Viper Energy: Royalty Company Growing via CF-Accretive Deals

James Davolos of Horizon Kinetics presented his in-depth investment thesis on Viper Energy Partners (US: VNOM) at Best Ideas 2019.

Thesis summary:

Viper Energy Partners was taken public in 2014 by Diamondback Energy (US: FANG) in order to monetize a royalty position in the Midland Basin on acreage owned and operated by Diamondback. The transaction facilitated an independent valuation for royalty acreage, which requires minimal working capital, as compared to capital-intensive operated acreage. Diamondback maintains a sizable stake in Viper Energy.

In contrast to most public energy “royalty” companies at the time, Viper was the first growth-oriented company, which has been facilitated by drop-down transactions with the parent. Viper has expanded beyond sponsored transactions from the parent and acquired assets from third parties. Royalty acreage has grown by 4.4x since the IPO.

Viper and its peers have limited acquisitions to cash flow accretive deals. This has resulted in an accretive acquisition mechanism, whereby the company can purchase acreage at a 50+% discount to the implied value of the acreage.

A critical variable to this compounding mechanism is capital structure; historically the company has only utilized short-term debt in the form of a revolving credit facility to close acquisitions. Subsequently, the company issued shares to pay down the revolver. To the extent that the company can issue shares at a material premium to the acquired acreage, the transactions are accretive on a cash flow and NAV basis.

Based on trailing distributions, Viper trades at a forward distribution yield of ~8%. While declines in oil prices will impact this rate in the short term, James expects organic production growth and hub basis differentials to mitigate the impact over the next year.

The following transcript has been edited for space and clarity.

At Horizon Kinetics, I would consider us to be contrarians, but not for the sake of being contrarian, more as a function of where the opportunities exist and where we can find strong opportunities mostly driven from a valuation standpoint. Viper Energy Partners is a company that is systemically and structurally undervalued for a variety of reasons, particularly for its sensitivity to commodities. Investor malaise through commodity companies is probably reaching an extreme where the energy operating companies, as evidenced by the iShares Energy Select ETF or index has underperformed the S&P 500 by almost 1,500 basis points annually over the past decade, while the VanEck Gold Miners index has underperformed the S&P by 800 basis points annually over 10 years. This is in spite of higher gold and silver prices compared to a decade ago and marginally higher oil prices. So, something doesn’t work with operating company investments, or it hasn’t, although there is a niche that is vastly underappreciated by investors within the commodity sphere.

Here’s an introduction to royalty companies. Most people are familiar with royalty companies through the lens of precious metals. The preeminent royalty company is Franco Nevada

Corporation, which is a gold and precious metal focused royalty company that traces its roots back to 1983, when Pierre Lassonde founded the company in Canada as a financing mechanism for gold mines. The returns from 1983 through 2001 were staggering, although it's not quantifiable as it was a private company. In 2001, it was acquired by Newmont Mining, which then grew the business but listed it through an IPO/spinoff in December of '07 in order to fund a new royalty portfolio acquisition. Franco Nevada's performance back to the spinoff out of Newmont Mining has been compared to the Gold Miners index, GDX, which has had a substantial capital loss over that period. Meanwhile, gold prices are up again, but not that strongly over a 10-year period on an annualized basis.

Gold and silver royalty companies are primarily a financing mechanism. They will provide upfront capital for a mine in the form of cash, which allows the mine to be developed. Rather than taking a cash interest payment, the company buys future production from that mine, usually in terms of ounces of gold, silver, potentially metals in the platinum metals group, at discounted rates. For example, you provide $100 million day one, and you expect production to start in year five. Spot gold prices at the time of financing are at $1,300 an ounce, but your forward purchase commitments are at $200 an ounce. That discount provides an inherent interest rate in that loan, and it's proven to be very successful, but it makes sense for the mine and the mining company as well because they can't take on large corporate level debt and cash interest obligations. Thus, it serves well both end markets- the financier and the miners.

Franco has historically been focused on gold, silver, and a little into the platinum metals group. However, recently they started to invest in energy royalties. Energy royalties, as opposed to gold and silver royalties, are a function of land ownership. Texas is used as a case for Viper Energy. With land ownership, you might sign an operating lease with a provider if you're a rancher and you owned the mineral interest. For example, you can use precedent transactions where the oil and gas company might pay you an upfront payment of $50,000 to $70,000 for a premier acre in the Delaware Basin, but on top of that, they're going to pay you 20% in a standard transaction of all oil and gas produced from these wells. This is a function of land ownership as opposed to a financing mechanism. Many public companies, "energy royalties" have fractional interests in liquidating operating leases. Certain examples are Permian Basin Trust, Sandridge Permian Trust, Prudhoe Bay Trust, and the San Juan Basin Royalty Trust, which are wells and fields that are in steep decline. There's no new capital expenditure going in, and little new drilling. As a result, they're valued on a current yield basis, and on a dividend-based rate.

Viper is amongst the new breed of about five or six publicly traded, energy royalty companies that are growth oriented. Viper was taken public in 2014. It was only a small patch of royalties owned by Diamondback Energy and was called the Spanish Trail formation in the Midland Basin. Since then, Diamondback has facilitated Viper being a highly accretive NAV growth entity where they have grown production, royalty acres and distributions above the underlying assets as a function of active management. There's a need to differentiate between the old standard of a liquidating royalty trust versus an accretive growth-oriented royalty company.

An example of illustrative working interest is using a $40 barrel of energy pricing. That includes the BOE, the barrel of oil equivalent- a certain mix of gas and natural gas liquids, propane, butane, natural gasoline, and ethane. Pioneer has a working interest in a well. Upon paying $2.50 in production and ad valorem tax, $6.50 of operating cost, which is basically lease operating expenses and transportation for piping that oil or gas from a gathering system to a backbone pipeline, and to a hub, $14 for finding and development cost, which is exploratory drilling, the illustrative margin is the remaining $17, i.e. 43%. All of these expenses are necessary before one can even get that well and get that oil out of the ground. Compared to the royalty well where the standard royalty is the production and ad valorem tax of $2.50, 94% is netted back to the royalty owner. The economics are extremely compelling in terms of a PV10 – a standardized metric of a discounted 10% NPV. A well-level IRR in the 20% range, which is currently very low even at $45 oil, 70% of the economics go to the royalty owner. At a 50% well-level IRR, 40% go to the royalty owner.

There are different types of royalties, since not all royalties are created equal. The example of a rancher, who would lease out his or her land as a mineral ownership in the state of Texas, is just known as a mineral interest as opposed to a surface interest. It's a perpetual interest to exploit the minerals in that land, and you can sign a lease with whoever you choose to exploit those minerals. The middle is a non-participating royalty interest, where you do not participate in any expenses, or any of the taxes. It's 100% cost free. If the operator of that well realizes $70 a barrel and you have a 10% NPRI, you get $7. The third is an overriding royalty interest, which is a part of a working interest override, much more similar to the old standard of the liquidating, declining trusts.

When the minerals have yet to be leased in the case of KRP, Kimbell, which is a publicly traded company, they can carry all the expenses on themselves, and they'll have all the revenue. Alternatively, they do the lease where they get the upfront cash payment. In return, they share the economics with the operator. Depending on the location, they might be spending $6 million to $8 million just to drill the hole, all the finding and development cost, tens of millions of dollars, transportation costs, etc. However, they're spending zero capital by letting somebody take on that burden. In this case, the royalty owner might be taking 20% to 25% revenue of the economics for the trouble, while the operator takes 75% to 80% of the revenue. However, the cost is 0% to Kimbell, and 100% to the operator. These are not perpetual leases. In the case of the Delaware Basin, you might want to be exploiting a certain layer, and you can only do that within 10 years, that reverts to the royalty owner upon lease termination.

The benefit of royalty, relative to a working interest, is zero working capital requirements-simply cashing checks with minimal OPEX. In some cases, you might have a little share if it's an NPRI, some production tax and ad valorem, but zero working capital or CAPEX. You use minimal or no debt funding since you don't control the wellhead. Most companies have only used debt through a revolving credit facility to finance new acquisitions, and then they plug that through an equity raise. Finally, you have exposure to both production growth and commodity price growth as a free call option. If you place 30-year oil prices into a Black–Scholes model, it's going to deliver a massive premium, not a discount where people are worried about energy prices exposure.

Viper Energy Partners was created in 2014 as a limited partnership. It has converted to a taxable entity effective May of 2018. It started in Midland County original acreage and since then, it has expanded into New Mexico, then parts of Western and even Central Texas, the Greater Permian Basin. They separated into the Delaware, which is newer, deeper and most robust resource, but it was more complex. Therefore, it's been less explored than the Midland Basin, which has been explored for quite a while. Basic statistics is if you've got 124 million shares, or as they used to call them units, the market cap is pulling from 12/21. To put this into compliance with the current data, it's 15% higher. Currently they have net debt of about $280 million, and liquidity on the revolver of $275 million. The enterprise value is $3.35 billion, relative to net royalty acres of 13,908. In Texas private markets, a net royalty acre nets out the royalty interest per acre. For instance, if you have a 20% royalty interest on one acre, five acres would be one net royalty acre.

In the Midland Basin, the part of the Greater Permian, there are eight layers of shale beds. In the geological zones carbon is decomposed into hydrocarbon-producing rock. That rock is very porous and brittle and it breaks up to create huge wells. Basic math from RSP Permian, one of the best operators in the basin, shows 46,700 net acres, 1,600 locations, a new location for every layer, and for every well. They might do 12 wells in Wolfcamp A, and they might do six or eight in Wolfcamp B. The important thing here is a billion barrels of resource through these acres. If we divide the billion barrels by 46,700 acres, that comes out to about 21,000 mboe nomenclature for a thousand barrels per acre. Since Delaware Basin is more robust, Reeves, Ward, Loving County is going up into Eddy and Lee County in New Mexico. There are over nine layers, but Wolfcamp A, which is the most robust part of the basin, is so large, that it breaks up into the Wolfcamp XY, and the Lower Wolfcamp A. Overall, 45,200 acres and 1.8 billion potential resources equates to nearly 40,000 barrels of oil equivalent per acre.

To shed light on the misinformation about these wells, we consider the cumulative production of the core Wolfcamp A and the months of production of this 1.5 million-barrel large robust well in the core of the Delaware basin. There is no need to have such robust wells, as you get out into the fringes, and more densely drilled. We model between 600,000 and 700,000 barrels per well, depending on the location. With around 15 months in, you can already be at about 450,000 barrels, so 30% of the well in the first year and a half of well life. It’s good that you’re getting a lot of oil very quickly, and you’re getting your capital return, so your IRRs benefit immensely from that. Negative press will say there’s a huge decline rate, and you have to keep on drilling to keep up. That’s true, but these are high-IRR wells. The companies out there are very efficient and fast with their drilling. For most of the basin, you’re getting about 60% liquid oil, 20% of NGLs, and 20% dry gas. Dry gas is methane. Henry Hub pricing was at about $3, then spiked to $5. Still most people’s long-term decks are below $3.

Simple math shows what the NPV of one of these wells would be if the acre was drilled immediately and started producing tomorrow. To consider the benchmark pricing, West Texas Intermediate Oil is at $46. It currently ranges between $45 and $50. NGLs, which are difficult to price properly, are generally at about 60% of liquid oil pricing. It depends on how much propane, butane and natural gasoline are in that stream, whereas ethane and the dryer stream are a little cheaper. Dry gas pricing is using a weighted average of 60% oil, 20% NGL, 20% gas. That gives a composite of $36.72, which is quite low. However, considering the Delaware Basin spot pricing, we assume that you are going to do each acre, it has 40,000 barrels for the Delaware and 20,000 barrels for the Midland. We then use a 17-year decline rate where it’s very heavily loaded to the front, and you’re getting 1/3 before you’re at the half year mark. Discounting that back at a 7% discount rate for the 40,000 barrels per acre, you get an NPV of $1.1 million per net royalty acre. For the 20,000 or 21,000 in the Midland, you’re getting about $580,000. To sum up, that’s a 17-year type curve, discounted back to present value at 7% using current spot pricing.

To get the answer where Viper Energy Partners implied acreage price, the enterprise value is divided by net royalty acres that gives you an imputed value of about $241,000 per acre, at $25 to $30, in the range of $250,000 to $280,000 or the implied price per net royalty acre. There’s a big mismatch between that and $1.1 million and $580,000. In the discounting future production, we’re still using the 7% NPV, but we’re assuming a weighted average of 10 years until production. Within the first 10-year window, some will produce at year 10, and others going out further about a 30-year resource to look at how the full lifecycle of drilling within the current inventory is. So, to use spot pricing the Delaware gets you to about

$560,000, and the Midland gets you to $300,000. Based on the mix of acreage between Midland and Delaware, as well as a little of Eagle Ford, around $425,000 per net royalty acre using fair value method, that would equate to about a $50 stock relative to the high 20s today. That's quite conservative because it assumes zero price recovery in hydrocarbon prices, and assumes no accretive growth, no dropdowns, no extended timeline to the resource base. It also assumes relatively slow development consistent with certain bottlenecks in getting oil and gas out of the basin. So you're in a fair value of about $400,000 per net royalty acre using spot pricing.

Spot pricing is a huge point of misunderstanding for people, especially when it pertains to the Permian Basin. Viper data of the third quarter shows where production is at, the distribution per unit, and the DPU. Viper realized oil at the price of $54.51 in the third quarter of 2018. To take a simple average of the 90 days in the second quarter, West Teas for Cushing delivery averaged close to $70 a barrel during that quarter. This is a $15 spread where Viper was realizing this huge discount, and this is a result of a pricing differential because they were delivering mostly into the Midland hub. Since the growth rate in the Permian Basin exceeded even the wildest forecast, and there weren't enough pipelines to get oil up to Cushing and realize that $70, so it stayed in Midland.

Plains All America has a lot of pipeline capacity and infrastructure in the region. A lot of the Midland hub capacity today goes up to the northeast of Cushing, which is right in the middle of the stream. Interestingly, all of the capacity is being built in the Delaware Basin. There's also Cactus I, Cactus II, a joint venture and a couple of other pipelines, which are delivering into the Gulf. There's a Magellan contract to regulate Gulf-based pricing, but Gulf is benchmarked to Brent. Brent Crude, which is a North Sea contract, has averaged about a $10 premium to West Texas Intermediate. West Texas is currently at $45 and Brent is at $55. As you get to the Gulf, you're not going to realize full Brent pricing because you have to pay a seaborne transportation fee to get it to those hubs. There're a lot of complex reasons why Brent trades at a premium to WTI- notably, the API gravity and refinery configurement, also the fact the US has a glut of oil and gas relative to infrastructure and refining capacity, as well as it relates to sulphur and European refineries having a much higher diesel and bunker oil mix.

Raymond James Financial shows a straight-line production estimate for the Permian. The backlog is easing up in the second quarter of '19 and then really catching up in the third quarter with some new pipelines, the EPIC pipeline, a private company, Sunrise, which is Plains All America, Gray Oak, which is Phillips 66, and then Cactus II. You're going to have overcapacity to get the oil and gas out of there by the end of '19. Probably, there'll be less congestion by the middle of the year. If they were getting $55 at a $15 discount to WTI, you'll eliminate the Midland differential, but you'll actually add $5 to that, as you start realizing Brent pricing as opposed to getting the Cushing WTI price.

The valuation comes from the MLP mind-set. New growth-oriented royalty companies have focused on yield and investors laser-focused on accretive acquisitions. This has created a massive mechanism of accretive unit growth and the acquisitions that Viper engaged in in 2018 ranging from about $20 million up to closer to $200 million. The operators were in Delaware Basin, Midland Basin, and BP/Devon/Conoco in Eagle Ford. If you're trading at an implied value of about $250,000 an acre, but they're buying from $100,000 to $200,000 an acre, that's a function of the market. The market is not giving you any value for unproducing acreage. They're valuing the current acreage to buy it at a 10% yield to make it accretive, otherwise, they're not going to buy your property. At the end, they can buy the unproducing acreage at a massive discount, and the producing acreage at a slight discount to trading. If you’re buying it at $150,000 an acre, you’re using currency valuing it at $250,000 an acre, which is highly accretive in the long term. That mechanism where you use a revolver to close day one gives them a lot of operating leverage and a lot of scale since not many people can write a $175 million check day one. Fill in that revolver, plug it with an equity issuance, and issue shares. Hence, this is a very powerful accretive growth mechanism.

Besides, Diamondback continues to be a majority shareholder, and they have a very large equity interest in Viper. They don’t want to alienate this cash flow stream to the parent company, so they’ve continued to drop down mineral acreage and royalties as they’ve made acquisitions and had success in developing more resource. The drop-downs come through a mechanism of two things. 1) Acreage that was not previously producing goes into production. There’s a cash flow, so you can drop it down. 2) They’ve been aggressive with acquisition, Brigham Resources to name one. As that portfolio has royalty acreage, they can drop that down. At a steady state using $45 oil, NPV-ing the royalty stream and getting to $50, you should give some value to this growth mechanism on top of getting your current 8% dividend yield.

Regarding oil prices there’s a lot of misinformation about breakeven. You’ve seen several promotional CEOs talk about $20, even less breakevens in the Delaware Basin, which maybe possible if you take the very best acreage and you have extremely efficient pad drilling, you can then drill a well and make such breakeven. That’s assuming a 0% IRR or a profit margin at $20, but doesn’t include many economics. RS Energy published a chart in The Wall Street Journal, where they’re showing the breakeven that you might cite for the Delaware Basin at $35 at the low end. That’s just a well. So what’s my cost to sink a hole, get the oil up, transport it, and get my money back? What do I need to break even just looking at that? At $45 for the Delaware, other overhead costs are also included, not the least of which is corporate SG&A. You have debt service and many of these companies run at about 2x to 3x EBITDA of debt, so their cost of capital is not cheap. Further, you go up to $50 when the price of land is also included.

RS Energy study included a 10% profit margin. These are rational capital allocators and PV10 is a standard in the industry demanding a 10% rate of return. This gives a better idea of where the pain threshold is. At $50 for the Delaware, and given the fact that WTI is at $49, they’re still getting $10 haircut going to Midland. Also, the turnaround and differentials for Viper is about 20% of the barrel in gas this year. Gas in Henry Hub is about $3, but Waha, Texas, which is a small West Texas gas hub, got to the point where gas delivered there was getting virtually zero in the fourth quarter of this year because there’s too much gas and it costs money to store. So, as you get capacity to get that out of there, you’re going from zero up to $3 for that gas. The NGL mix has better economics. There’re a lot of ethylene crackers being put into Louisiana, Port Charles, Corpus Christi, Texas, so that’s a much stronger market.

Moving to OPEC and the large international oil providers, a fiscal breakeven balances their budget. Brent is at $58.24. Based on the budgets of Iraq, Russia, Kuwait, Qatar, they all are still balancing their budget at $58 Brent. However, very large producers, such as the UAE, Oman, Algeria, Angola, and most importantly, Saudi Arabia are at $88. The Saudis have an estimate of about $500 billion of reserves in their federal bank. If you’re $30 below, you’re breakeven and you start to bleed $5, $10, $15, $20. It might even be above that if these prices hold in your national coffers. Geopolitics aside, what’s going on over in Saudi Arabia, bleeding the reserves does not help anybody.

Putin and Russia have been resolute in saying they’re fine, but he’s not too far off either.

Further up, you've seen a lot of supply disruptions in Libya, Nigeria with rebels and different factions taking supply offline there. The economic breakevens for oil are well above $45 at West Texas, and $55 at Brent. There is a lot going on in the fourth quarter- algorithms, trading patterns, short-termism, and manipulation for days, but, not to go down into the political spectrum, if Iran is not allowed to export, they don't break even anywhere. If they are able to get some out in the black market, they're not getting benchmark pricing, so a lot of pressure there. The plan for them was to go under sanctions where they would no longer be able to sell into international markets again in early November, and our administration decided to grant them a waiver for six months for about 75% of their oil.

OPEC doesn't want a price spike. It's bad for them if you get $100, $120, $130 oil because then you start getting the Norwegians, and the French, and the South Americans doing these massive offshore projects. A little well in the Permian giving you 2 million barrels is nothing compared to these deepwater 50-year resources, but those projects need $90, $100, $120 to make sense with a 10% IRR. Ahead of Iran coming offline, the Saudis, probably had some discussions with our government, began over producing, so there wasn't a supply shock when Iran came offline. This lasted for months. Unilaterally, the United States decided to extend those waivers. So all of a sudden, you have a couple of million barrels of extra Saudi and Iranian oil on the market and the market was trying to balance and adjust for it. You see stockpiles showing up in the United States and abroad, and the market plummets in the short term because of the fundamentals.

In the fourth quarter, as oil's deluge continued, the inventory data was really meaningless because none of the production cuts started until the beginning of the year. There were no pain points where certain non-core shale beds would curtail production. If you have your wells and your drilling crews up and running, you're not going to take that well offline. The balancing act might take another three to four months until you see it in inventory numbers. Currently there's a very odd situation. The last time Saudi's actual resource base inspected and approved by international petroleum engineers was in the late 1970s. They've been producing heavily ever since, and they've revised their proven reserves, double what it was when the British and the Americans confirmed those resources 30 years ago. Probably the Crowned Prince is pulling the Aramco IPO. They probably aren't perpetual marginal producer of oil. He realizes they need to get away from a purely petroleum-based economy. He wanted to take Aramco, the chemical business, and the refinery public. However, he wouldn't allow international petroleum engineers to confirm the resource. So, the world views the Saudis swing production- switch on or switch off two million barrels a day at their behest as a balancing mechanism.

Energy securities are orphan securities. Energy was close to 15% of the S&P 500 a decade ago. Now it's down to 6%. If you look at the S&P Energy Index, where 90% of allocators are investing, you've got 40% of the index in Exxon and Chevron. There's also Schlumberger, an oil field service, three refinery-based companies, and Halliburton- a service provider. Not only is energy a pariah and an orphan security, there's no passive fund flows and no investor demand.

To sum up, here is a risk disclosure for compliance. There are some interesting ways to pair along oil and gas royalty companies such as Viper where you're getting 8% a year. You can short futures on oil prices as many times they're in very steep contango. So, you can fund your short of the underlying spot commodity through your yield. To the extent, the historic economics of royalties are more attractive than underlying prices you'll earn a decay of the contango. You can fund the short through a good amount of your yield. It makes a pairs trade or a hedge trade quite intriguing.

The following are excerpts of the Q&A session with James Davolos:

Q: How do you think about capital allocation in this space? What ought to be the priorities? Is there room for return of capital here? Is it about drilling and finding more resources?

A: That's a good question. There was a mutiny amongst large oil investors halfway through this year where the old standard of the previous 30 years, when investors demanded to replace whatever you take out of the ground every year in new resource. If you're going to pull up a million barrels, you better replace that and make sure that you're not depleting your resource space. Whereas the institutional community came to the drillers this year and said, "You need to focus on free cash flow. You need to focus on economic returns to your shareholders and not only building an empire." That is a new dynamic to create more discipline. You're going to see stricter funding as people want to build resource.

As it applies to the royalty companies, they should prioritize growing their resource base and creating a larger and longer stream of resource as opposed to distributing 100% of the cash flow. It goes from the MLP mindset where you distribute everything and then grow through stock issuance and drop-downs. However, if you can buy a highly accretive acre that is not producing today, you'd rather buy that acre at an embedded rate of return that magnitudes higher than your current acreage and forego a dividend. It's about aligning the investor base to a combined component of NAV growth with yield. That's the happy median gold companies have reached over time, where Franco, even today, has about a 2% distribution, but they've grown NAV tremendously and investors appreciate that. Energy needs to evolve their royalties to have an NAV growth component with a yield component.

Q: Could you talk more about management incentives? Is high insider ownership the only way to align incentives? Are there other ways as well?

A: As a firm, we are highly skewed towards actual equity skin in the game, whether they are options, restrictive stock units, or incentive bonuses. They tend to be short term. We want you to be able to lose money, not only earn money in the case of a misstep. The Diamondback ownership is a very strong incentive for the parent company, which is quite large and one of the best in the basin. However, individual management at the Viper level is incentivized through direct stock ownership. That should be optimized as they're primarily looking at distribution growth and total shareholder return, which is a large element, but they can be incentivized to grow NAV in addition to other metrics.

Q: There's a lot of moving things here and data. What are the key data points to gauge value creation? You talked about a number of the metrics that can be tracked. Which do you think are critical?

A: The best metric to use, and this is at odds with how Wall Street likes to look at the world, is your net royalty acreage relative to your share count. That can be reconciled with your production growth and distribution growth. In terms of evaluating the industry, the well-level economics, how far they are drilling on a lateral basis. In some cases, it's 5,000, 7,000, 10,000 feet. How many barrels of oil are coming out of that well?

Everything we're seeing is showing a robust rate of return in the core Delaware and core Midland Basins, and this is the preeminent resource. It's going to be interesting to see where the less robust resource is. You go into SCOOP and STACK in Oklahoma, which are phenomenal but not quite on the level of the Permian, same thing with the Eagle Ford. You have a much higher spread as you go up into the D-J Basin, Powder River Basin, and Williston

Basin as you go further north. At a royalty level, it's the acreage growth relative to units, combined with distributions, and you need to keep an eye on the industry itself and just continue to see how much the wells are producing, whether they're realizing spot pricing, or they're still getting haircuts. If all of that congeals well, it should all work out well for everybody in the industry.

Q: This sector obviously offers many interesting opportunities at this time. By sector, I mean companies tied to crude oil pricing. How do you think about going with an E&P company versus a service provider or even further away, some of the tanker companies and others that are leveraged to the energy cycle?

A: One of the reasons why we are so fond of royalties is the minimal or zero use of debt. You've seen through every cycle a lack of discipline in both gold markets and oil markets, where prices are high, budgets extend, capital markets are friendly, and you take on too much debt and expand capacity that requires high pricing. We are very fond of any E&P company or service provider that has the appropriate balance sheet, which will allow them to continue to weather a prolonged period of cyclical downturn and then have a commensurate capture of the upside. It's dictated by the business model and the balance sheet. Certain E&Ps have wonderful assets, wonderful balance sheets, but they're still very capital intensive, and a lot of cash flow is reinvested into future production and growing the resource base.

Service providers are going to have a tougher time, especially the offshore providers. Pressure pumping and frack spreads do not generate a lot of value adds. If there're too many pressure pumps and frack spreads, it's going to be hard for them to get pricing. The guys in the Permian have been able to exert pressure on them. I'm very fond of tankers, especially because there's so much water-borne transport to get better pricing and better economics. A huge fan of Cheniere Energy, huge fan of Navigators. If you want to go esoteric, there's an interesting player, American Shipping. They own Jones Act vessels subleased to day rate charters, generating a guaranteed minimum, mostly in the Gulf, and they transport oil and gas primarily to Florida because Florida doesn't have pipelines. At the current base rate, they're getting about 8% yield owning the stock, which includes debt amortization. However, if the market gets tighter, there's much upside. In that case, they have the right asset in the right place. To sum up, business model, asset base and capital structure, and there are some phenomenal ways to play this cycle.

About the instructor:

James Davolos is a Portfolio Manager at Horizon Kinetics LLC. He serves as Co-Portfolio Manager to the Kinetics Internet Fund, an equity fund with approximately $150 million in assets, and he is an investment team member of the Kinetics Paradigm Fund, Kinetics Alternative Income Fund, Kinetics Global Fund, Kinetics Small Cap Opportunities Fund, and Kinetics Market Opportunities Fund, all of which are a series of Kinetics Mutual Funds, Inc. James is also directly responsible for a variety of custom and concentrated equity managed account strategies, is a Co-Portfolio Manager on certain private funds, and is on the investment team across the core managed account strategies. He is a member of the Firm's Investment Committee and Research Team, and is actively involved in research, valuation and portfolio allocation for many of the Firm's high conviction investments. James joined the Firm in 2005 as a research analyst. He earned his undergraduate degree (B.B.A.) from Loyola University of Maryland in 2005, and his Master's in Business Administrator (M.B.A.) from New

York University in 2016.