Kimmeridge

What Remains: North American Upstream Inventory

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Introduction: Where Has All the Good Inventory Gone?

Observers of the energy industry may be forgiven for being a bit confused. Despite ongoing hostilities facing a number of the largest energy-producing countries, the world appears to be adequately supplied with both oil and gas. However, all of the recent energy M&A activity across North America would suggest that producers have an issue with organically finding future onshore inventory, with the cost of undeveloped locations continuing to rise across all the major basins. Thus, here's the paradox for the midterm outlook for energy supply: North America should not be able to keep growing supply at its historical rates—rates on which the rest of the world has been heavily reliant for the past 15 years.

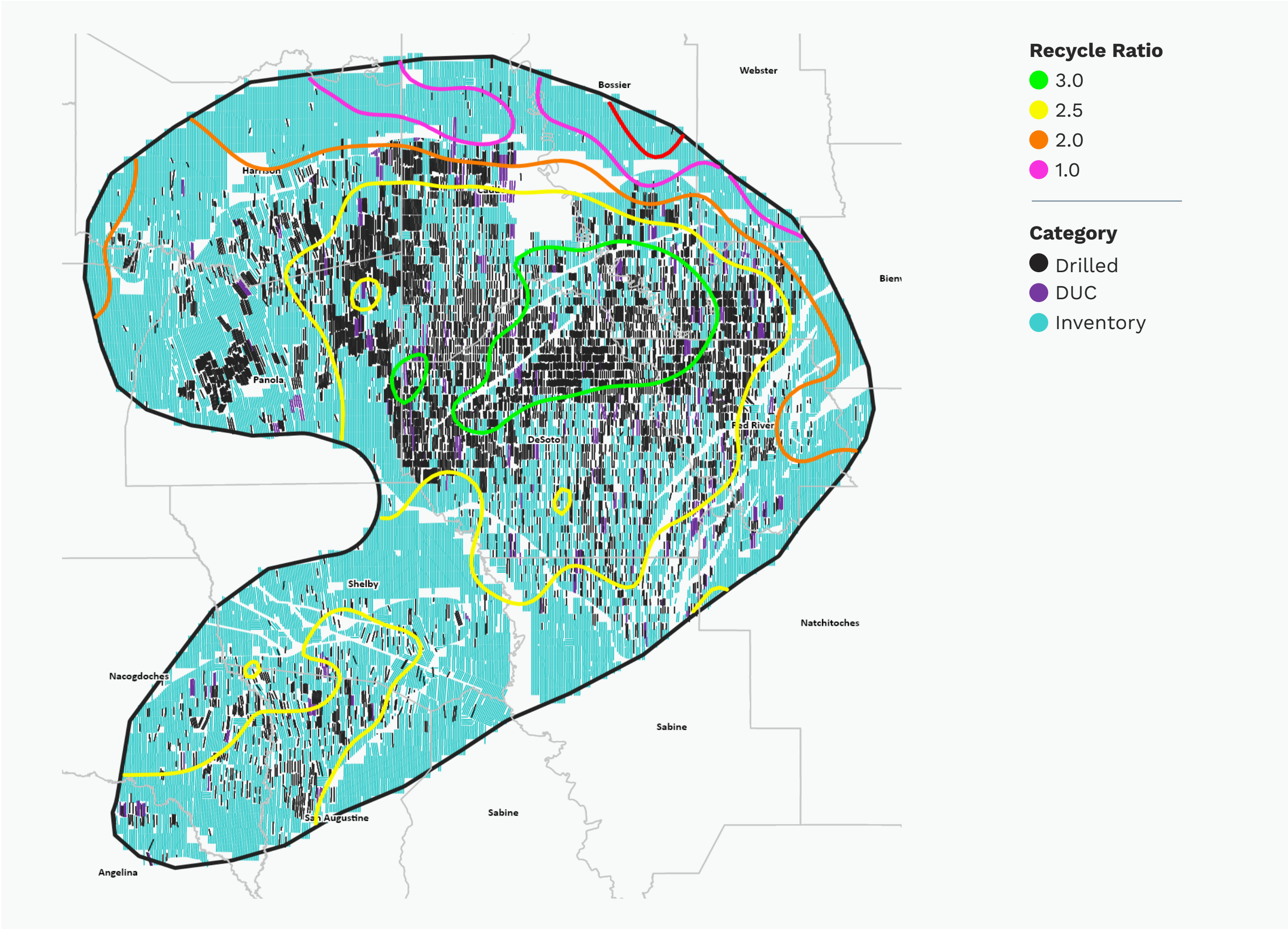
To understand how much growth is left, we look to the historical development of inventory in order to help predict the future rate of exhaustion. This also requires a view on the economics of remaining well locations. There are plenty remaining locations that are economic at $100 or $200 per barrel, but what about $50 or $60 per barrel?

Therefore, we set out to model well economics for the majority of foreseeable North American shale inventory to provide a nuanced, bottom-up view on where the industry falls within the capital efficiency life cycle. (Our definitions of terms and workflows can be found in the appendix.) Then we used this information to achieve a greater understanding of the current investment opportunity landscape and what the future has in store by coupling historical well data with our inventory characterization to illustrate the full life cycle of shale capital efficiency. We finish this piece with our views on Kimmeridge's large remaining investment opportunity set, and also some notes on potential global supply implications from our work.

How Did We Get Here?
Reflecting on Shale's First 20 Years

Over the last 20 years, operators have used geological interpretation and drilling trial and error to determine which areas of each play were most economical. These are the areas where operators focused their development programs first. Figure 1 illustrates this point for the Haynesville, showing a strong correlation between the existing (or drilled) well concentration and where our standardized "blank slate" mapping suggests the core of the play is located.

FIGURE 1: Map of the Haynesville Indicating Drilled, Drilled but Uncompleted (DUC) and Undrilled 'Inventory' Wells, Based on Kimmeridge's Inventory Database



Source: Kimmeridge proprietary analysis.

When we step back and look at high-level development and performance trends across the industry over the past 20 years, we can see that the preference to develop the "best rock first" has been coupled with improvements in development practices. These practices include extending lateral length (which decreases capital expenditures per horizontal foot since the cost borne in the vertical section is spread out across more footage), increasing stimulation intensity and increasing the spacing between wells (Figure 2).

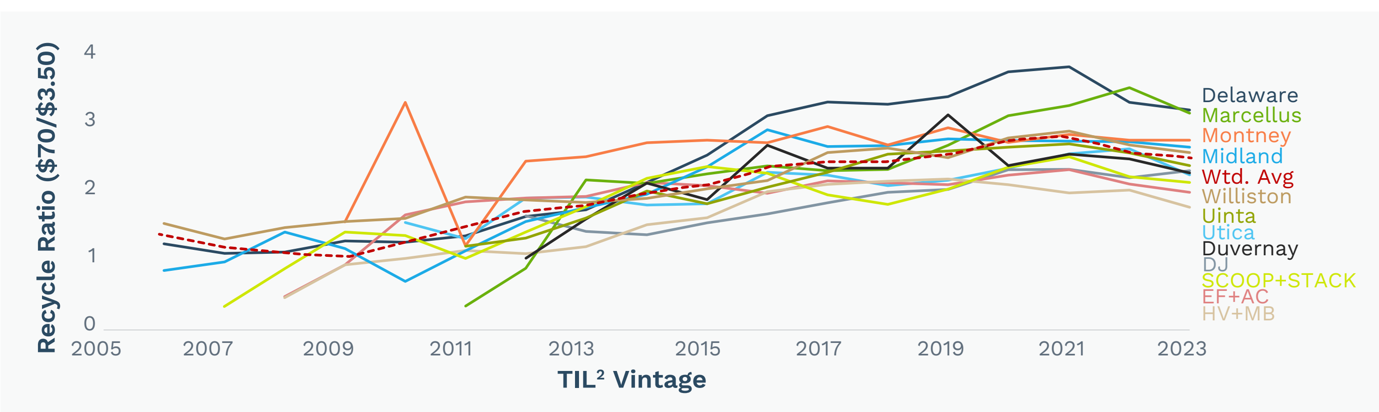
This yielded consistent year-over-year improvements in estimated ultimate recoveries (EURs) from 2012 until ~2018, when core area inventory began to run out.

We can see the evolution of North American capital efficiency more clearly when we use our inventory framework and recycle ratio methodology to calculate average North American recycle ratios over time for existing wells under a constant commodity price assumption. Figure 3 shows that if commodity prices had remained consistent at midcycle levels over the past 20 years, recycle ratios would have increased from 1.3x in 2010 to 2.9x in 2021, before gradually declining to their current level of approximately 2.6x. For the purpose of this analysis, we assumed midcycle commodity prices of $70 per barrel of oil and $3.50 per million Btu.

FIGURE 2: Macro Trends Across All Major North American Oil Shale Plays

Source: Enverus.

FIGURE 3: Modeled Average Recycle Ratios by Basin Through Time



Source: Kimmeridge proprietary analysis.

As we noted in prior research,[1] this stalling out of North American capital efficiency likely contributed to the material decline in the number of public E&Ps (80 at year-end 2017 and 43 at year-end 2023) resulting from M&A deals and bankruptcies.

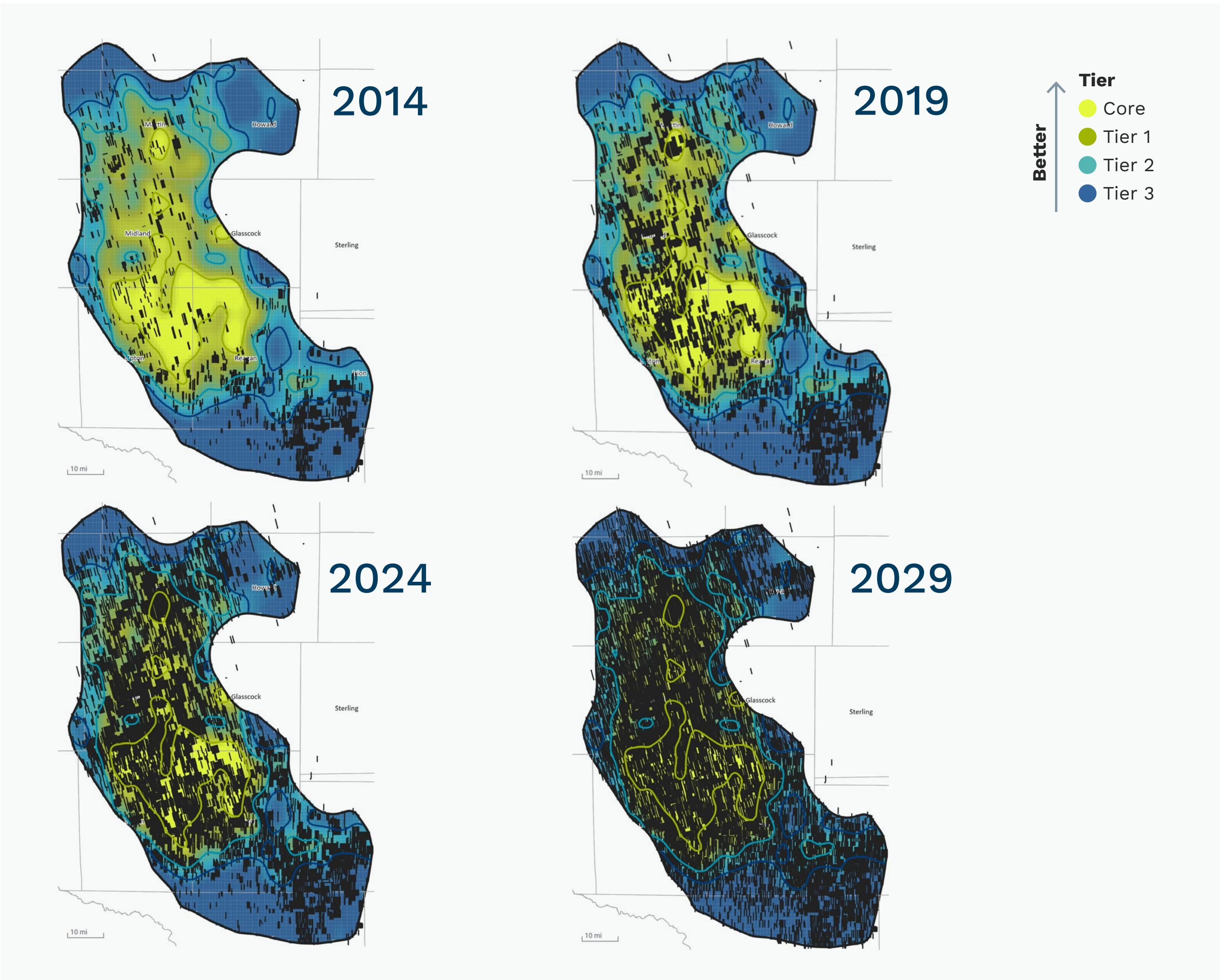
[1] Refer to our previous research piece, "Shale's Golden Years: Can Consolidation Keep the Industry Young?"

[2] TIL = "Turn in Line" and represents the moment when a well starts producing oil and/or gas.

A Case Study: The Midland Basin Through Time and Into the Future

To illustrate the trends in inventory exhaustion and capital efficiency, we have composed a time series of how one of the most prolific plays within the Midland Basin, the Wolfcamp B (or "WCB"), has been developed over time; and importantly, what the future development of this play may look like (Figure 4).

FIGURE 4: Midland Basin Wolfcamp B Inventory Through Time 2014-2029

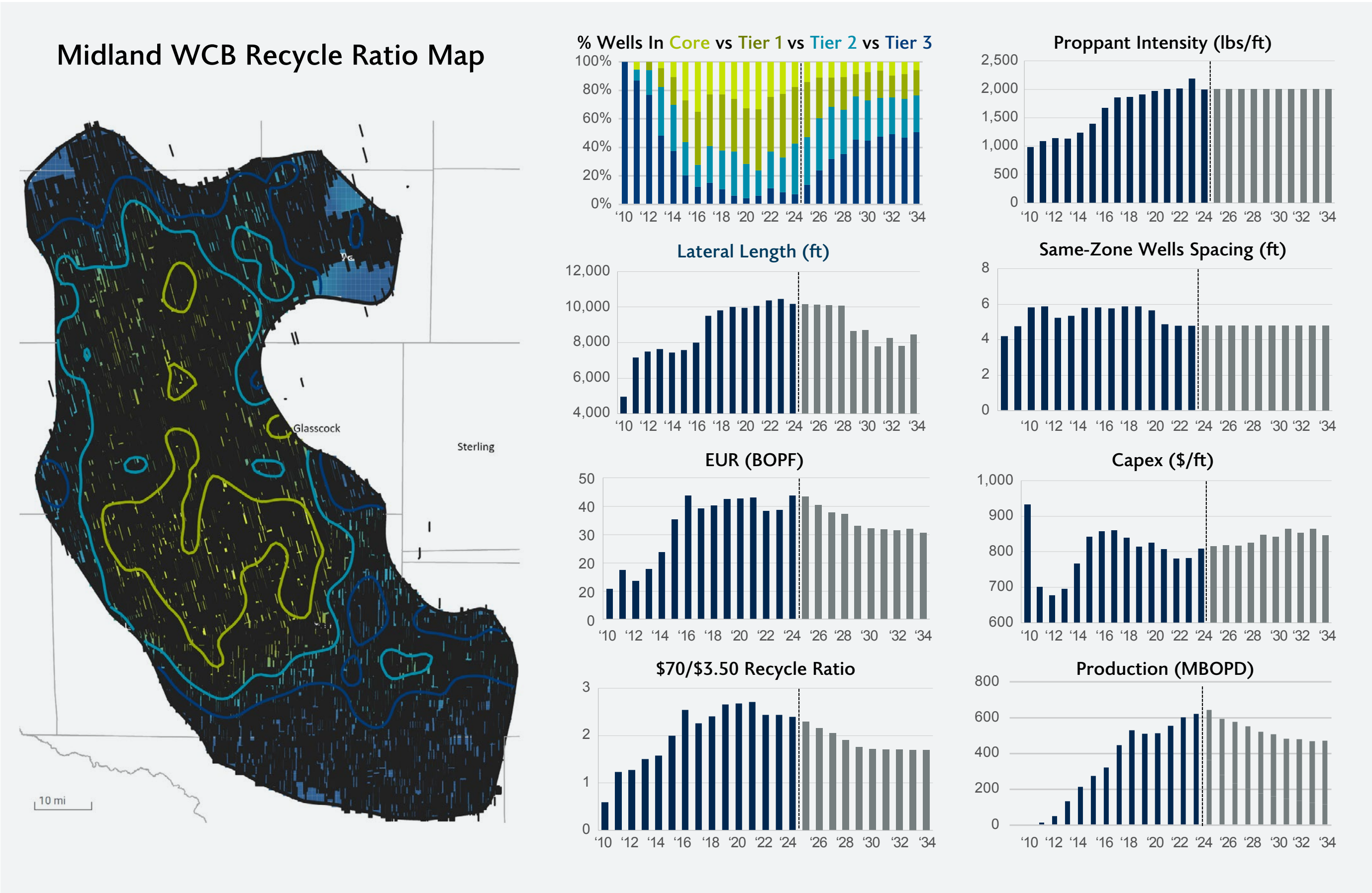


Source: Kimmeridge proprietary analysis. Black sticks are drilled wells.

What is evident from this historical evaluation and future prediction is that by 2024 most of the "Core" and "Tier 1" well inventory, based on recycle ratio, has been drilled. Our prediction is that this completely disappears by 2029, with the focus moving to "Tier 2" and "Tier 3" inventory, which has very much diminished well economics, assuming a world in which oil prices are flat.

Interestingly, in Figure 5, it appears that the inflection point of capital efficiency is behind us, and going forward the recycle ratio in the Basin will continue to fall unless oil and gas prices adjust higher.

FIGURE 5: The End Game for the Midland Basin in 2034



Source: Kimmeridge internal analysis.

Basin Rankings: What Remains?

Despite core plays becoming increasingly exhausted, substantial amounts of high-quality inventory still exist. Specifically, we estimate approximately 60,000 remaining locations with recycle ratios above the 2023 front-end threshold of 2.6x.

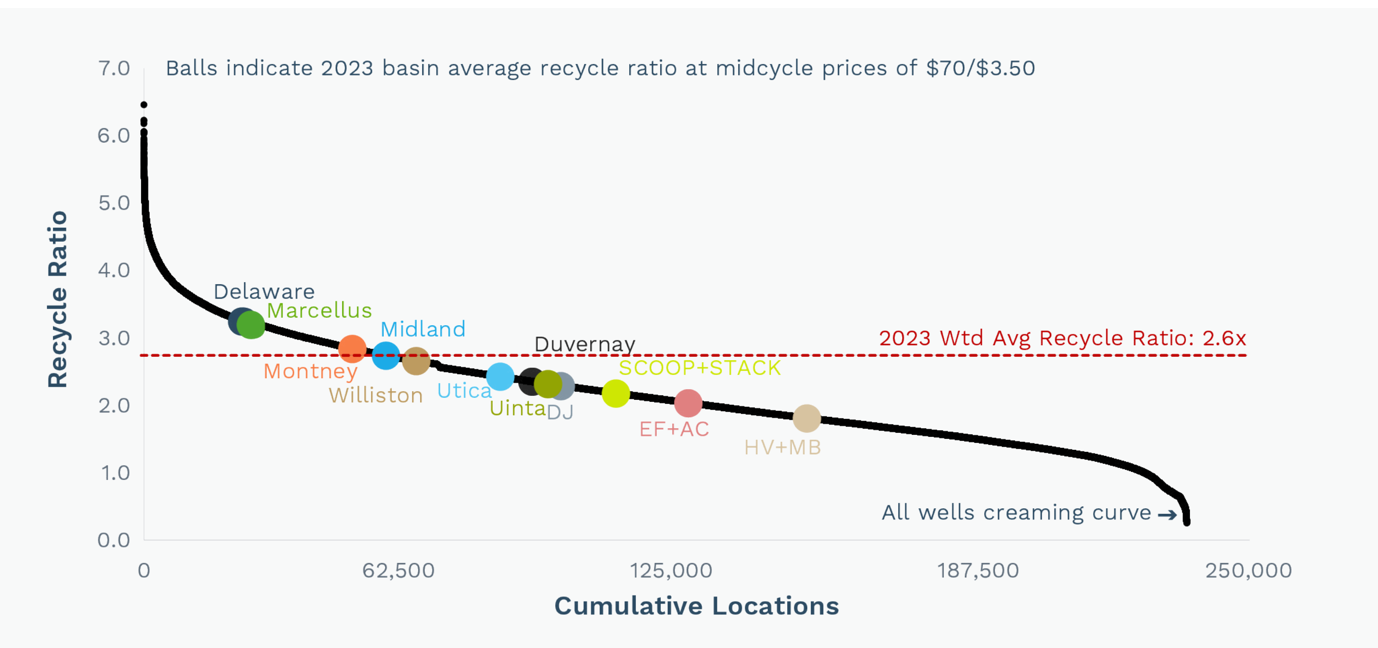
How do the basins compare from an inventory quality standpoint? We believe there are three ways to answer this question.

The first approach is to examine the average 2023 recycle ratios by basin. This analysis helps us identify which basins are currently the most favorable for drilling. Based on this method, the basins would be ranked as follows:

1. Delaware at 3.24x
2. Marcellus at 3.19x
3. Montney at 2.79x
4. Midland at 2.69x
5. Williston at 2.61x

While ranking the basins on the current average recycle ratio is useful, it doesn't tell the entire story. It is an average number, and in a basin that spans a large areal extent and covers the spectrum in rock quality, the average can be pulled down by operators whose best inventory is that which exists in the relatively large Tier 1 or Tier 2 areas (an example would be the Eagle Ford and Austin Chalk plays.) Conversely, some plays can benefit from the opposite situation, where the economics across the play are so challenging that operators are drilling only their absolute best locations, driving the average recycle ratio up and making the basin appear more economical than it really is (the SCOOP/STACK would be one such example). Figure 6 shows the 2023 basin average recycle ratios at midcycle prices against the North American creaming curve.

FIGURE 6: 2023 Kimmeridge Modeled Basin Average Recycle Ratios Against the North American Creaming Curve



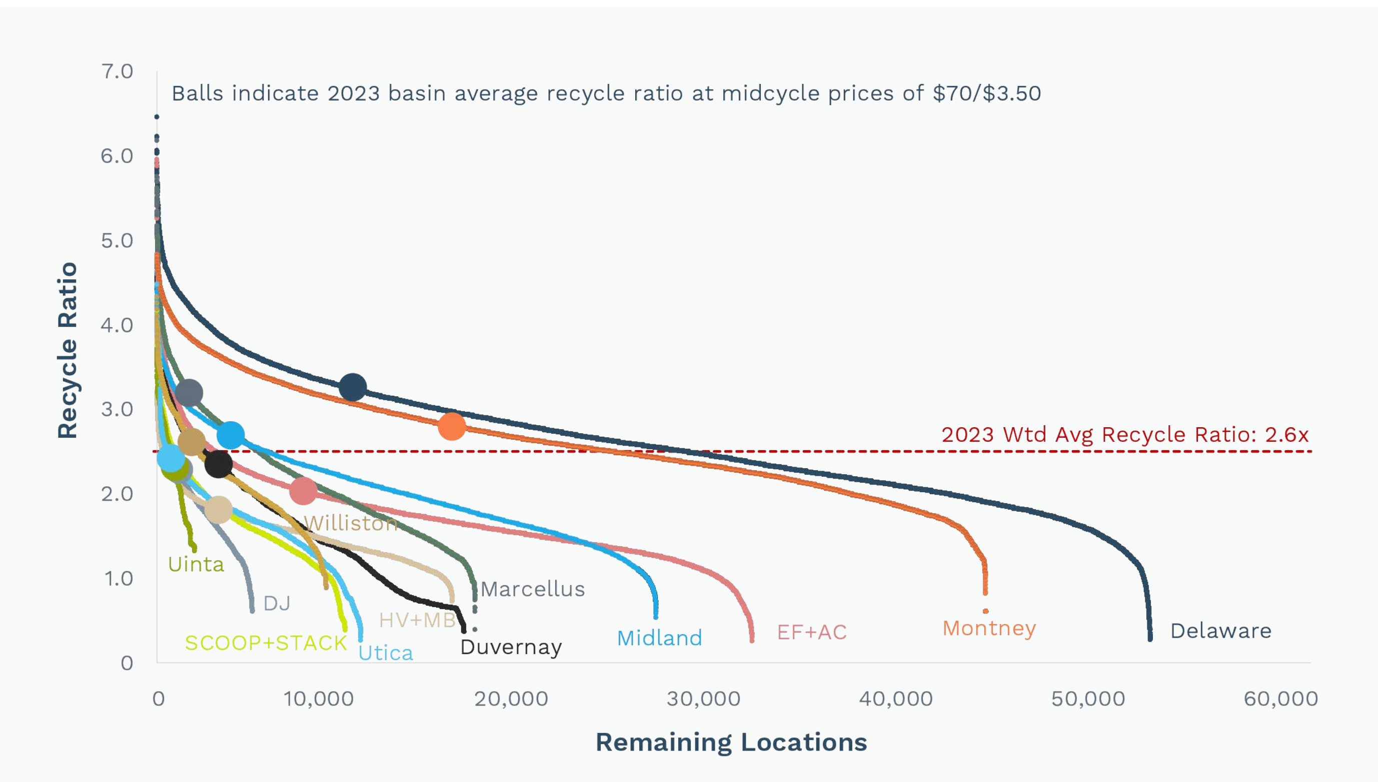
Source: Kimmeridge proprietary analysis.

A second way to compare inventory quality is to count the total number of locations with economics above a certain threshold. For instance, using recycle ratios above the 2023 average of 2.6x, we can rank the basins as follows:

1. Delaware at 24,000
2. Montney at 20,000
3. Marcellus at 4,600
4. Midland at 4,500
5. Eagle Ford and Austin Chalk at 2,400

Ranking the basins in this manner is useful for understanding the overall potential, but it is limited because it ignores the pace of development. A play may have a respectable amount of front-end inventory, but if operators are burning through that inventory quickly, there might not be much opportunity to buy this inventory at a reasonable price. Figure 7 shows Kimmeridge's modeled average recycle ratios against each basin's creaming curve, which adjusts for remaining locations within each basin.

FIGURE 7: 2023 Kimmeridge Modeled Average Recycle Ratios Against Each Basin's Creaming Curve



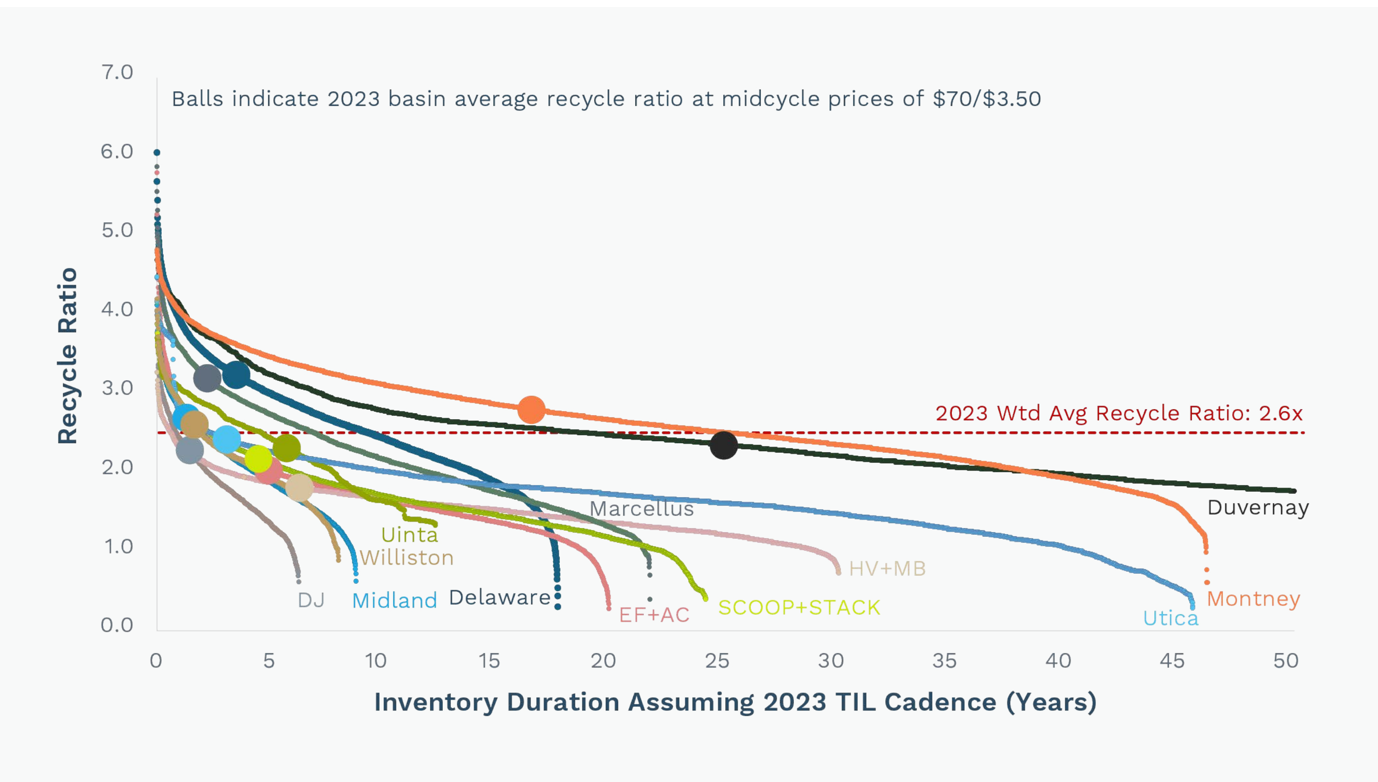
Source: Kimmeridge proprietary analysis.

The third and, in our view, best method to compare inventory between basins is by front-end inventory duration. This means evaluating how long it would take for operators to drill from the highest to the lowest recycle ratio locations at the current activity pace (2023, in this case) until they start drilling below-2023-average wells (i.e., below the average recycle ratio.) Figure 8 shows Kimmeridge's modeled average basin recycle ratio against each basin's duration.

Our analysis suggests the basins can be ranked as follows:

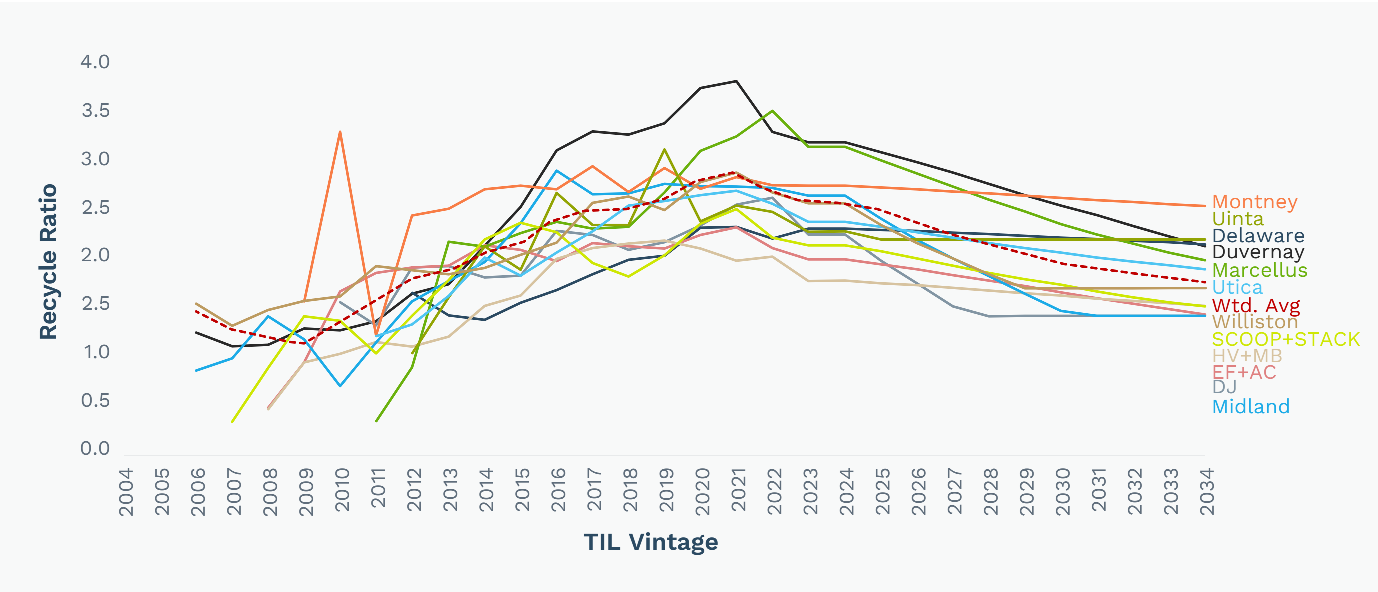
1. Montney at 22 years
2. Duvernay at 15 years
3. Delaware at 8 years
4. Marcellus at 6 years
5. Uinta at 4 years

FIGURE 8: Kimmeridge Modeled Basin Average Recycle Ratios Against Basin Duration



Source: Kimmeridge proprietary analysis.

FIGURE 9: Historical and Projected North American Recycle Ratios Assuming Midcycle Prices



Source: Kimmeridge proprietary analysis.

Our key findings and thoughts from this analysis are as follows:

- **Our Approach Is Ultimately a Simple Extrapolation of Status Quo Development and Productivity Trends.** One area we may be overly optimistic in is modeling economics of secondary benches that are stratigraphically deeper than a primary bench. These types of locations may experience additional costs and productivity degradation due to the shallow pressure and volume depletion created by (earlier) primary bench development. Our modeling assumed operators would co-develop primary and secondary bench locations as much as possible to avoid this economic degradation, which is reasonable; however, every operator is different. We expect economic degradation to be correlative to the difference in time between primary and secondary bench development, and some operators may elect to never drill the location at all due to subpar project economics. However, we may have been a bit punitive in some areas, as well. As an example, our inventory characterization and dispatch methodology assume no major development practices that could improve well economics. There are several technological and development approaches currently being trialed that have this type of potential (ultra-extended lateral lengths [> 2 miles], U-turn wells, multi-lateral horizontal wells, refracking, etc.). We plan to monitor these approaches and update our inventory characterization as they mature. For now, we think these opposing difficult-to-predict forces will roughly offset one another and that capital efficiency trends will approximately follow our prediction.

- **The Pace of Decline Varies by Play.** The rate of decline in each play depends on inventory quality, remaining duration, and historical TIL rates. Certain plays, such as the DJ and Williston basins, are expected to fall off more quickly, while others, such as the Montney, Uinta and Duvernay, may sustain higher returns for longer. Other smaller and currently less active plays to keep an eye on may be the Utica and the Powder River basins.

- **Overall Decline in Front-End Threshold.** Broadly, we expect the annual average North American recycle ratio to decline from ~2.6x in 2024 to ~2.0x by 2030 and ~1.8x by 2034. However, as this is an average, significant variation will exist within each play.

The Good News: A Large Opportunity Set

Even though North American inventory quality and duration have begun to decline, our inventory work gives us confidence that there are still plenty of great investment opportunities out there, some that the general market sees the value of and some that it does not. Furthermore, we believe that our findings give us a competitive advantage, as we can define and acquire high-quality and high-duration assets before they are all spoken for or drilled up in the next 10 years or so. By coupling our inventory work with location acquisition cost assumptions (from internal market research) and proved developed producing (PDP) valuation (from internal analyses), we have developed a ranking system for compelling acquisition targets across North America, ordered by the number of current front-end (≥2.6x at midcycle prices) locations per $100 million of fair value (or "estimated deal size"). This proactive sourcing model empowers us to target specific assets that fit our strategy, rather than waiting for assets to come to market.

This asset-first approach allows us to actively pursue exposure via public markets, joint ventures or private transactions. Though the North American inventory landscape is maturing, it remains dynamic. We believe those who can appreciate the varying factors of its past and present will maintain a competitive edge in unlocking value into the future.

Wrapping It Up: Conclusions and Implications

The Front-End Threshold Is Shifting: The front-end threshold was ~1.3x in 2010, and it gradually increased to ~2.9x in 2021. This steady increase is due to continuous progress in extending lateral lengths, development optimization (landing point, completion design, well spacing), driving capital expenditures ("capex") down through efficiencies (economies of scale, practice, pad development), and preference for developing the best areas of the best intervals first. Since 2021, the front-end threshold has gradually decreased from its peak of ~2.9x to its 2023/2024 position of ~2.6x. This decrease reflects a rate of EUR per foot degradation associated with core interval area exhaustion that is beginning to outpace the rate of capex per foot improvements associated with extending lateral lengths. We believe these trends will continue and that the front-end threshold will be ~1.8x by 2034 barring major technological improvements.

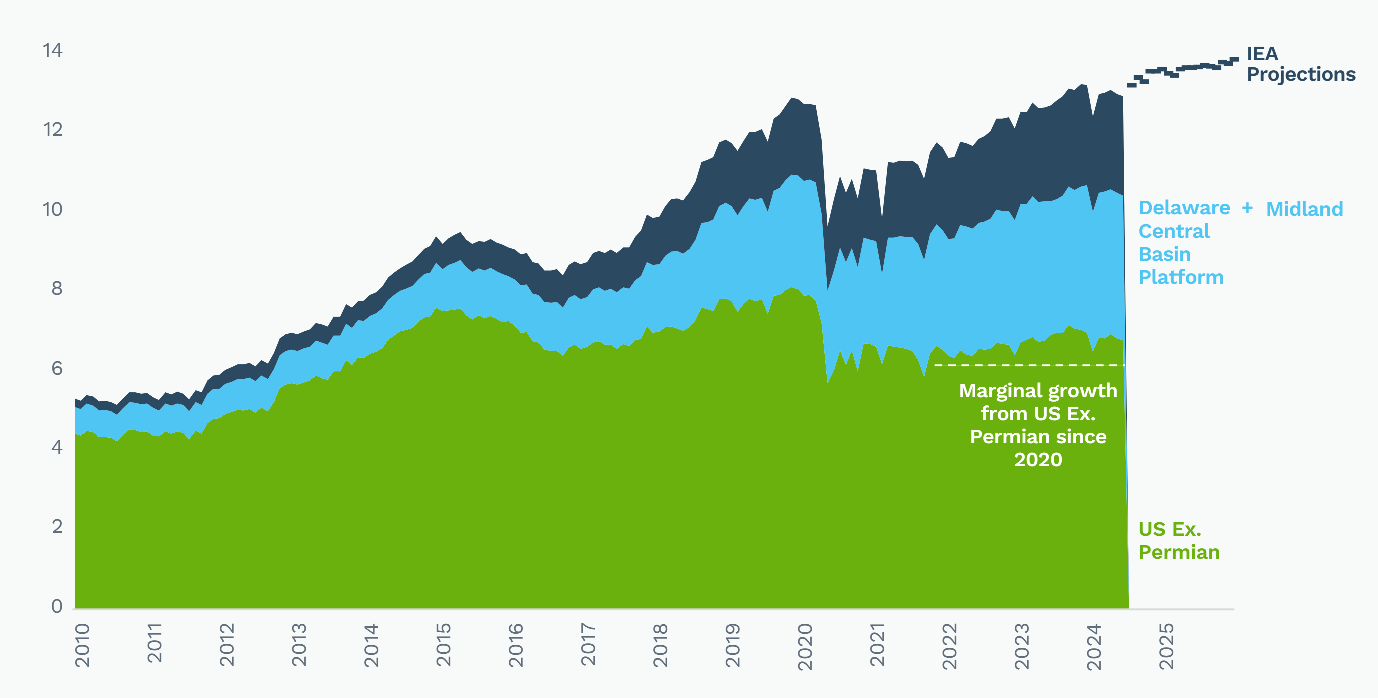
All Basins Have Some Front-End Remaining Inventory: Every major basin has some amount of front-end inventory; however, quantity/duration varies widely. The five plays with the most total remaining front-end inventory as of 2024 are: Delaware, Montney, Midland, Marcellus and Eagle Ford/Austin Chalk. The ranking of the top five basins by average recycle ratio will change over time. Below is our ranking of the top five basins by annual average recycle ratio:

- 2024: Delaware, Marcellus, Montney, Midland, Williston.
- 2029: Delaware, Montney, Marcellus, Duvernay, Uinta.
- 2034: Montney, Uinta, Duvernay, Delaware, Marcellus.

There is still a lot of great inventory out there. We estimate there are 60,000 locations at the front end of the 2024 cost curve. We have identified over 100 assets (operator/basin combinations) with at least 100 front-end locations.

The Step-Change in Production Growth Is Behind Us: We expect that declines in capital efficiency should cause North American production to plateau and ultimately begin to decline over the coming decade. This will likely set a floor for commodity prices longer-term, as the industry will struggle to deliver the hydrocarbons the world demands. This dynamic will also undoubtedly spur further consolidation of the North American E&P sector over the next 10 years, as shale matures. This is best illustrated by studying the production of the Permian basin (since the Permian is responsible for most US production growth since 2010 and practically all of production growth since 2020), within the context of both US and global oil supply (Figure 10). In Figures 4 and 5, we highlighted how one of the most prolific plays in the Midland Basin, the WCB, recently began to plateau in production. We are seeing in this phenomenon in many other plays as well.

FIGURE 10: US Oil Production (MMbbl/d) by Basin and IEA Projections



Source: Kimmeridge Proprietary Analysis, EIA.

Appendix: Recycle Ratios, the Cost Curve and the Front-End Threshold

We wanted this paper to contain some background around our workflow; reviewing key terms and concepts that we have written about in prior research (such as the recycle ratio, the cost curve and the front-end threshold) and providing context for why we use a midcycle commodity price assumption throughout most of the paper. We outline below several sections (a) explaining how we use our differentiated data sets, experience and skill sets to create a differentiated inventory database, (b) discussing the methods we used to validate our predictions, and (c) evaluating which basins have the most inventory (by quality and duration).

As we discussed in prior research,[3] the recycle ratio is a useful economic metric for determining and comparing profitability at the well, asset or company level. Specifically, we have discussed in depth how the proved developed recycle ratio can be determined at the company level from Form 10-K data and is useful for comparing capital efficiency both between companies in a given year as well as for the US oil and gas industry through time. In its simplest form, the recycle ratio calculation is:

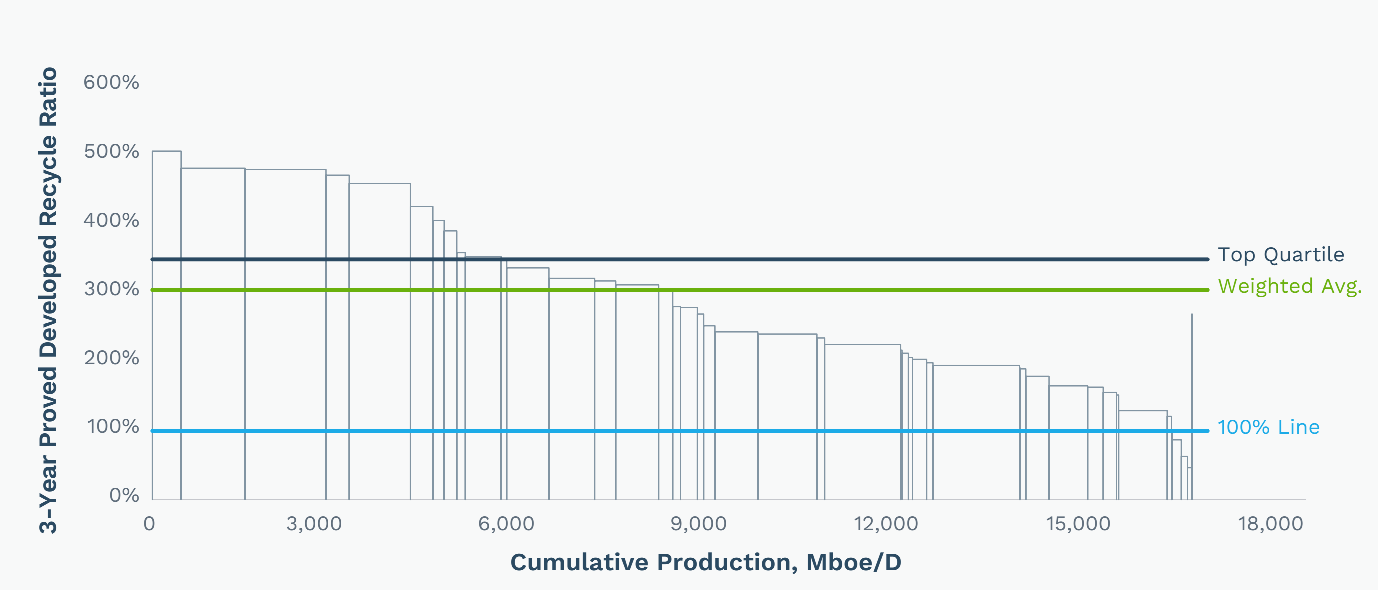
$$\textit{Recycle Ratio} = \frac{\textit{Operating Cash Flow Per Barrel of Oil Equivalent (BOE)}}{\textit{Find \& Development Cost Per Barrel of Oil Equivalent (BOE)}}$$

Said another way, the recycle ratio is the operating cash flow generated per barrel produced divided by the cost to add a barrel of reserves to replace it. This metric indicates whether you are generating enough cash flow to replace the barrels you are producing, and therefore can grow economically through internally generated cash flow. As an example, a recycle ratio of 200% (or 2.0x) means the operator is generating $2 for every $1.00 invested. A recycle ratio of 50% (or 0.5x) means the operator is only generating $0.50 for every $1.00 invested, which suggests capital is not being invested in an efficient manner.

When a company's proved developed recycle ratio is greater than the US production-weighted average, we say that wells the company drilled during that period sit at the "front end of the cost curve." Please see related note on the preceding in-text reference to Figure 11. shows the US cost curve for the most recent period and the weighted average proved developed recycle ratio (green line). Throughout this paper, we refer to the weighted average recycle ratio for a specified population of wells as the "front-end threshold."

[3] Refer to our previous research piece, "All-In-One"

FIGURE 11: US Cost Curve for Most Recent Three-Year Period (2021-2023)



Source: Internal US Cost Curve Database, Form 10-Ks.

Why is it important to invest at the front end of the cost curve? Locations that sit at the front end of the cost curve will not only generate better-than-average single well returns at average (or "midcycle") commodity prices (~$70/BO and $3.50/MMBtu; Figures 12 and 13), they are also the locations that give operators the highest probability of weathering periods of below-midcycle commodity prices.

FIGURE 12: Historical Monthly WTI Oil Price Data and Trailing 20-, 15-, 10-, 5-Year Averages

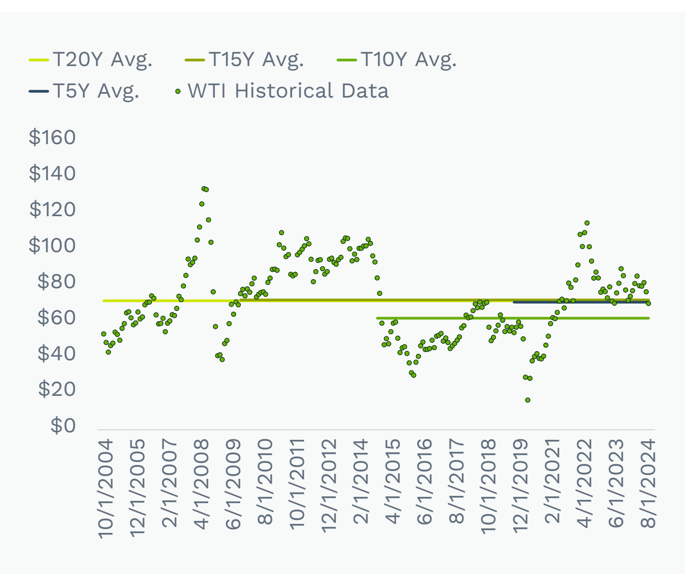
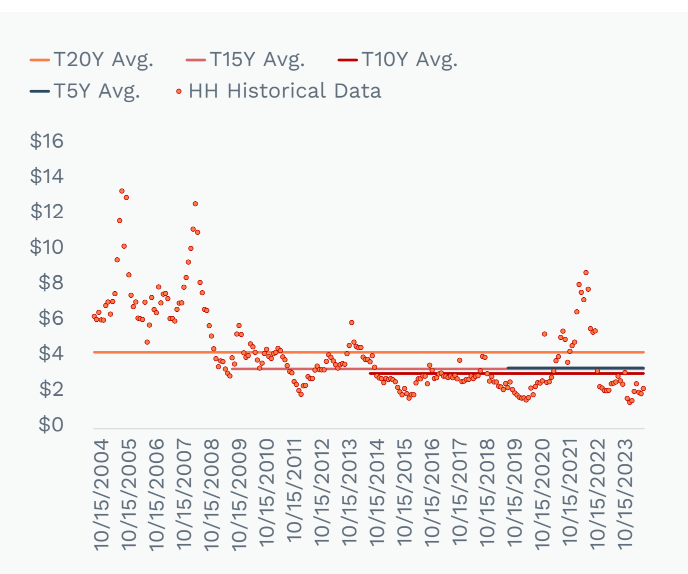


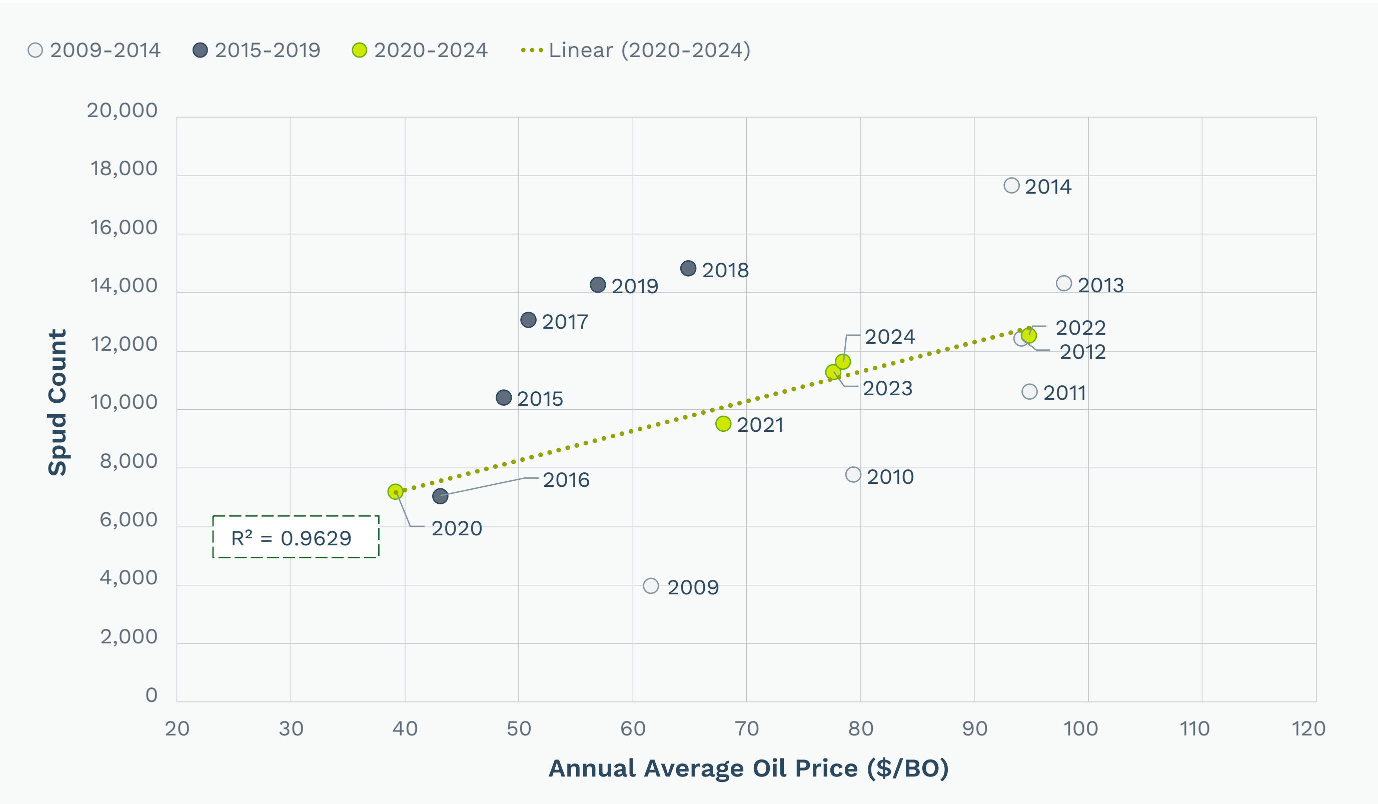
FIGURE 13: Historical Monthly HH Gas Price Data and Trailing 20-, 15-, 10-, 5-Year Averages



Source: EIA.

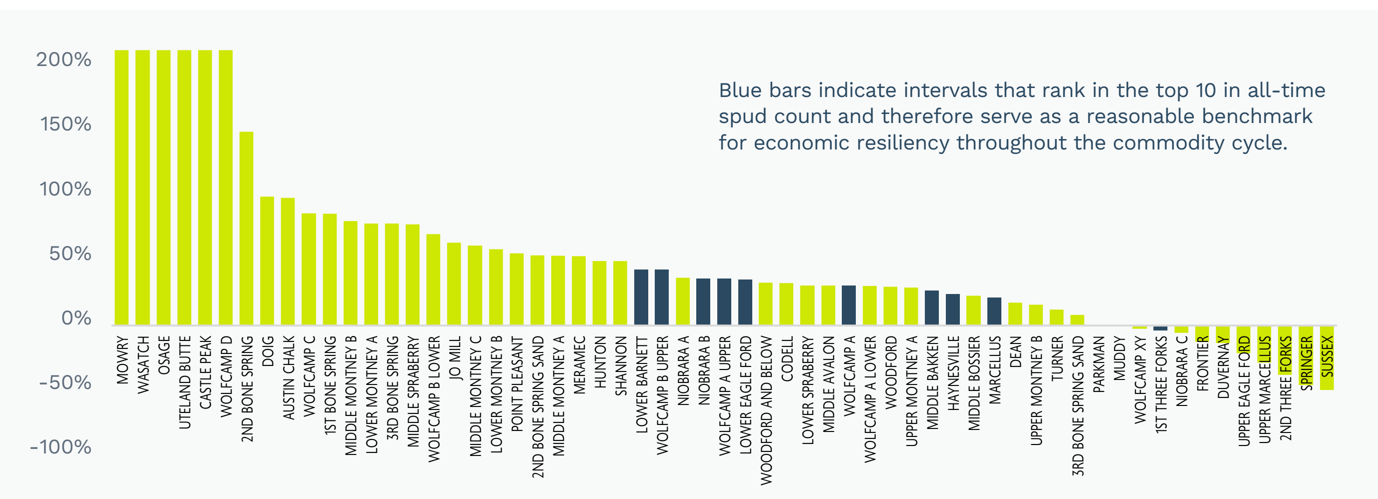
Since 2020, Lower 48 (or "L48") spud counts[4] and oil prices have been highly correlated (Figure 14). Not surprisingly, the change in activity levels is largely driven by lower-quality locations (Figure 15). Lower-quality locations that need higher commodity prices to be economic should be the first to be abandoned when prices fall, which is confirmed by the data in these figures. As an example, in 2020 the spud count was around 7,000 locations, as average oil prices were in the 40s. Since the rise in prices following COVID, we've seen a resurgence in the spud count.

FIGURE 14: Historical Spud Count for the Major L48 Basins vs. Average Oil Price



Source: Enverus, EIA.

FIGURE 15: Percentage Increase in Spud Counts From 2020 to 2021 by Play in Major L48 Basins



Source: Enverus, EIA.

[4] The term "spud" refers to the beginning of the drilling process on an oil or gas well.

Modeling Future Inventory: Building a Differentiated Data Set

The US shale industry is nearing 20 years of activity, with thousands of wells drilled across hundreds of basin/bench combinations. Our goal was to identify which remaining locations were most likely to sit at the front end of the cost curve as a function of time and inventory exhaustion. To accomplish this, we first needed to build and populate an inventory database that housed key parameters for all remaining locations (given some governing assumptions); parameters such as position coordinates, basin name, interval name, true vertical depth, lateral length, child designation,[5] stimulation details, spacing details, estimated ultimate recovery (EUR), capex, operator, commercial parameters and various economic metrics.

Kimmeridge's deep expertise across geology, engineering, data science and economics positions us well to build such a database. We built our inventory database in four major steps:

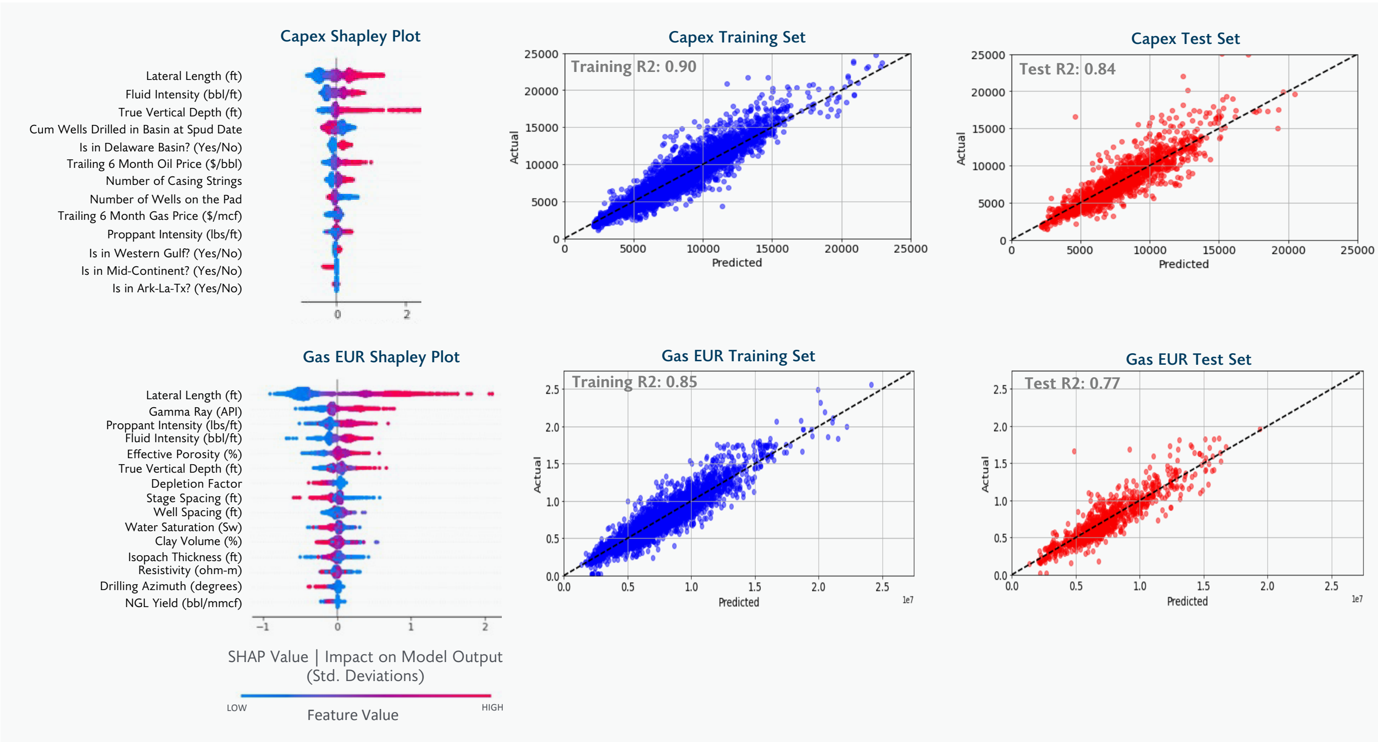
Step 1: Build and Train Machine Learning (ML) Models

The first major step in our analysis was to build and train ML models for two key metrics: estimated ultimate recovery and capex across 25 major oil and gas plays. The goal was to better understand the complex relationships between parameters in driving outcomes and to enable predictions for future wells based on input assumptions. To assess the impact of each input variable on the model's outcome, we utilized Shapley plots.[6] These plots allow us to understand the contribution that each variable has on the outcome and to evaluate its relative importance in the model. For training, we used 70% of the available data ("actuals") to train the ML model. We used the remaining 30% as blind test validation to ensure out-of-sample accuracy. In Figure 16, we show some typical model outputs for the Haynesville play as an example.

[5] The term "child" refers to a well that is drilled following and near an existing well. Since being put on production, the existing (or "parent") well has depleted some resource and pressure from the reservoir. This "depletion" can and often does negatively affect the child well's production profile. We want to be able to identify these locations to account for the lower performance expectations.

[6] A Shapley plot shows the contribution of each variable to an ML model's prediction in a way that is visually interpretable. Each point on the plot represents a prediction. Variables that have large and spread-out values on the plot tend to have a significant impact on the model's predictions. Smaller and tighter values indicate less impact.

FIGURE 16: Montage of Shapley and Validation Cross Plots for Haynesville Gas Estimated Ultimate Recovery (EUR) and Capital Expenditures



Source: Kimmeridge proprietary ML models.

Step 2: Establish Commercial Assumptions Models

The second major step in our process was to establish a framework for estimating key commercial parameters for any given well location. To build the "training data," we sourced information from a variety of places, including Kimmeridge-operated assets, data rooms we have participated in, and public E&P financial statements. We modeled several parameters—including net revenue interest (NRI), basis differentials and effective tax rates—to be constant across the inventory. In contrast, parameters such as shrink, NGL yield, and operating expenses were made to be dependent on mapped fluid phase properties. Figure 17 illustrates the average mapped value[7] for each of the eight commercial parameters by basin.

FIGURE 17: Average Mapped Value for Each of the Eight Commercial Parameters by Basin

Parameter	8/8ths NRI	Gas Shrink	NGL Yield	Oil Diff	Gas Diff	NGL Diff	AV + Sev Tax	Op Expenses
Units	%	%	Bbl//MMcf	$/BO	$/MCF	% WTI	% Revenue	$/BOE
Montney	100%	93%	14	-3.0	-1.3	30%	12%	7.0
Delaware	80%	68%	112	-2.4	-1.9	30%	7%	8.4
Western Gulf	75%	69%	82	-1.0	-0.5	30%	5%	12.2
Williston	80%	72%	86	-5.0	-1.0	30%	8%	12.0
Midland	76%	71%	90	-2.4	-1.9	30%	7%	8.1
Ark-la-tx	80%	100%	11	-1.4	-0.4	30%	7%	5.6
Appalachian	84%	72%	60	-12.0	0.0	35%	4%	13.1
Duvernay	100%	52%	35	-4.0	-1.0	37%	14%	10.1
Anadarko	75%	71%	80	-2.0	-1.0	30%	7%	12.0
Denver-Julesburg	80%	72%	70	-2.6	-1.8	30%	8%	8.5
Uinta	80%	81%	0	-15.0	-3.0	30%	6%	12.6
Utica	84%	90%	60	-10.0	0.0	30%	4%	6.0

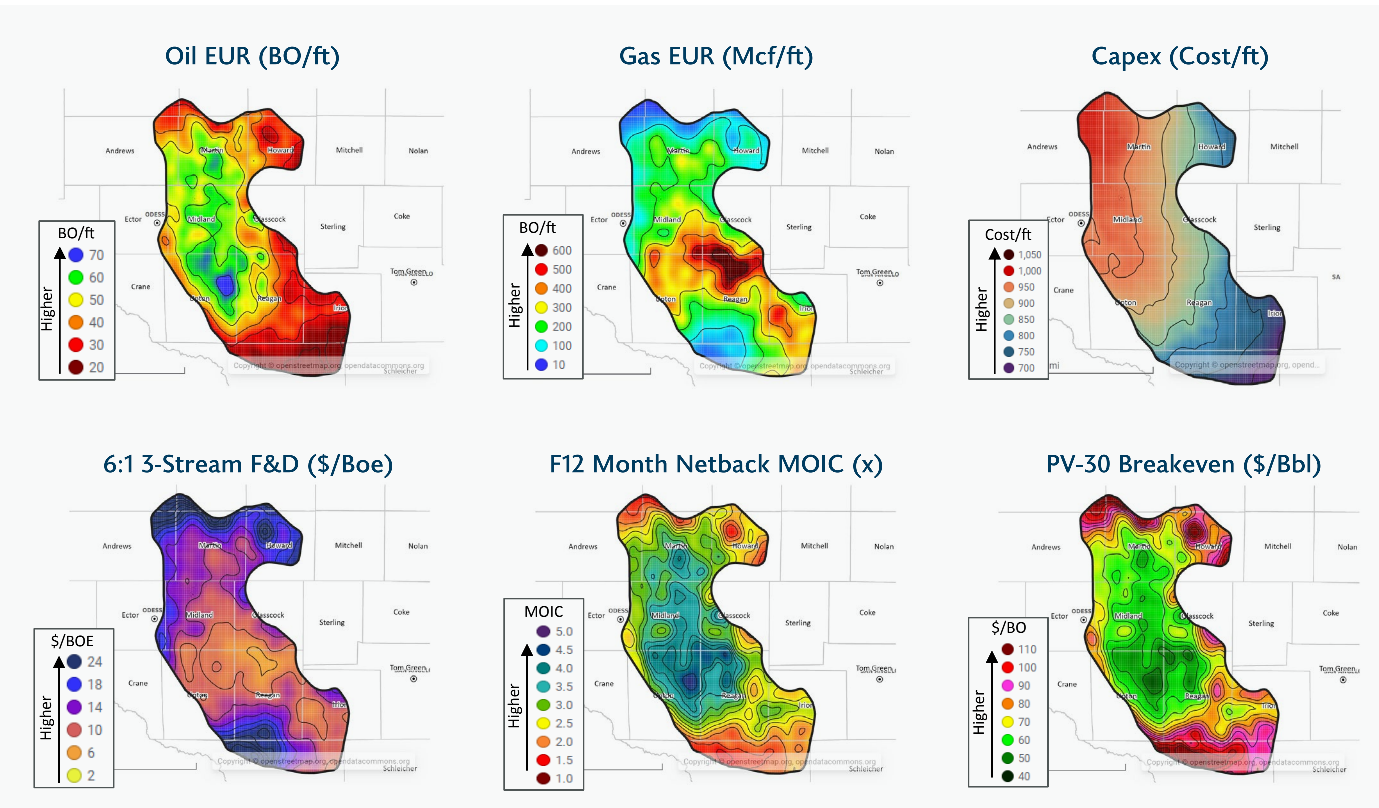
Source: Kimmeridge proprietary Commercial Assumption Database.

[7] The average mapped value refers to the mean, or typical, value of a particular parameter (or set of parameters) that has been "mapped" or calculated across each play.

Step 3: Make Standardized Maps

The next step in our process was to establish standard, go-forward well spacing and completion design assumptions for each play. We then used our trained ML models to predict EURs and capex across each play under these assumptions, ultimately generating standardized maps for EURs, capex and economic performance. These maps now help us identify spatial trends and pinpoint the specific areas (or "zip codes") within the play where we are most likely to want exposure. Figure 18 shows an example of mapped predictions for the Midland Basin Wolfcamp B play.

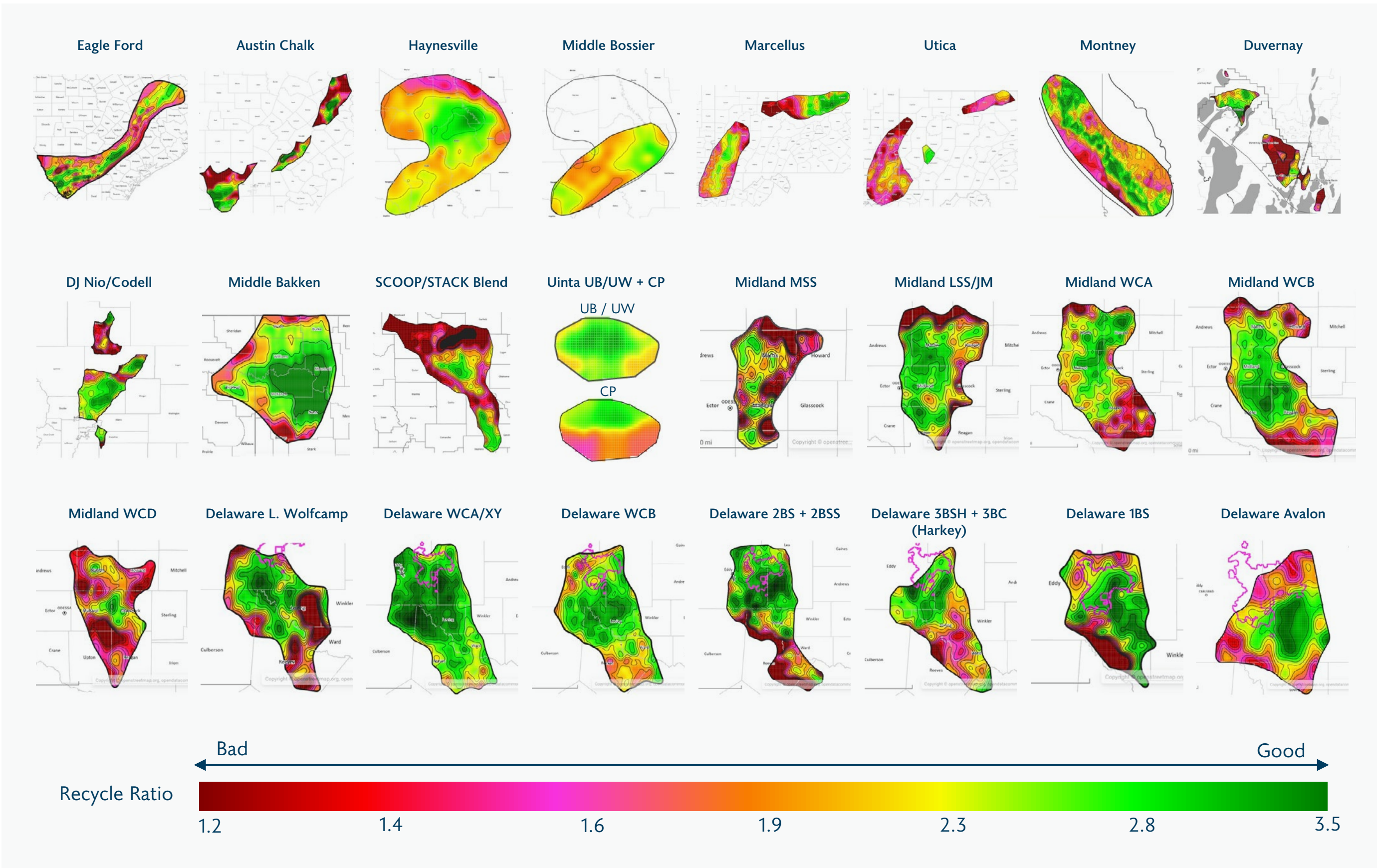
FIGURE 18: EUR, Capex and Economic Predictions for the Midland Basin Wolfcamp B Play



Source: Kimmeridge proprietary analysis. Assumes 10,000-foot lateral lengths, 2,500 pounds per foot, and 50 barrels per foot.

Figure 19 effectively shows the recycle ratios one might expect if we developed all 25 major plays all at once and with modern development practices, as if the play were a blank slate. Unfortunately, this is not the case. The montage shows standardized recycle ratio maps at midcycle prices, generated using this process.

FIGURE 19: Standardized Recycle Ratio Maps for the 25 Major North American Plays



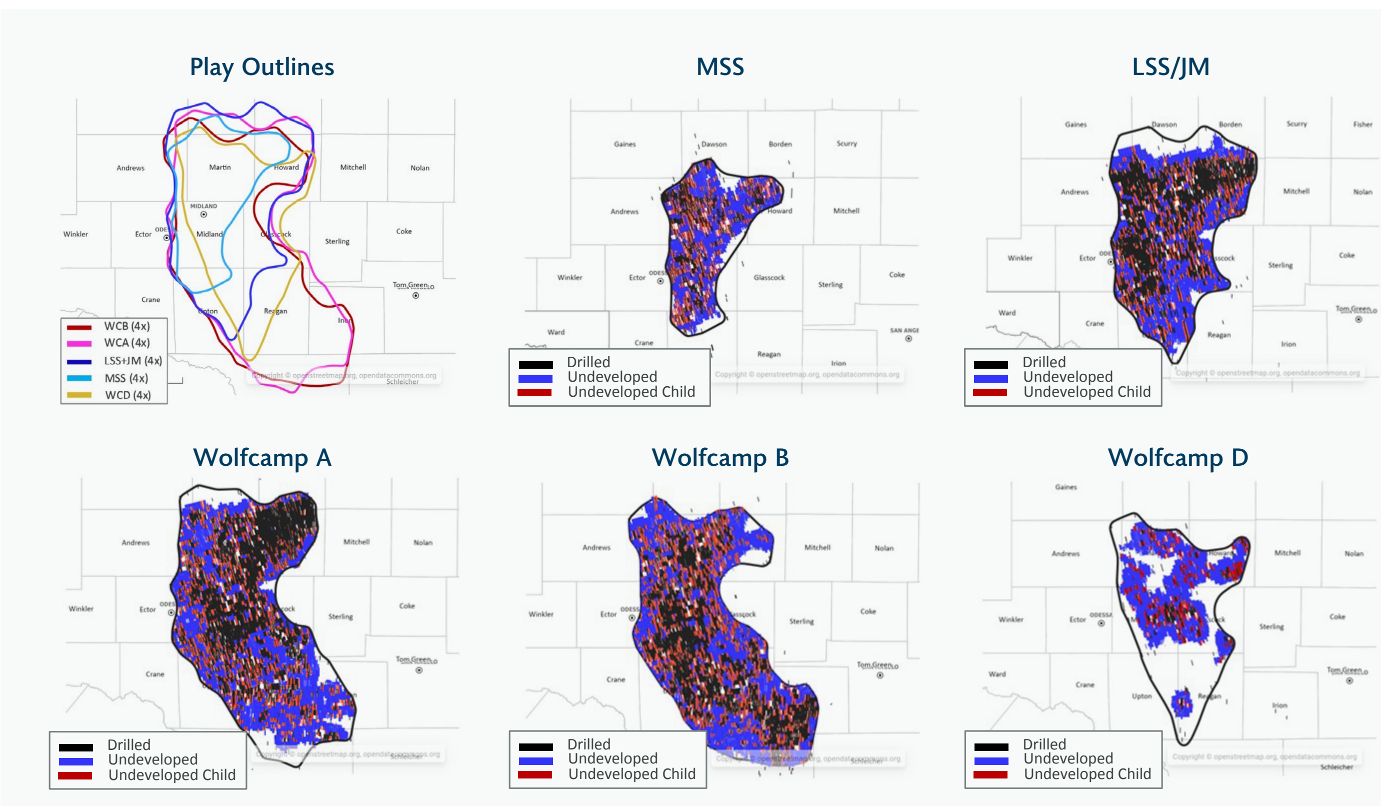
Source: Kimmeridge proprietary analysis.

Step 4: Construct Inventory Shapefiles and Database

The final step in our process utilized our in-house geographic information systems (GIS) expertise to create "shapefiles" representing the remaining inventory in North America. Using the same well spacing assumptions from the standardized mapping workflow, we extrapolated inventory shapes between existing wells and out to the basin edges. Each location was credited with as much lateral length as possible, given nearby offsets and land constraints. Each remaining location required a modern well within a five-mile radius. Key details—such as lateral length, child designation, likely operator, true vertical depth, and completion design—were populated for each location. EUR and capex predictions were then extracted from the nearest mapped grid point and scaled based on the actual lateral length of each location. Finally, commercial assumptions were applied to calculate the well's recycle ratio at midcycle $70 oil and $3.50 gas prices.

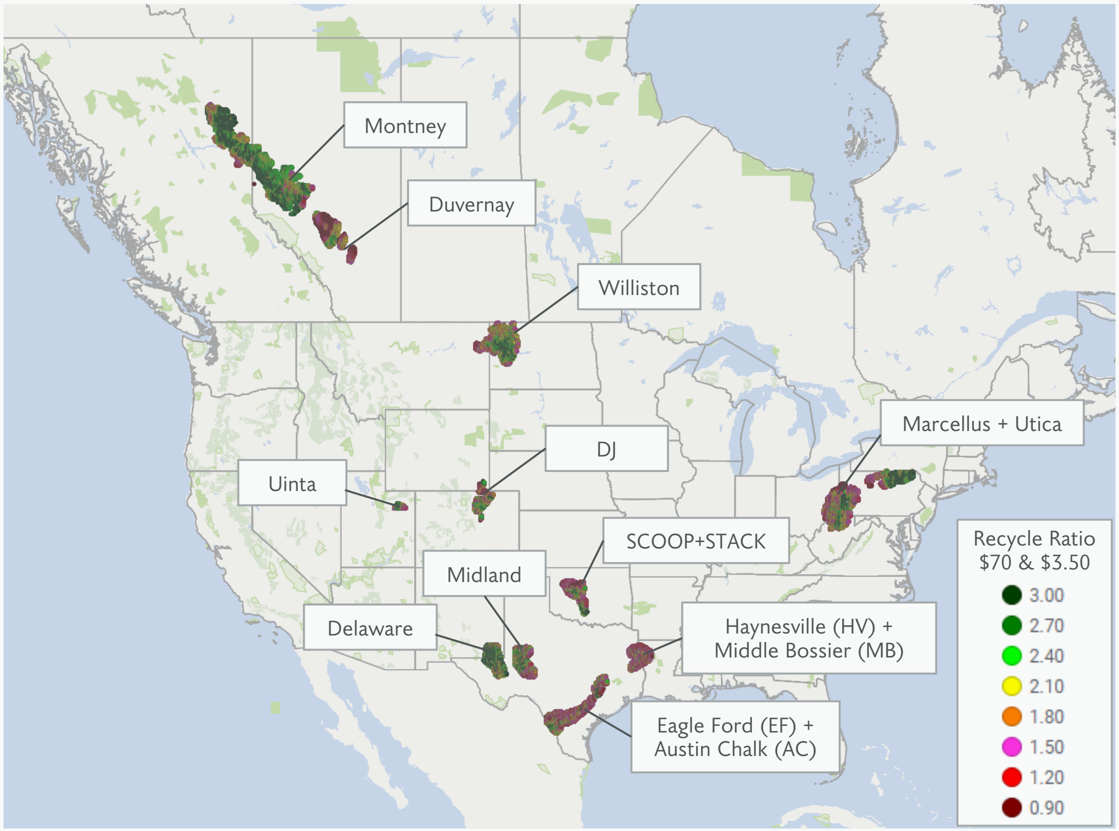
As an example, Figure 20 illustrates basin outlines and inventory credit for five plays in the Midland Basin. In all, this process yielded ~240k remaining locations across the 25 major plays, which accounts for ~20 years of inventory at the 2023 TIL[8] pace. When combined with the ~160k producing wells that served as our training & test sets for our EUR ML models, our inventory database covers ~400k (drilled and undrilled) locations. Figure 21 shows our database's coverage against a map of North America.

FIGURE 20: Basin Outlines and Inventory Credit Given for Five Midland Basin Plays



[8] TIL = "Turn in Line" and represents the moment when a well starts producing oil and/or gas.

FIGURE 21: Kimmeridge's Map of Remaining North American Inventory



Source: Kimmeridge proprietary analysis.

Comprehensively Validated: Ensuring Prediction Accuracy at the Micro and Macro Scales

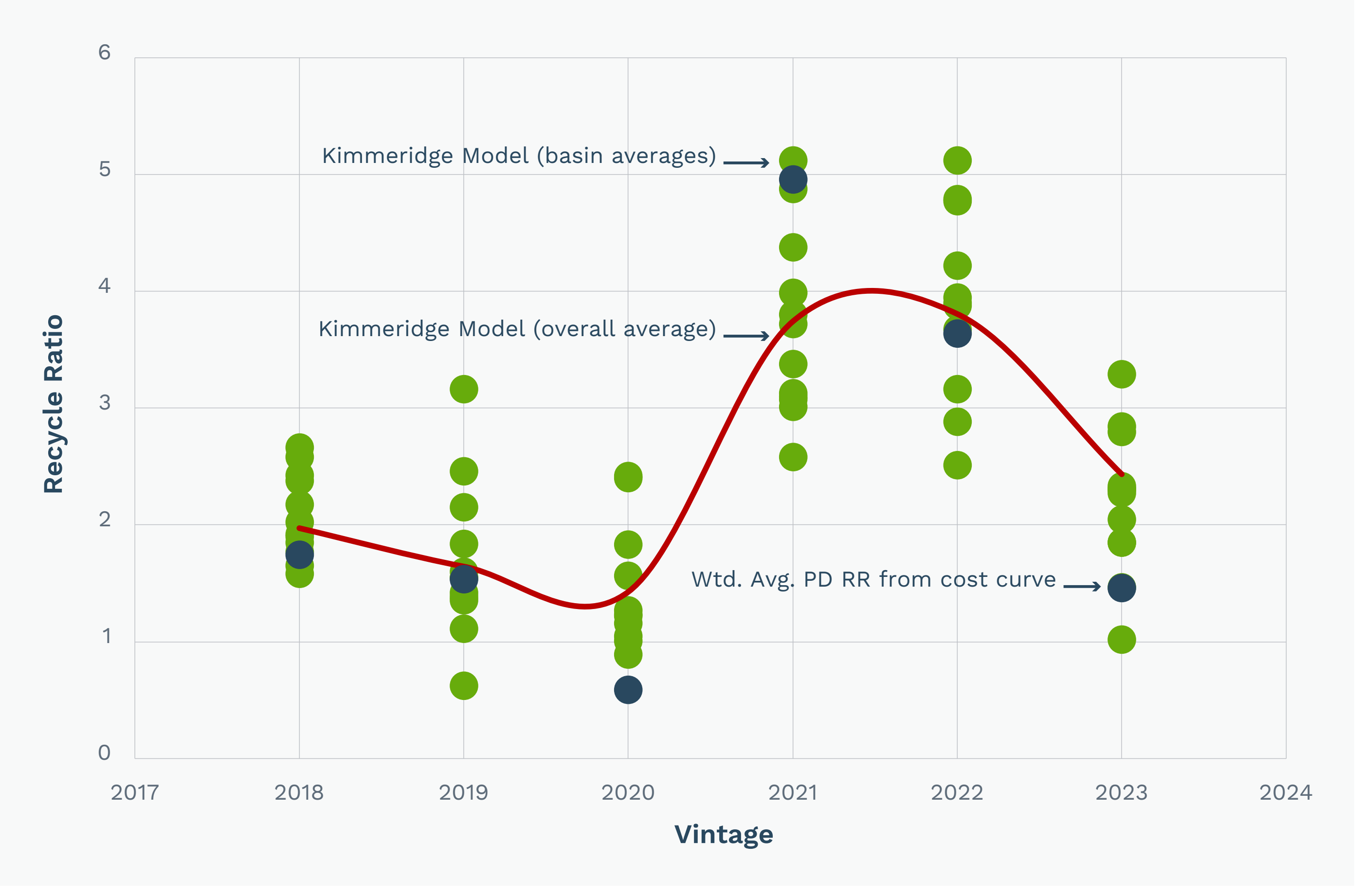
Prior to use, we sought to validate the accuracy of our predictions. As we discussed earlier, we train our machine learning models using 70% of the available data set. The trained model is then used to predict the values of the remaining 30% of data points, allowing us to assess out-of-sample accuracy. This approach is an effective way to validate our predictions at the micro level.

We also wanted to validate our predictions at the macro level. We did this in three distinct ways.

The first exercise was to see if by using our recycle ratio calculation framework we could directionally re-create the historical one-year production-weighted average proved developed recycle ratios determined from the US cost curve (company-level 10-K data). The first step was to forecast the EURs for all wells drilled across the 25 major plays and apply the same commercial assumptions as those used in Figure 16 (on page 17) to calculate each well's lifetime operating cash flow. The commodity prices were unique for each well and assumed the next-six-months' average price for West Texas Intermediate (WTI) and Henry Hub (HH), following the well's TIL date.

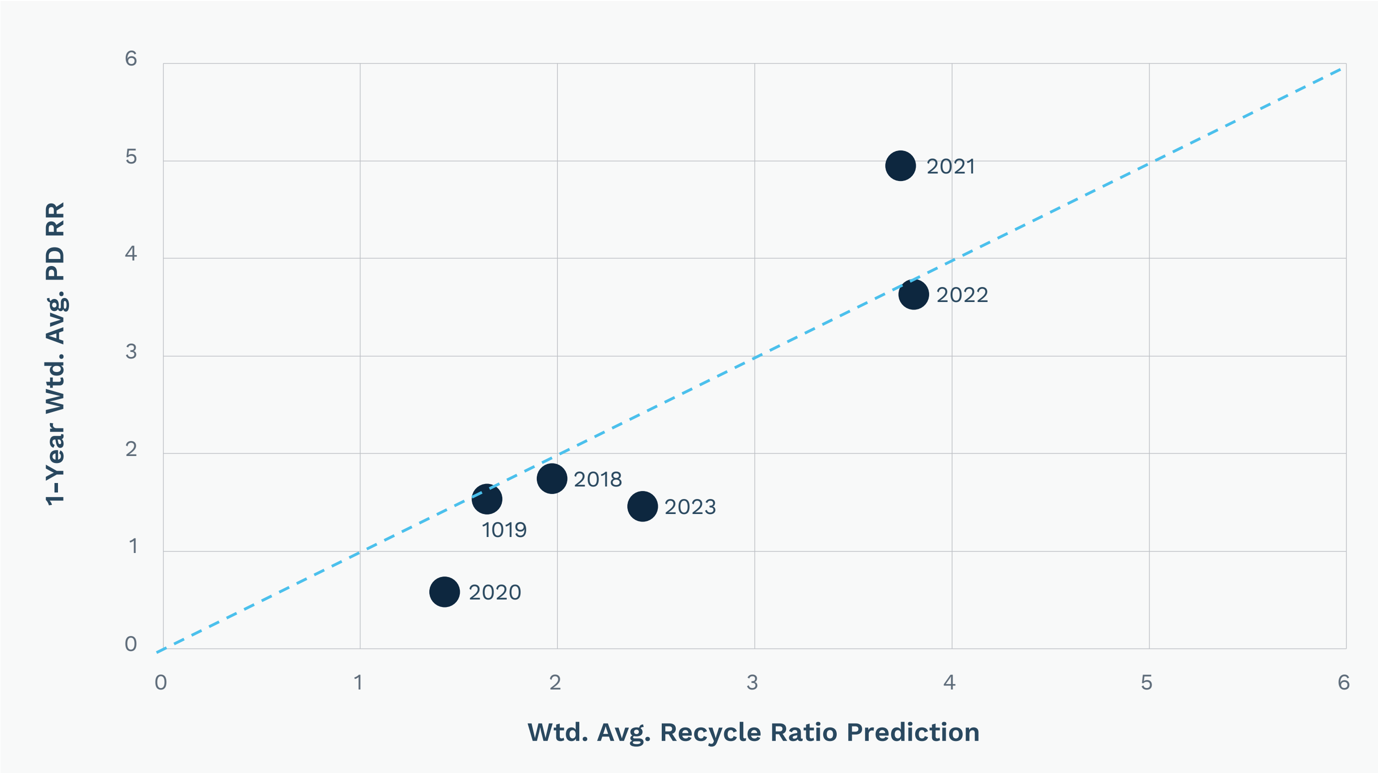
Next, we utilized our ML capex model to estimate each well's capex based on its unique basin, depth, completion design, trailing 6-month average commodity pricing and applicable inflation considerations. Finally, the well's lifetime operating cash flow was divided by its capex to arrive at its unique recycle ratio. Figure 22 demonstrates that our calculations closely align with the historical one-year production weighted average proved developed recycle ratios from the US cost curve. Figure 23 shows that the proved developed recycle ratio data derived from the cost curve tend to be 15-25% lower than those determined from our model. This discrepancy arises because the operating cash flow metric in the proved developed recycle ratio calculation includes some corporate costs (such as DD&A, non-cash incentive compensation and deferred taxes), whereas our well-level recycle ratio predictions do not.

FIGURE 22: Kimmeridge Modeled Recycle Ratio vs. the Wtd. Avg. Proved Developed Recycle Ratio From the US Cost Curve



Source: Kimmeridge proprietary analysis.

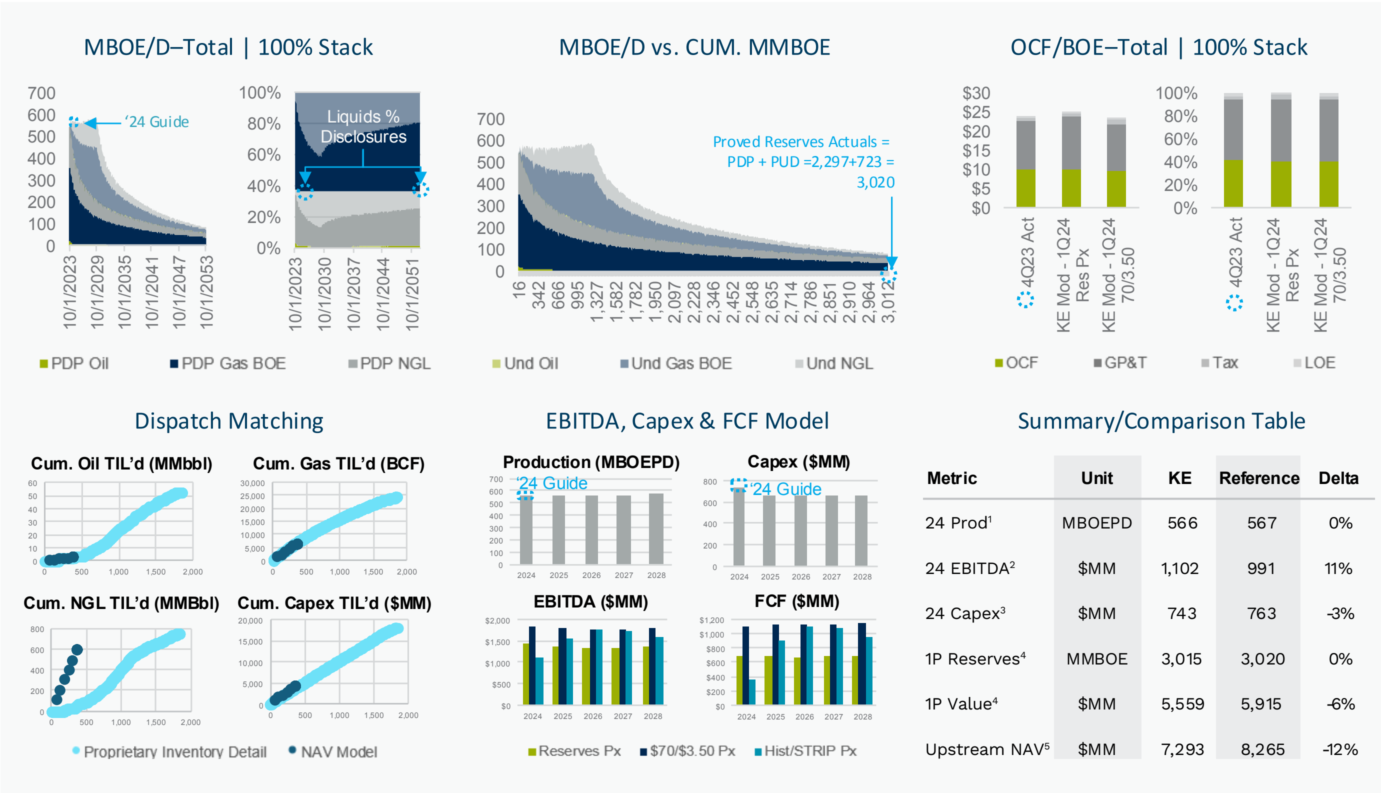
FIGURE 23: Cross Plot of Kimmeridge Modeled Recycle Ratio vs. the Wtd. Avg. Proved Developed Recycle Ratio From the US Cost Curve



Source: Kimmeridge proprietary analysis.

The second method was to ensure that we were able to use our inventory detail as direct input assumptions into a valuation model and tie out to various production, EBITDA, capex and net asset value metrics for publicly traded company guidance and public filings. Figure 24 showcases a comparison of modeled 2024 production, 2024 EBITDA, 2024 capex, 1P reserves, 1P value and Upstream NAV and how they correlate well with very high-quality reference/validation data points.

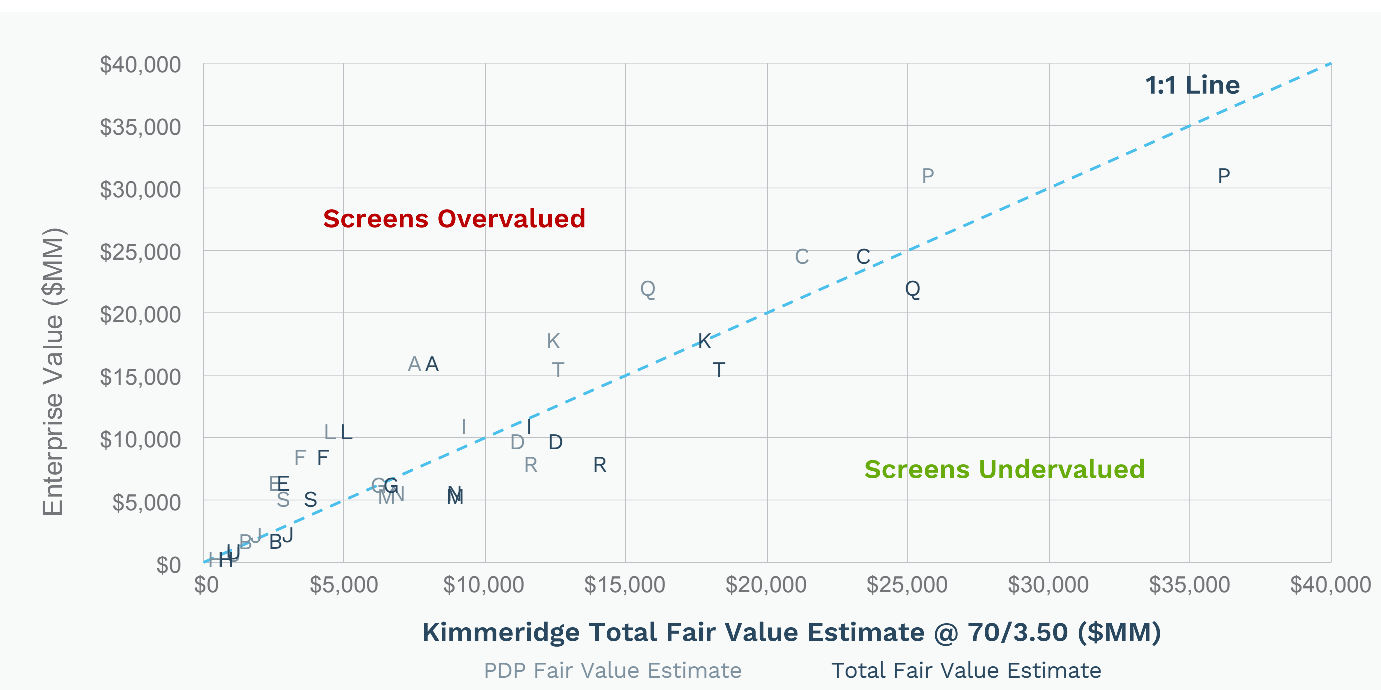
FIGURE 24: Montage of Visuals Comparing Our NAV/Cash Flow Model Inputs and Outputs vs. Various Calibration Points



Metric	Unit	KE	Reference	Delta
24 Prod[1]	MBOEPD	566	567	0%
24 EBITDA[2]	$MM	1,102	991	11%
24 Capex[3]	$MM	743	763	-3%
1P Reserves[4]	MMBOE	3,015	3,020	0%
1P Value[4]	$MM	5,559	5,915	-6%
Upstream NAV[5]	$MM	7,293	8,265	-12%

Source: Kimmeridge proprietary analysis. 1. Reference is August company guidance. 2. KE quoted at Hist/Strip Px scenario. Reference is September Consensus. 3. Reference is August company guidance. 4. Reference is YE23 Reserves report disclosed in 2023 form 10-K. 5. Unhedged PV-10 at strip. Reference is Enverus 2Q24 upstream NAV estimate.

FIGURE 25: Cross Plot of Kimmeridge Estimated Total Fair Value vs. Current Enterprise Value for 42 North American E&P Companies



Source: Kimmeridge proprietary analysis.

The final method we employed was to leverage our inventory work to generate "fair value" estimates for publicly traded L48-focused E&Ps and ensure some general agreement with the companies' enterprise values. For our purposes, the fair value equation is:

*Fair Value = PDP PV-10[9] + (Current Front-End Location Count[10] * Estimated $ Per location)*

The "total fair value" is the summation of all the fair value estimates across a company's portfolio. Figure 25 shows our total fair value estimate at midcycle prices against each company's enterprise value.[11] We have also included the total fair value estimate assuming no credit for the company's undrilled inventory, meaning the value is derived solely from PDP assets. Our method of characterizing fair value for undeveloped locations clearly provides additional explanatory power in understanding each company's enterprise value.

Having validated our inventory predictions at both the micro and macro scales, we are able to leverage the database to yield insights into the inventory and investment landscape with great confidence.

[9] PDP PV-10 refers to the present value discounted at 10% for the proved developed producing reserve category. Simply put, PDPs are those wells that are currently producing oil and/or gas.

[10] Current Front-End Location Count refers to the number of locations with a recycle ratio ≥2.6x at $70/$3.50.

[11] As of November 2024.

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