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Maximizing Well Deliverability in the Eagle Ford Shale Through Flowback Operations

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Abstract

Flowback procedures for wells producing from sub-normally or normally pressured reservoirs are usually straightforward and non-technical due to the short flowing periods that are inherent with low pressure wells. Over-pressured formations can naturally flow for several months and even years. However, uncontrolled procedures can potentially affect the well productivity and its profitability. Flowback techniques for wells flowing from over-pressured reservoirs can vary widely and have a significant impact on short and long term economic performance.

This paper focuses on the evolution of flowback operating procedures for wells in the Eagle Ford shale play and highlights how these procedures can impact short and long term well performance. The workflow demonstrates how choke management, or drawdown strategies, can influence potential damage mechanisms in the reservoir, completion and wellbore. Techniques are then presented for using rate transient analysis (RTA) that allows for a robust understanding of early time well performance while also monitoring for damage downhole. The data shows that using RTA with high frequency data to help drive operational decisions during the flowback period can deliver optimal drawdown procedures and maximize well deliverability. This in turn maximizes time sensitive economic metrics by taking full advantage of variables like the well's completion efficiency and stimulated volume.

The drawdown management workflow outlined in this paper has proved to significantly outperform predetermined choke procedures that have historically been common practice in industry. Results also show how practical field applications of technical interpretations can be used on a daily basis to significantly increase value and drive operational efficiencies in the field while minimizing the potential risk of damaging the completion.

Introduction

In 2013, Devon Energy acquired producing acreage in the Eagle Ford shale play in South Texas. The core of this field is located in the volatile oil and retrograde condensate windows in DeWitt County. Multi-stage fractured horizontal wellbores (MFHWs) have been used to develop this field since 2008. Currently, most of the acreage in Dewitt County is being developed with infill wells. With this environment, the primary focus has been directed towards maximizing the value of the core acreage.

The Eagle Ford shale is upwards of 250 feet thick and is commonly broken into Upper and Lower intervals, with the latter being the primary target. The Lower Eagle Ford primarily consists of carbonate and shale, with the best intervals having little clay content. The Lower Eagle Ford is an over-pressured reservoir with volatile fluids. Due to the mineralogy and over pressured system, production is accompanied by geo-mechanical effects such as pressure dependent permeability that are not fully quantified. Typical well and reservoir characteristics are summarized in Table 1.

Table 1—Typical wellbore, reservoir and fluid properties in a Lower Eagle Ford well in DeWitt County.

Total Vertical Depth	11,000 to 14,000 feet
Average Lateral Length	5,000 feet
Typical Number of Fracture Stages	18
Well Spacing	330 to 660 feet
Reservoir Temperature	300-320 °F
Gross Reservoir Thickness	200 to 300 feet
Initial Reservoir Pressure	10,000 to 11,500 psia
Critical Pressure(Bubble & Dew Points)	3,800 to 4,200 psia
Gas/Oil Ratio	750 to 20,000 scf/bbl
API Gravity	47 to 60
Water Cut	5 to 15%

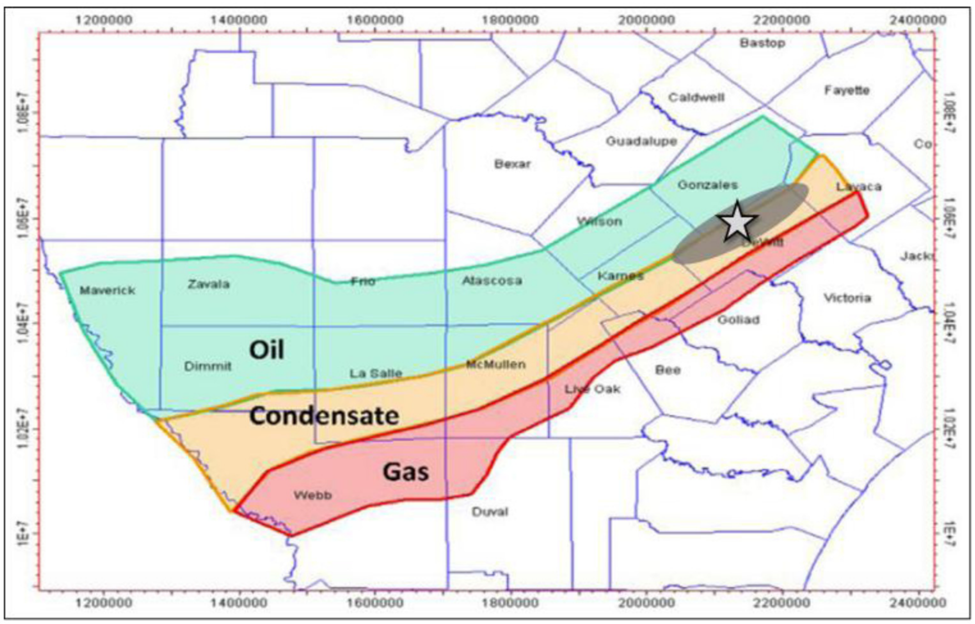

Figure 1—The general area of interest for this study relative to the entire Eagle Ford play. Map taken from Ramirez, et al. 2014

One of the first tasks that management presented to our engineering team after the acquisition was to develop a "choke management" strategy. Choke management is a catchphrase that alludes to drawdown management. A choke is a mechanical device, usually integrated into the wellhead equipment, which is used to regulate flow area, production rates and flowing pressures of the well. This practice is mostly implemented during the initial flowing period of a well's life, which is also referred to as the flowback stage. Drawdown management has been heavily studied in offshore and onshore environments as a way to preserve or enhance propped fractures (Soliman and Hunt 1985; Robinson et al. 1988; Barree and Mulkherjee 1995). Improvements to long term well performance have been linked to both "aggressive" (Anderson et al., 1996) and "conservative" (Crafton 2008) drawdown practices in low permeability, fracture stimulated wells. Williams-Kovacs and Clarkson (2014) recently summarized a workflow that focus on using high resolution flowback data to infer induced fracture and reservoir properties. This work expands the application of this topic and delivers a practical way to use RTA interpretations to guide daily field operations that optimize performance from individual wells.

The fact that this reservoir is over-pressured and relatively soft, post-fracture treatment (Akrad et al. 2011), makes the drawdown, or flowback, procedure absolutely critical to well performance. The legacy drawdown strategy that Devon inherited with the field was predicated off of the perception that these two variables, coupled with aggressive flowback practices, could lead to catastrophic damage to the reservoir, completion or wellbore. So the field flowback procedures were rooted in a conservative approach that required a slow ramp up of choke sizes that stopped at a maximum 12/64 inch choke size. When faced with these conditions, an operator must balance the potential early-time economic benefits of an aggressive strategy with the inherent risks that excessive drawdown practices pose on long-term reservoir performance. The workflow presented was used to develop an optimal drawdown strategy that manages all of these variables.

Methodology

Understanding the foundational goal of the field development strategy is essential in order to truly create an optimal drawdown strategy for any well. Why are you investing the money to drill and complete a particular well? The answer to that question is actually what defines optimum. Obviously each operator could have different goals, so therefore each operator could have a different drawdown strategy that is optimal for their circumstances. It should also be noted that these circumstances and goals can change during the life of a field.

At the time of the acquisition, there were approximately 350 producing wells in this field. The stage of field development was focused on infill drilling. The goal directed by management for developing a drawdown strategy was to maximize discounted net present value (NPV). Figuring out how to maximize near-term value was easy, simply increase revenues by maximizing initial production rates. But understanding how to maximize value without causing damage to the well, which could destroy long-term value, was much more difficult. In order to do that, one must understand all the key variables that drive well performance, as defined by the goal, and how each variable impacts each other when changed.

Before analyzing the potential rewards of increased rates, a study was performed to make sure that the existing strategy was not causing damage to the reservoir. It should be noted that all producing wells were still flowing naturally and they had essentially the same drawdown procedure. After thorough well reviews using RTA techniques, there were not any specific examples that showed that the legacy drawdown strategy caused damage to a well. This also meant that there was not proof, amongst the operated wells, that an aggressive drawdown strategy could cause damage to a Lower Eagle Ford well.

The next step in this study involved formulating economic sensitivities from production forecasts that could result from different drawdown strategies. The team learned that some offset operators that also had conservative strategies tended to follow a predetermined procedure that targeted a certain drawdown pressure decline over time. Other operators in this same area implemented aggressive practices that seemed to target faster choke size ramps stopping at approximately 32/64 inches. Competitor production data in these adjacent areas with similar reservoir properties were evaluated and production forecasts were projected off of this data. The following constraints were used to define the impact that drawdown procedures could have on production rates and estimated ultimate recovery (EUR):

1. The drawdown strategy could not increase EUR
2. Drawdown practices could potentially decrease EUR

3. The drawdown strategy could accelerate recovery with higher initial production rates or delay recovery with lower initial production rates

Results from this exercise are illustrated in Fig. 2. EUR prediction, well costs and commodity price forecasting were used to conduct economic evaluations but are outside the scope of this paper. It is recognized, yet also outside the scope of this study, that several factors aside from the drawdown strategy, such as reservoir quality and completion design, influence well performance.

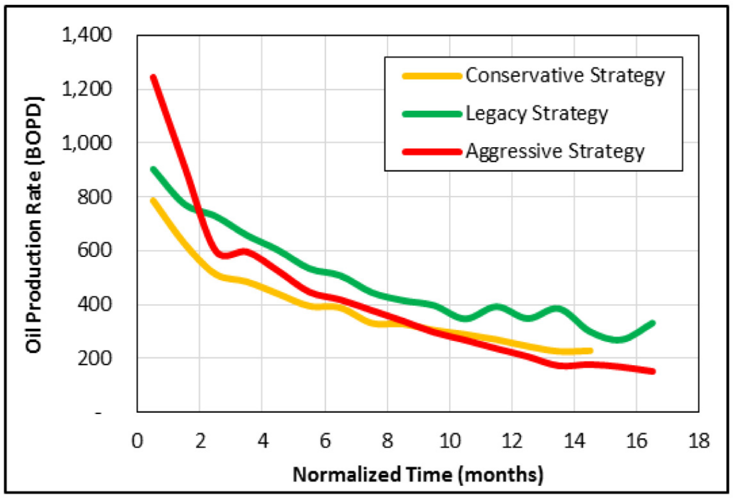

Figure 2—This graph shows an analysis that was conducted for several wells from different operators in a similar area. The "legacy strategy" refers to the historical well performance of the operated wells while the conservative and aggressive strategies represents well performance from other companies who exercised different drawdown procedures.

The aggressive strategy is characterized by a steep decline rate that may be indicative of reduced EUR from damage; while the conservative strategy may maximize EUR but reduce economic benefits. It is recognized that an optimal balance should be maintained. One takeaway from this comparison is that the legacy drawdown strategy for the operated wells resulted in the best economic returns; but it was more conservative compared to some operators and there was potential to accelerate production and increase value. With this generalized understanding of the potential reward the next step involved identifying and understanding the potential risks, or damage mechanisms, that could occur. The possible downhole damage mechanisms that could result in conductivity losses within the completion or reservoir cannot be succinctly quantified but Table 2 summarizes the team's thoughts on these mechanisms and also how a drawdown strategy could mitigate them.

Table 2—Summarizes the likely downhole mechanisms that can cause damage to the completion and how the team concluded that a drawdown strategy could affect them.

Possible Downhole Damage Mechanisms	Causes	Potential Impact on Performance	How can the drawdown strategy affect the completion?
Fines & proppant migration	Tensile rock failure of the reservoir and transport of solids due to high drawdown	Equipment erosion, partial or complete loss of connectivity to the reservoir	Drawdown management can directly affect, if not, totally prevent fines migration
Pressure dependent deliverability • Creep/collapse of the matrix • Proppant Embedment • Proppant Crushing • Closure of unpropped fractures	Function of net effective stress exerted on the matrix, fracture system and proppant pack	Partial or complete loss of connectivity to the reservoir	The drawdown strategy cannot prevent any of these from occurring, at best it can only delay the process
Changes to relative permeabilities • Condensate banking • Fluid viscosity changes • Early breakthrough of gas	Reservoir pressure decline over time	Increased gas-to-liquids ratio	
Mineral precipitation • Proppant diagenesis • Scale/salt formation	Chemical reactions between fluids and solids due to reservoir pressure and/or temperature decline	Partial or complete loss of connectivity to the reservoir	
Residual stimulation fluid damage	Interaction of frac fluids with the reservoir	Blockage of pore throats, loss of fracture conductivity	The drawdown strategy cannot prevent this from occurring entirely, if at all

There are three major takeaways from this analysis:

1. The potential impact of these damage mechanisms on performance could be catastrophic
2. The drawdown strategy could only potentially prevent one mechanism from occurring
3. The probability of damage occurring increases with time

The truth was that the potential risk and reward were both high but the likelihood of the risks was unknown. This reality was the critical point for the entire project. Initial efforts were directed towards predicting the scale and sequencing of these damage mechanisms because it was determined that a combination of multiple mechanisms would likely take place. There was also a belief that delaying the degradation of conductivity would result in larger EURs. But the fact is that predicting such complex scenarios with any accuracy was not feasible and not all reserves carry the same value. We had to place a premium on early-time production due to the time value of money and because uncertainties with production forecasts throughout the life of the well. The decision was made to push forward and fully test the boundaries because the upside would be significant if it worked.

The conclusion was made that any predetermined drawdown procedure would not ever be truly optimal for each individual well due to the uncertainties with accurately predicting well performance and given the inherent complexity of the reservoir. Instead of guessing which damage mechanisms would occur and how each would affect performance, it seemed more rational to monitor for damage and be prepared to react quickly if damage was noticed. In a sense, analyze well performance and adjust the drawdown accordingly to optimize each specific well. The technique does not require quantifying the impact that completion design, lateral length, depletion, geology, reservoir fluid properties, wellbore orientation, etc. all have on well performance; but they should still be considered when interpreting data. Well testing data (production flow rates and pressures) is the only source of information that is influenced by, and therefore provides insight into, all the dynamic and complex variables that govern well performance.

As stated before, the goal is to maximize value by accelerating production without causing damage to the well. The conclusion was made to use RTA as a tool to track well performance and monitor for any possible damage during the flowback period. Using hourly data from the flowback reports with existing RTA software proved to be a complete game changer for monitoring and understanding well performance. One diagnostic plot that had the biggest impact was the rate normalized pressure vs square root of time plot in Fig. 3. This comparison of hourly and daily data highlights the benefit of using high frequency data to monitor trends and changes over time. This plot, also referred to as reciprocal productivity index (RPI), has been used to analyze well performance from MFHWs because certain completion properties can be inferred such as reservoir connectivity and apparent skin (Crafton 1997, Bello & Wattenbarger 2010). Degradation of productivity or the inferred completion values could indicate damage to the well's completion or the reservoir.

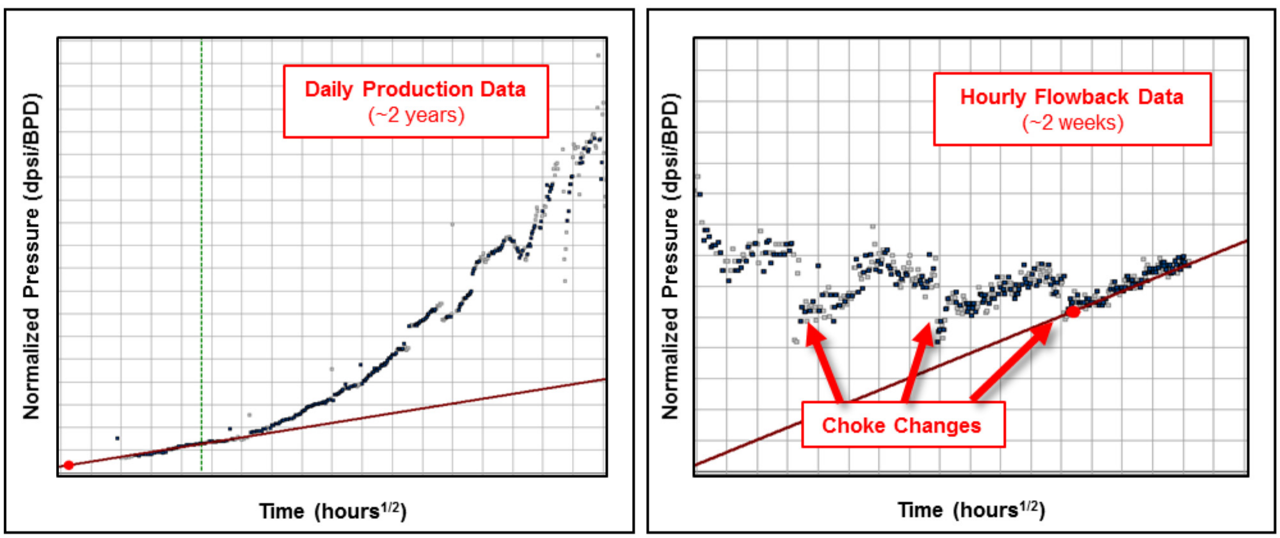

Figure 3—RPI plot of daily production data (left) and hourly flowback data (right) from the same well. Notice the dramatic difference in resolution of the early time high frequency data set.

Aside from being able to analyze trends much faster with the hourly data than daily data, we also discovered apparent enhancements to the well when the choke sizes were increased. Not only did the absolute value of the productivity improve but also the apparent skin, as measured by the decrease of the y-intercept, and possibly even the connectivity to reservoir, as measured by the flattening of the straight line slope. It must be noted that due to the uncertainties of input variables and assumptions of this RTA technique (Thompson, et al. 2012), the qualitative information from these plots is much more valuable and relied upon than the quantitative calculations. Fig. 4 illustrates the changes in well performance over time during the flowback. Fig. 5 annotates the interpretation of this performance throughout the life of the well and how it is used to optimize the drawdown during the flowback stage with surface chokes.

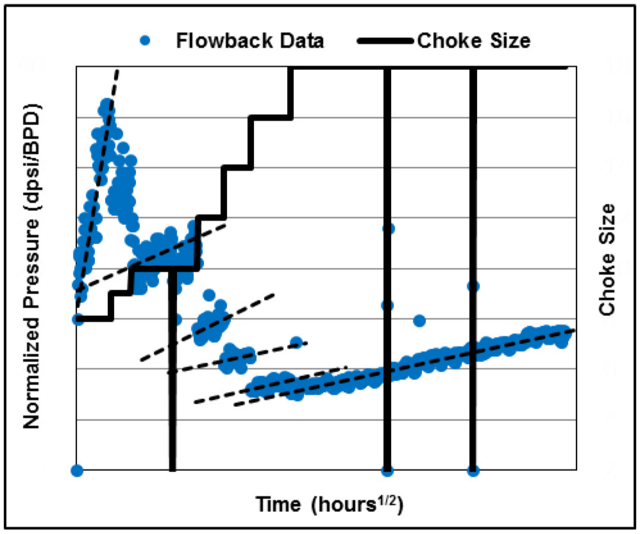

Figure 4—Actual rate normalized pressure data plotted with choke size from flowback report. Data shows a decrease in apparent skin and potentially improvements in the contact area.

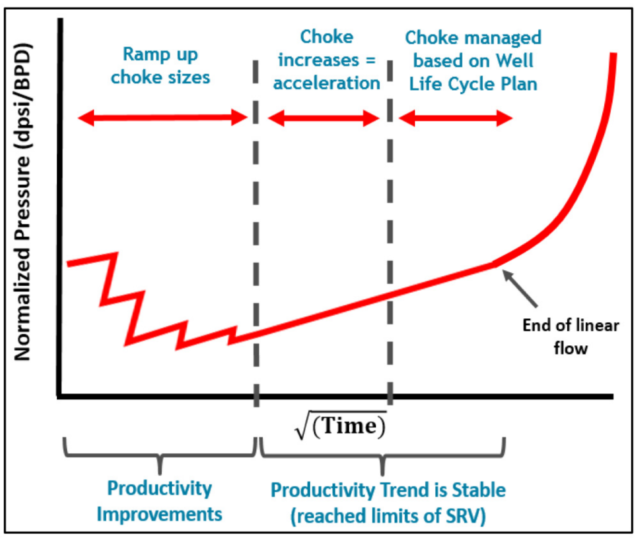

Figure 5—This simplified interpretation illustrates how we use rate normalized pressure data to drive operational decisions during flowback (note that the drawing is not to scale).

It is crucial to use multiple diagnostic plots when evaluating well performance in order to maximize the value of RTA and make valid interpretations. Varying workflows have been published by Anderson, et al. (2013) and Anderson and Liang (2011), however each approach should be calibrated to the specific reservoir properties and purpose of the analysis. It is important to have a workflow that captures high resolution data in an environment when reservoir and operating conditions can change rapidly. Using standard rate time plots with additional data, such as choke size and annotations, allows for a more transparent understanding of downhole conditions. For example, changes in flow path from a pressurized pipeline to stock tanks or the implementation of full well stream coolers can have a significant impact on the analysis of very volatile fluids. Additional plots, such as the log-log plot of flow rate versus normalized time, can also be incorporated to validate the flow regimes seen in hydraulically fractured shale wells (Thompson, et al. 2012). Identification of flow regimes allows for more accurate interpretations and subsequent field operations recommendations. The bottomhole flowing pressure versus cumulative production plot gives a qualitative sense for the drawdown and can help identify early signs of damage or depletion. The dashboard in Fig. 6 can be expanded further to incorporate multi-well pads and parent well flowback data in order to understand reservoir behavior and well performance over a large area. The authors believe that none of these plots should ever replace good multi-disciplinary communication and thus it is vital that collaboration take place before, during, and after the flowback.

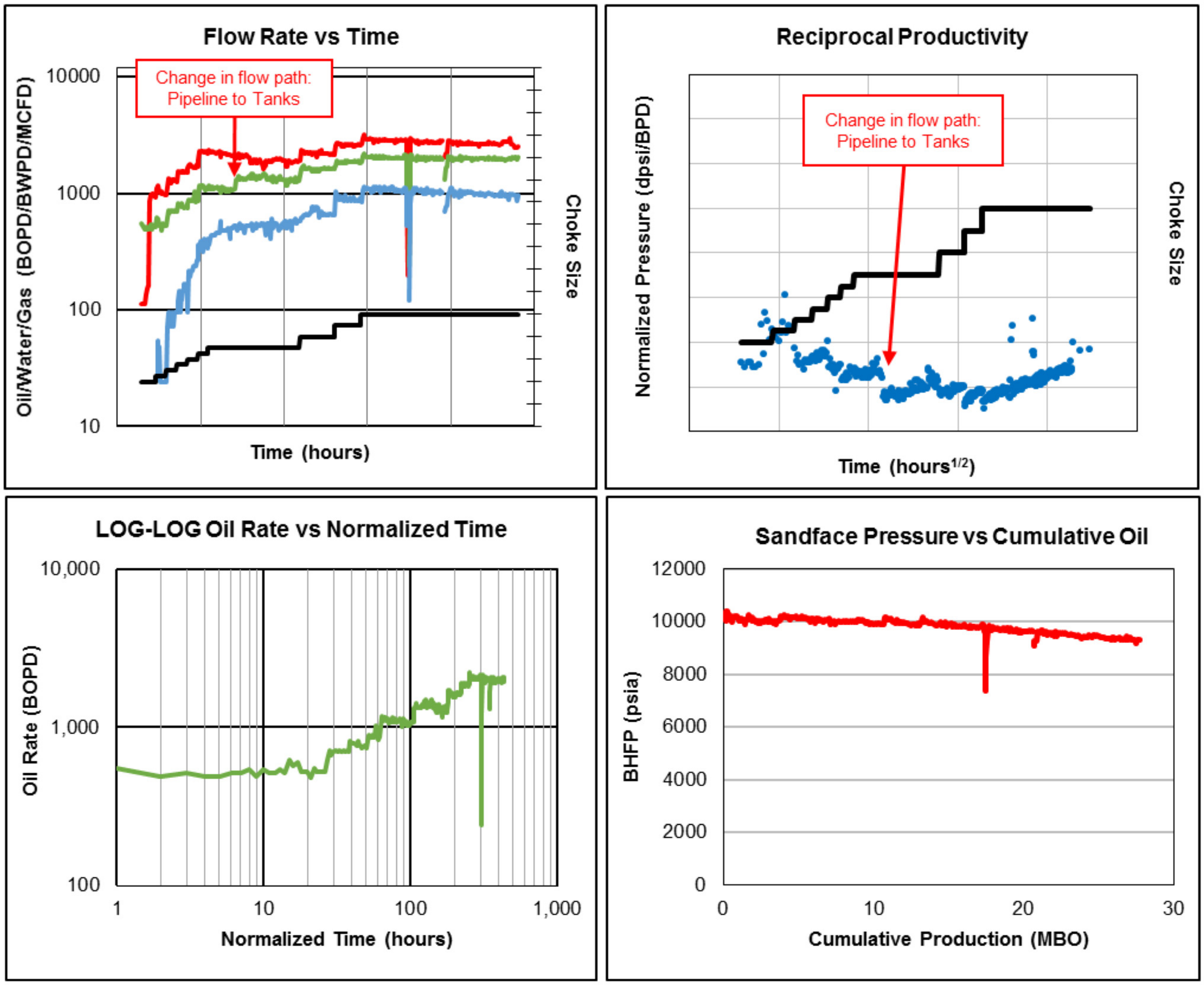

Figure 6—Dashboard of standard diagnostic plots that are used to analyze flow rates, productivity, flow regime and depletion trends over time for each well. This illustration is an example of a single well but this assessment often includes multiple wells for relative comparisons.

In order to optimize well performance and accurately detect damage with this method one has to start with high quality data. RTA is only as good as the data that is acquired so significant effort was dedicated to standardizing measurements in the field. Standardized reporting templates, procedures and measurement techniques should be a best practice in any area. This was only the first of many operational hurdles that had to be resolved in order to fully implement this strategy on every new well. Production related issues such as handling higher rates and volumes, higher produced fluid temperatures, sand production, takeaway capacity limits, timing of artificial lift and well work all had to be addressed and coordinated in order to fully realize the benefits of this new strategy. The specifics of these hurdles and the solutions that were implemented would require a separate published paper to fully characterize them. It should be noted that these situations emphasize the need for constant multi-disciplinary interaction and an integrated approach to the well life cycle planning and execution processes.

Results

Due to several different operational constraints with production equipment, takeaway capacity and EHS concerns, full implementation of this new drawdown strategy was not carried out on every new well for roughly four months. This constrained period of time from June thru September, 2014, is referred to as the "delayed strategy" in Figs. 7 and 9. These production limitations were eventually resolved and starting in October, 2014, the production team was able to implement the new drawdown strategy on almost every new well across the field. The individual well performance and economic results have improved by up to 100% in the best areas.

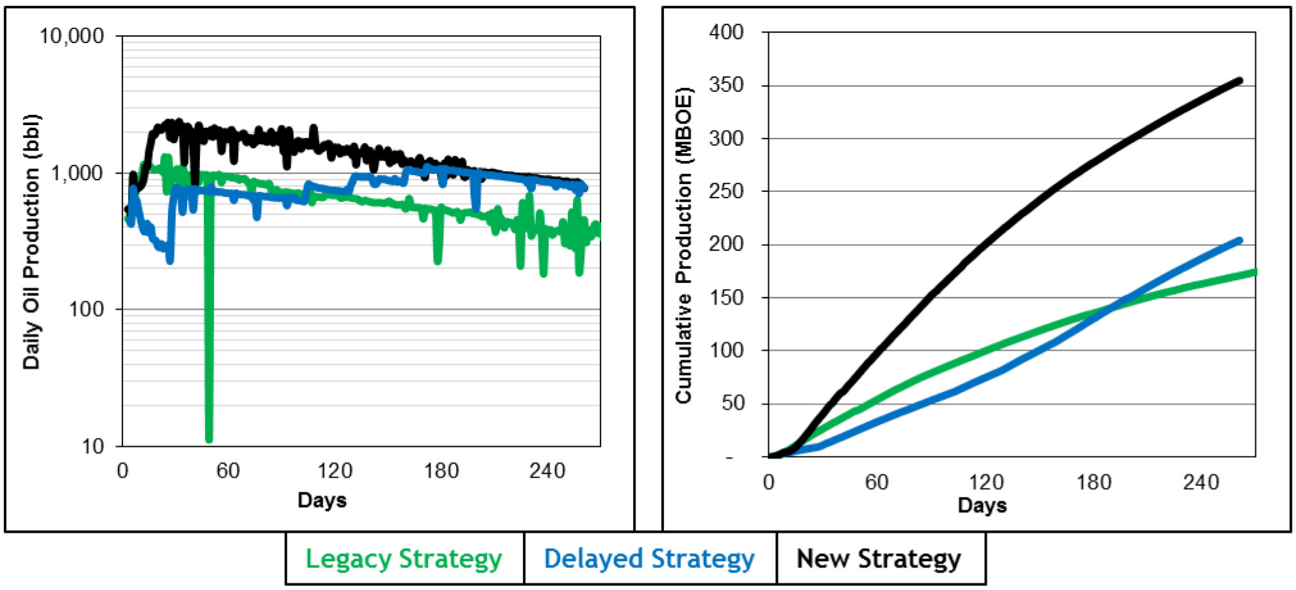

Figure 7—Production results from the first well that experienced the new drawdown strategy (black) compared with offset wells that experienced the legacy strategy (green) and a delayed implementation of the new strategy (blue). These wells are direct offsets to each other in the same unit with equivalent lateral lengths and no drastic changes to the completion design.

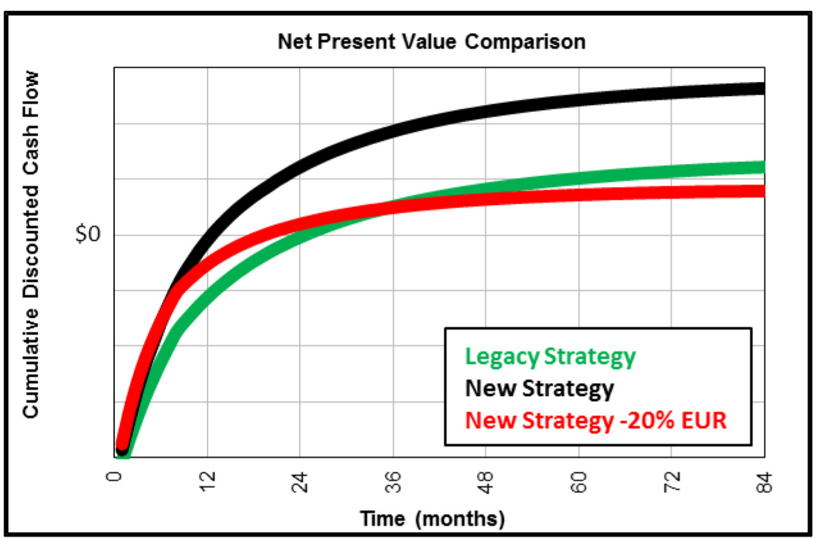

Figure 8—Comparison of the cumulative discounted cash flows for the legacy strategy, the new strategy and the new strategy assuming it caused damage that results in a 20% reduction in EUR. The black and green curves represent actual wells that were drilled adjacent to each other yet experienced different drawdown strategies – these included a combination of actual and forecasted production. The red curve includes the same actual production as the black curve with a reduced production forecast to simulate damage. Capital costs and EUR are prediction are out of scope but it is noted that the economics were evaluated assuming flat commodity pricing of $56/bbl oil and $3.15/mcf gas.

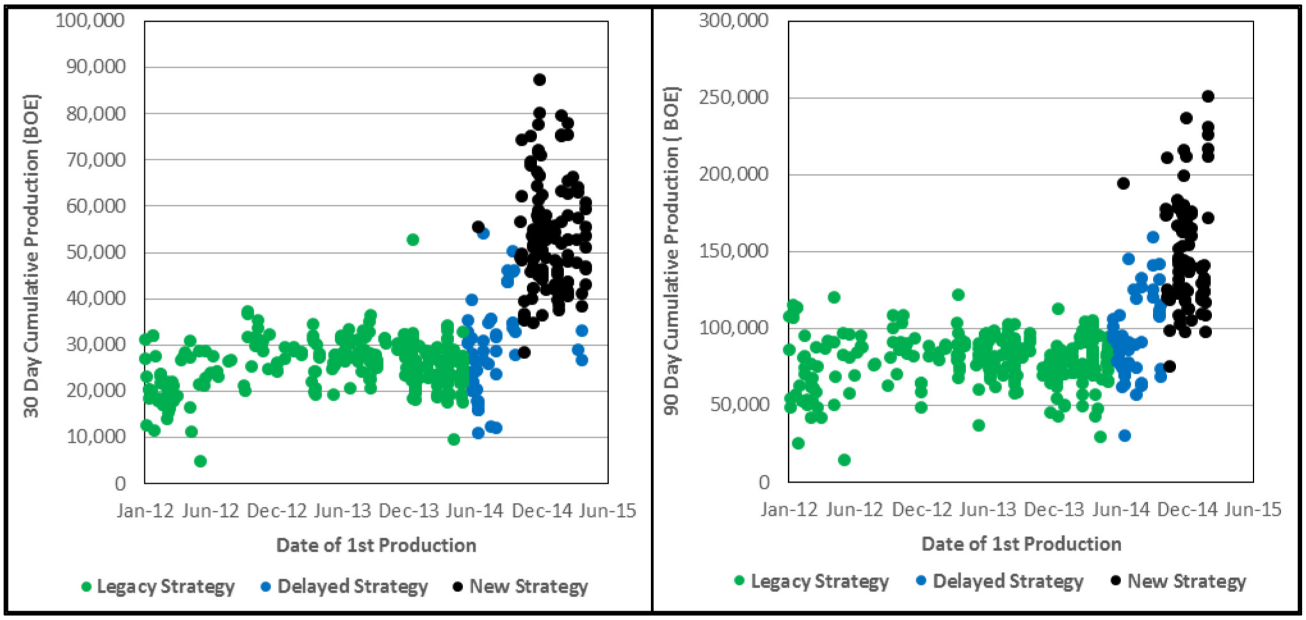

Figure 9—The data points in these graphs account for every infill well that started producing from January 2012 thru March 2015. These wells expand the entire field which encompasses the volatile oil and retrograde condensate phase windows. Respective well counts for each time period are as follows: Legacy Strategy = 287, Delayed Strategy = 53 and New Strategy = 114 wells with 30 day cumulative production and 83 wells with 90 day cumulative production. These results show a 100% and 87% increase in average 30-day and 90-day cumulative production volumes respectively between the legacy strategy and the new strategy.

It is accepted that there is potential for the new drawdown strategy to cause damage to a well in the future and, although unseen to date in any operated wells, the effect that damage could have on future production was simulated by decreasing the forecasted EUR. Various economic sensitivites were then evaluated to quantify the risk of the new strategy and the uncertainties of forecasts. These simulations highlighted the discounted value of accelerated production and also the benefits of de-risking EUR projections. Production is never guaranteed and issues such as frac intereference from new offset wells or equipment integrity concerns are real and these risks increase over time. The value comparison in Figure 8 illustrates one of the sensitivity cases from this simulation.

Individual well performance results can be affected by several things and often vary widely for unknown or uncontrollable reasons. For this reason, we closely monitor field wide performance over extended periods of time to understand the true impact of operational changes. Figure 9 quantifies the improvements in well performance for the entire field over the past three years. These production numbers are not normalized for the various geologic, reservoir and wellbore properties. But given that this is the complete data set and that activity stayed fairly constant across all areas of the field during this time period the averages are representative of the overall impact that the new strategy has had on well performance. Completion practices have continually evolved over time and, despite being exhaustively studied, there has yet to be any correlation to step changes in production as a result of these variables. As of the writing of this paper, initial results of 180 day cumulative production volumes appear to be on a similar trend to the 30 and 90 day volumes shown in this plot.

Aside from the increased production volumes and a more efficient capital program, this workflow has greatly increased our knowledge base about key reservoir performance drivers, completion efficiencies and development plans. Common industry practice has been to obtain several months of production data before drawing conclusions about well performance. This method utilizes hourly data with RTA which has allowed our team to learn more about well performance in the first week than we used to know after several months. Capabilities are now in place to begin using Supervisory Control and Data Acquisition (SCADA) equipment that increases data resolution from hours to minutes. Measurements through

SCADA equipment are able to be refreshed in RTA software on a near real-time basis. Trials are presently underway to pragmatically optimize this data frequency for various fields and applications. This technology is being implemented across the company in order to further accelerate the feedback loop from production performance to field development and individual well planning.

Conclusions

Drawdown procedures and flowback strategies obviously have a significant impact on well performance and require prudent management in over pressured plays. The workflow presented not only produces optimized results but also allows an operator to understand performance drivers of each well within the first week of production. The application and learnings from early-time analysis could apply to normal or under-pressured plays as well. Well production testing data is the only single source of information that is affected by, and therefore provides insight into, all the complex and ever-changing variables that influence well performance – so it is important to utilize the information. Below are the other key takeaways:

- Aggressive drawdown strategies can damage a well's completion while conservative drawdown procedures may hinder near-term economic performance. There is an optimal balance between these two approaches that should be maintained based on the business goals of each play.
- An engineered drawdown strategy has been developed and validated that accelerates production while minimizing the risk of decreasing EURs or damaging the productivity of the well.
- Accelerating production with this approach reduces uncertainty and adds significant economic value to Lower Eagle Ford wells in DeWitt County.
- With this new procedure, well performance drives operational decisions in order to optimize production from each individual well. This is something that cannot be fully accomplished by following a pre-determined procedure.
- Successful execution of this workflow requires a multi-disciplinary approach with clear communication and a constant focus on maximizing value.
- RTA using near real-time high frequency flowback and production data should be a best practice for surveilling and optimizing well performance from unconventional MFHWs.

Given the constant evolution of RTA workflows for unconventional reservoirs, questions remain about some of the technical interpretations and underlying physics of well performance. But the qualitative insights and practical field application of this work has driven well performance improvements and financial gains. Continued research and development of the techniques and understanding of these tools should be pursued by industry.

Nomenclature

°F	Degrees Fahrenheit
bbl	Barrel
BHFP	Bottomhole flowing pressure
BOE	Barrels of oil equivalent (6:1 gas conversion)
BOPD	Barrels of oil per day
BWPD	Barrels of water per day
dpsi	Differential pounds per square inch
MBOE	Thousand barrels of oil equivalent
MCFD	Thousand cubic feet per day
psia	Pounds per square inch at atmospheric conditions
scf/bbl	Standard cubic feet per barrel
SRV	Stimulated reservoir volume

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SI CONVERSION FACTORS

(°F − 32)/1 .8	E-01 = ºC
bbl × 1.589 873	E-01 = m^3
ft × 3.048*	E-01 = m
inch × 2.54*	E+00 = cm
psi × 6.894 757	E+03 = Pa
scf × 2.831 685	E-02 = m^3

* Conversion factor is exact