COMBINED UNCONVENTIONAL NODAL INFLOW AND CHOKE-DEPENDENT OUTFLOW PERFORMANCE PREDICTION

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RESUMEN

El análisis integrado de la capacidad de entrega del yacimiento y la capacidad de las instalaciones generalmente son requeridas en el desarrollo temprano del campo. La infraestructura de la superficie de tamaño inapropiado puede limitar severamente la producción de hidrocarburos y el cashflow si la capacidad de rendimiento es demasiado pequeña o puede causar un gasto excesivo significativo si es demasiado grande. Este dilema se ve exacerbado en el desarrollo de yacimientos no convencionales caracterizado por los altos caudales de producción inicial seguidas de declinaciones rápidas. Además, las herramientas analíticas que tienen disponibles los ingenieros en reservorios y producción para construir pronósticos sólidos de pozos de vida temprana para pozos no convencionales para una variedad de esquemas de choke management pueden hacer que este choke management integrado y la optimización del tamaño de las instalaciones sea difícil. En muchos escenarios, esto puede conducir a sistemas de producción no optimizados que son demasiado grandes o pequeños en relación con la capacidad de entrega del yacimiento.

Utilizando un modelo híbrido basado en datos y física, este documento propone un método para pronosticar los caudales de petróleo, agua y gas para pozos no convencionales, validado en el desarrollo de petróleo negro de Shell en el esquisto de Vaca Muerta. El método incorpora observaciones empíricas del rendimiento del flujo de salida del pozo y el principio de superposición lineal para la solución a la ecuación de difusividad para generar pronósticos de producción para cualquier esquema de choke management de vida temprana. El pronóstico de producción utilizando el método propuesto permite planificar el choke management y los aumentos de producción de pozos para llenar la capacidad existente de las instalaciones. Además, los pronósticos a corto plazo se pueden combinar con funciones de declinación de Arps a largo plazo para permitir la planificación de instalaciones e infraestructura a largo plazo para el desarrollo de los campos no convencionales. El método propuesto proporciona a los ingenieros la capacidad de pronosticar la entrega de los pozos, planificar el choke management para aumentar el rendimiento de hidrocarburos en los sistemas de producción, maximizar el valor de los pozos existentes y optimizar las decisiones de desarrollo para las métricas económicas relevantes.

INTRODUCTION

Engineering Challenges in Unconventional Reservoirs

In the past several decades, unconventional oil and gas reservoirs have taken a more prominent role in global hydrocarbon production. Unconventional reservoirs are characterized by their ultra-low permeability and large areal extent that often require long-lateral horizontal wells with massive, sand-propped hydraulic fractures to produce at commercially and economically viable rates. These extensive fracture networks are challenging to characterize. As such, development of unconventional reservoirs has caused a paradigm shift within the Reservoir Engineering discipline.

Many classical reservoir engineering analyses and forecasting techniques rely on volumetric methods, material balance, inflow performance relationships, and other analytical techniques that often depend on the assumption of boundary-dominated flow and a well-characterized reservoir (porosity, permeability, heterogeneity, PVT). However, in unconventional reservoirs, hydraulic fractures are difficult to fully characterize. Additionally, many hydraulically fractured wells, due to their ultra-low permeability, can remain in transient flow regimes for months or years and so conventional inflow and outflow methods are not valid. The complications associated with unconventional reservoir drainage make many classical methods and techniques for forecasting inappropriate or inadequate.

In response, most forecasting work done for hydraulically fractured wells in unconventional reservoirs relies on data-driven or empirical methods. Data analytics and statistical/machine learning methods have become popular in recent years to analyze the often-large data sets associated with unconventional reservoir developments because of large well counts. Data models can be useful in analyzing geological and spatial trends, well performance as a function of completion design, and the impact of well spacing on production performance. Other empirical methods for well performance analysis such as Arps decline curve analysis on developed wells are also widely used for generating full well-life production forecasts. Both data-driven and empirical methods for production forecasting can be useful when input data comes from wells with similar attributes and operations to the ones being forecasted. However, these methods lack the ability to generate forecasts under different well ramp-up assumptions that may be required for fields or areas where facility designs are not determined and surface infrastructure development decisions are ongoing. Currently, these empirical and data-driven methods allow long-term trend forecasting but lack the ability to adapt early-life forecasting to a variety of choke management conditions.

Forecasting of Early Well Life and Choke Management

A standard oil and gas development question relates to the sizing of surface facilities given the deliverability of the well and reservoir system. Large facilities allow for high initial production and early cash-flow but are often capital intensive and may only be fully used and filled early in the life of the wells. Alternatively, smaller facilities will be less costly and will be filled for longer but may require significant choke-back of wells which can delay cashflow. This dilemma applied to an unconventional reservoir development is exacerbated by the characteristic high initial rates and rapid decline of multi-stage hydraulically fractured wells. This can make economic decisions about separator sizing and choke management difficult. Complicating the problem further is that reservoir engineers, often relying on empirical and data-driven models for production forecasting, are generally unable to estimate rates for a variety of scenarios for well ramp-up.

To date, reservoir deliverability under a range of choke management schemes has been difficult to forecast. This lack of forecasting power, in-turn, can lead to ad-hoc solutions to integrated choke management and facility sizing optimization. To address this problem, this paper presents a hybrid data and physics-based model that incorporates routinely measured field data that is capable of forecasting production under a range of choke management schemes. The method presented is designed to support reservoir and production engineers in forecasting production to contribute to optimal facility and infrastructure design and to maximize cash flow from unconventional reservoir development.

The method to create the model requires daily production data from representative wells that have been operated with different choke sizes. Routinely collected data such as rates and pressures can be incorporated to construct a data-grounded model that can be used to forecast early-life well performance for any choke management scheme. The short-term forecasts can be used to consider sensitivities on choke management and surface facility sizing to optimize infrastructure. The model can then be tied to any typical long-term forecasting method such as an Arps decline function to yield full well-life forecasts.

The approach is primarily data driven with a goal of requiring only that data typically collected for unconventional wells. The data inputs required are oil, water, and gas rates, pressures measured at the wellhead, and basic well construction and PVT data used to calculate bottom hole pressure. The model makes no assumption about the size and shape of the stimulated reservoir volume, permeability, porosity, net pay, number of fractures, and fracture half length. This makes the method simple, easy to generalize, and broadly applicable.

Previous Work

Rojas and Lerza (2018) have examined choke management strategies using an optimal drawdown rate for wells in the Vaca Muerta. The recommended standard drawdown procedure was grounded in a study to maximize net present value (NPV) while considering completion damage and estimated ultimate recovery (EUR) impacts of various choke management strategies (Rojas and Lerza 2018). While the recommendation is optimized to maximize NPV, the details of economic metrics can vary for different companies and thus the recommended drawdown may not be broadly applicable.

Molinari *et al.* (2019) presents a method to generate rate forecasts using pressure-normalized rate trends, a material balance method, and a bottom hole pressure trend. Specifically, using an empirically derived pressure-normalized rate trend and an instantaneous drainage volume, they calculate the average reservoir pressure in the drained region. Using a separate empirical bottom hole pressure versus cumulative liquid production function, they combine both methods to generate a rate forecast as a function of time (Molinari *et al.* 2019). This method can be used to calculate inflow performance relationships at different times and can be used to forecast production. The method is specifically designed to normalize and smooth over choke changes using pressure-normalized rate, delivering a final forecast that will represent an average of the choke management schemes in the data used to fit the pressure and rate functions.

This paper presents an alternative method to parameterize rate and pressure with time using the superposition principle for a reservoir in linear transient flow as well as observations of rate and pressure operating pathways. When each of these principles is used separately, they have little to no predictive power. However, when the concept of operating pathways to describe outflow performance of wells is combined with the superposition principle to characterize reservoir performance, engineers can use the integrated method to predict well performance under different choke management schemes. This forecasting ability can then be used to answer development questions, perform well and reservoir surveillance, size facilities, and optimize key economic metrics for development of unconventional fields.

Data Source and Model Development

The data shown and used to build and validate the model is from black oil wells in Shell Argentina's Vaca Muerta development in the Neuquén Basin. The Vaca Muerta formation is a self-sourced, liquid rich unconventional play that is developed through horizontal wells with massive, transverse, sand-propped hydraulic fractures (Minisini and Sanchez-Ferrer 2020). Reservoir properties are shown in Table 1.

Reservoir Properties	
Formation	Vaca Muerta
Reservoir Depth	10500 ft TVD
Fluid Type	Black oil
API Gravity	37 º API
Gas Oil Ratio	550 scf/stb
Saturation Pressure	2200 psia
Initial Reservoir Pressure	9500 psia
Porosity	10%
Oil Saturation	80%
Absolute Permeability	~300 nd (P50 from core analysis)

Table 1. Reservoir properties for Shell-operated Vaca Muerta (black oil, Neuquén Basin, Argentina).

METHODS

Inflow and Outflow Performance

A common analytical method used in Production Engineering for conventional wells and reservoirs is the use of inflow and outflow performance relationships to characterize well performance. Inflow performance, defined as the relationship between rate and pressure for a given reservoir, describes the ability of a reservoir to deliver fluid for some pressure drawdown. While this is easily definable for a pseudo steady- state conventional reservoir, the inflow performance relationship (IPR) is non-constant for any reservoir in transient flow, making the concept more difficult to apply for hydraulically fractured shale wells that often exhibit linear transient flow for months or years after the well comes online (Sadeq Shahamat *et al.* 2015). A further obstacle is the complicated and unknowable details of the fracture geometry of multi-stage hydraulically fractured wells. An IPR is therefore impossible to determine a priori and is still difficult to describe using historical well performance and non-constant for wells in early life.

Vertical lift performance (VLP) curves define the relationship between the flow rate and the bottom hole pressure for a well and describe the pressure required to lift a certain amount of fluid to the surface for a given wellhead pressure. VLP curves, unlike IPR curves for unconventional wells, are quite simple to determine and a wide variety of methods exists to generate VLPs for a given well and fluid.

In a conventional reservoir setting, nodal analysis of IPR and VLP curves is often used to analyze the production system. Nodal analysis takes an integrated approach because the fluid produced from the reservoir depends on the pressure in the production system and the pressure drop in the production system likewise depends on the fluid flow rate. Therefore, the entire system must be analyzed as a single unit. Using the principle of continuity in systems analysis, the intersection of the VLP and the IPR must be the point at which the system operates. Changes in inflow or outflow performance can be analyzed by observing, calculating, or forecasting the impact to the operating point or "node" (Brown and Lea 1985). Figure 1 shows the operating point pathway over time as it changes in the pressure and liquid rate space for an unconventional well. Although the exact shape and slope of the IPRs may be uncertain, the operating pathway is ascertainable though observation of the rates and pressure of a naturally flowing well.

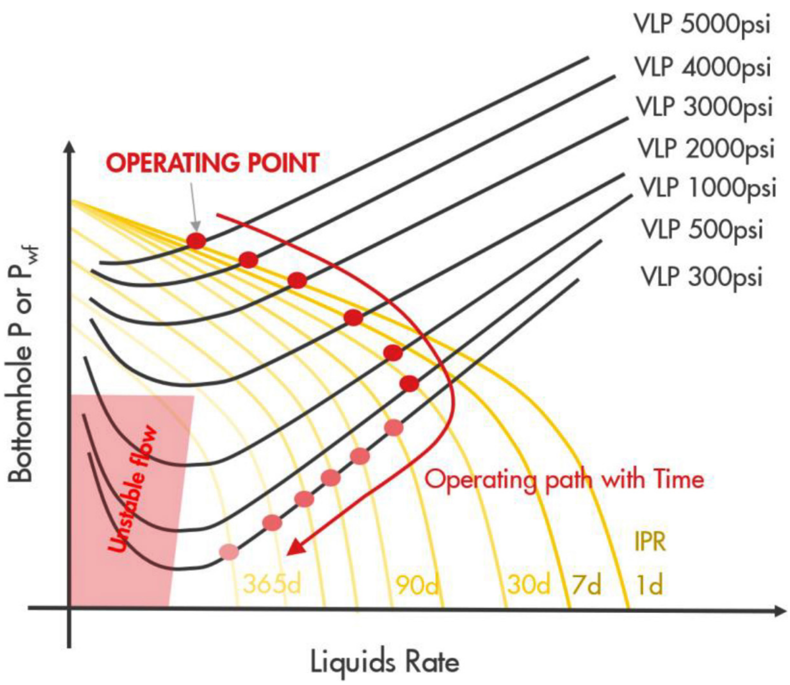

Figure 1. An operating pathway defined by the intersection of variable IPRs and VLPs for unconventional hydraulically fractured wells.

The operating point, simply the rate and bottom hole pressure for a well, can easily be tracked over time if the rate and pressure are known. This operating point or node is observed to follow set trends for the data set of naturally flowing Vaca Muerta black oil wells produced through a choke. These trends or "operating pathways" can be empirically characterized and studied for use in production forecasting.

Regressing Operating Pathway Trends

To observe the operating pathway, the bottom hole pressure for a well or grouping of wells must be computed. This can be done using various softwares, most notably PROSPER, using tubing correlations that will account for the PVT, fluid composition, well equipment and diameter, and flow pathway to calculate friction and hydrostatic head as a function of fluid hold up. While PROSPER is a common industry software, other methods using calculations for tubing correlations or company-internal tools may be used; however, specific methods for calculating bottom hole pressure are beyond the scope of the paper.

For the set of wells being analyzed (a set of 53 black oil wells), daily production is quality-checked with rate and pressure outliers and any other erroneous data being removed. Daily bottom hole pressure can be calculated using daily rates and a plot of calculated bottom hole pressure versus liquid rate (oil rate + water rate) is generated and shown in Figure 2.

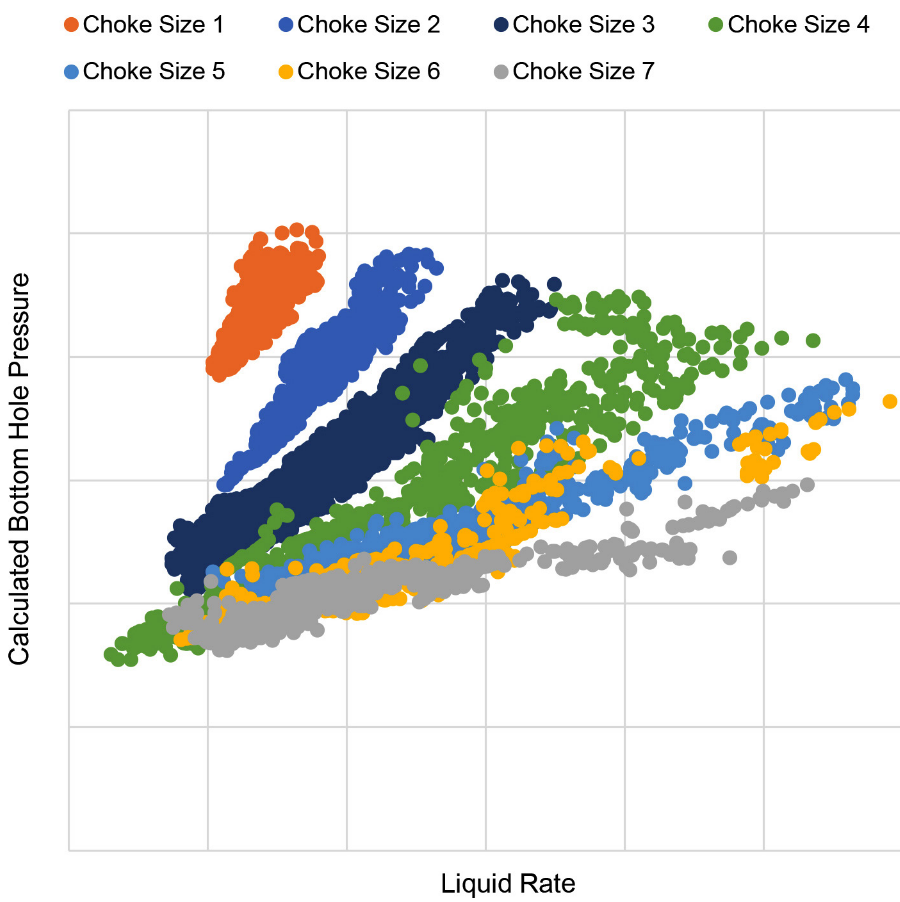

Figure 2. Operating pathways for various choke sizes for selected black oil Vaca Muerta wells.

In the dataset shown, choke 1 is the smallest and choke 7 is the largest. It can be observed that larger chokes display greater rates and lower operating pathway slopes. Likewise, the smallest chokes appear to show the largest slopes.

In all cases, the operating pathways appear linear and for the purpose of simplicity, they will be modeled as such. It is possible to fit other non-linear functions through the data (e.g. polynomials, etc.); however, the observed trend between bottom hole pressure and liquid rate supports the use of linear trends over a wide operating envelope for black-oil wells. Another observation is that all pathways appear to decline to the same bottomhole pressure on the y-intercept. This is consistent with the minimum bottomhole pressure for a well equal to the y-intercept of a VLP defined for the minimum wellhead pressure (i.e. the bottom hole pressure corresponding to the wellhead pressure equal to the gathering system backpressure that cannot decline further).

Linear regression is performed on the operating pathways, using a common y-intercept, yielding the result in Figure 3.

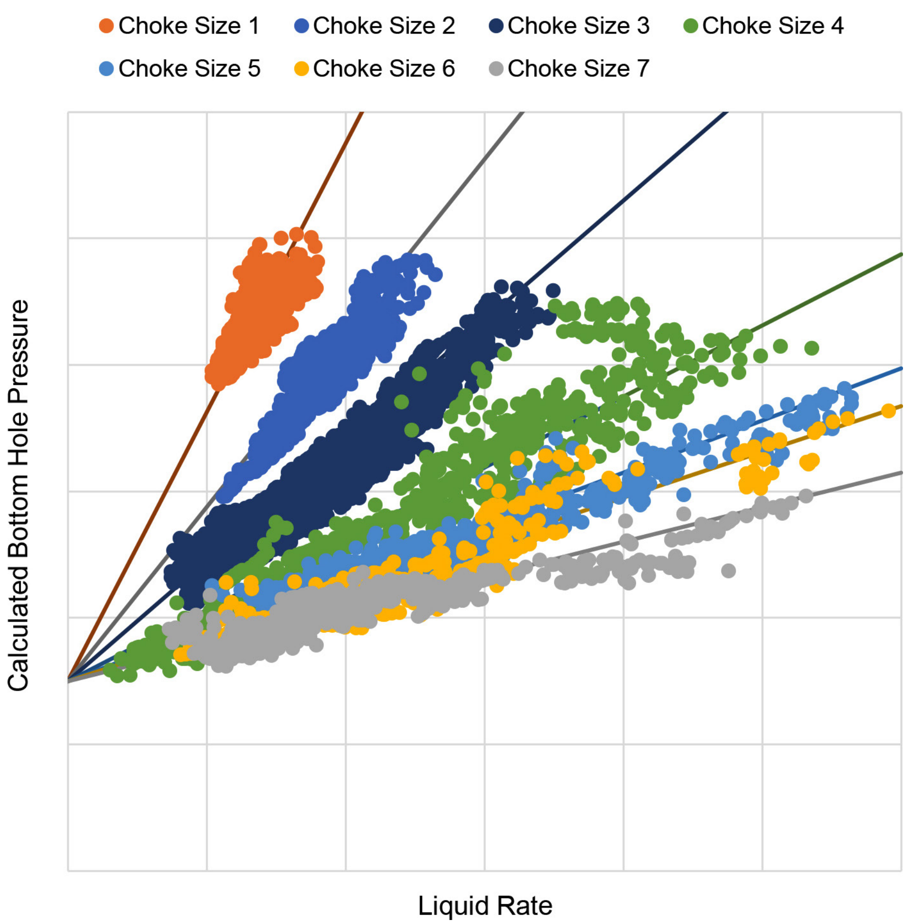

Figure 3. Linear regression to operating pathways for various choke sizes. The liquid rate displaced on the x-axis is the sum of the oil and water daily production rates.

To be able to model production at any choke, it is necessary to fit a mathematical relationship to the slopes of the operating pathways. This would allow for extrapolation to higher-than-tested chokes (e.g., to hypothetical Choke Size 8) or to allow for interpolation between previously tested choke sizes (e.g., hypothetical Choke Size 3.5).

The linear model considered previously that describes the operating pathways is as follows:

$$BHP = m \cdot q_{liquid} + b \tag{1}$$

Or, written alternatively:

$$q_{liquid} = \frac{BHP - b}{m} \tag{2}$$

Where the slope parameter, m, is a function of choke size. If the relationship for fluid flow across an orifice for a constant pressure holds that:

$$q_{liquid} \propto A_{orifice} \propto choke\ size^2 \tag{3}$$

Then m, most simply, would have to take the form:

$$m = f(choke\ size) = c \cdot choke\ size^{-2} \tag{4}$$

Such that the final equation for liquid rate as a function of bottom hole pressure and choke size takes the form:

$$q_{liquid} = \frac{BHP - b}{c} \cdot choke\ size^2 \tag{5}$$

Where b represents the y-intercept of the BHP v. liquid rate operating pathways and c must be regressed to the operating pathway slope versus choke size trend. In Figure 4, a value of parameter c is regressed to the black-oil well data and shows good agreement with the slopes of the operating pathways (parameter m).

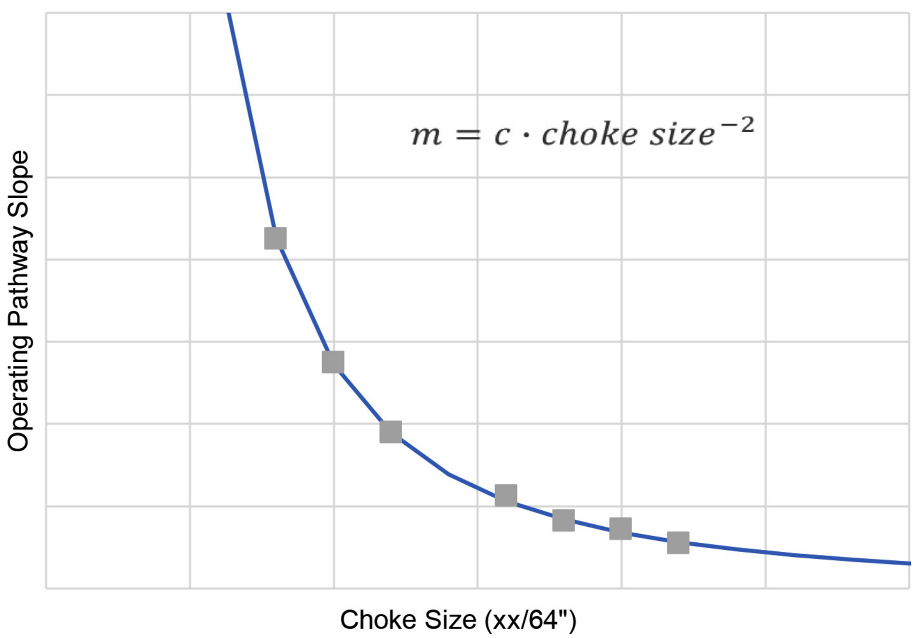

Figure 4. Operating pathway slope v. choke size.

Application of the Superposition Principle to Well Forecasting

The VLP and IPR nodal analysis presented previously gives a method for surveillance and well performance tracking in a rate and pressure space. Although these rate-pressure trends are characterizable, the challenge for forecasting is to parameterize these trends with respect to time. It is possible to parameterize rate and pressure with time using the superposition principle for a reservoir in linear transient flow. Although there are alternative solutions for wells in boundary-dominated flow, the linear superposition solution is the most valid approach to generate forecasts during well ramp-up and early decline, as the well is in linear transient flow.

The superposition principle is a common method in Well Testing that generates solutions of complicated and variable rate and pressure histories using the linear combination of simpler, constant rate or pressure solutions. For fluid flow through a porous medium, governed by the diffusion equation, the principle of superposition relies on the mathematical principle that linear combinations of solutions to the diffusion equation also honor the diffusion equation. Therefore, the mathematical computation relies on and accounts for the flow-rate history to generate an analytical model of the pressure (or vice versa: the pressure history can be used to model the rate).

For a linear flow regime, oil superposition time is defined as the following:

$$t_{linear\ superposition} = \sum_{j=1}^{n} \frac{q_{oil,j} - q_{oil,j-1}}{q_{oil,n}} \sqrt{t_n - t_{j-1}} \quad (6)$$

In practice, superposition time is a time function that can be used to create straight-line relationships when data from different rates are plotted together. The specific superposition time function depends on the geometry of the flow regime being analyzed. Because hydraulically fractured wells in early life exhibit linear flow, it is possible to observe a linear relationship between rate-normalized pressure and linear superposition time (Oyewole *et al.* 2018). Figure 5 shows a plot of rate normalized pressure versus linear superposition time for a hydraulically fractured shale well in early well life.

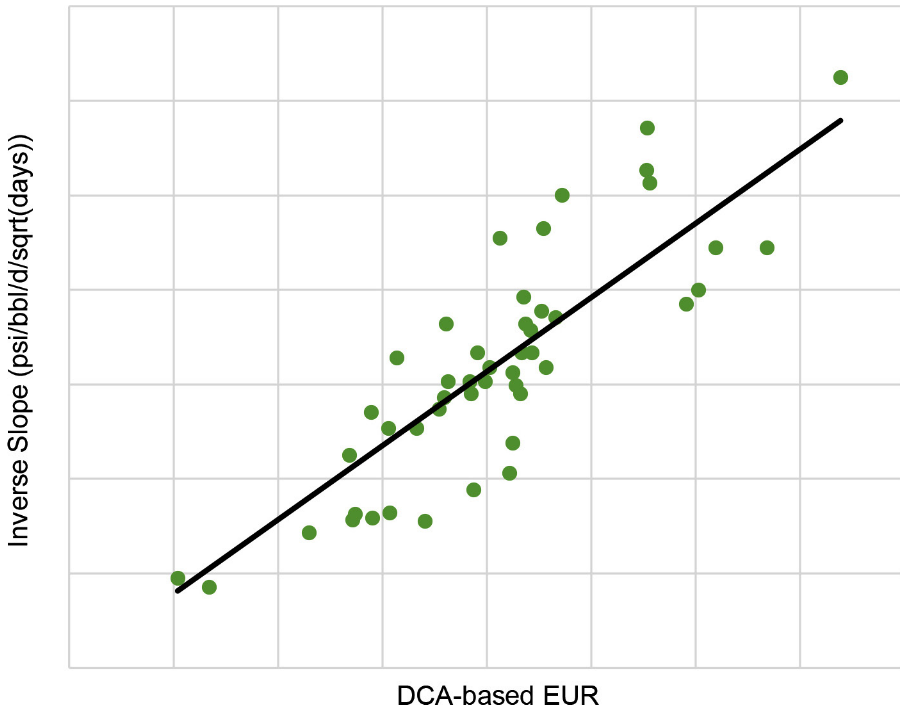

Figure 5. Linear regression of rate normalized pressure (RNP) v. oil linear superposition time for a selected Vaca Muerta black oil well.

The linear regression of this slope can be used to construct a separate relationship between rates and pressures from hydraulically fractured wells. Given the linear relationship between rate normalized pressure (RNP) and linear superposition time, the following relationship can be established:

$$RNP = \frac{P_i - BHP}{q} = m' * t_{linear\ superposition} + b' \tag{7}$$

Substituting in the definition of linear superposition time:

$$\frac{P_i - BHP}{q} = m' * \sum_{j=1}^{n} \frac{q_{oil,j} - q_{oil,j-1}}{q_{oil,n}} \sqrt{t_n - t_{j-1}} + b' \tag{8}$$

And rearranging to isolate BHP, the following relationship is established:

$$BHP = P_i - q_{oil} * \left[m' * \sum_{j=1}^{n} \frac{q_{oil,j} - q_{oil,j-1}}{q_{oil,n}} \sqrt{t_n - t_{j-1}} + b' \right] \tag{9}$$

Where m' and b' are the slope and intercept of the RNP versus linear superposition time plot for a given well. For a linear plot, the intercept, b', captures several near-wellbore effects such as skin and finite fracture conductivity. However, for a correct initial bottom hole pressure assumption and a well in linear flow (i.e., minimal flow resistance caused by finite fracture conductivity that would result in bi-linear flow), it should be approximately zero and is assumed to be so for the linear regressions considered. The slope, m', is related to well performance in the superposition time solution (i.e. constant pressure solution) to the transient linear diffusion equation through the following relationship (Oyewole *et al.* 2018):

$$m' \propto \frac{B_o}{n_f \cdot h \cdot x_f \cdot \sqrt{k}} \sqrt{\frac{\mu}{\varphi \cdot c_t}} \tag{10}$$

With the area of the fracture being:

$$A_f = 4 \cdot n_f \cdot h \cdot x_f \tag{11}$$

Therefore, the inverse slope of the RNP versus linear superposition time plot is related to stimulation size and effectiveness through the following:

$$\frac{1}{m'} \propto A_f \sqrt{k} \tag{12}$$

The inverse slope, for the black oil well sample considered shows a strong correlation with several well performance metrics such as decline curve analysis (DCA)-based estimated ultimate recovery. Figure 6 shows the relationship between the inverse slope and DCA-based EUR.

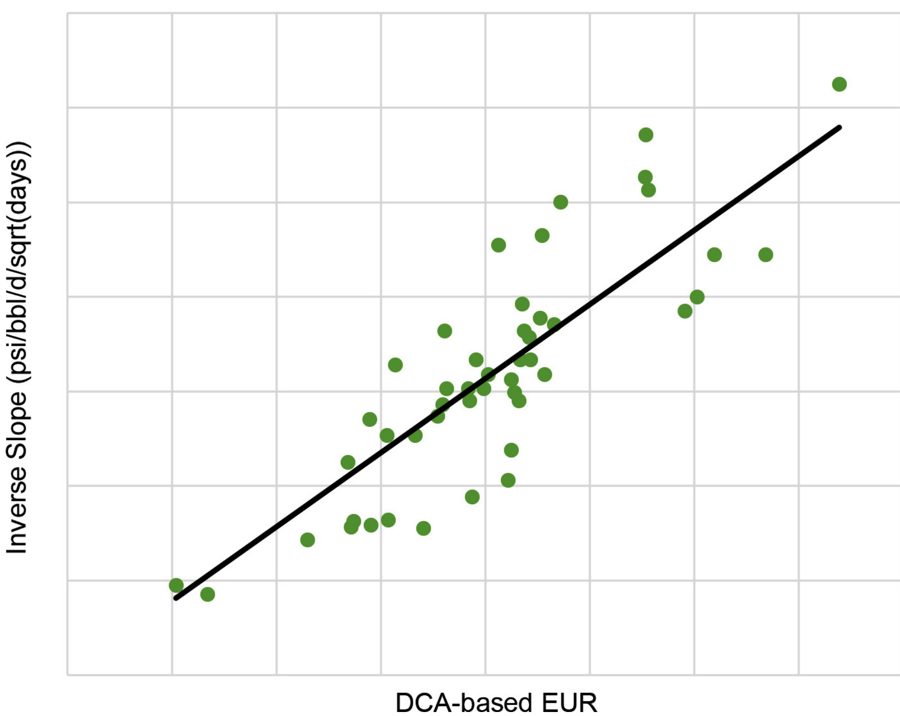

Figure 6. Inverse slope of linear superposition time plot v. estimated ultimate recovery for selected Vaca Muerta black oil wells.

The benefit of using EUR as a well performance metric is that it is generally already estimated for undeveloped wells and often incorporates many different performance-impacting variables such as lateral length, completion design, interference factors, and production interference and parent-child depletion discounts. Thus, for an undeveloped well, the best-estimate type curve EUR can be used to estimate an inverse slope. There are, however, many different production metrics that could be used to empirically reference the inverse slope of undeveloped wells depending on what is convenient and well-characterized for a specific area or asset. This relationship, when combined with observations of operating pathways discussed previously, can be used to parameterize rate and pressure declines with time.

Defining a Water Cut Trend

To tie liquid rate and oil rate between the two pressure and rate functions (operating pathway function and superposition time function), a water cut function must be developed. Due to the large volumes of water injected into the reservoir during the hydraulic fracturing of unconventional reservoirs, high initial water cuts, often near 100%, are observed. In Shell's black oil Vaca Muerta well development though, after a short time, the water cut declines and approaches a constant value. Due to a low initial water saturation, a flat water cut below 10% is generally observed for Shell's black-oil developments in Sequence 1 of the Vaca Muerta formation.

For the representative wells factoring into the data model, the water cuts can be plotted against a function that quantifies the technical maturity of the well, e.g., dimensionless cumulative oil production, defined as cumulative oil production normalized by EUR, as shown below:

$$Dimensionless\ cumulative\ oil = \frac{Q_{oil}}{EUR} \tag{13}$$

Where dimensionless cumulative oil varies between 0 and 1 at the beginning and end of well life, respectively. When water cuts for the well sample are plotted, along with the P50 of the trend, a function can be fit through the P50, as shown in Figure 7.

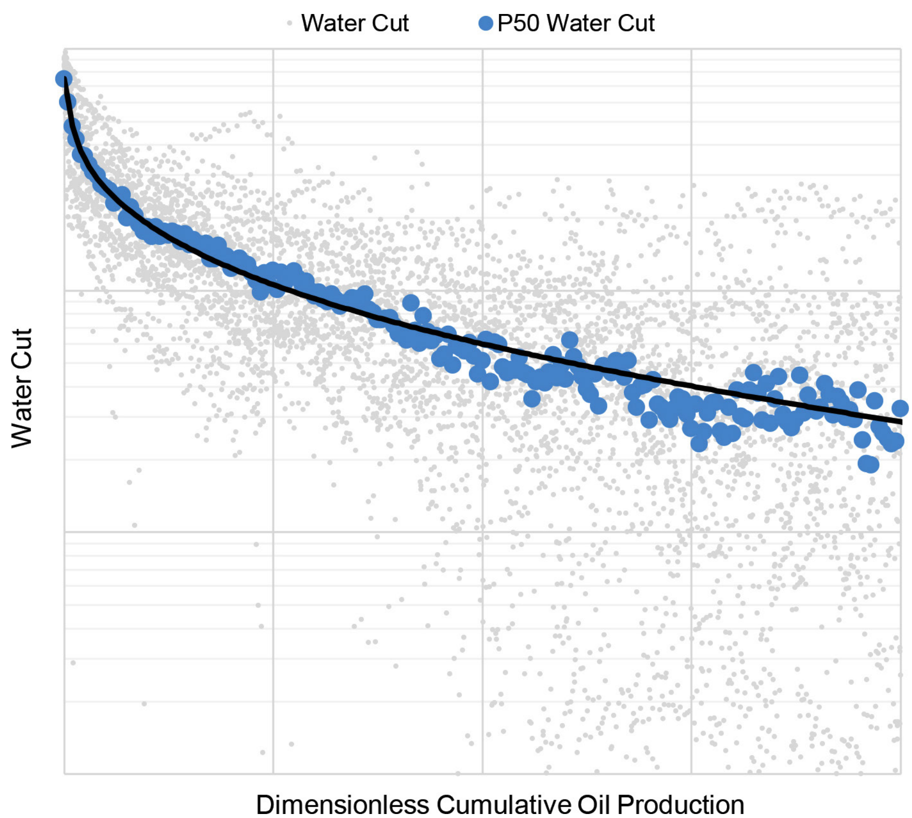

Figure 7. Water cut v. dimensionless cumulative oil production for selected Vaca Muerta black oil wells. Dimensionless cumulative oil production is defined for each daily water-cut measurement as the cumulative oil production (up to that same time) divided by the oil EUR of the well.

The specific water-cut function used will likely vary by geologic area due to different initial fluid saturations and by completion designs due to variability in water injected during hydraulic fracturing. Some geologic regions or sequences may decline to a steady-state water production of near zero, other regions may observe long-term non-zero water cuts. Thus, water cut functions must be defined for specific completion designs and common geologic regions.

The water cut trend shown in Figure 7 is a particular function that is defined for Shell's black oil acreage for a representative completion design.

Implementing a Time Step Method

Three functions have been defined thus far that can be used to characterize the relationships between oil rate (and oil rate history), liquid rate, and bottom hole pressure. The primary functions that will be used to generate forecasts are as follows.

An operating pathway function:

$$q_{liquid} = \frac{BHP - b}{c} \cdot choke\ size^2 \tag{5}$$

A superposition time function:

$$BHP = P_i - q_{oil} * \left[m' * \sum_{j=1}^{n} \frac{q_{oil,j} - q_{oil,j-1}}{q_{oil,n}} \sqrt{t_n - t_{j-1}} + b' \right] \tag{9}$$

And a water cut function:

$$q_{oil} = q_{liquid} \cdot f\left(\frac{Q_{oil}}{EUR}\right) \tag{14}$$

These functions, when initialized for some bottom hole pressure, defined by the initial reservoir pressure, can be each be solved in an iterative manner to define liquid rate, oil rate, and bottom hole pressure as a function of time on productions, given a choke management strategy. This method is shown in Figure 8.

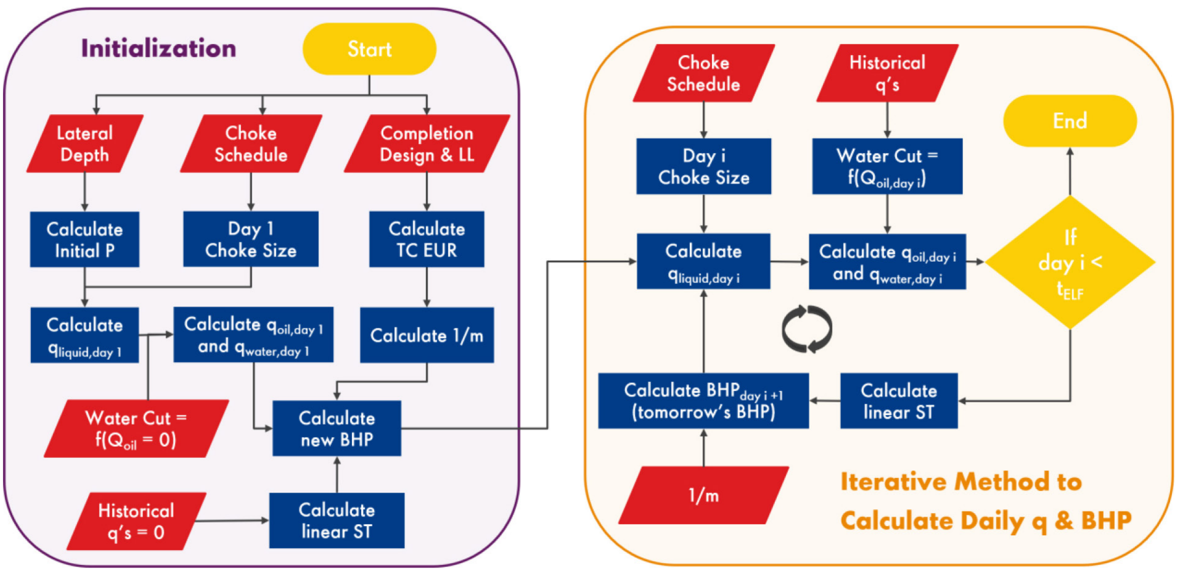

Figure 8. Time step method for production forecasting using operating pathway and superposition time functions for production forecasting.

The method can be split broadly into two steps: initialization and iteration through time. To initialize the model, three primary inputs are needed: (1) the depth of the lateral used to calculate initial bottom hole pressure, (2) the choke schedule used to calculate the liquid rate on day 1 of production, and (3) the lateral length and completion design used to calculate the EUR for the well (an input to the inverse slope and intercept of the superposition time plot). Once these inputs are defined, the liquid rate on day 1 can be calculated using the operating pathway equation and the oil and water cut can be calculated using the water cut function. Lastly, for the calculated withdraw of oil from the reservoir, the superposition time function can be used to determine the new bottom hole pressure for the subsequent day.

To continually iterate to solve the set of rates and pressures for the time forecast, the liquid rate is again solved using the operating pathway equation, the oil and water rates are calculated using the water cut function, and the bottom hole pressure for the following day is calculated using the superposition time function. This iterative step is repeated continually for as long as desired, or input assumptions are valid. In the model, the end of linear transient flow (t_{ELF}) is considered the end of model validity due to the breakdown in assumption of linear transient flow. When the pressure transient signal in the reservoir region between fractures begins to overlap (leading to cluster-level interference), the well is said to have entered boundary-dominated flow (BDF) and the assumption of transient linear behavior breaks down. For the data set of wells in this black oil reservoir, this is generally observed to be between 6 to 12 months from the start of production. Beyond this time, the physical assumptions of the model become invalid and other forecasting methods, such as multi-segment Arps decline functions, must be used. In addition to subsurface properties, the time to BDF is also dependent on completion design parameters such as the number of perforation clusters, cluster spacing, and proppant and fluid intensities.

While the method shown and discussed in this paper uses daily time steps to calculate rates and pressures, it is possible to modify time steps as necessary (e.g. hourly steps). Additionally, the method shown here is general and the calculations required are simple enough to be implemented in a variety of programs such as Python, MATLAB, or even Microsoft Excel.

RESULTS

Validating Model Results for Selected Choke Management Trials

Forecasts generated with the model can be compared to historical production data to validate the theory of the method and implementation of the model. Several wells that were part of a choke management acceleration program in Shell's black oil development were compared to model forecasts. Well-specific lateral lengths and completion designs were used and the choke management program as executed was programed into the model. Model forecasts are compared to actual liquid and oil rates for the first 90 days on production in Figure 9.

In addition to the best-estimate, or P50 forecast, a range of uncertainty in the forecasts was developed to compare to actual wells. A low case and high case forecast were developed using low and high cases in the input assumptions. Specifically, high and low cases were developed for the operating pathways, the inverse slope v. well EUR relationship, the initial reservoir pressure gradient, and the water cut v. dimensionless cumulative oil production assumption. Thus, a total of three models are built.

Although the combination of low-case assumptions in the same model (and vice versa with high-case assumptions) may result in an unrealistically extreme forecast result, individual low and high assumptions can be adjusted such that the resulting forecast uncertainty range appropriately fits the observed production data.

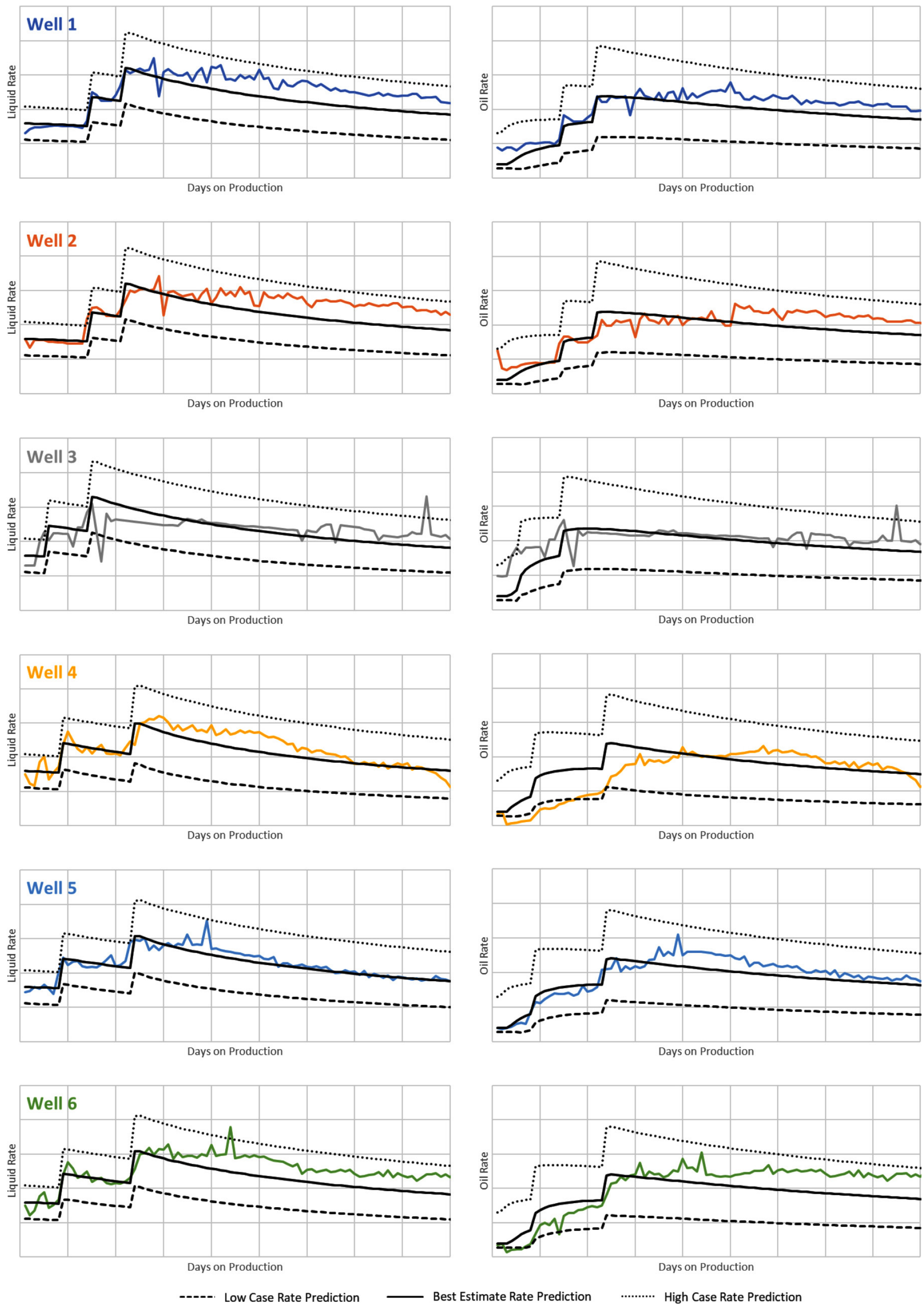

Figure 9. Actual production compared to model forecast and range of uncertainty for selected trial wells.

Generating Forecasts for Rates and Pressures

To further illustrate the forecasting ability of the proposed method, an example with some arbitrary choke management schedule is shown in Figure 10. In this choke management schedule, the well is ramped up to a maximum choke within 80 days on production and thereafter the well begins to decline.

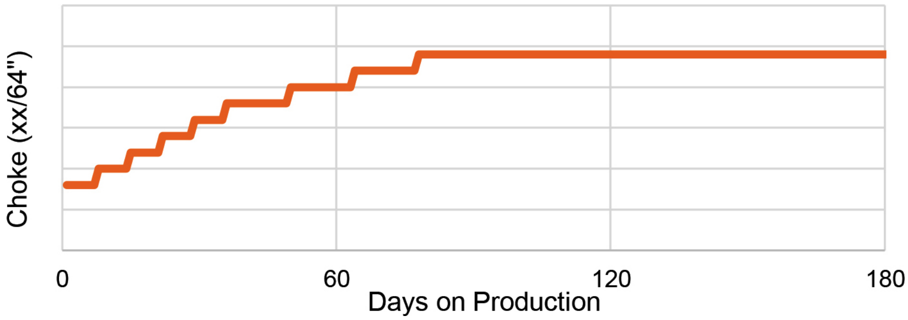

Figure 10. Example choke management schedule.

For the lateral length, landing depth, and completion design of the well, the undeveloped well EUR is calculated, and the forecasting method described is carried out. The following oil, water, gas, and liquid rate estimates are generated. These forecasts are shown in Figure 11.

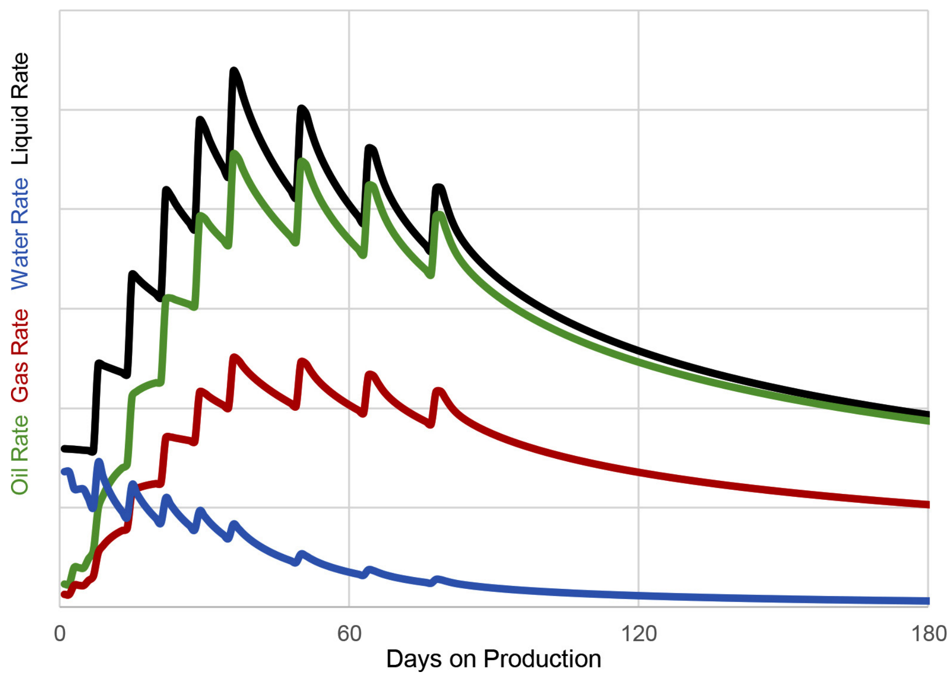

Figure 11. Oil, water, gas, and liquid rate forecast for example choke management schedule.

Along with the rate forecasts, a bottom hole pressure forecast is also generated. From bottom hole pressure and calculated rates, the wellhead pressure can also be calculated. Both pressure forecasts are shown in Figure 12.

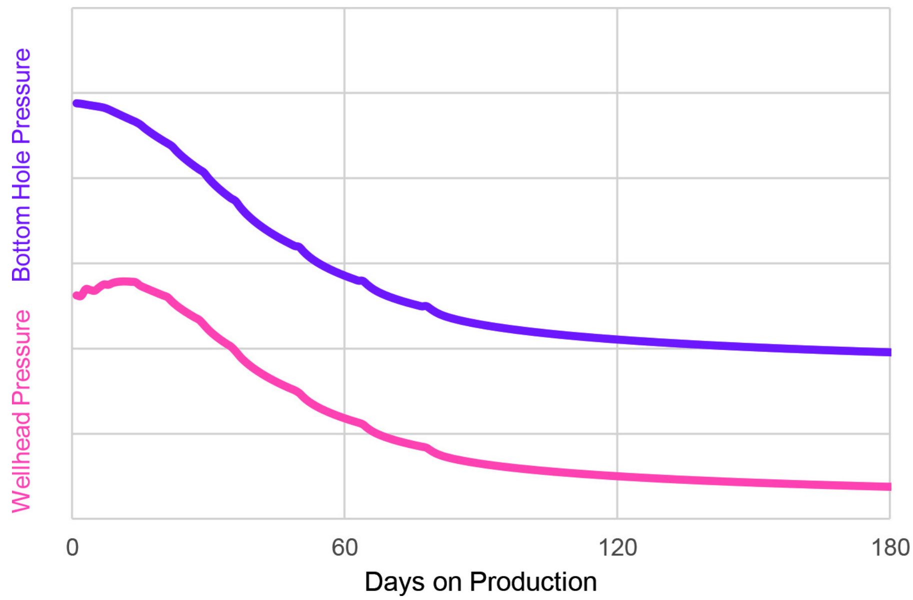

Figure 12. Wellhead and bottom hole pressure for example choke management schedule.

Lastly, using the forecasted liquid rate and bottom hole pressure, the operating pathway can be plotted to visualize the pressure and rate response of the given choke management. The plot shown in Figure 13 can be used as a surveillance tool to compare pressures and rates of wells compared to forecast.

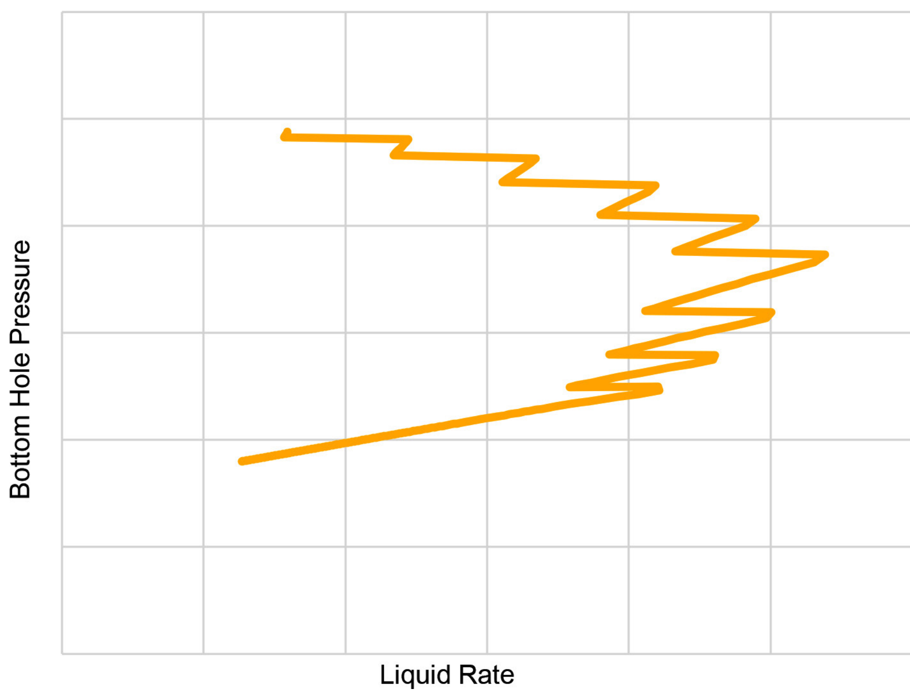

Figure 13. Operating pathway for example choke management schedule

Designing Choke Management

The coupled operating pathway and superposition time function model generates oil, water, and gas rate forecasts as a function of time for a given choke management scheme. Using this model to predict rates allows choke management schedules to be designed for given surface constraints. These constraints could be separator capacities, spurline constraints, gathering line constraints, or central processing facility capacities and may be fixed or time-variant.

For example, Figure 14 below shows a separator constraint with a single-well liquid rate forecast and the corresponding optimized choke management plan. In the scenario, the choke management schedule has been designed to ramp the well up to the liquid rate of the separator and minimize ullage in the separator up to a maximum choke, after which the well is allowed to decline naturally.

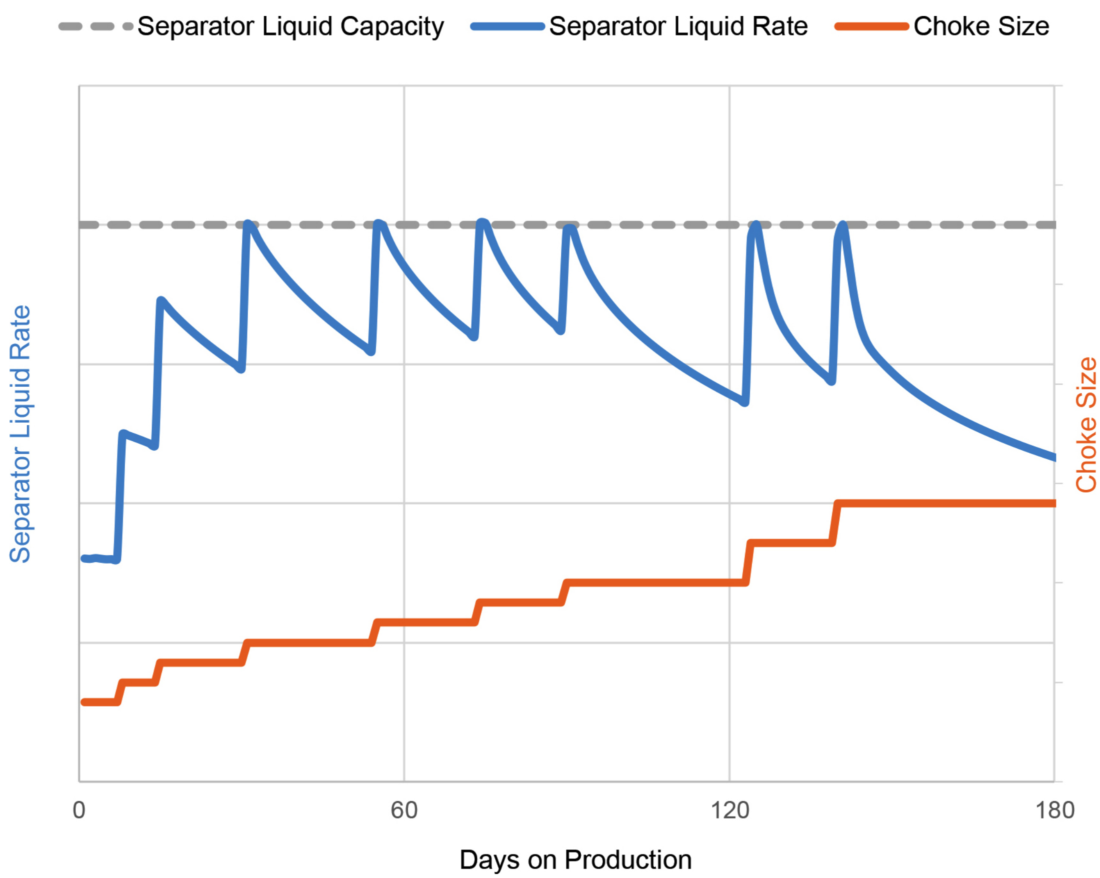

Figure 14. Choke management and liquid flow rate v. separator capacity for example optimized production system using production forecast

The benefit of the model is that this exercise can be performed for a variety of well designs (lateral lengths and completion designs) that are taken as inputs to calculate the linear superposition time function. Thus, highly specific scenarios for choke management planning and surface constraints may be considered.

Using the model to consider many different subsurface and surface development scenarios, reservoir and production engineers can generate production forecasts. These forecasts can be used for short-term planning or for long-term production system and field optimization.

As mentioned previously, the short-term production forecast, valid only for the model period beyond which fundamental physical assumptions break down, can be tied to longer-term production forecasting methods. Single-well type curves, often generated using a multi-segment Arps decline function can use the early-life well ramp up assumption generated by this model. Long-term decline can then be tied to this early forecast, to generate a full well-life forecast given the type curve EUR. For the example considered, Figure 15 shows the full-life type curve for the well using the choke management scheme optimized to separator capacity.

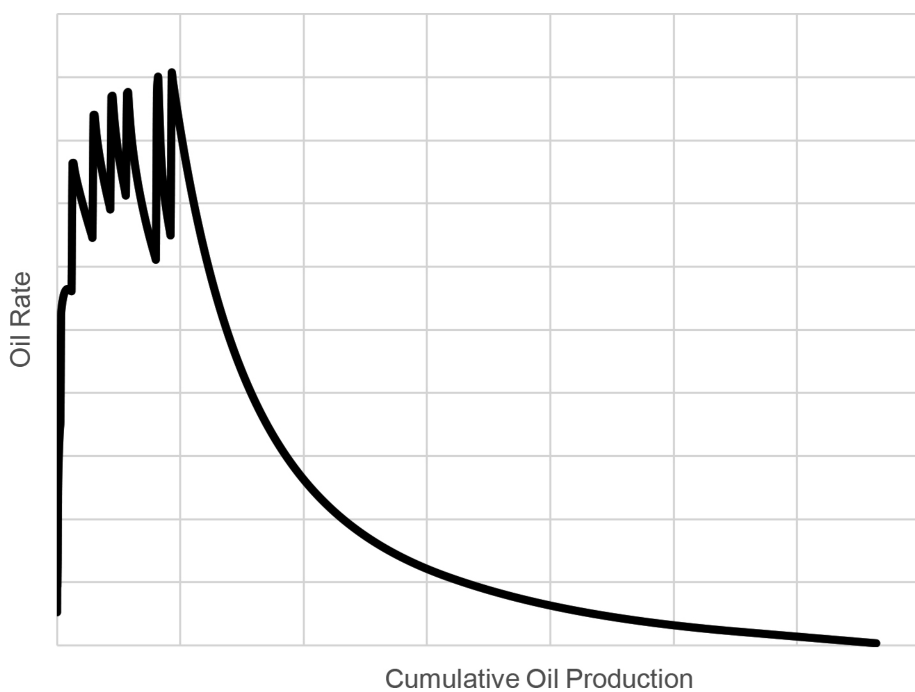

Figure 15. Long-term production forecast using Arps decline function tied to short-term model forecast for optimized separator example

CONCLUSIONS

Integrated analysis of reservoir deliverability and facility capacity is often required in early field development. Inappropriately sized surface infrastructure can limit hydrocarbon production and cashflow if throughput capacity is too small or can cause significant over-capitalization if too large. Additionally, the limited number of analytical tools available to design optimized production ramp-up schedules for unconventional wells makes integrated choke management and facility sizing difficult. In many scenarios, this can lead to non- optimized production systems that are too large or too small relative to reservoir deliverability.

The hybrid data-driven and physics-based model proposed can generate oil, water, and gas rates for unconventional wells given a specific choke management scheme. Currently, the model is developed and validated using black oil wells in Shell's Vaca Muerta development. While in principle, the method could be extended to other single-phase hydrocarbon and other unconventional reservoirs, this has not been validated or proven with data. Some empirical observations, such as linear operating pathways or a strong correlation between inverse slope of the linear superposition time plot with single-well EUR may not hold for different data sets. Thus, the method may require modification to be applied for other unconventional developments.

An additional limitation is that the current method assumes no change in well productivity for excessively large drawdowns. For aggressive choke management, there is a risk of loss of stimulation effectiveness due to completion damage (proppant embedment, proppant crushing, etc.) Although these effects are not observed or obvious to date in Shell's Vaca Muerta development, it is possible that some model assumptions break down for excessive drawdown or aggressive choke management.

Further, the proposed method has been regressed to data from Shell's black-oil wells, meaning the model is primarily valid for the choke management scheme used historically. While the model is useful in estimating production for the choke sizes and programs executed in the past, trials at larger chokes and more aggressive choke management strategies would expand the model's current range of validity. Shell is undertaking these choke acceleration trials currently to expand the input data and improve model robustness to optimize facility and choke management planning.

The proposed method enables early production forecasting for black oil shale plays and improved choke management planning that optimizes the "drill-to-fill" concept. Additionally, short-term forecasts can be coupled with relevant subsurface dynamic modeling and long-term Arps decline functions, allowing for better facility and infrastructure planning for unconventional field development. The proposed method provides petroleum engineers with to ability forecast well deliverability, plan choke management to increase hydrocarbon throughput in production systems, maximize value from existing wells, and optimize development decisions for relevant economic metrics.

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