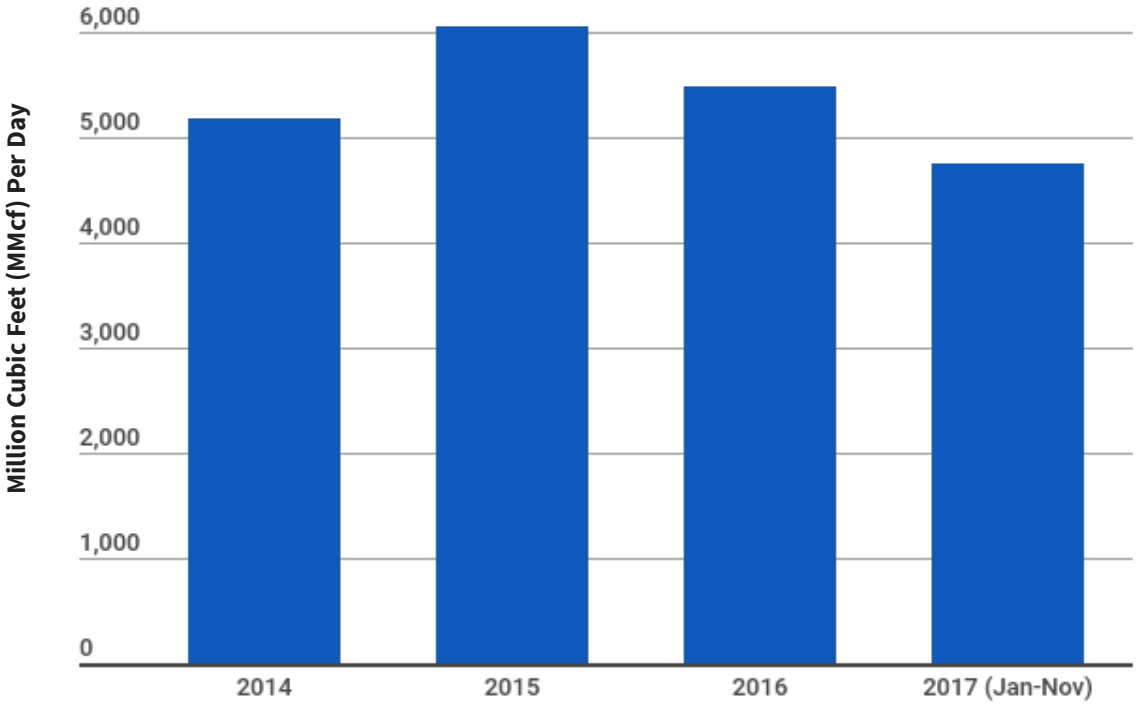
Condensate production follows oil decline



Source: Railroad Commission of Texas Production Data Query System (PDQ)

Condensate production increased by 1,500 per cent between 2010 and 2015, before declining with well counts.

Natural gas production peaks in 2015



Source: Railroad Commission of Texas Production Data Query System (PDQ)

Natural gas production climbed by 1,800 per cent to 6 billion cubic feet per day from 2010 to 2015. But low prices since then have resulted in a decline of 1.3 billion cubic feet per day

Duvernay Review

Duvernay Review

Drilling in the Duvernay didn't really begin until 2011, well after other western Canadian unconventional plays such as the Montney and Bakken were under development.

The original focus for exploration was the southwest corner of the Duvernay in the Willesden Green area with deep natural gas being the initial target. Early drilling also focused in the Kaybob area to the north with higher condensate or oil production. The vast majority of Duvernay wells has been drilled at Kaybob but there is increasing activity in what is called the East Duvernay shale basin in 2017 targeting oil in shallower zones.

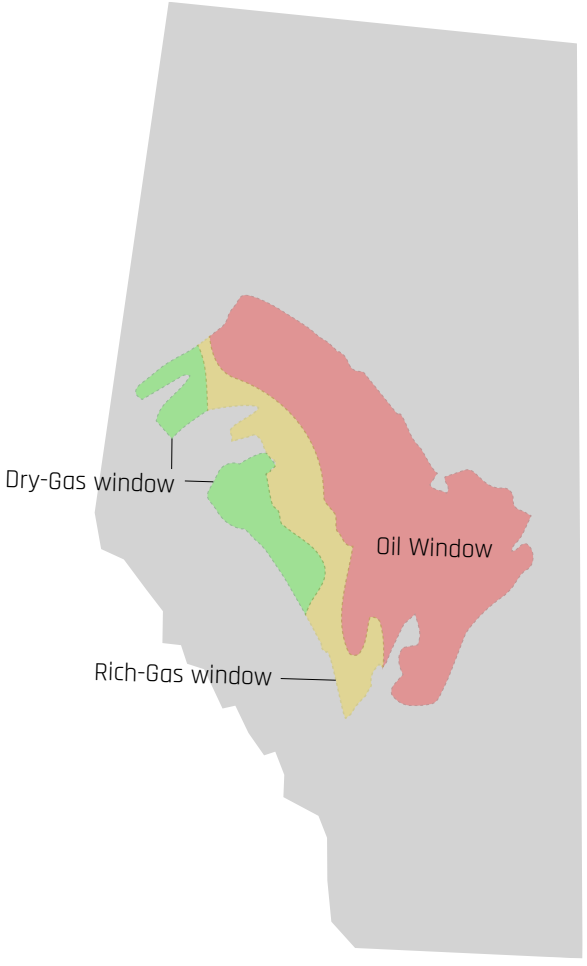
Like the Eagle Ford, the Duvernay has deep, over-pressured zones on its western flank prospective for natural gas, a liquids-rich sweet spot mid-basin, before becoming more shallow and oil prone as it moves eastward.

There are, however, some differences between the two plays.

The resource base of the Duvernay is spread over a greater geographical area, and is less thick in certain areas. But like the Eagle Ford, the shale is moderately brittle and has low clay content allowing for effective fracture treatments.

Duvernay Play Characteristics	
Estimated Area (sq. miles)	38,610
Depth (metres)	2,800-3,600
Net Thickness (metres)	25-60
Carbonate Content (%)	30-90
Mineralogy (% non-clay)	70-90
Total Organic Content (%)	1-7.5
Average Porosity (%)	6.0-7.5
Permeability (nD)	10-400

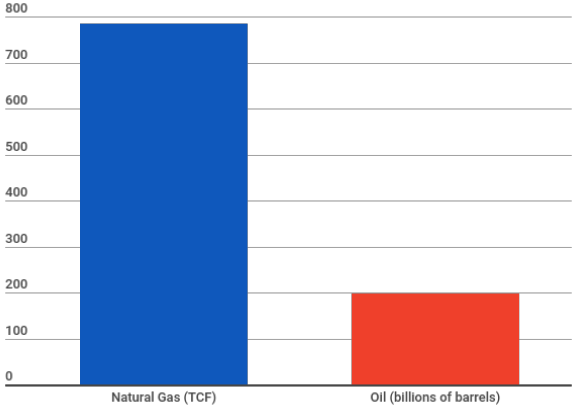
Source: Alberta Energy



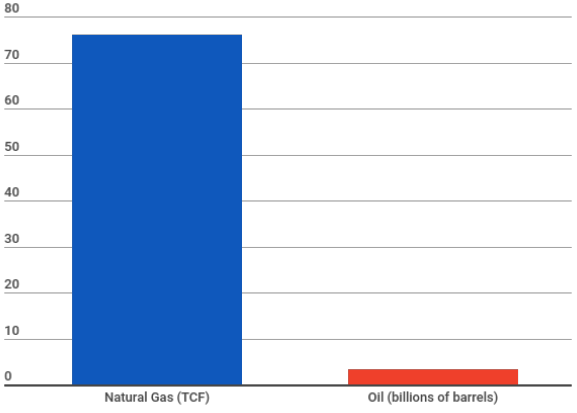
Duvernay Review

There have been a number of recent studies completed on the resource potential, technically recoverable resources, and marketable resources in the Duvernay in the last few years. The studies show the Duvernay has much more potential for natural gas and liquids production than the Eagle Ford with less oil potential. However, with oil exploration in the early stages in the East Basin this may change.

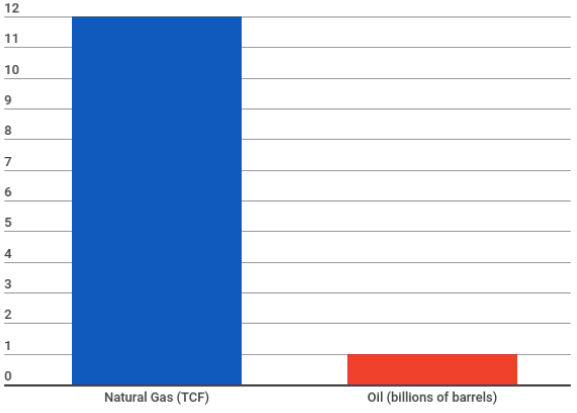
Original Petroleum in Place



Estimated Technically Recoverable Resources



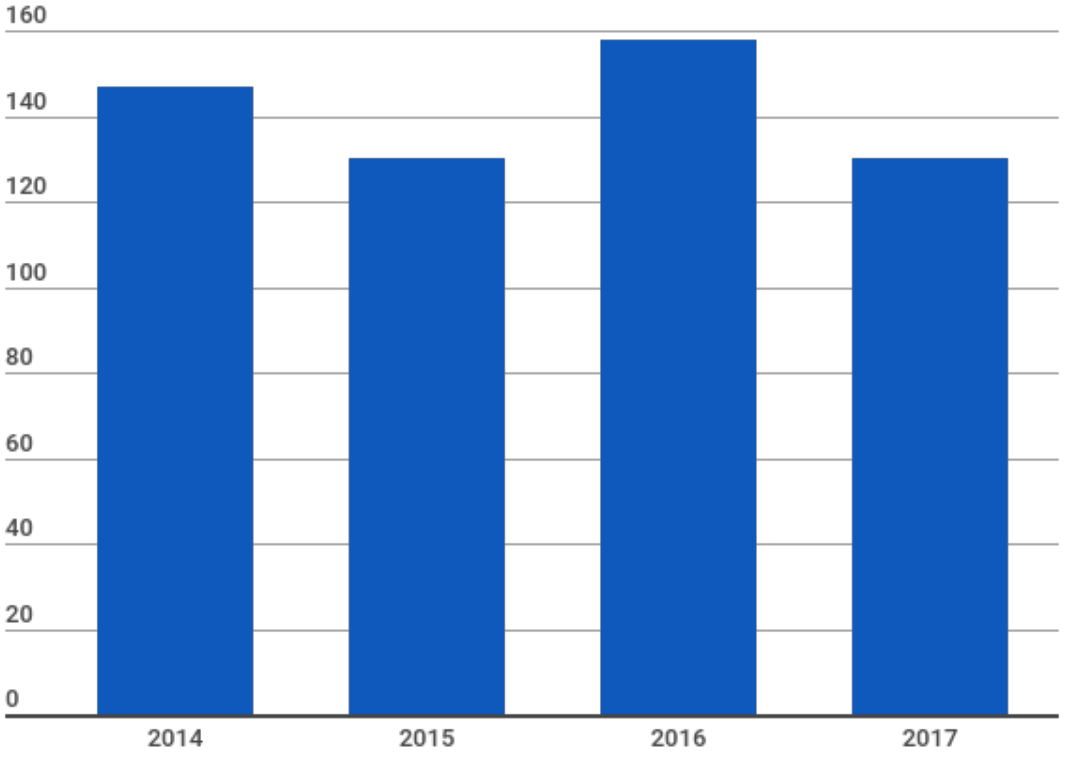
Estimated Marketable Resources



Note: Marketable resources at 2017 prices

Source: Alberta Geological Survey

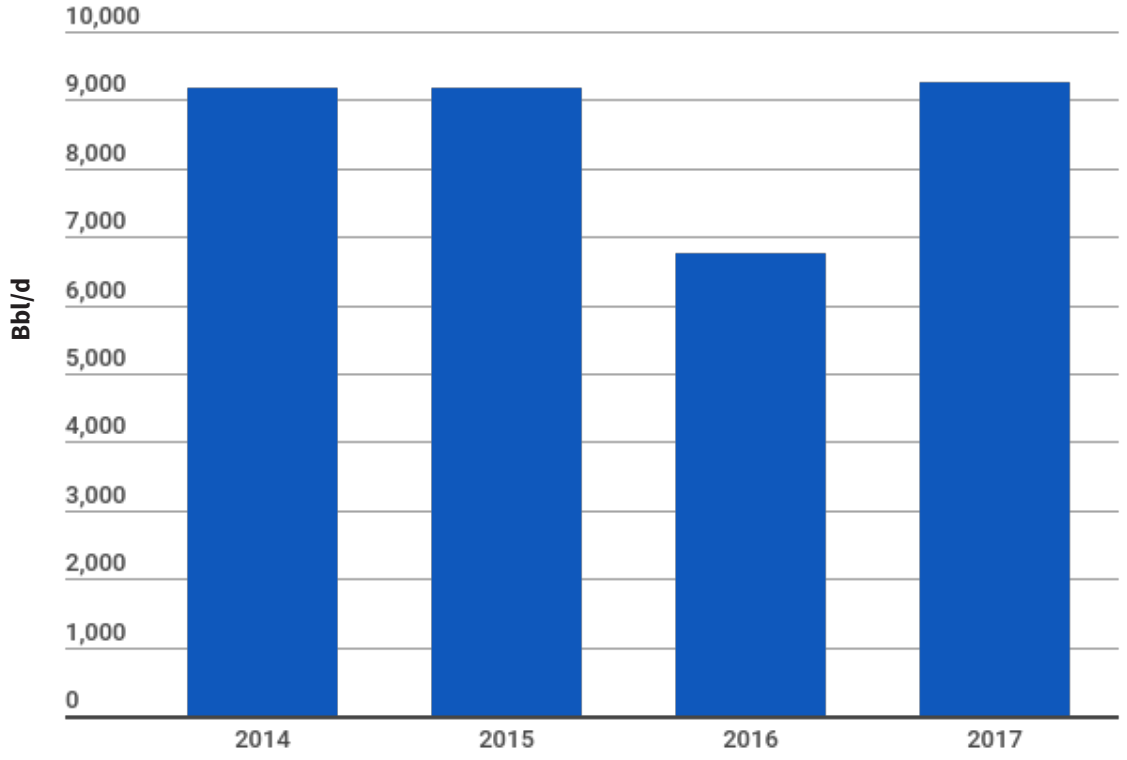
Drilling ramp-up slow and steady



Source: CanOils

The number of wells drilled in the Duvernay climbed by 58 per cent between 2013 and 2014 to 147 wells before commodity prices collapsed. Since then they have been relatively flat.

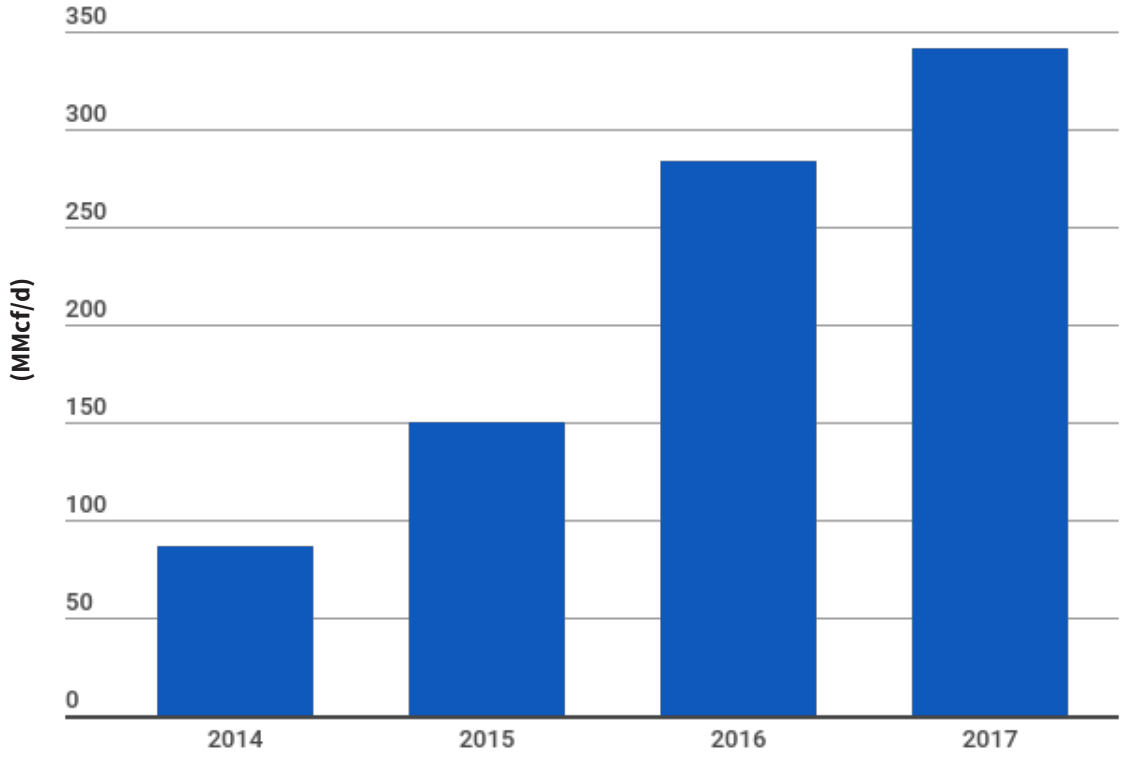
Oil production



Source: CanOils

While still in the early stages of development, oil production has climbed by 320 per cent from the first quarter of 2013 to the final quarter of 2017. This upward trend is expected to continue as more wells are drilled in the oil prone East Basin.

Natural Gas production on upward trajectory



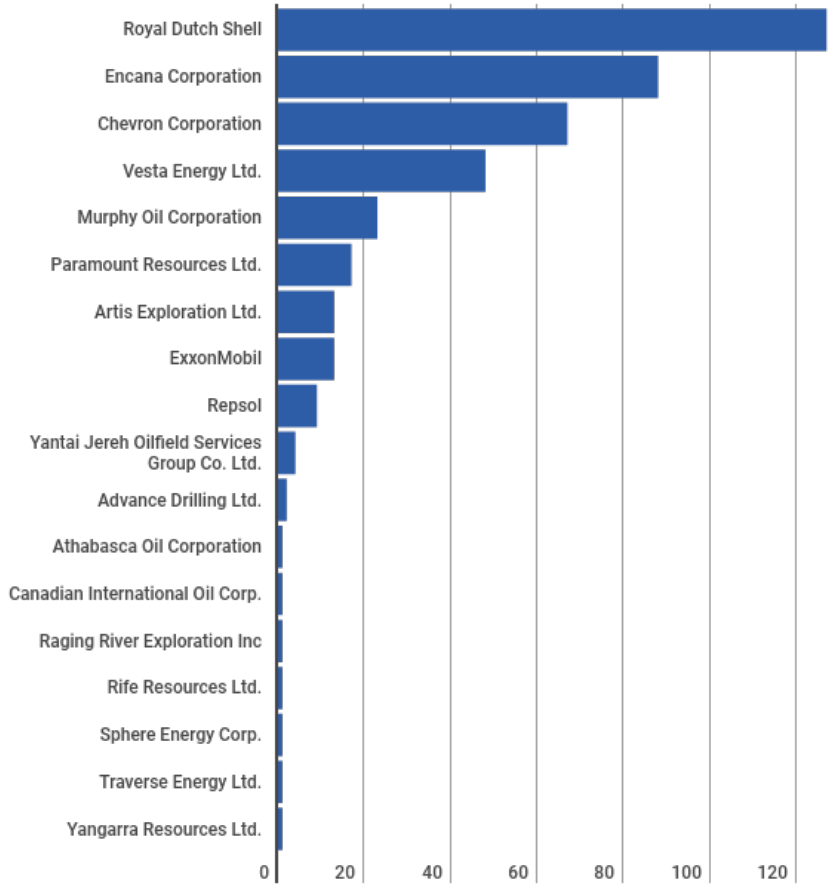
Source: CanOils

Duvernay natural gas production has climbed by over 1,200 per cent from the first quarter of 2013 to the final quarter of 2017. Operators targeting condensate rich areas of the play that improve well economics have largely driven this increase.

There are no accurate figures for condensate production in the Duvernay.

Wells spud by operator

Number of wells spud between 2015-17 by current licensee (as of Dec 2017)



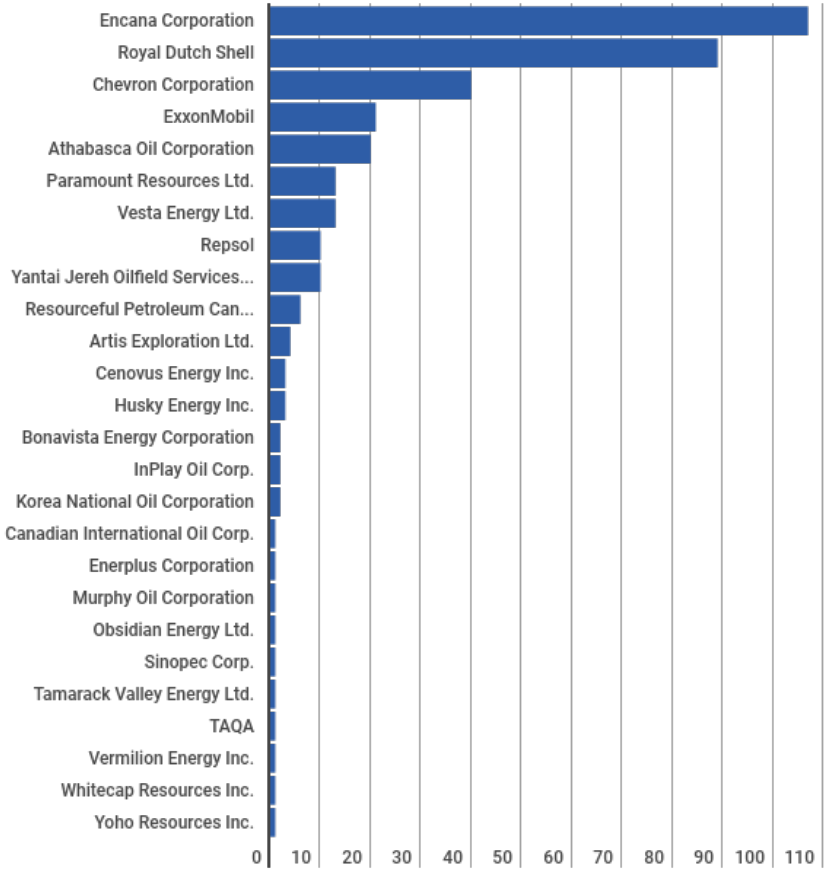
Source: CanOils

A small number of large operators are responsible for the majority of wells drilled into the Duvernay the last three years, with the top three accounting for more than half of wells drilled in the play.

In the East Duvernay, Vesta Energy and Artis Exploration have drilled almost all wells in the play.

Active wells by operator

Number of active wells as of Dec 2017 by current operator (only including wells spud since Jan. 1, 2013)



Source: CanOils

Again, large operators dominate the number of active wells producing in the Duvernay with EnCana the largest operator, followed by Shell and Chevron.

Technology Comparisons

Drilling technologies

High performance drilling rigs featuring AC drive systems, automated pipe-handling, walking systems, large pipe-racking capacities and the ability to drill with stands as long as 90 feet dominate activity in both the Eagle Ford and Duvernay.

These top tier rigs, combined with the best crews due to the slowdown in activity the last three years, have driven drilling productivity upwards across North America and both plays have benefitted.

Average lateral lengths increasing

Both the Duvernay and Eagle Ford have seen increases in the average length of laterals in the last three years, although the Duvernay has seen a much more pronounced increase.

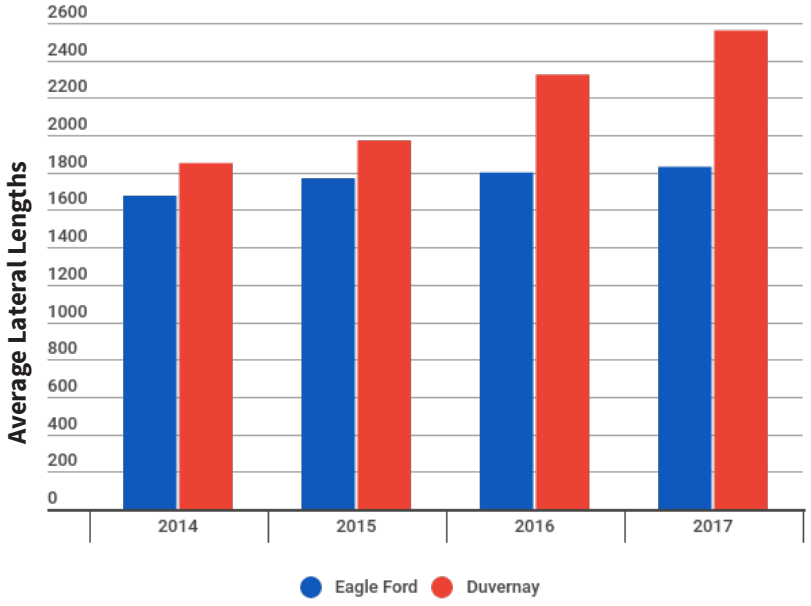
There are a number of reasons for this difference. The Eagle Ford has more fragmented surface lease holdings, limiting lateral lengths. Also, with more well density in core areas there is more infill drilling. EOG Resources' activities fall within this scenario. It reports typical lateral lengths of 1,600 metres in its core Eagle Ford area.

Outside of these areas, lateral lengths have been increasing with Chesapeake Energy drilling laterals over 3,000 metres on wells in 2017 with a recent lateral reaching almost 5,800 metres.

There is also significant variation in Duvernay lateral lengths. In 2014 lateral lengths varied from 1,200-2,400 metres. In 2015 upper range lateral length climbed to 2,800 metres. By 2017, the largest cluster of laterals drilled in the play was in the 2,500 to 3,000 metre range. Like in the Eagle Ford there have been some outliers, including a 7,7770 metre lateral drilled by Shell Canada.

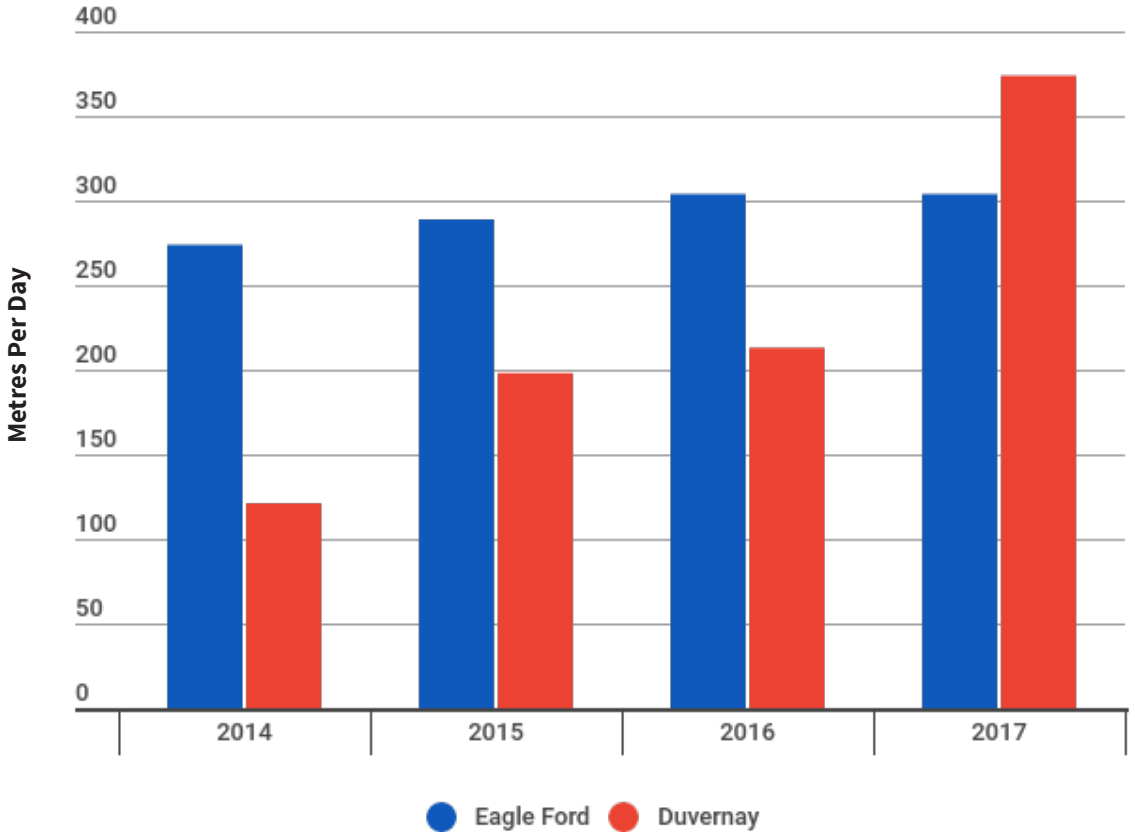
Operators in the East Duvernay were able to rapidly adopt longer laterals into their well designs, growing from 2,000 metres in 2016 to 3,000 metres in 2017.

Duvernay operators have been able to take advantage of technological advancements to drill longer laterals in the early development phase of the play.



Sources: McDaniel & Associates Consultants Ltd Duvernay update November 2017, CanOils, corporate presentations, EIA data

High performance rigs drive average drilling speeds

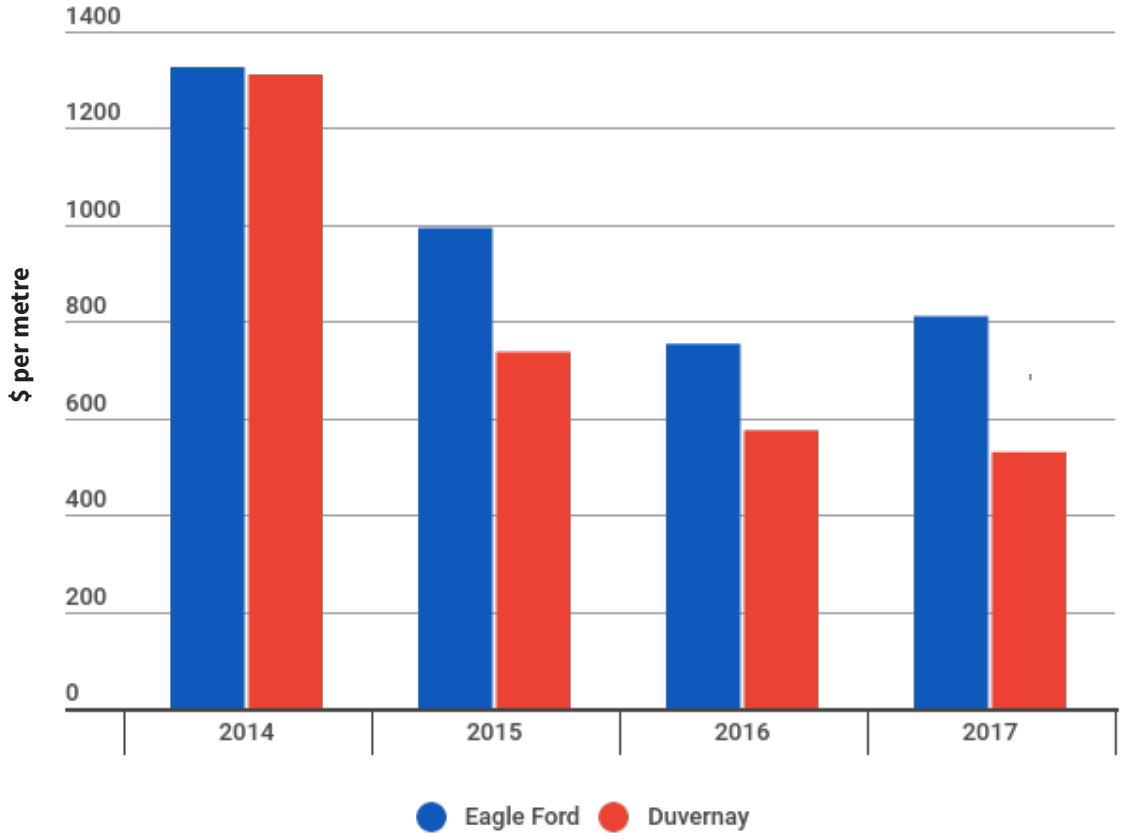


Sources: McDaniel & Associates Consultants Ltd Duvernay update November 2017, CanOils, corporate presentations, EIA data

With Eagle Ford operators deep into the manufacturing stage in the core areas of the play, average drilling speeds have leveled off in the 300 metres per day range. There are, however, outliers claiming much higher rates running as high as 700 metres per day.

Duvernay drillers have rapidly caught up and surpassed the efficiency of their Eagle Ford counterparts, more than tripling metres drilled per day since 2014 as they move from exploratory drilling to pad development.

Drilling costs decline faster in Duvernay



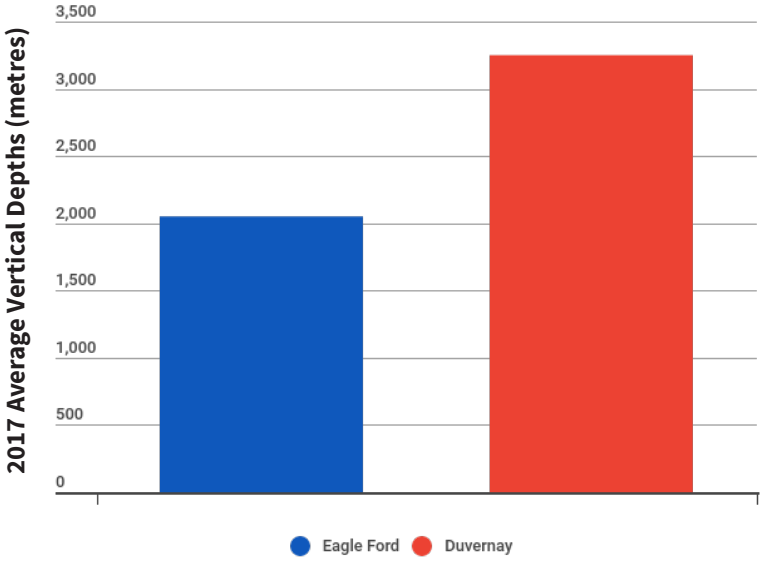
Sources: McDaniel & Associates Consultants Ltd Duvernay update November 2017, CanOils, corporate presentations, EIA data

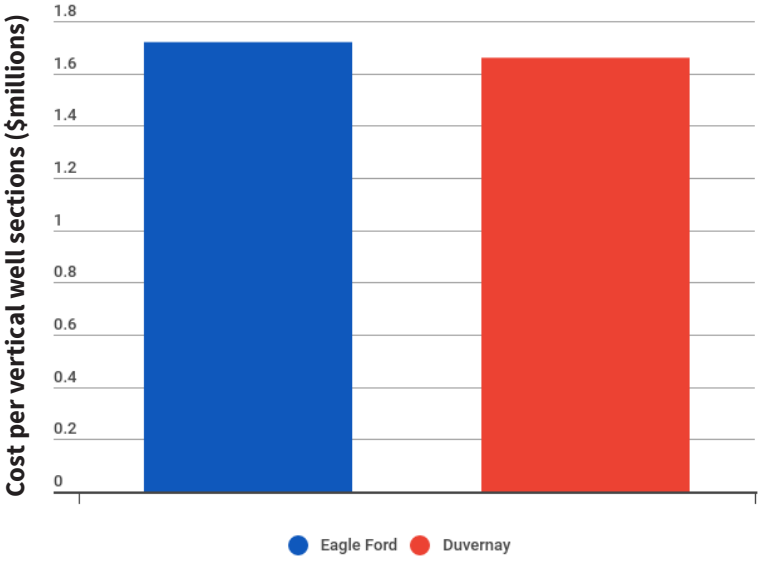
The cost per metre drilled have declined in both plays due to increased rig efficiency and lower day rates from the decline in activity. But higher day rates in the Eagle Ford due to competition for top tier rigs from the nearby Permian Basin, and better average drilling efficiencies in the Duvernay, give the Canadian play an edge.

Again, East Duvernay operators were able to quickly take advantage of increased drilling efficiency, cutting their cost per metre of lateral drilled from $710 per metre in 2016 to around $621 per metre the first half of 2017, and round $560 per metre in more recent wells.

Deeper targets drive up Duvernay drilling costs

The large majority of wells drilled in the Duvernay have targeted condensate and volatile oil found in Kaybob area of the play at depths greater than 3,000 metres. In the Eagle Ford area, the majority of wells drilled since prices recovered in early 2017 are being drilled in shallower regions of the formation targeting oil, at depths averaging a little over 2,000 metres. This difference in vertical depths adds around $630,000 to the cost of an average Duvernay well. East Duvernay wells are being drilled at similar depths to the Eagle Ford, with slightly lower costs.





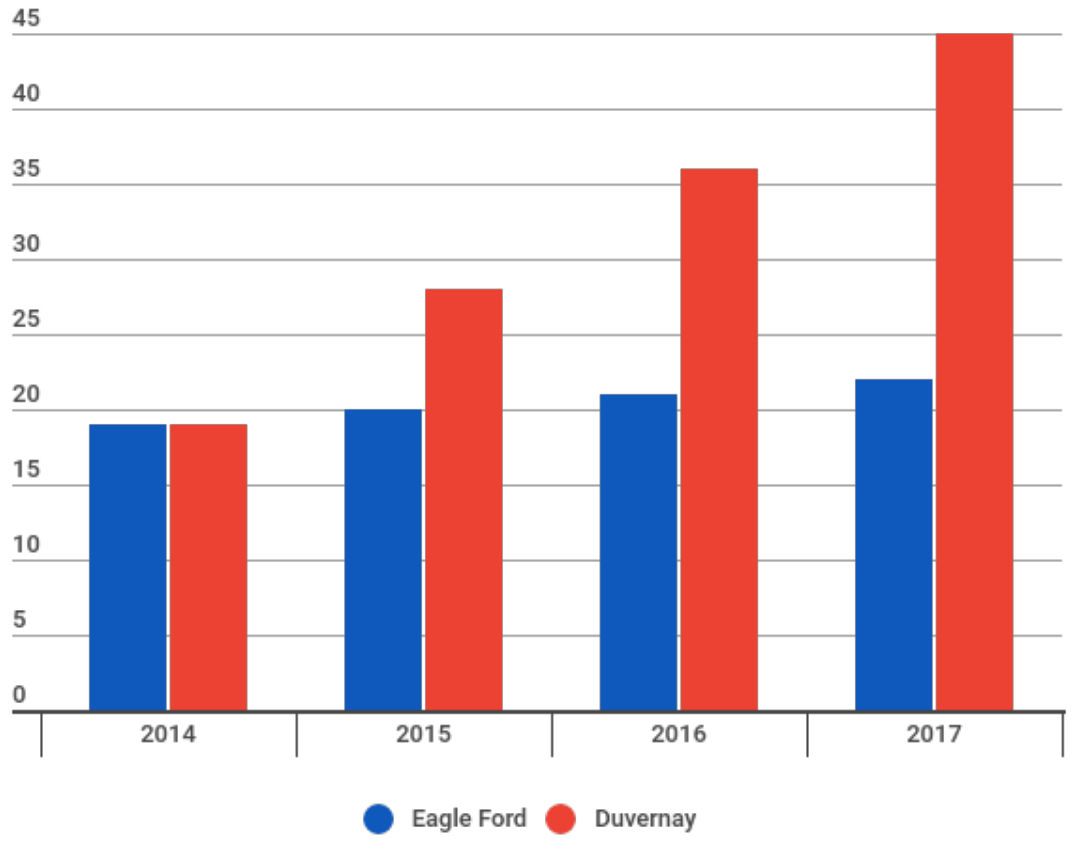
Sources: McDaniel & Associates Consultants Ltd Duvernay update November 2017, CanOils, corporate presentations, EIA data

Completions technologies

Operators in the both the Eagle Ford and Duvernay continue to optimize their completions technologies to cut costs and enhance resource recovery. Plug and perf technology has become dominant in both plays, with sliding sleeve and ball drop technologies also being used. Slick water or hybrid slick water with gel fracs are common. There is also an effort underway to optimize the use of sand as proppant to cut costs.

But the biggest change in completions in both plays is in fracturing intensity. Longer laterals, more stages per lateral, more perforations per stage, and vastly increased proppant loads are driving productivity improvements.

Fracture stage counts up rapidly in the Duvernay



Sources: McDaniel & Associates Consultants Ltd Duvernay update November 2017, CanOils, corporate presentations, EIA data

With the ability to drill longer laterals, Duvernay operators have been able to rapidly increase the number of fracturing stages per lateral when compared with the Eagle Ford. But again there is substantial variation between wells.

In 2015, the majority of Duvernay wells were stimulated with between 25 to 35 stages. That changed in late 2016 when there was a bump in wells with fracture stages ranging from 45-95 stages.

But this is only part of the story. In the Eagle Ford many operators are vastly increasing the number of perforation clusters within stages, creating more fracture events within each stage.

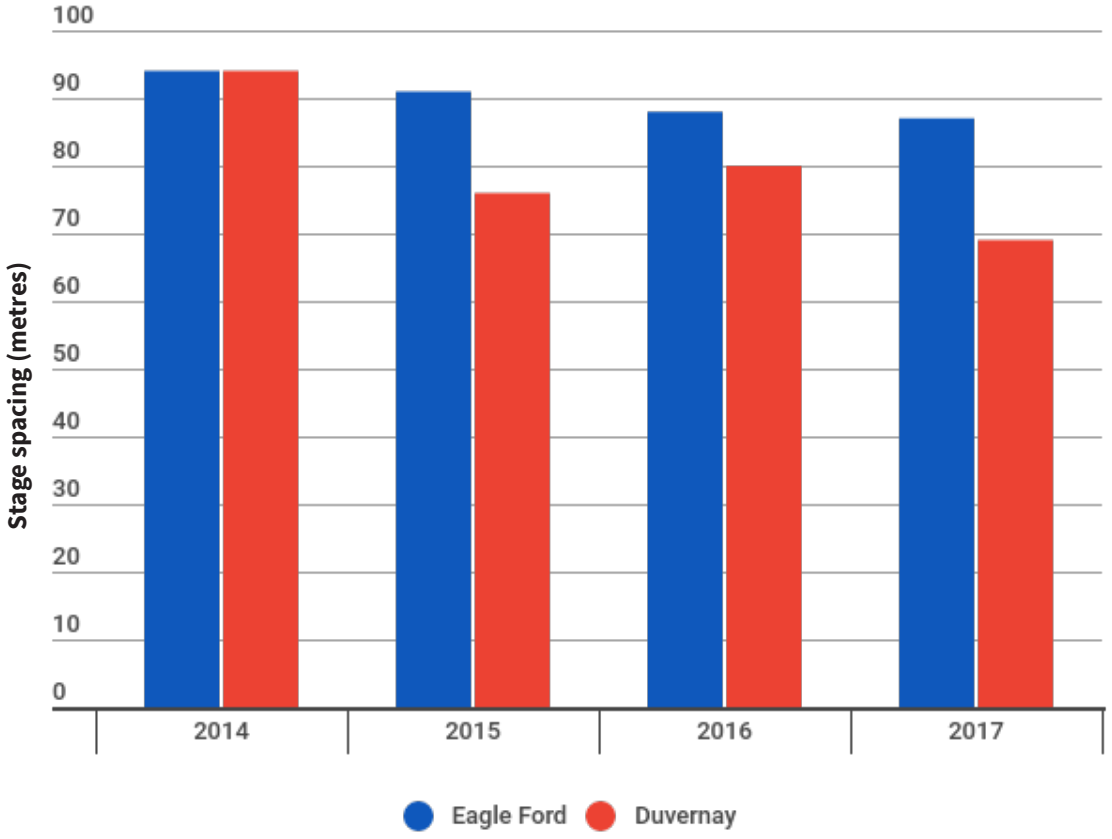
In the East Duvernay the stage count has also rapidly increased, growing from around 28 stages pre-2016 to an average 60 stages in 2017.

East Duvernay costs per stage rapidly decline

Cost per Stage	
2015	$128,000
2016	$65,000
2017	$63,000

Completion costs per stage in the East Duvernay have declined by greater than 50 per cent in the last three years and Vesta sees further reductions due to design evolution and more multi-well pads.

Tighter spacing driving stage count

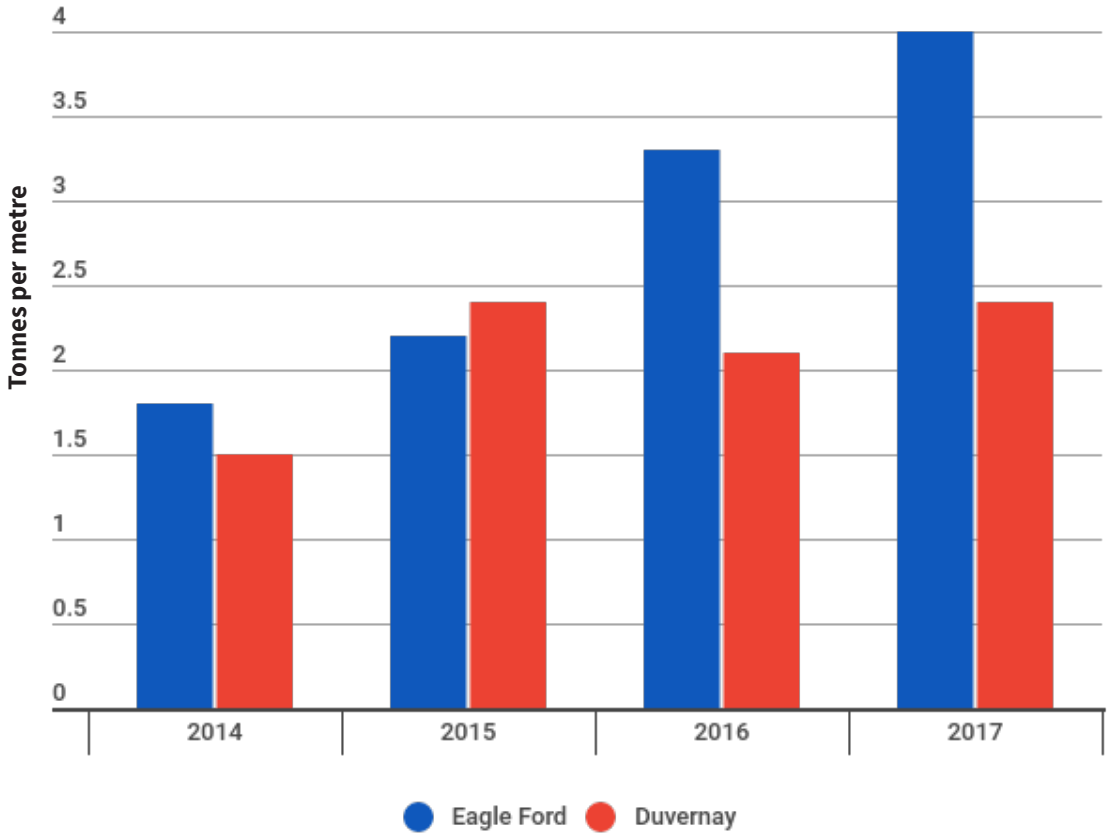


Sources: McDaniel & Associates Consultants Ltd Duvernay update November 2017, CanOils, corporate presentations, EIA data

While operators in both plays are using tighter stage spacing to increase fracture treatments along laterals, again the Duvernay has surpassed the Eagle Ford.

In the East Duvernay stage spacing averaged 55 metres in 2017 as operators were able to take advantage of learnings in other plays.

Proppant loads rapidly climbing



Sources: McDaniel & Associates Consultants Ltd Duvernay update November 2017, CanOils, corporate presentations, EIA data

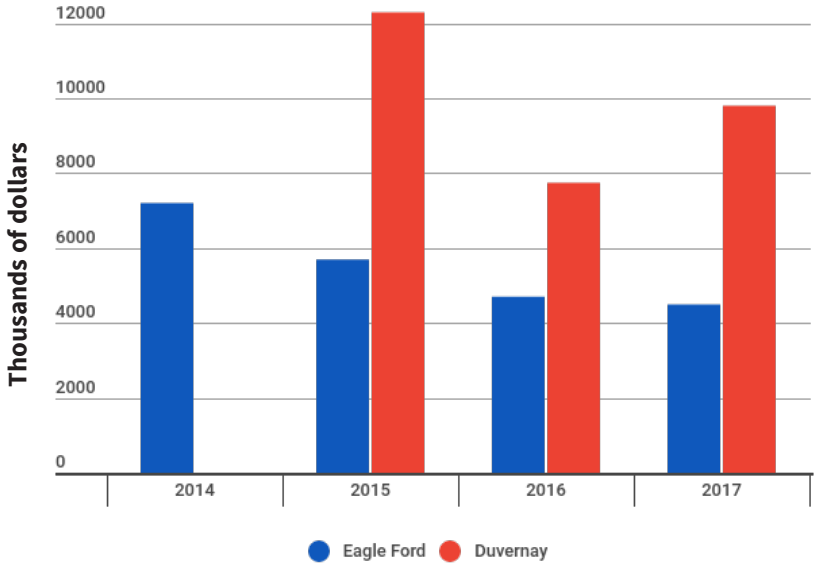
Average proppant loads per metre of lateral length have been rapidly increasing in both plays, although fracturing intensity is more pronounced in the Eagle Ford. There is, however, a growing belief there are economic limits to the amount of proppant that can be placed. A number of Eagle Ford operators are testing those limits and loads could slightly decrease in 2018 as they find their sweet spot.

Economic performance

Drilling & completion costs

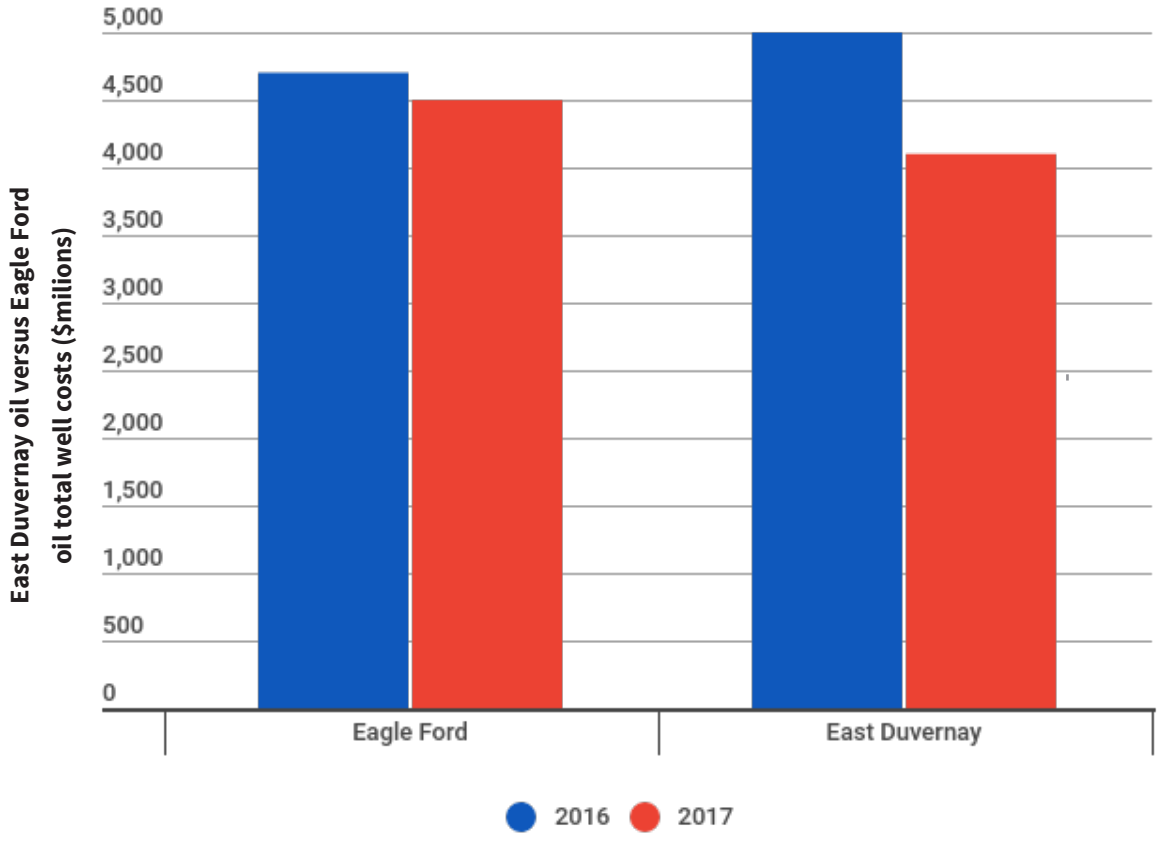
Over the last three years Eagle Ford operators have managed to cut drilling and completion costs by 37.5 per cent, all the while increasing lateral lengths and completions intensity. Outside of technological improvements, one of the biggest efficiency gains the Eagle Ford enjoys over the Duvernay is that around 90 per cent of wells are drilled on multi-well pads that offer around $1.5 million savings over individual wells.

Duvernay operators have seen a 20 per cent drop in total drilling and completion costs. The lesser decline is due largely to major increases in lateral lengths compared to the Eagle Ford, and a major increase in completions stages per well. Expect average Duvernay costs to drop significantly as fewer single wells are drilled and more pad development drilling takes off.



Sources: McDaniel & Associates Consultants Ltd Duvernay update November 2017, CanOils, corporate presentations, EIA data

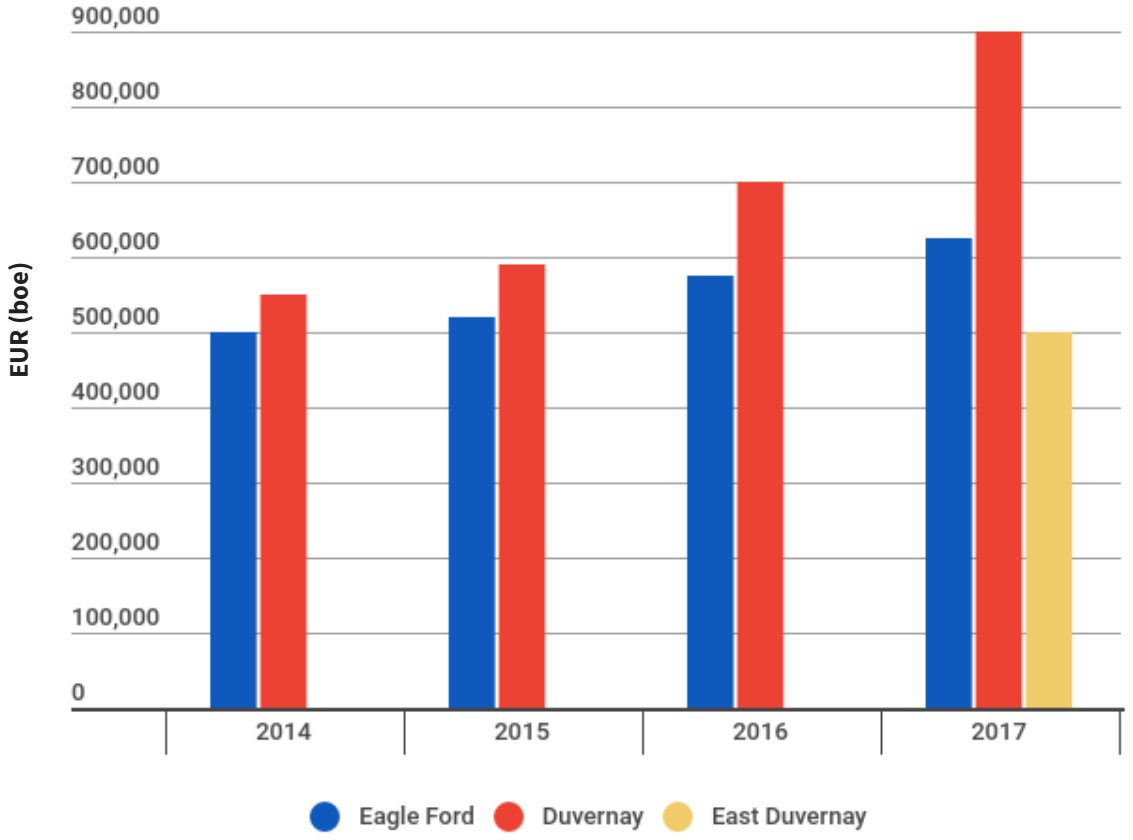
An apples to apples comparison of total well costs



Source: Company Presentations

A more direct comparison of drilling and completions costs between the two plays are wells drilled in the Duvernay East Shale Basin and the oil prone regions of the Eagle Ford. Both plays are found a little over two kilometres deep with many wells having horizontal laterals of 2,000 metres. While the data is limited in the East Duvernay oil play, it shows the play is more than competitive with the Eagle Ford. East Duvernay lateral lengths are increasing, with many wells now being drilled to 3,000 metres.

Rapidly climbing Estimated Ultimate Recovery (EURs) justify higher Duvernay costs



Sources: McDaniel & Associates Consultants Ltd Duvernay update November 2017, CanOils, corporate presentations, EIA data

The combination of longer laterals and greater completions intensity is paying off in higher EURs in the Duvernay. EURs have increased by 63 per cent as the play has moved from its exploration to early development phase.

Eagle Ford operators have experienced EUR increases of around 25 per cent in the last three years as they optimize the manufacturing process. They have done this, however, while rapidly decreasing drilling and completion costs.

The East Duvernay is in very early stages of development and EURs are likely to increase as more wells are drilled.

Operational efficiencies will drive profitability

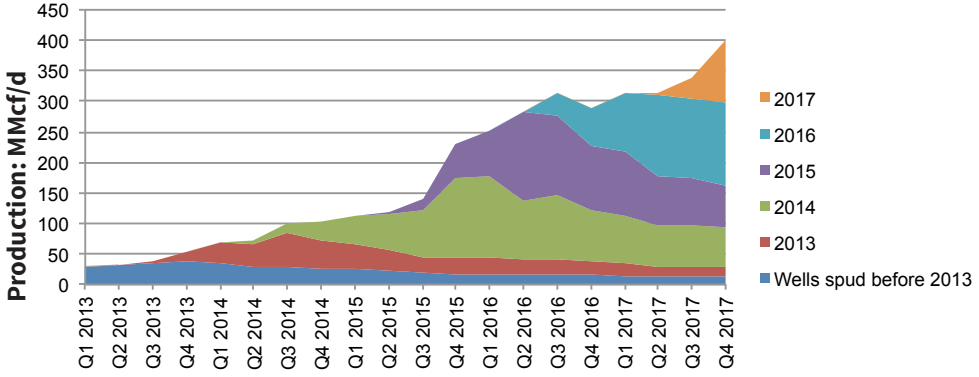
While cutting capital costs per boe recovered is a major step in commercialization of the liquids rich Kaybob and East Duvernay oil plays, ultimately managing production to keep wells operating as long as possible will determine their profitability.

This is a function of high early decline rates, meaning that despite strong initial production rates most of the expected ultimate recovery of resources will happen well after the first few years of production.

Long payout times for wells at current prices also mean wells won't begin to turn a profit until later in their production cycles, adding to the importance of maintaining production and avoiding unnecessary production costs.

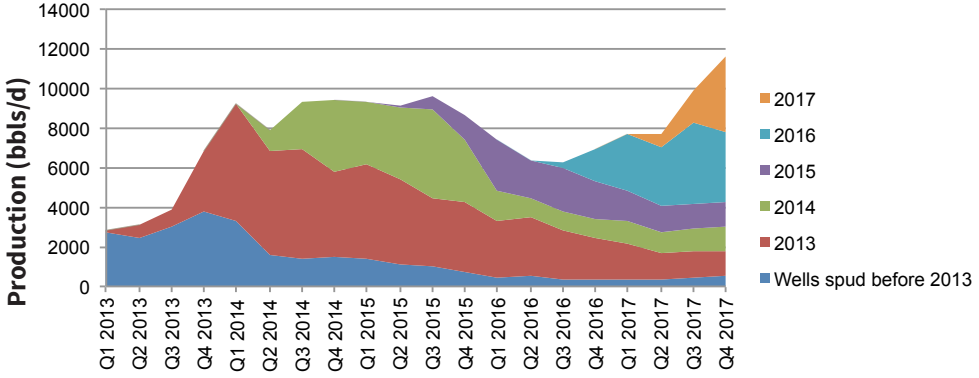
Decline rates

Gas Production by year wells drilled showing decline rates



Source: CanOils

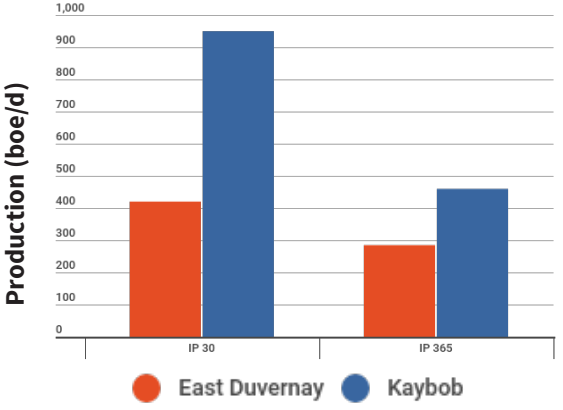
Oil Production by year wells drilled showing decline rates



Source: CanOils

Like all unconventional resource plays, the Duvernay enjoys high initial production rates that rapidly decline in the first year. In the East Duvernay, Vesta Energy reports IP90s of 420 boe/d but first year IPs decline to 285 boe/d. Only around 20 per cent of the expected ultimate recovery is captured during the first year of production. In the Kaybob area, Athabasca Oil Corp. is reporting IP90s of 750 boe/d before declining to 460 boe/d for the first full year of production. Around one-quarter of total expected recovery is captured in the first year.

Both the Kaybob and East Duvernay have rapid early declines



Payouts

How quickly developers can recapture their capital costs in drilling a well plays a key role in their profitability. While increases in productivity in the Duvernay are adding more barrels of production early on, at current oil prices payouts on wells remain extended compared to during the high price environment in 2014. In the East Duvernay, Vesta estimates it takes around 17 months to pay for a well in its central core area. Athabasca estimates it will take 26 months for payback on its West Kaybob wells. Keeping wells flowing at optimum rates after payout drives profitability.

Average payout at $55 per barrel oil (months)	
Kaybob	26
East Duvernay	17

Source: Vesta Energy, Athabasca Oil Corp.

Artificial Lift key to Duvernay oil profitability

With installation costs of around US$ 250,000 and replacement costs as high as US$150,000, maintaining and managing pumping systems ensures optimum production from Duvernay wells. Operators from other shale plays like the Eagle Ford have reported significant challenges in managing artificial lift

The most common production sequence in the Duvernay is:

1. Free flow where wells run without artificial lift
2. Electrical submersible pumps (ESPs) are used when volumes are high
3. Pump and rod systems are installed when production declines, and ESPs are no longer optimal. Some operators go straight to pump and rod systems

Managing paraffin wax build-up

East Duvernay operators aren't seeing paraffin issues until wells have been on stream six to nine months. Wax build-up begins when well pressures decline and the downhole temperature declines to the cloud-point of the oil.

There are a variety of ways to manage wax deposition, including:

1. Hot oil treatments, preferably with a dispersant added to the fluid, which is the traditional methods in western Canada
2. Paraffin inhibitors, which are added to fracking fluids during well stimulation, provide a proactive means to eliminate deposition before it starts.
3. There are also chemical treatments for use to remove wax deposition after the fact.
4. Various paraffin inhibitor or dispersants can be injected into well production to manage paraffin formation and build-up

Scale deposition a challenge

Many operators are reporting scaling issues in Duvernay oil production. The problem is especially pronounced with ESP units. It is too early in development in the East Duvernay to see if scaling problems are impacting pump and rod systems. Scaling challenges can be dealt with proactively by adding chemical treatments into well stimulation treatments. There are also chemical treatments available to prevent scale from forming or to manage/remove once it becomes an issue.

Managing line pressures

Wax deposition can result in increased line pressures that can negatively impact production. East Duvernay wells are seeing wax build-ups in the upper 900 metres of the wellbore, and into flow-lines. Dispersants are commonly used to remove or move wax build-up. Demulsifiers can be utilized to increase oil-water separation, also helping to lower line pressures. There are, however, new generation products using a combination of dispersants and emulsifiers.

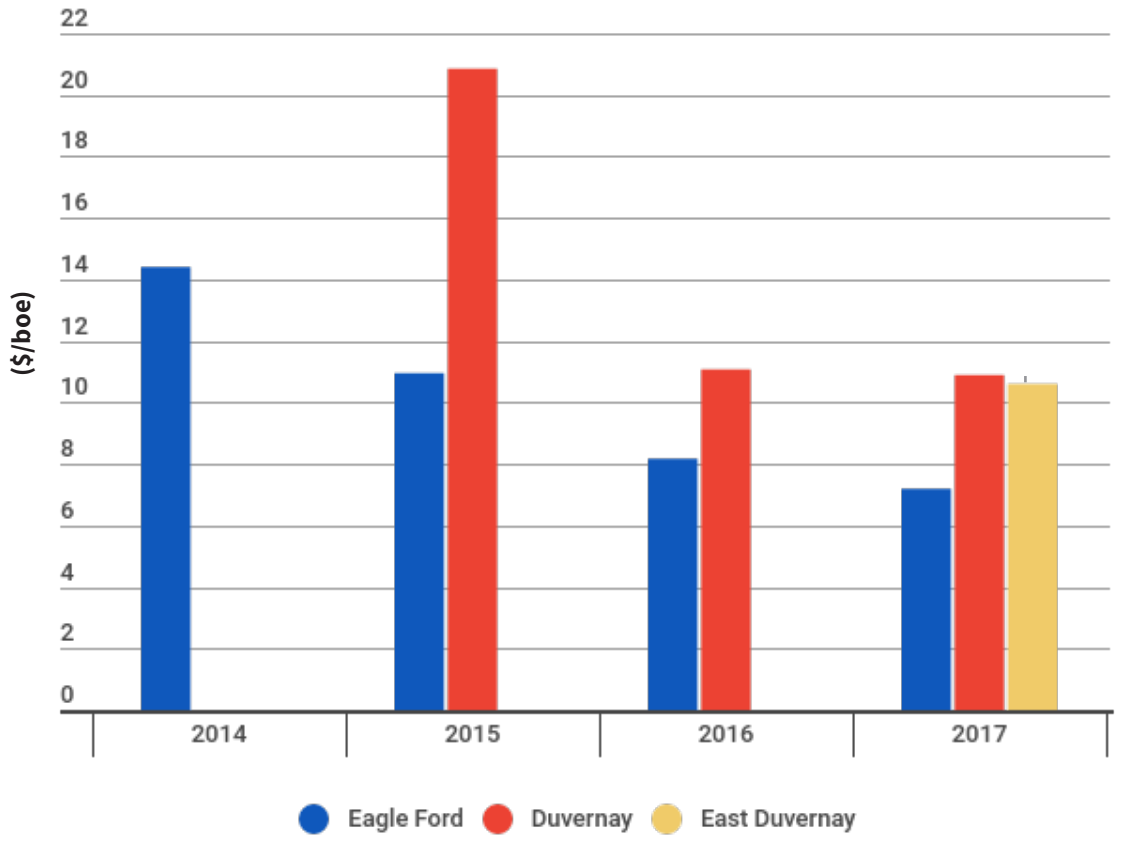
Managing oil quality

East Duvernay operators can also increase profitability throughout the production phase through pretreating oil on location. During oil and water separation they can use a demulsifier. Demulsifiers can also be used in oil storage tanks before trucking or pipe transport to save treatment costs downstream.

Bacteria suppression and H2S production

East Duvernay operators are beginning to see bacteria in produced water. There are questions whether it is coming from water used for fracking or if it comes from the reservoir. Bacteria can produce H2S, leading to corrosion. If H2S is produced it can lead to oil production not meeting requirements for sweet pipelines. There are numerous biocides on the market to handle bacterial problems. H2S scavengers are available to mitigate souring issues.

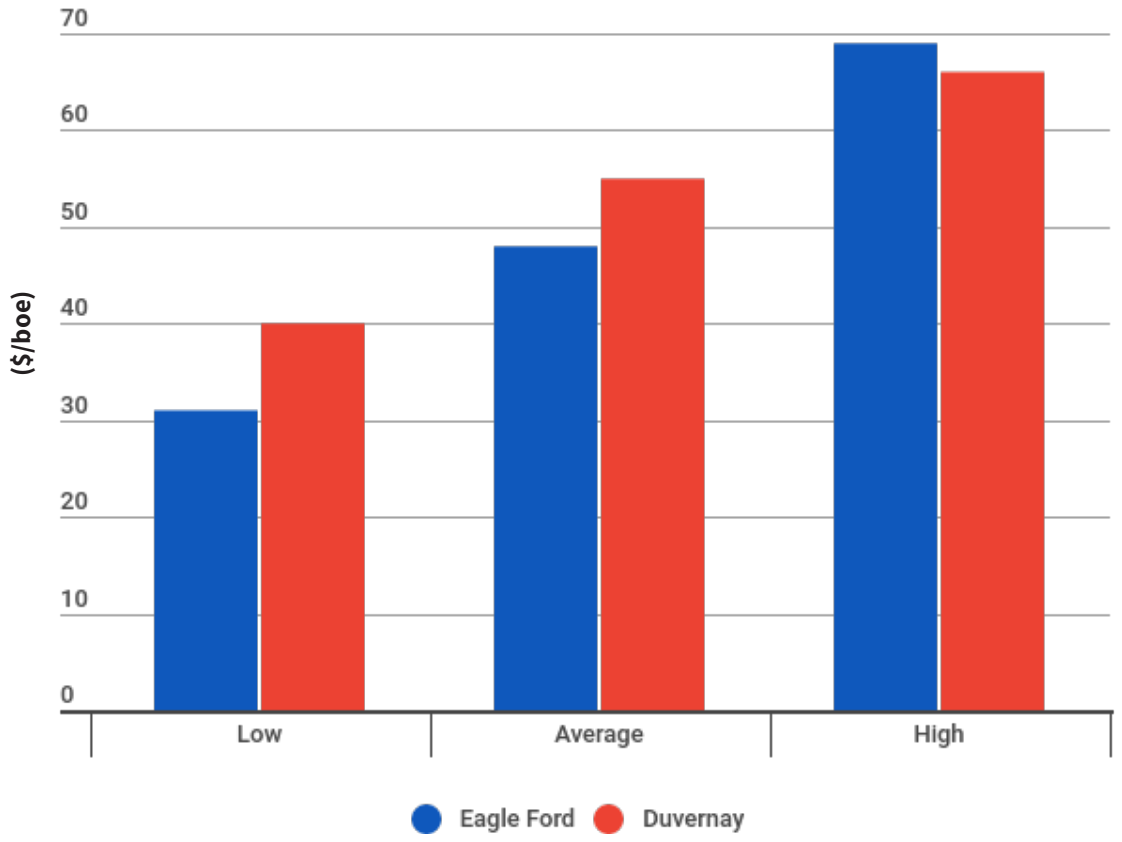
Capital costs per boe of EUR down significantly



Sources: McDaniel & Associates Consultants Ltd Duvernay update November 2017, CanOils, corporate presentations, EIA data

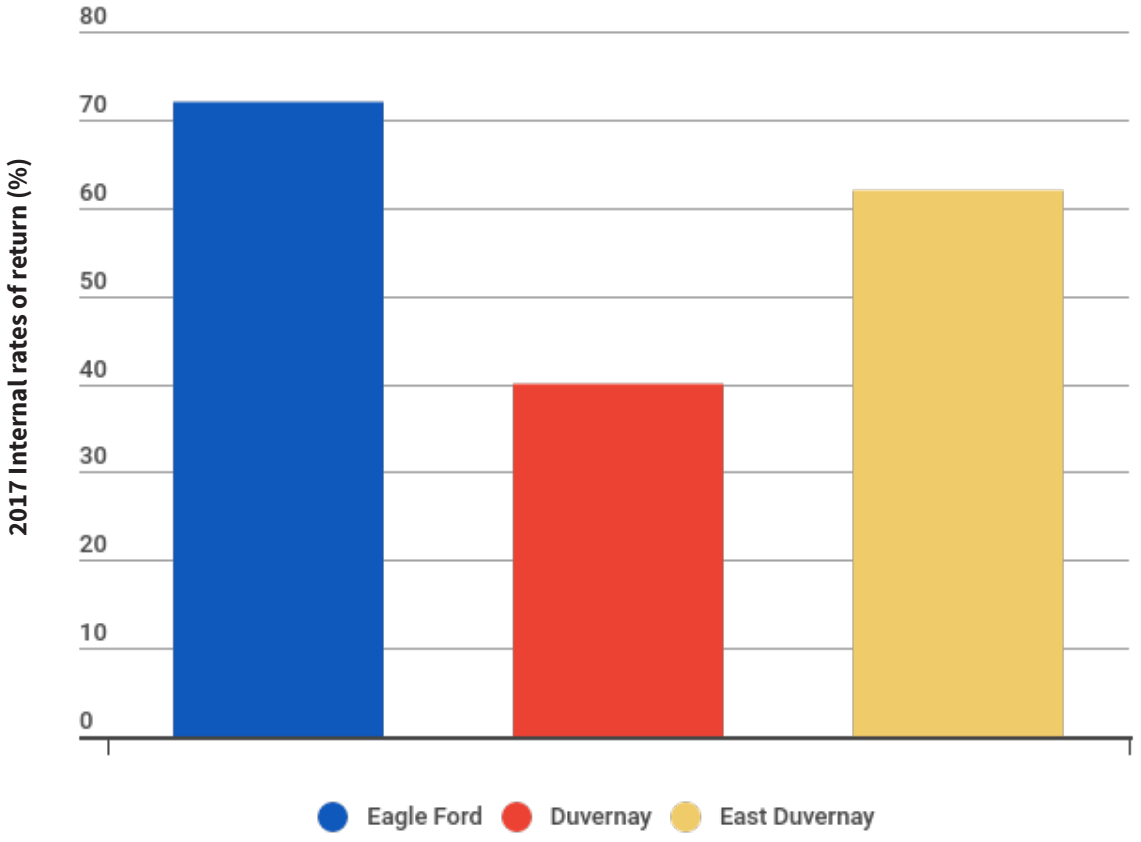
Ultimately, the measure of success of oil and gas explorers and producers is how effective they are at converting their capital into recoverable resources. While operators in both plays have managed to improve their capital efficiency in the field, the Eagle Ford continues to enjoy a substantial advantage. Eagle Ford operators have managed to cut their capital costs per boe of EUR by 34 per cent in the last three years, down to an average $7.40 per boe. While Duvernay operators have seen a greater percentage decline, at 46 per cent, capital costs per boe of EUR averaged $10.89 in 2017.

Break-evens favour the Eagle Ford



Sources: McDaniel & Associates Consultants Ltd Duvernay update November 2017, CanOils, corporate presentations, EIA, Wood Mackenzie

Internal rates of return favour Eagle Ford



Flat commodity pricing ($US 55 WTI, US$3 MCF)
Based on wells with 2,200 metre laterals
Based on company reported data

Internal Rate of Return (IRR) is a metric used in capital budgeting to estimate the profitability of potential investments. Generally speaking, the higher a project's internal rate of return, the more desirable it is to undertake. The Eagle Ford has a higher IRR percentage than both Duvernay plays. However, given the early stages of development of the Duvernay this metric will likely change.

Summary

Since its inception in 2008 the Eagle Ford shale play in south Texas has been one of the fastest growing unconventional resource plays in North America.

Many operators in the Duvernay shale play in Alberta often present the play as an analog to the Eagle Ford, with similar geology and prospective resources.

Because of a later start Duvernay operators have been able to incorporate technological advances in drilling and completions and lessons learned in the Eagle Ford in their operations at an earlier stage of development.

Duvernay operators have been able to incorporate longer laterals made possible by extended reach horizontal drilling technology into their development plans while taking advantage of high performance rigs to cut drilling times and cost per metre drilled.

Duvernay operators have also been able to rapidly incorporate high intensity well completions techniques including tighter stage counts and increased proppant loads to increase well productivity and estimated ultimate recoveries (EURs).

As a result Duvernay operators have been able to quickly bring their capital costs per boe of EUR down to levels approaching Eagle Ford developers.

While supply costs are still somewhat higher than in the Eagle Ford, as the Duvernay moves into manufacturing mode drilling and completing standardized wells on multi-well pads that spread will lessen.

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