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U.S. UNCONVENTIONALS

$10 Billion of cash — and even more in value — laying on the factory floor

Wood Mackenzie

Unconventional operators can unlock up to $10 billion of cash which could be reinvested to deliver up to $65 billion of potential revenue. What would it take to unlock this potential?

The US oil and gas industry responded to the 2014 price crash by significantly reducing well breakeven costs across liquids unconventional plays from a median of $76/barrel in 2014 to just under $50/barrel in 2018. While this achievement has been praised by investors, many are concerned that the cost reduction was cyclical rather than structural and that the industry will revert to old habits now that oil prices are rising. The current challenge for the industry is to generate free cash flow while also growing production. To do that, operators must ensure tight and sustained control over how much of their cash is tied up in the well production system.

Analytics from our North American Well Analysis Tool (NAWAT) imply that operators do not have as tight a control on costs, cycle times and the efficient use of cash as they often suggest in investor presentations. Frequently, they reference only the best-performing wells in the best areas rather than the operating and financial efficiency of the overall well factory. Wood Mackenzie estimates that at least $26 billion in cash is tied up in what is commonly known as the well factory, in the form of drilled uncompleted wells (DUCs) alone (as defined by the EIA). We recognize that some level of capital will always be tied up in the form of DUCs, and that there are a variety of reasons for this including strategic choice. But Wood Mackenzie and its partner Strategic Project Solutions (SPS) have found that operators can unlock up to 40% ($10 billion) of this cash simply by upgrading from the current well factory approach to a truly optimized well production system.

If utilized efficiently, the $10 billion of unproductive capital could deliver an additional 1,000 to 1,500 producing wells, which translates into a staggering $40 to $65 billion of revenue (real terms) over the life of the wells.[1] Alternatively, operators can use the cash released for debt reduction or return it to shareholders via buybacks and/or dividends.

While these numbers are large in terms of value, we believe this is just the tip of the iceberg. For this example we are only calculating the impact of DUCs and do not take into account the billions of dollars of cash tied up in other activities (e.g. engineering, land/permitting, field development plans, etc.) We believe this value leakage is a substantial issue for the industry, and that operators can and must do better to manage it.

This article is the first in a series addressing value leakage in relation to the existing well factory approach compared to a true well production system. Subsequent articles will offer more in-depth and detailed insights on individual company performance, why this situation has occurred, and how operators can reduce their levels of unproductive capital.

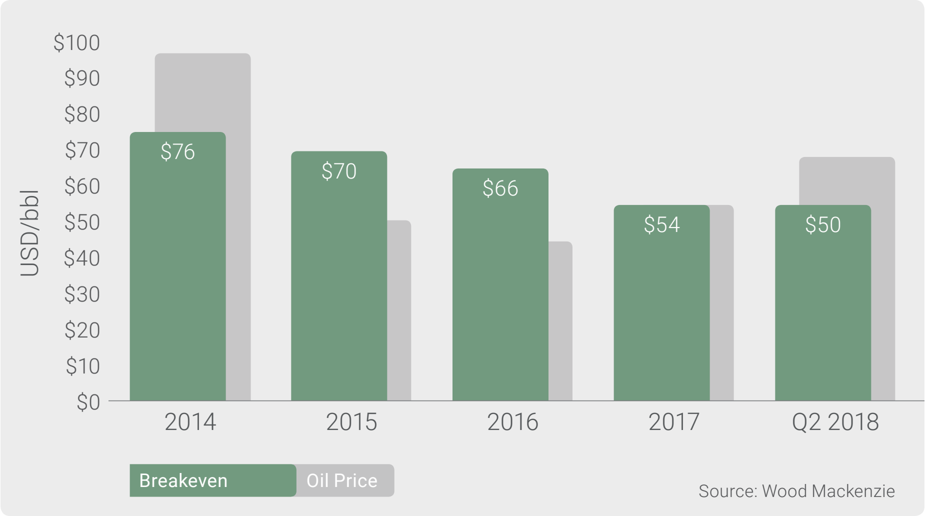
[1] Assumes revenue split of 60% oil at $70/bbl; 15% NGL at $35/bbl; 25% natural gas at $2.75/MMBtu

Unconventional operators have achieved a $26/barrel reduction in well breakeven costs; was it a crash diet or a lifestyle change?

Unconventionals (UCs) have become the success story of the oil and gas industry, helping the US to become the largest gas and liquids producer and the world's most flexible oil producer. However, UCs require a different approach to field development than the industry has historically taken due to the sheer number of wells to be drilled, associated requirements of coordination, and the required speed of decision-making (among others). Following the price crash in 2014, operators undertook multiple initiatives to reduce costs and become more efficient. These included negotiating lower service and equipment costs, improving productivity through technology/learnings, reduced headcounts, de-scoped or deferred investment, and drilling their more productive well locations first (including those nearest to infrastructure).

This improvement has resulted in the industry successfully working on both sides of the breakeven equation: higher field and well productivity as well as reduced costs. As a result, the median wellhead breakeven cost in US unconventional liquids plays has fallen by almost 35% from $76/barrel in 2014 to $50/barrel in Q2 2018 (Figure 1). However, this reduction in breakeven cost is still below the ~50% drop in oil price from 2014 to 2016.

Figure 1: Opportunity Lost? - Median WTI Breakeven Cost for US Unconventionals versus Oil Price



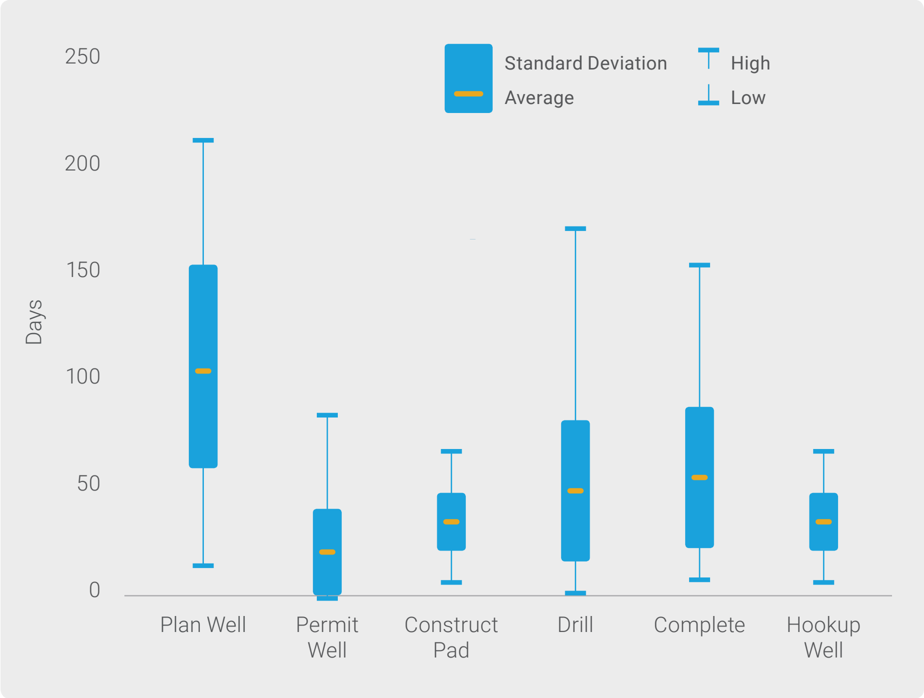
Interestingly, many operators claim that the driving force behind achieving the reduction in breakevens was the application of the current well factory approach. We argue that while they may have nominally created a "factory" model, the gains to date were largely a result of cyclical and incremental improvements and localized efficiencies rather than the structural change required to deliver the full benefits possible from a true well production system. As a result, most operators do not have an integrated, efficient well production system, and our NAWAT data reflects this.

High variability in performance implies the current well factory approach is not a truly optimized well production system.

A symptom of the current well factory approach is high variability in costs and development time. Variability in the context of a production system is defined by the Project Production Institute (PPI)[2] as non-uniformity or variation in operating parameters that occur in the course of executing the work activities.

Figure 2 shows an example of the variability of time it takes for one operator to "produce" or deliver a well through the well production system. The chart shows the average, the standard deviation and the minimum and maximum cycle times for each operation. Drill time, for example, took an average of 48 days and had been as low as 10 days and as high as 165 days, with a standard deviation of 30 days. This variability exists in any well production system, but investor presentations often do not reflect this reality. The failure to understand and address this variability and its consequences results in higher costs and the inefficient use of time and cash.

Figure 2: Variability in Cycle Time for Key Operations of an Example Well Production System (one operator in one play for similar wells)



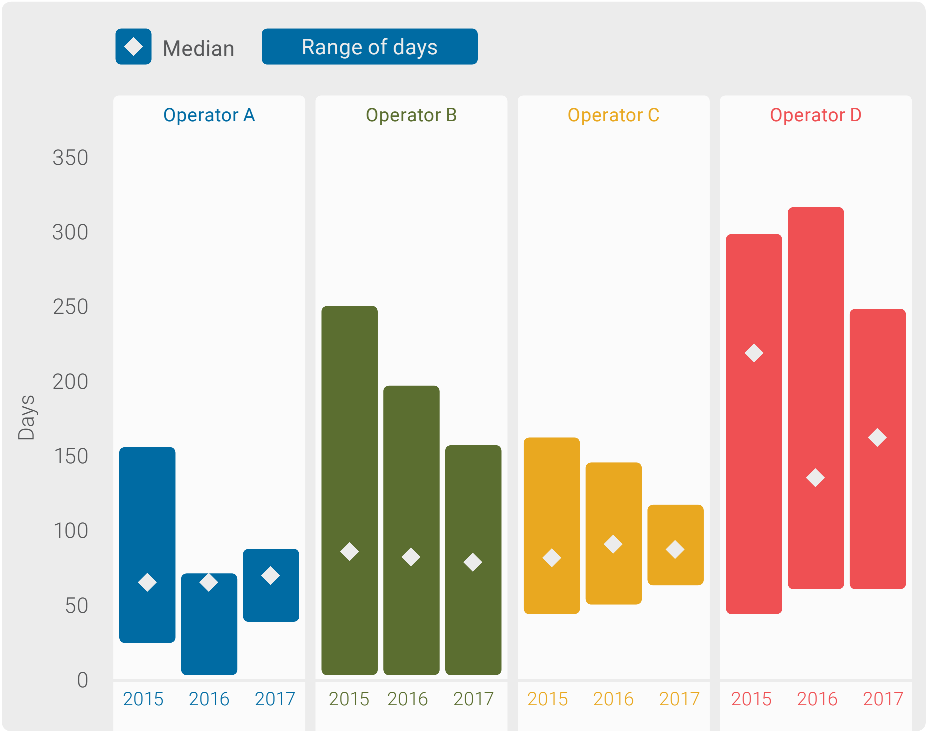
Source: SPS

[2] Project Production Institute (PPI) is a not-for-profit organization dedicated to education, awareness and dissemination of operations science to capital projects. http://projectproduction.org/resources/glossary/

If we take a closer look at well data across operators in the same sub-play over time, we see a similar picture with significant differences in cycle times across operators. Figure 3 shows the range of days and the median days between the end of drilling and the end of completion for a sample set of operators in the Midland "Deep Basin" sub-play over time (includes Howard, Midland and Martin counties).

While the median days are quite similar across players and time, the variability inherent in their current well factories is significant. Operator C appears to have the tightest control over its cycle time, with low variability and a competitive median. Operator D, on the other hand, shows high variability in its operations. While some of the observed variability is good, as it recognizes design changes or operating changes which add value to the business, we also argue that too much variability is bad, demonstrating complexity and inefficiency in UC operations. This variability can also increase costs and development time, which results in unnecessary locked-in cash.

Figure 3: Variability of Time between Drilling End and Completion End for Sample Set of Operators in the Deep Basin Midland Sub-play



Source: Wood Mackenzie NAWAT

* Sample set operators have drilled at least 5 wells in each year shown; wells analyzed are comparable on laterals/frac stages/depth

Inefficient systems lock up cash; DUCs are one symptom of an inefficient well production system.

A true well production system reduces cycle time, which increases project value and frees up capital. With the variability we are seeing in cycle times today, both within one operator in one play and across all operators in the same play, current well factories are clearly not as efficient as they could be.

We stated as we opened this discussion that UC developments have trapped at least $26 billion of cash, of which $10 billion could rapidly be made available for re-investment or returned to shareholders. To get to the $26 billion, we looked at the current level of 8,000+ DUCs across the US multiplied by an average cost of $3.2 million for all well costs, excluding completion and tie-in. Based on the experience of Wood Mackenzie and its partner Strategic Project Solutions (SPS) in modeling, optimizing and controlling well production systems, we estimate that up to 40% of this cash ($10 billion) could be recycled back into the business or returned to shareholders. The opportunity cost of not reinvesting that $10 billion of cash represents $40 to $65 billion of lost revenue.

Efficient well production systems generate only the inventory necessary to ensure a smooth flow through the factory, and variability disrupts this flow. Excessive inventory before or after any operation is an indication of system inefficiency. In this example, excess DUCs represent one type of unnecessary inventory within the well production system. Assuming that the operators of these wells would not consciously choose to tie up $10 billion in unproductive capital, these DUCs are a symptom of an inefficient well factory.[3]

[3] To simplify the calculation we only considered the drilled uncompleted (DUC) inventory in UC developments (as defined by the EIA). This simplification excludes the inventory elsewhere in the development process, such as wells completed but not put on production (possibly due to offtake constraints), well pads completed prematurely or not ultimately utilized due to a change of plan, and many other sources of trapped cash.

What does an efficient well production system look like?

In other industries, factory and system characteristics such as variability are modeled, optimized and controlled through the application of operations science.[4] Efficient manufacturers are systematic and relentless in their pursuit of higher quality products at lower costs and faster time to market. This systematic approach extends to the entire supply chain, is integrated to a high degree, and is seen as a critical part of the overall production system. This is an "and world" regardless of the external market environment. We believe there is sufficient data to challenge E&P companies on whether they have the level of insight and control required to deliver and sustain a highly efficient well production system.

Figure 4 shows a simplified view of a typical well factory or well production system, from well scoping all the way through to handing the well over to be put on production. The well production system shows the individual operations required to "produce" a well, including well scoping, planning, permitting, pad construction, etc. In addition, it recognizes the "inventory" of knowledge work, materials and executed work which is "waiting" between each operation as identified by the green triangles. Whatever form this inventory of work takes, too much or too little of it in each green triangle will result in unproductive capital (cash tied up) and inefficient operations (higher cost and longer duration).

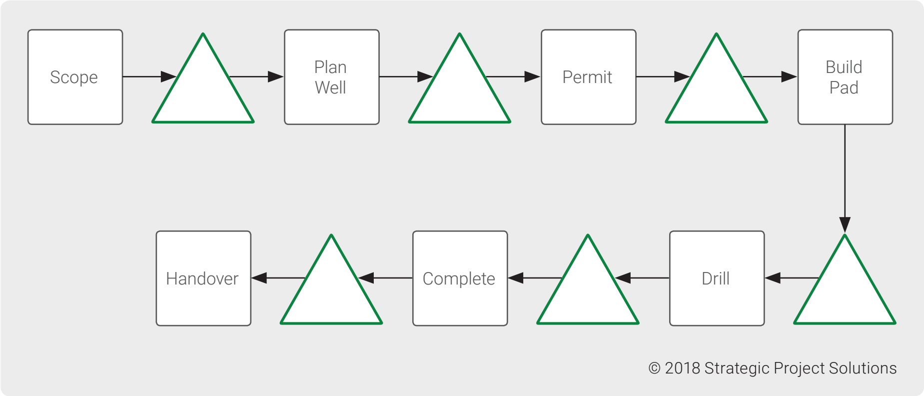


Figure 4: A Simplified Unconventional Well Production System

To free up this unproductive capital, companies must understand their optimal well production system both within and between operations. In our experience, many oil and gas industry executives know the time and cost within an operation (e.g. drilling days and drilling cost/well), but few know what the time and cost is between operations. Even fewer know what the time and cost "should be" for optimum performance. Understanding this is critical to controlling cash tied up and the associated value leakage.

[4] W.J. Hopp and M.L. Spearman, Factory Physics, Third Edition Waveland Press Inc., 2011; E.S. Pound, J.H. Bell and M. L. Spearman, Factory Physics for Managers, McGraw-Hill, 2014.

Implementing a true well production system can unlock billions of dollars of value and drive capital efficiency.

To master a well production system, operators must move beyond the current well factory approach of locally optimizing each operation in the factory, treating it like an assembly line on which each operation must be fully utilized, and focusing on the isolated performance of each operation (e.g. drilling, completion, flowback). In our experience, this approach does not optimize the overall system. Instead, operators could more fully understand and implement a true well production system focusing on optimizing business performance.

In a recent project, we identified a $300 to $500 million reduction in cash required to deliver 200 wells over one year simply by optimizing the current factory system. This required the counterintuitive action of reducing the work being executed in the system, despite requests to put more in the front end of the process. The system view itself showed that this merely added cash requirements without increasing the number of wells delivered by the system. Since these dynamics are counterintuitive for many leaders in oil and gas, understanding them becomes critical for effective decision-making in a well production system.

With up to $10 billion of cash and $65 billion in lost revenue on the table, this implies many operators have at least $1 billion of revenue at stake.

This is the new reality. Now that industry executives are aware of the problem, they should seek to understand the value implications for their company and prepare themselves to address investor concerns on the efficiency of their well production system and any associated value leakage.

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