CASE STUDIES OF FIT-FOR-PURPOSE WELL AND RESERVOIR SURVEILLANCE TO SUPPORT DEVELOPMENT PLAN DECISIONS

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Resumen

Este trabajo presenta tres casos de monitoreo de pozos y yacimientos realizado por Shell en los activos no convencionales de la Formación Vaca Muerta para determinar inputs críticos para el plan de negocios. Los métodos de monitoreo empleados brindaron soporte a la maduración de los bloques de petróleo negro operados por Shell a la fase de desarrollo.

El primer caso se centra en una locación de tres pozos donde se realizaron múltiples pruebas de interferencia para analizar el grado de comunicación horizontal entre los mismos y estimar el impacto en EUR para el primer pozo confinado del activo. Inicialmente, el trabajo de modelado dinámico se realizó con datos de los primeros seis meses de producción y después de un año adicional, que incluyó varios períodos de cierre y pruebas de interferencia de presión, los modelos fueron recalibrados. El trabajo analiza el impacto de la disponibilidad de un historial de producción más largo en las predicciones de EUR.

El segundo caso se refiere al impacto en el EUR causado por la longitud lateral y distintos diseños de terminación en una locación de tres pozos. Además del análisis geoquímico, se utilizaron trazadores químicos para determinar la contribución de producción. El comportamiento de producción sirvió para calibrar los factores de escalamiento aplicados al EUR para pozos más largos y con trabajos de fractura hidráulica de alta intensidad a ser ejecutados en la fase de desarrollo. Los resultados empíricos fueron complementados por modelos integrados (geomecánica-simulación numérica) previamente cotejados con los pozos del caso 1.

El último caso analiza cómo se utilizó el análisis geoquímico para estimar la capacidad de sello del nivel calcáreo basal ubicado entre las secciones Vaca Muerta Superior (Orgánico) e Inferior (Cocina), lo cual es fundamental para la factibilidad de desarrollo de múltiples capas a futuro.

Abstract

This paper presents three case studies of well and reservoir surveillance methods utilized in Shell[1] Argentina's unconventional Vaca Muerta assets to determine specific key inputs to the business

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plan. These fit-for-purpose surveillance methods delivered inputs to the annual business plan and supported the decision to mature the Shell operated black oil blocks to development phase.
The first case study focuses on a three-well pad where multiple interference tests were performed to understand the communication between the wells and to estimate the EUR for the asset's first confined well in Lower Vaca Muerta. Modeling work was initially performed based on the first six months of production data. After one more year of production, which included several shut-in periods and interference tests, the models were recalibrated to the longer production history. The impact of longer production history on the EUR forecasts is discussed.
The second case study focuses on the EUR impact of varying lateral lengths and completion designs. For this purpose, a multi-well pad with varying well lengths and completion designs were utilized. In addition to the geochemical analysis, chemical tracers were used for inflow profiling. Performance of all these wells were later used to calibrate the scaling factors applied to EUR for longer wells and high intensity completion jobs. The results were supported by geomechanics based dynamic models calibrated to the multi-well pad performance in the first case study.
The final case study discusses how geochemical analysis were used to understand the nature of the limestone layer between Upper and Lower Vaca Muerta at the first data hub of the asset, which is critical to the feasibility of dual layer development.

Introduction

Early understanding of development parameters and subsurface mechanisms is critical in building a successful unconventionals business, where the development pace is fast. There are major under- or over-capitilization risks measured in hundreds of millions of dollars due to suboptimal planning and execution (Ugueto et al. 2018). Additionally, the advancements in technology and technical knowledge from unconventional plays around the world always present an opportunity to further optimize the development parameters.
One big challenge in this high-risk, high-reward business is the scarcity of data in the pre-development phase. Often there are limited number of wells, most of which with shorter lateral lengths and smaller completion designs than the ones to be used in the future development wells. Furthermore, it is risky to execute large scale integrated field trials due to large capital investment requirements.
In 2018, Shell Argentina matured three of its black-oil blocks to the development phase. In order to achieve this milestone, the asset utilized small-scale field trials to unlock the specific parts of the puzzle. In the coming sections, three of these trials are discussed, focusing on the optimization of major development parameters:

- Well spacing in Lower Vaca Muerta (LVM)
- Timing of Upper Vaca Muerta (UVM) development
- Completion designs
- Well lateral lengths

In the unconventionals business, it is not possible to optimize every parameter by small-scale trials, where main learnings come from utilizing large data sets. Therefore, in the final section, we will discuss the future to support and build on the initial learnings.

Interference Testing for Confined Well EUR Estimation and Well Spacing

In order to understand the impact of well spacing on well EURs, interference tests have been executed in a three-well pad. The pad and interference test set-up and the dynamic modeling workflows and results for this pad were discussed by Cakici et al. (2018) in an earlier publication. In summary, the pad consists of three horizontal wells, which will be called as Western Well (WW), Center Well (CW) and Eastern Well (EW). The lateral trajectories of the wells were drilled in parallel with 320 meters between the wells. CW is the first confined well, i.e. a well with an offset producer on each side, in the asset. All three wells landed at the same target zone, LVM. Pressure data was collected via bottom hole memory gauges until the end of first 6 months of production. The empirical data was used to calibrate the multi-phase flow correlation used to estimate bottom hole pressures from wellhead pressures and fluid rates.

18 months after the first production date, a review of the analysis was conducted. The additional production data spanning a one-year period included several shut-ins, mainly due to evacuation constraints and a dedicated interference test one year after the wells started producing. In this late interference test, EW and WW were shut-in, while CW continued to produce. One month after the start of the test, EW was returned back to production Two weeks later WW was opened to production. Figure 1 shows the BHP history. The changes in the BHP slopes during the late interference test period confirmed the communication between the wells as in the case of the early production test.
Figure 2 compares the historical and model estimated CW bottom hole pressures. The models, calibrated to the first 6 months of data, has a very good match for the first 8 months of production. However, beyond the 8th month, the model predicted BHPs were underestimated. The underestimation was more severe during build up periods.

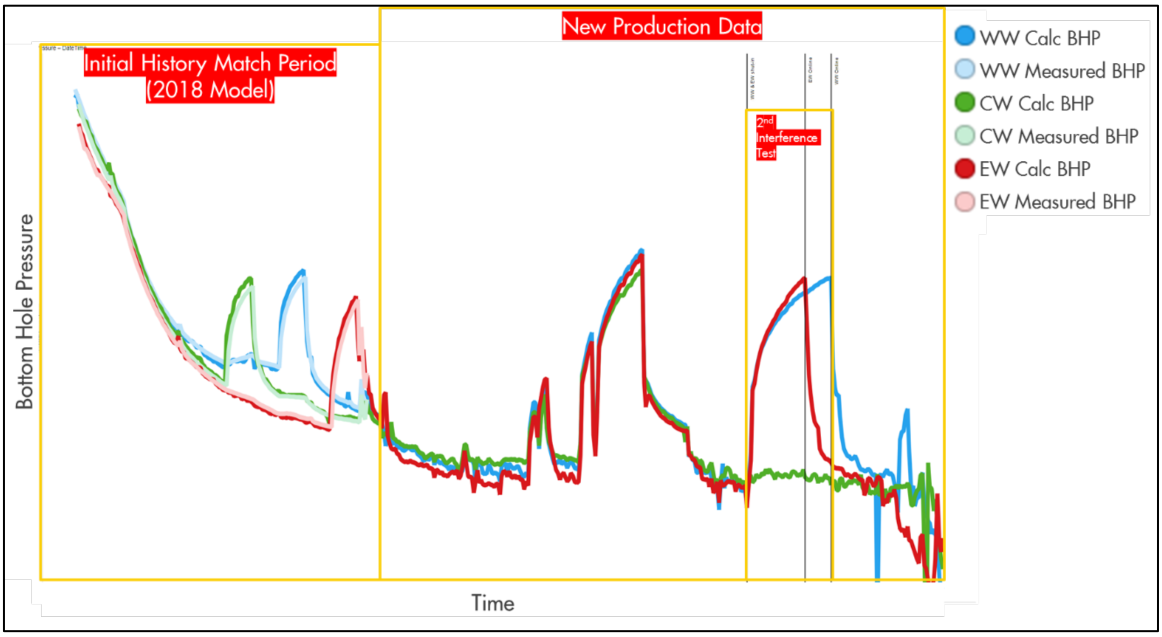

Figure 1 - Historical bottom hole pressure data showing the data used in the 2018 and 2019 history match studies. The lighter colors are the actual gauge measured bottom hole pressures.

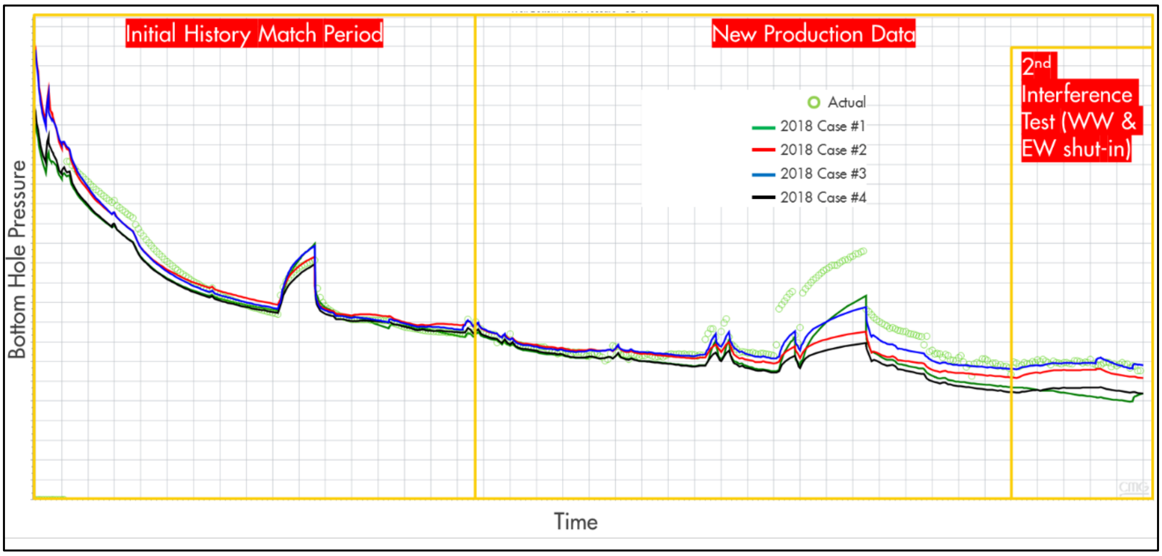

Figure 2 - Comparison of actual bottom hole pressure data with estimated BHPs from 2018 history matched models

History match was redone to improve late BHP matches by adding the last one year's production and BHP data. Figure 3 shows the CW pressures from the models calibrated to the longer production history. The overall pressure levels and build up pressure matches were improved significantly. However, one shortcoming of the updated dynamic models is the connections between the wells. As seen in Figure 3, the pressure response to the late interference test is exaggerated in the updated models. This is mainly due to the model set up, which uses a single perforation stage. This set-up assumes the number of connections for the single stage will be replicated at every perforation stage, thus overestimating the number of connections. Modeling the entire lateral length of the wells will prevent this artifact and enable detection of the minimum number of connections required to mimic field observations.
The comparison of EURs forecasted by models tuned to 6 months and 18 months of data is shown in Figure 4. The median EUR forecasted by the updated models is 18% larger than the median of the models tuned to first 6 months of production history. The same figure also shows the ranges of EUR estimations by two modeling studies. As mentioned earlier, the well-to-well connections were overestimated with the current modeling set up. Therefore, the interference factors based on the updated models were not used to calibrate interference factors for the confined wells. The increase in EUR ranges is also supported by the decline curve analysis.
The study described above highlights the importance of long-term data in EUR forecasting. The modeling work successfully matched the historical pressure levels for all three wells required for accurate EUR estimations. However, due to lack of subsurface data acquisition, there is not enough data for high confidence quantification of interference between wells. Interference tests by themselves are good for identifying the existence of connections between wells. However, it needs to be supported by other data (such as fiberoptics and microseismic) to understand the underlying subsurface mechanisms of well-to-well communication. Improving the subsurface knowledge will help in creating more accurate models.

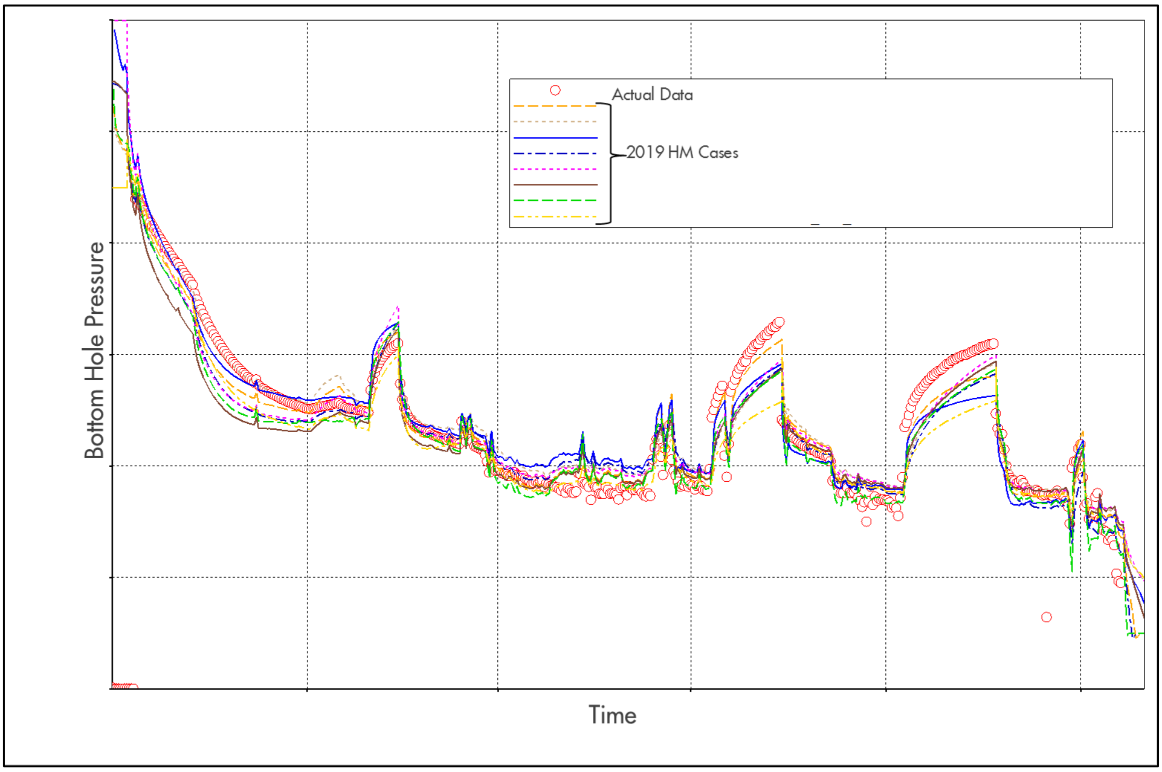

Figure 3 - Bottom hole pressure match of the CW historical data by 2019 dynamic models

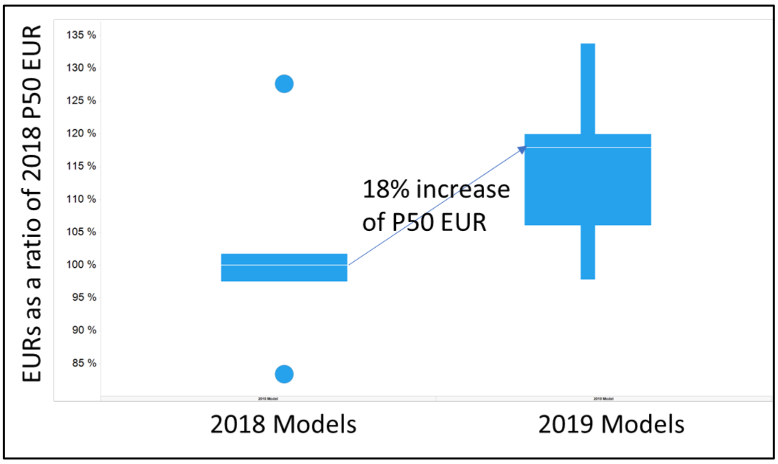

Figure 4 - EUR ranges forecasted by 2018 (calibrated to 6 months data) and 2019 (calibrated to 18 months of data) history matched models

Performance Analysis for Lateral Length and Completion Scaling Parameters

Since the start of exploration activities in Shell Argentina's black oil blocks, the key development parameters have been evolving. As the field development plan was considering longer wells and higher intensity completions for the development phase, lateral length and completion uplift factors were required to estimate the EURs for the wells planned for the development phase.
To quantify the impact of longer laterals and higher intensity completions, a field trial with three LVM wells was executed. The wells were laterally placed far enough to prevent any interference. Table 1 below summarizes the key parameters being tested in this trial.

Table 1. Summary of lateral length and completion parameters at the trial pad				
Well Name		**Lateral Length**	**Stage Length**	**Proppant Intensity**
Well-R	Base Case	LL_R	SL_R	PPI_R
Well-C	Completion Trial	LL_R	$0.8*SL_R$	$1.15*PPI_R$
Well-L	Lateral Length Trial	$1.21*LL_R$	SL_R	PPI_R

The data acquisition plan for this pad included geochemical sampling and chemical tracers. Geochemical analysis performed on the fluid samples collected from the wells confirmed that the fracture heights were similar for all the three wells and in the same range of the earlier wells. Since Well-L was a longer lateral trial, unique oil and water chemical tracers were injected into each stage of this well to understand stage distribution used in the EUR estimation. Figure 5 shows the tracer analysis results. In summary, the tracer analysis shows that 70-80% of the stages were contributing to the production. Most of the non-contributing stages were in the toe stages, from 1 to 6.
Figure 6 shows the oil rate and BHP history for the wells. All wells followed a similar BHP decline. Well-R, with the base development parameters, had lower production rates compared to other two wells with longer lateral length and larger completion jobs. Well-C and Well-R production rates are comparable, and it is not clear from the production data which change increased the production more.
In order to quantify the uplifts from lateral length and completion changes, three different methods were used:

- Initial rate comparison
- Linear plot análisis
- Rate Transient Analysis (RTA)

Linear plot analysis for the wells is shown in Figure 7. The slopes are used to quantify well productivity and lower slopes means better well productivity. For Well-R, -C and -L, the slopes are 0.75, 0.59 and 0.65, respectively. These slope differences correspond to 127% uplift for the completion change and 115% for the lateral length change.

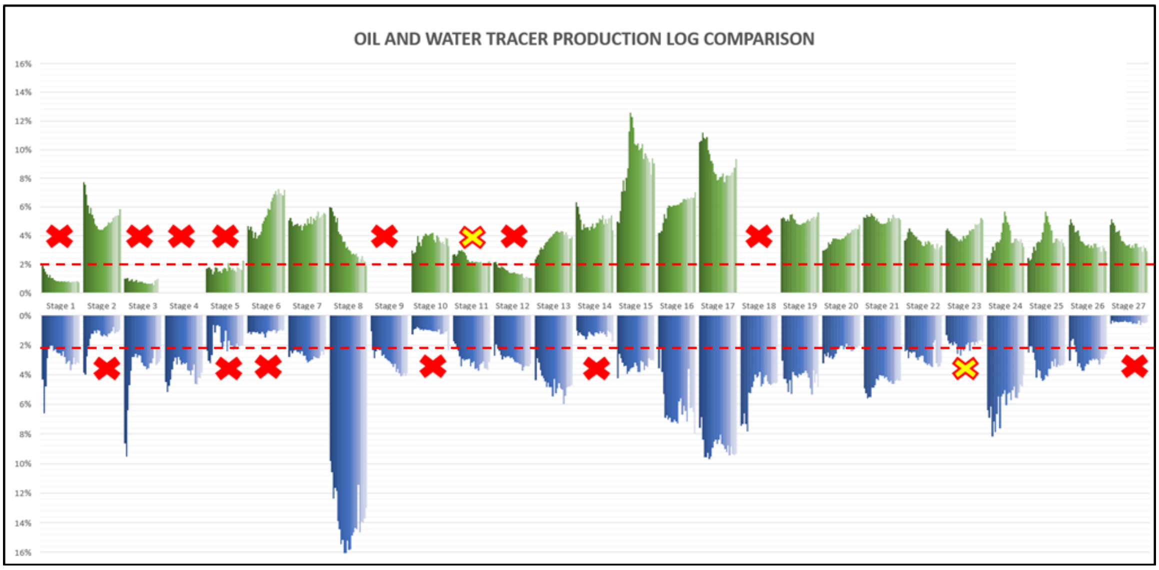

Figure 5 - Oil and water tracer production results by stage in Well-L

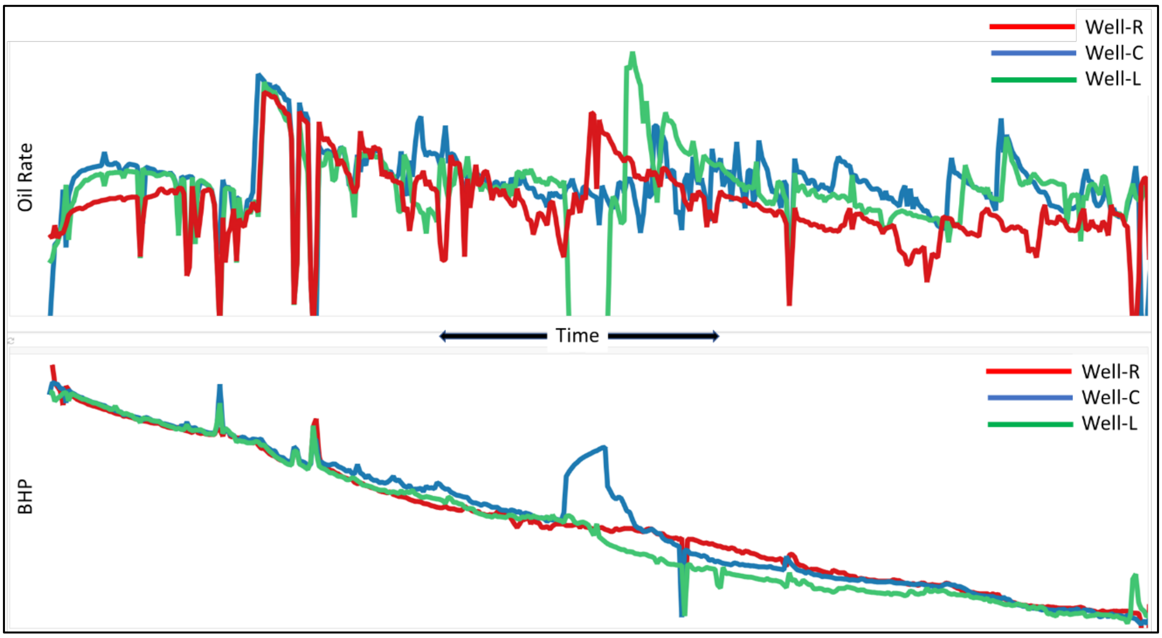

Figure 6 - Historical oil rate (top) and bottom hole pressures (bottom) for the wells in trial pad

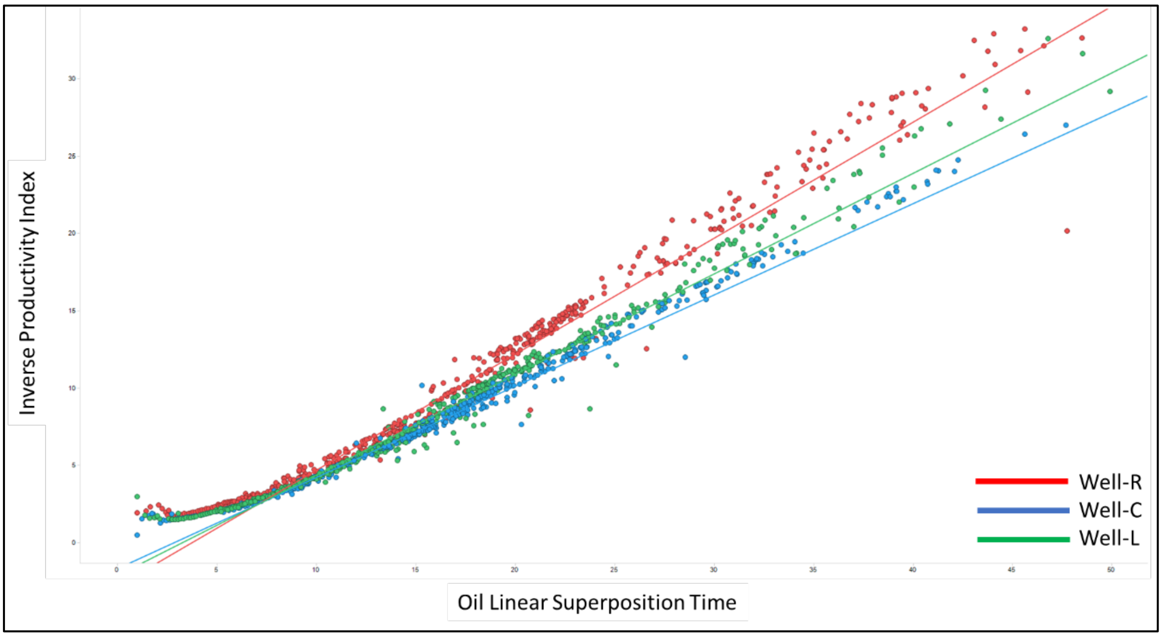

Figure 7 - Linear plot analysis results for the trial wells

Third method used to quantify performance impact of the changes is RTA. For this analysis, first the reference well, Well-R, was modeled. This first model gave us the calibrated inputs: number of active clusters (i.e. completion efficiency), fracture half lengths, SRV permeability and compaction factors. Match quality for Well-R RTA model is shown in Figure 8. For the completion trial (Well-C) and the lateral trial (Well-L) cases, the wells were modeled by using the exact calibrated input parameters from Well-R model, except for the number of clusters. By changing the number of clusters, we were able to gauge the changes in completion efficiency due to lateral length and completion changes. Table 2 shows a summary of RTA outcomes. Compared to the reference case, the models for both trial cases showed lower completion efficiencies (ratio of the number of active to the total number of clusters). The longer lateral well's completion efficiency (68%) is comparable to the results from tracer analysis, which had a range of 70-80%. For the case of completion trial, Well-C, the reduction in completion efficiency can be explained in two ways. First, it is possible that the completion jobs created fractures with similar frac geometries to Well-R, but the short stage lengths decreased the number of active clusters. Second, it is possible that, there is no reduction in completion efficiency, but the new completions had smaller fracture geometries.

Figure 8 - RTA model match for Well-R

The summary of analysis used in the uplift factor calculations is displayed in Table 3. All three methods are showing consistent results for the lateral length uplift factor. A 21% increase to the base lateral length results in 16% increase in EUR.

In contrast, the uplift factors, for increasing the completion intensity from base design to the one applied to Well-L, has a wider range. Independent of the discussed trial, a geomechanics coupled dynamic modeling study (Cakici et al. 2018) had shown 9% uplift for the discussed completion changes. The wide range of results may be caused by the data each method is using. Uplift factors larger than 20% are mostly calibrated to early production data, whereas the dynamic models are tuned for the entire production history. Therefore, it will be better to change the type curve shape for the high intensity case instead of applying a constant factor. This means that high intensity wells will have 8-10% EUR uplift with accelerated production rates in the early production period (20-25% larger than base case).

Finally, it should be noted that these results are for a single trial. As a best practice in the unconventionals, these learnings should be supported with a statistically large sample size.

Table 2. RTA results summary

Well	Total Number of Clusters	Completion Efficiency	Number of Active Clusters	EUR	Uplift
Well-R	N_R	75%	$0.75*N_R$	EUR_R	-
Well-C	$1.27*N_R$	70%	$0.89*N_R$	$1.09*EUR_R$	9%
Well-L	$1.23*N_R$	68%	$0.83*N_R$	$1.16*EUR_R$	16%

Table 3. Summary of uplift factor analysis

Method used	Well-R	Well-C	Well-L	Comp Uplift	Lateral Length Uplift
Initial Rate Comparison	Q_i	$1.22*Q_i$	$1.17*Q_i$	22%	17%
Linear Plot Slope	m_R	$1.27*m_R$	$1.15*m_R$	27%	15%
RTA	EUR_R	$1.09*EUR_R$	$1.16*EUR_R$	9%	16%

Utilizing Geochemical Analysis to Identify Pressure Communication between Layers

A major uncertainty impacting the dual layer development decision is the nature of the limestone layer separating Upper and Lower VM. If this layer is proven to be a true fracture and pressure barrier, the development of these two horizons can be executed sequentially. However, if the limestone layer is not entirely sealing, the field development plan should consider co-developing these two layers to prevent any value loss due to parent-child issues.

Geochemical sampling and analysis is a tool used in Shell Argentina to determine effective hydraulic fracture heights. Wells are routinely sampled, and fingerprinting analysis are performed by comparing the samples to the core samples. Additionally, by looking at the compositional changes of the fluids produced, well-to-well interference can be identified in a multi-well pad.

Shell Argentina's first data hub is a good example for utilizing geochemical data for gaining insights on producing zones. The data acquisition program and the interference study performed at this pad was published by Chen et al. (2017). In summary, an integrated data acquisition is executed at a two well pad, composed of a deviated well (Well-A) and a horizontal well (Well-B). Well-A is a slanted with 2/3 of its producing section in UVM and the remaining 1/3 in LVM. 220 meters to the east of Well-A is Well-B, landed and completed entirely in LVM. Microseismic was acquired during the completion of Well-A, which showed events originating from UVM was growing above the limestone layer. Similarly, the events originating from frac stages in LVM grew below the limestone layer. The well-to-well communication was clearly identified by the interference test and chemical tracers. Geochemical fingerprinting at Well-B showed that frac height growth from the well is mainly contained in LVM, with low possibility to reach into the bottom parts of UVM.

Geochemical mixing results presented interesting results regarding the long-term contribution from each reservoir layer. In general, mixing results show compositional similarities between

fluid samples taken over a period. By monitoring the compositional changes of a well's fluid samples over time, it is possible to identify communication between wells and/or contribution from different reservoir layers.
In the data hub summarized above, wells have been sampled over a four-year period. The mixing results for samples of wells A and B are shown in Figure 9. Since Well-A is deviated and have been producing from both Upper and Lower VM, its time-lapse sampling and analysis provide important insights on the pressure communication through the limestone layer.

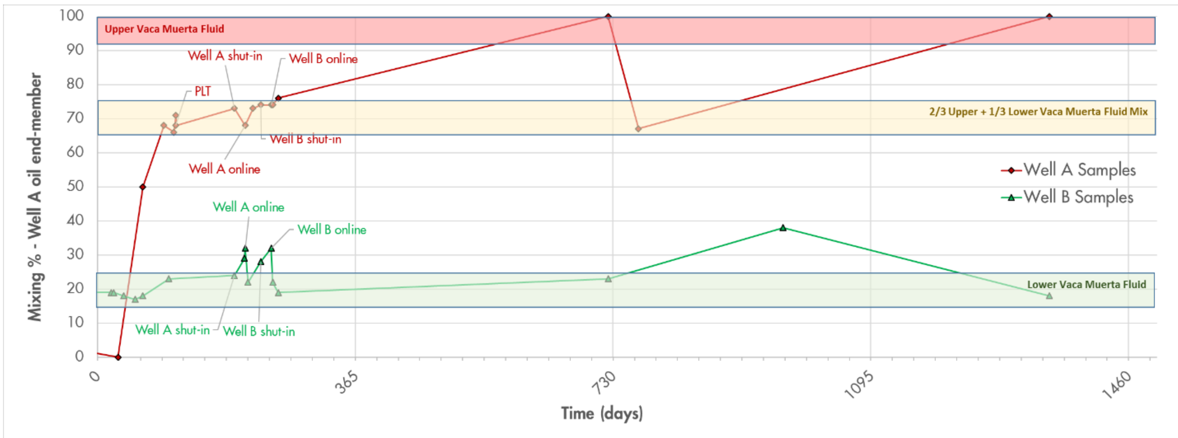

Figure 9 - Well-A and Well-B fluid mixing over time

As an example, let's focus on the results from the first 2 months of production. When the deviated Well-A came online, largest pressure differential between the wellbore and the reservoir was at the 1/3 toe section, which is in LVM. This caused Well-A fluid samples to be more similar to the samples taken from Well-B, i.e. with more LVM oil. As LVM drained further by both wells, the contribution from UVM to Well-A production increased as seen in the plot. A PLT was taken around three and a half months after the start of production, which showed uniform distribution of inflow along the wellbore, with 35% contribution from the LVM zone and 65% contribution from UVM stages.
During the interference test, which was conducted around 6 months after start of the production, mixing results from Well-A stayed at the same level, whereas Well-B showed more response to the interference test. However, it is not entirely clear, if these fluctuations were due to the interference between wells.
Last three samples taken give more information about Upper and Lower VM separation. In this two-year period, two Well-A samples revealed the most different compositions compared to Well B oils, which means that they were producing only from UVM at the time of sampling. However, there is also one Well-A sample with its oil similar to the samples taken in the first year, which were a mixture of both producing layers. These significant fluctuations of Well-A oil compositions can be explained by upper and lower layers being two separate pressure systems. Since both wells drain from LVM, at some point the pressure drop in the lower reservoir gets too large and the Well-A starts to produce only from its UVM stages. This corresponds to the sampling points with 100% UVM fluid. Overtime, the pressure difference between upper and lower sections is balanced and Well-A starts to produce from both reservoirs. The contribution changes to the deviated well repeats itself as the wells produce. However, the sampling frequency after the first year was not small enough to capture this phenomenon.
In conclusion, time-lapse geochemical sampling and analysis enabled us to understand long-term drainage mechanisms around the deviated well. The results indicate the limestone layer acts as a barrier between Upper and Lower Vaca Muerta. A similar field trial can be improved by increased frequency in the long-term fluid sampling program and by using behind the casing pressure gauges on the deviated well to confirm the impact of pressure imbalance on the sampling compositions.

Summary and Future Work

The case studies discussed above contributed to the asset's initial understanding of VM black-oil reservoirs, along with other data acquisition in VM and analogs from the North American unconventional plays. In the development phase, the optimization of development parameters continues. The 2019 wells will test a wide range of variables, including well spacing, lateral lengths and co-development of UVM and LVM. Moreover, an aggressive completion design testing program is in place, which will be executed in the next two years. As the number of wells in the field increases, the statistics will start to play a more dominant role in the development decisions.

Moreover, an integrated diagnostics pad is in plan, where fiberoptic technology will be utilized. This data will be supported by microseismic, geochemistry, chemical tracers, bottom hole gauges and interference testing. The goal is to understand the fracture growth in both LVM and UVM to support well spacing and completion design optimization, and the co-development decision. The extensive subsurface data collected will help the team in creating high-quality predictive models, which will enable the optimization of the field develop plans with smaller number of field trials.

Acknowledgements

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