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PINPOINT COMPLETION TECHNOLOGY IN THE VACA MUERTA SHALE: A CASE STUDY

AUTHORS: Eduardo Martinez (emartinez@pan-energy.com), Cristian Espina (cespina@pan-energy.com), Diego Alvarez (dnalvarez@pan-energy.com), Guillermo Lopez Peze (glopezpeze@pan-energy.com) – Pan American Energy; Luciano Fucello (lfucello@ncsmultistage.com), Ted Randolph (trandolph@ncsmultistage.com), Eric Schmelzl (eric@ncsmultistage.com) – NCS Multistage; David Anderson (danderson@atreservoir.com); John Thompson (jthompson@atreservoir.com) – Anderson Thompson Reservoir Solutions; Youssouf Zotskine (yzotskine@calfrac.com) - Calfrac

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SYNOPSIS

The development of unconventional resources has had a tumultuous and disruptive influence on global energy markets. The excitement and promise of previously untapped and unrecognized resources has led the energy industry to often rely upon the “tried-and-true” methods that brought unconventional production to the forefront in north America, in hopes that similar results could be achieved in other basins around the globe. In many cases, proving the economic viability of a new play is considered “good enough”, with optimization of the resource recovery left for some future date.

The presented case study will document one operator’s early steps towards well and reservoir performance optimization through the application of pinpoint completion technology in the Vaca Muerta shale. The resulting impacts on well completion costs, field operations, logistics, and forecasted ultimate reserve recovery will be presented. Finally, an overview of the theory regarding the impact of stress shadows and potential completion options that are entirely unique to the pinpoint completion method will be presented. The application of these new methods may hold the potential to redefine the asset values of many of the world’s largest untapped hydrocarbon energy reserves. It is crucial that the custodians of those assets are well informed of all the technologies and techniques available to them, and can reach optimized completion designs early in the life of the reservoir, when those impacts are capable of greatest effect.

INTRODUCTION

The Vaca Muerta shale is a large emerging resource play with the potential to provide essential resources and revenues to the Argentinian people and their government. Initially discovered in 2010, the formation is estimated to hold in excess of 16 billion bbls of recoverable oil reserves, and 308 tcf of natural gas. The formation covers an areal extent of over 12,000 square miles, and while its properties vary over that vast area, it is generally a mixture of black shale, marl and mudstone, with thickness exceeding 400m in some areas. It is known to be the source rock for other hydrocarbon bearing formations in the Neuquen basin, and holds the potential to supply Argentina’s needs for hydrocarbon energy for many decades into the future.

BANDURRIA CENTRO BLOCK GEOLOGY

The Vaca Muerta formation constitutes the main source rock of the Neuquén Basin. Due to its great extension, thickness and high values of TOC, it constitutes an unconventional Shale Oil and Shale Gas reservoir.

The formation consists of an alternation of fangolites and bituminous limestone fangolites ("marls"), accumulated in a platform / ramp environment distal to basin, deposited in a partially closed basin that was controlled by recurrent eustatic variations. The proximal deposits equivalent to the Vaca Muerta formation comprise a sequence consisting mainly of shallow water carbonates assigned to the Quintuco formation (Figure 1).

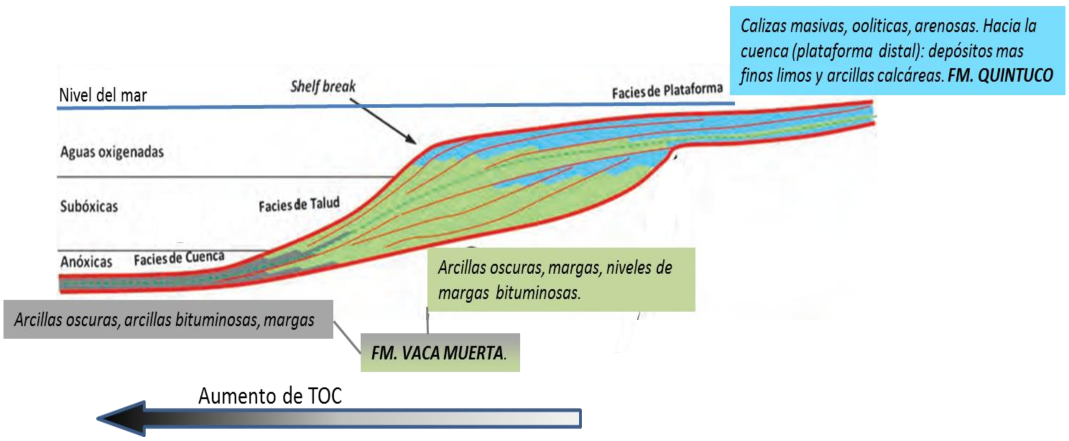


Figure 1. *A depositional model for a platform environment of clastic and carbonate composition. (Pose et al. 2014)*

The Quintuco-Vaca Muerta system consists of a large transgressive-regressive sedimentary cycle that begins with an abrupt flooding of the Pacific during the Upper Jurassic to Early Cretaceous above the continental deposits of the Tordillo formation (Figure 2), which maintained much of the basin under marine conditions of restricted and anoxic background favoring the accumulation and preservation of organic matter. Then, the Quintuco-Vaca Muerta system evolves as a ramp of clastic and carbonate composition to a platform with slope development, which progresses from the southeast to the northwest. The thickness of the Vaca Muerta formation ranges from 100 to 2000 m from the border to the center of the basin.

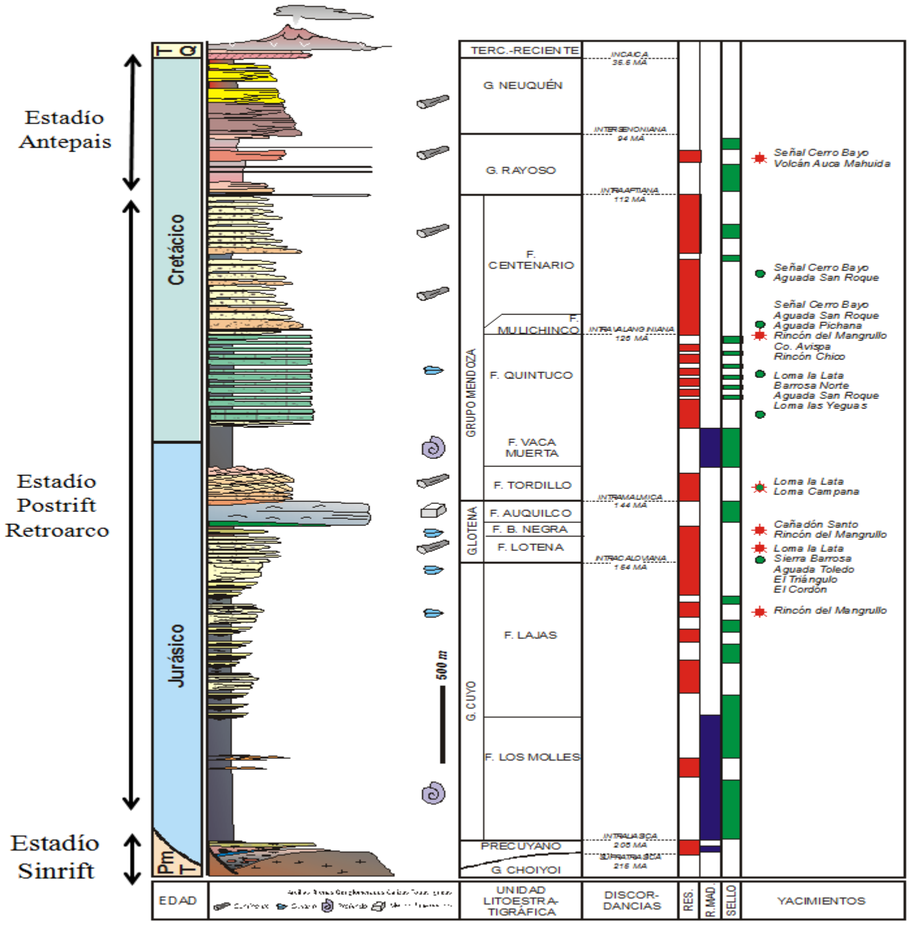


Figure 2. *Stratigraphic column. Neuquen Basin. (Brisson & Veiga. 1999)*

In the Bandurria Centro area, the interval corresponding to the Vaca Muerta formation involves a total thickness of marls up to 290 m. This interval contains a thickness with TOC > 2% of 160 m at the south-eastern end of the block and increases towards the central and northwestern sector at 240 m and 280 m respectively (Figure 3).

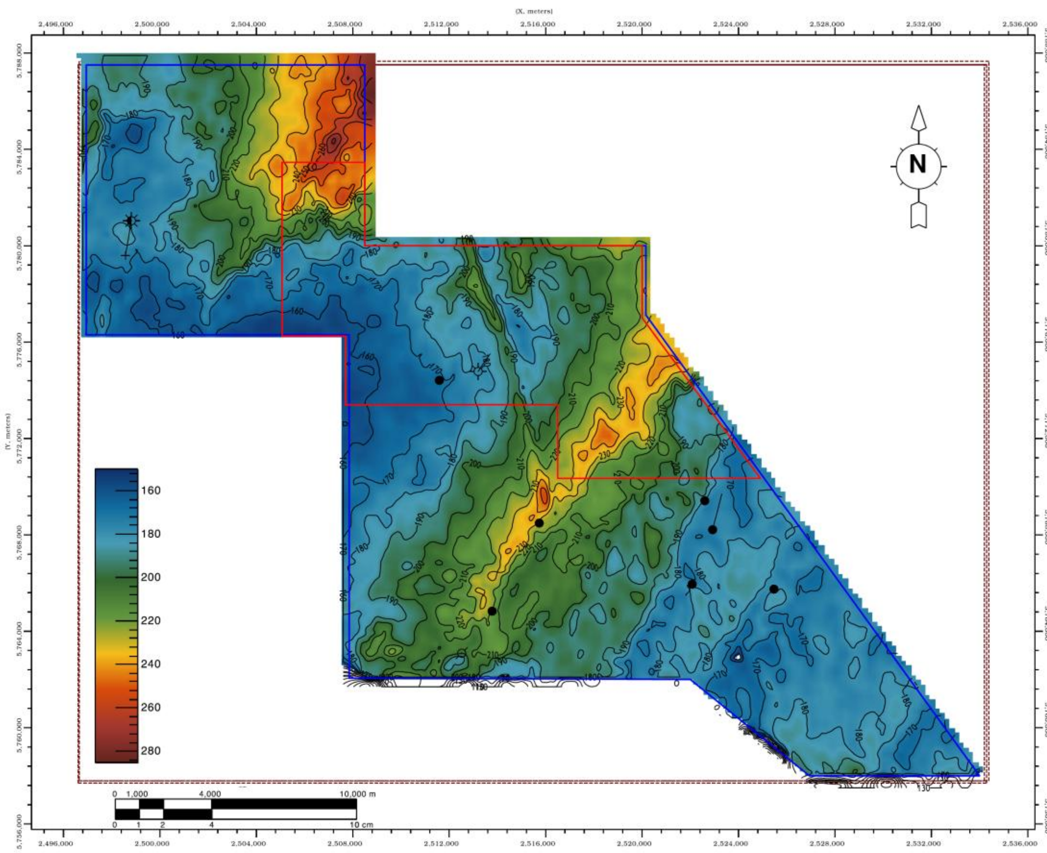


Figure 3. *Map of the thickness (m) of the Vaca Muerta formation with TOC > 2%.*

GEOCHEMISTRY

The kerogen that constitutes the Vaca Muerta formation is not fully homogenous on a regional scale. Although it is of marine origin, its variations are mainly related to the depth of deposition (degree of oxygenation) and to the quantity of material of terrestrial origin (distance of the coast) that composes it. In the area of the proposed well, the formation consists almost entirely of amorphous organic matter associated with paleomicroplankton, with little participation of terrestrial material.

The thermal maturity of the unit is in the oil generation window, as shown in Figure 4 by means of Tmax. These values correspond to a reflectance of the vitrinite of the order of 0.9 to 1.1%. In terms of rate of transformation (percentage of kerogen that has been converted to hydrocarbon), values are around 60-70%.

Regarding the content of total organic carbon (TOC), this shows an increase from the cuspidal towards the base. The section called Lower Vaca Muerta presents values between 4 and 6% (Condensed Section), while the rest of the unit varies between 0.5 and 4% (Figure 4).

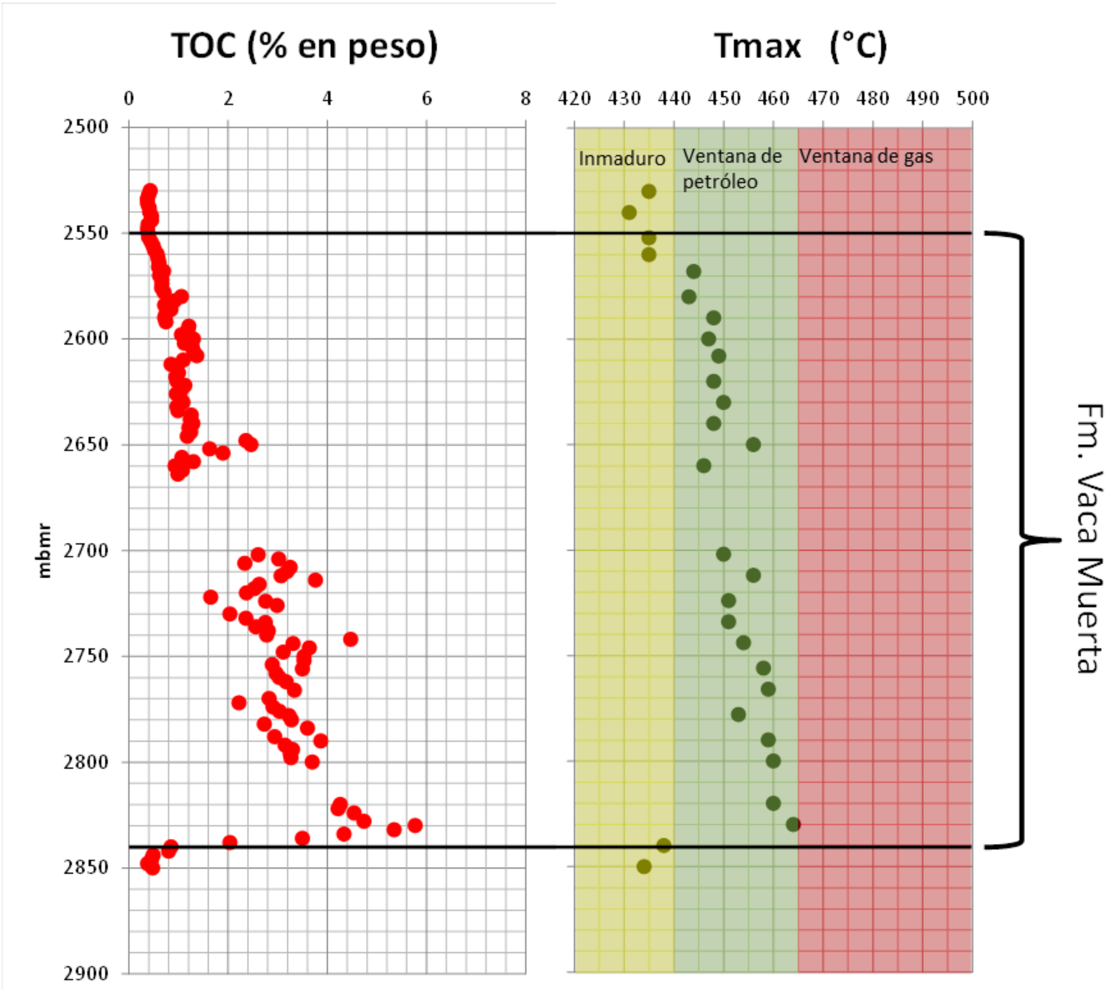


Figure 4. *TOC and Tmax values in the LCav.x-7 well from cutting.*

PETROPHYSICS

The well YPF.Nq.LCav.x-7 corresponds to the pilot well used for the petrophysical characterization of the Vaca Muerta formation in the Bandurria Centro Block.

Analyzing the response of the different logs, it was observed that GR in general has a high activity, with higher values towards the base of this formation. The resistivity presents relatively high readings, indicating kerogen content. In addition, an increase in the porosity (Sonic Density) registers towards the base of the Vaca Muerta formation (Figure 5), evidence of organic richness and / or overpressure.

Based on the analysis of the wells in a stratigraphic condition similar to the one proposed, Vaca Muerta formation could be characterized as follows for this sector of the basin:

- Condensed Section (30 m basal): GR ~ 175 API, NPHI ~ 0.26, DT ~ 105 us / ft, ILD 30 ohm.m
- Upper Vaca Muerta (roof S1 and S2): GR ~ 120 API, NPHI ~ 0.21, DT 78 - 104 us / ft, ILD 20 ohm.m

- Marl's top (S3): GR-60 API, NPHI ~ 0.15, DT 60-92 us / ft, ILD 25 ohm.m

For the TOC calculation, the density profile and the uranium profile (Spectral Gamma Ray) were used, calibrated with cutting data.

Figure 5 shows the profiles and interpretation of the LCav.x-7 well. The navigation interval (S2A) presents averages of TOC and porosity of 3.9% and 9.6% respectively, and a total thickness of 30 m.

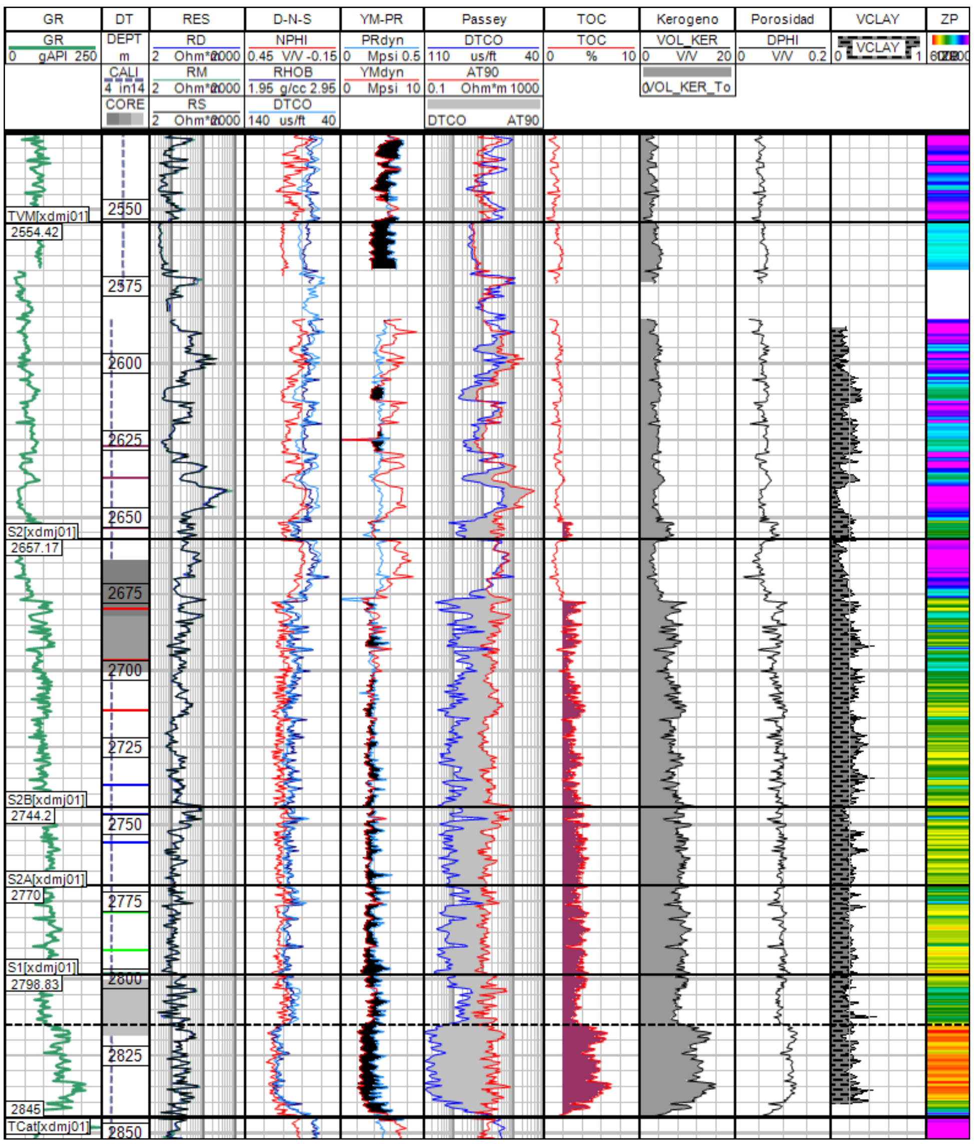


Figure 5. *Logs and petrophysical interpretation of the LCav.x-7 well.*

FRAC DESIGN

The treatments on both wells consisted of a hybrid fluid design beginning with a slickwater fluid and transitioning to a crosslinked fluid as the treatments progressed to aid in transporting the higher density, larger proppant at higher concentrations. The proppant started with 100 mesh sand progressing to 40/70 - 40/80 mesh proppants, on to 30/50 – 30/60 mesh proppants, and finishing with 5 ppa 20/40 mesh proppant. There was a minimal amount of proppant bridging during the treatments of both wells.

As can be seen from Table 1, the BCeCf-101h well had more lateral coverage which, given the consistent spacing between entry points, resulted in more entry points for this well than the BCeCf-102h well. This accounts for the greater fluid and proppant volumes being utilized for the 101h well as compared to the 102h. The average spacing was slightly greater for the 101h than for the 102h, but the overall entry point spacing between the two wells was very similar.

Well	**BCeCf-101h (Pinpoint)**	**BCeCf-102h (MCPP)**
Entry Points	58	54
Lateral Length (m)	1467.6	1323.8
Slickwater (bbls)	94,913	63,299
Gel (bbls)		1,092
Crosslink (bbls)	53,042	65,366
Total Fluid (bbls)	147,954	129,756
100 mesh	936,370	665,000
40/70 sand	2,617,000	2,549,900
40/80 Sinterlite	2,374,340	
30/50 sand		1,929,900
30/60 Sinterlite	1,532,250	1,913,400
20/40 Wanli	1,683,600	1,618,900
Total	9,143,560	8,677,100

Table 1. *Comparison of the treatment volumes between the two subject wells.*

The treatments performed on the two wells were similar in nature when viewed from an average proppant volume standpoint. As can be seen in Table 2, the BCeCf-101h well was treated with slightly less proppant volume per entry point than was the BCeCf-102h well. There was about 14% more fluid injected during the treatment of the 101h well as compared to the 102h well. One considerable difference was the increased injection rate per entry point (~35%) on the 101h well over the 102h.

While the total average volumes were similar, there were some differences in the composition of those average volumes. Most notably, the amount of slickwater and crosslinked fluid varied with the 101h well utilizing ~40% more slickwater and ~24% less crosslinked fluid than that on the 102h well. In addition, the 102h well averaged a greater amount of the proppant in the larger mesh sizes (30/50, 30/60, and 20/40) than was used during the treatment of the 101h well.

Well	**BCeCf-101h (Pinpoint)**	**BCeCf-102h (MCPP)**
Entry Point Spacing (m)	24.9	24.5
Slickwater (bbls)	1,636	1,172
Gel (bbls)	-	20
Crosslink (bbls)	915	1,210
Total Fluid (bbls)	2,551	2,403
100 mesh	16,144	12,315
40/70 sand	45,121	47,220
40/80 Sinterlite	40,937	
30/50 sand		35,739
30/60 Sinterlite	26,418	35,433
20/40 Wanli	29,028	29,980
Total	157,648	160,687
Injection Rate (bpm)	23.3	17.3

Table 2. *Comparison of the treatment volumes per entry point for each of the two subject wells.*

COMPLETION

There was one major difference the completions of the BCeCf-101h and BCeCf-102h well; the 102h well utilized the more traditional plug and perf methodology while the 101h well utilized a pinpoint completion via coil tubing shifted sleeves.

The plug and perf completion on the 102h consisted of perforating three (3) clusters, or entry points, per frac stage. These clusters were comprised of 10 perforations placed over 0.5 meters. The average spacing between the clusters averaged ~24.5 meters. With eighteen frac stages, a total of fifty-four clusters were perforated for the treatment. Isolation between frac stages was accomplished with composite bridge plug set by wireline.

The completion on the 101h well consisted of coil tubing shifted sleeves. The average spacing between each of these sleeves was ~24.9 meters; consistent with the entry point spacing utilized on the 102h. Isolation between frac stages was accomplished of a resettable bridge plug on the coil tubing conveyed bottomhole assembly used for opening the sleeves. A total of sixty full drift ID sleeves were placed as an integral part of the casing string and cemented. While sixty sleeves were placed, only fifty-eight were opened and treated; one sleeve failed to open and another was skipped due to concerns related to casing deformation issues.

The advantage of the pinpoint completion is the knowledge that the entire frac treatment volume is placed into each of the entry points in the casing. Since the pinpoint completion treats each entry point individually, the actual injection rate, fluid volume, and proppant volume for each entry point is known. The alternative multi-cluster plug & perf completion methodology does not share the ability to ascertain these parameters for each individual entry point. The simplest and easiest way to try to evaluate a multiple entry point treatment is to assume that the treatment is equally distributed into all the entry points. There is significant published information to the contrary (Algadi et al, Maxwell et al, Carrasco et al, Holley, et al). While it is known that two of the entry points were not treated during the pinpoint completion, there is no way to know how many of the entry points in the 102h well were not treated. In addition, there is no way to know how much of the treatment was distributed in each of the entry points that were treated. If everything is equal, then the premise that the treatment is equally distributed into each entry point might have some validity. However, if one looks at the breakdown pressure (only captured on BCeCf-101h) as well as ISIPs for the wells (Figures 6, 7, and 8) there appears to be a reasonable indication that all is not equal. The breakdown pressure for the BCeCf-101h shows differences in excess of 1,500 psi. While the ISIP data doesn't indicate variations of the same magnitude, there are still differences observed in the data. While ISIPs for the BCeCf-102h appear to be less drastic, the variability may be masked by an "averaging" effect of having 3 entry points open at one time or may be a result of higher breakdown clusters not being treated, which would tend to reduce the magnitude of the observed pressure data.

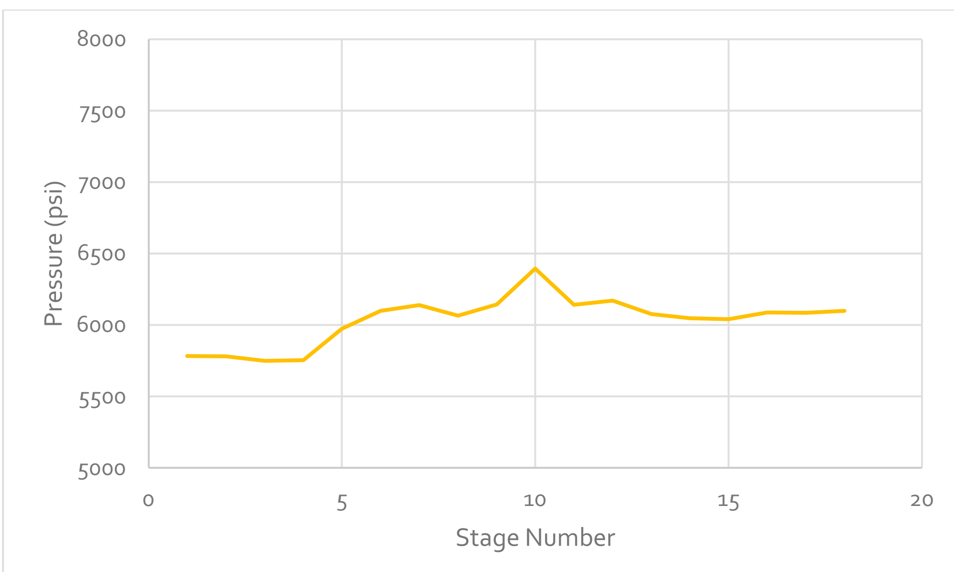


Figure 6. End of treatment ISIPs for BCeCf-102h

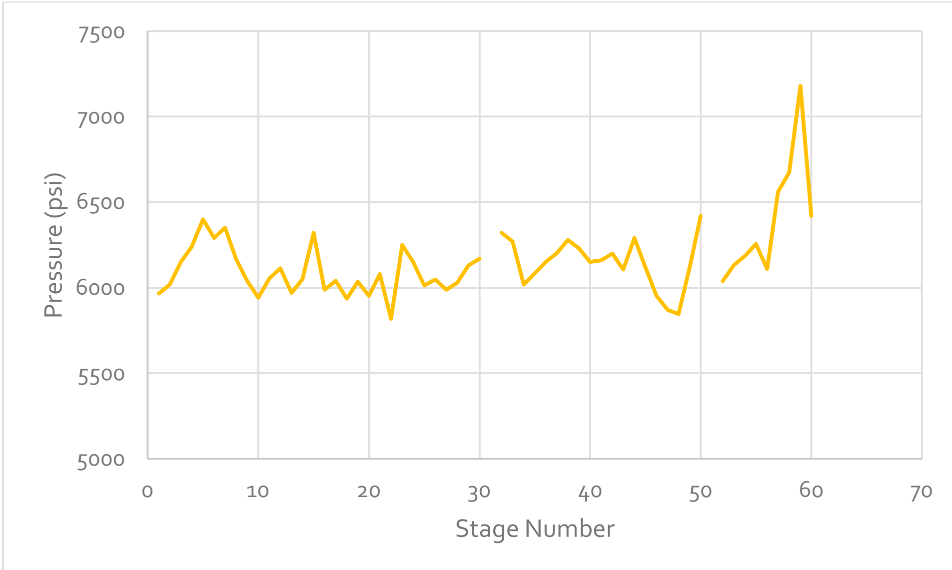


Figure 7. End of treatment ISIPs for BCeCf-101h

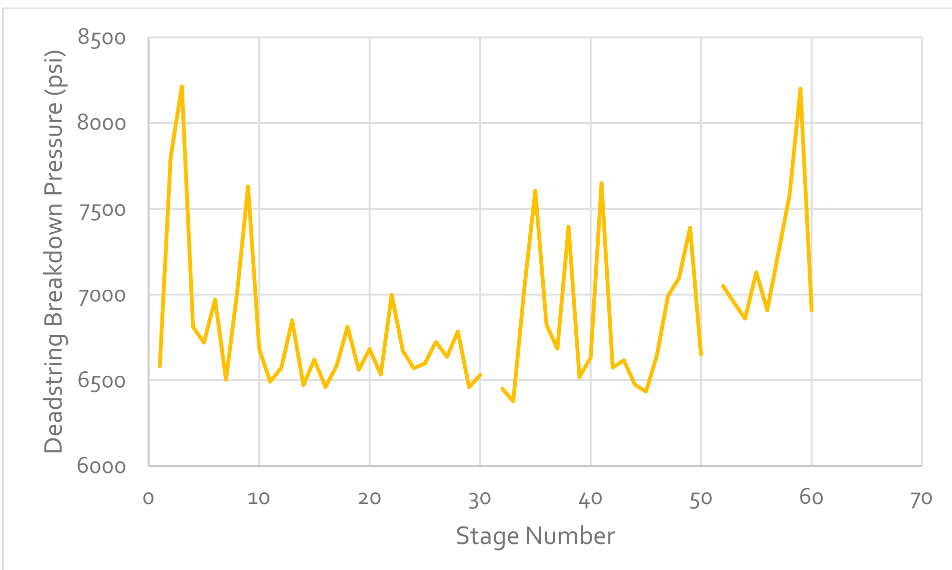


Figure 8. Deadstring breakdown pressures for BCeCf-101h

BOTTOMHOLE GAUGE DATA EVALUATION

An additional benefit to the coil tubing shifted sleeve completion is the ability to deploy a bottomhole pressure/temperature memory gauge in the bottomhole assembly (BHA) utilized for shifting the sleeves open. This data coupled with coil tubing deadstring pressure and frac data (surface treating pressure, injection rate, proppant concentration, etc) allows for evaluation of zonal isolation outside of the casing as well as near wellbore restriction. The use of the deadstring pressure allows a reliable method to evaluate actual bottomhole treating pressure during the treatments free from effects of changing hydrostatic head and changing friction in the wellbore. This is especially true given the changing treatment fluids, proppant concentrations, and proppant density during each stimulation. Not only does this apply during the evaluation phase, but it is beneficial during the actual treatment in allowing for quicker real time decision making.

To evaluate the pressure isolation, the primary tool is the pressure that is recorded on the memory gauge that is situated below the resettable bridge plug of the BHA. In the instance of good pressure isolation, the recorded memory gauge pressure will tend to decline at least marginally. When compared to the deadstring pressure (indicating pressure above the resettable bridge plug or bottomhole treating pressure) it allows for a better understanding of the potential cause of the zonal communication. This in turn aids in optimizing entry point spacing and/or adjusting other processes such as cementing practices. An example of good pressure isolation is shown in Figure 9.

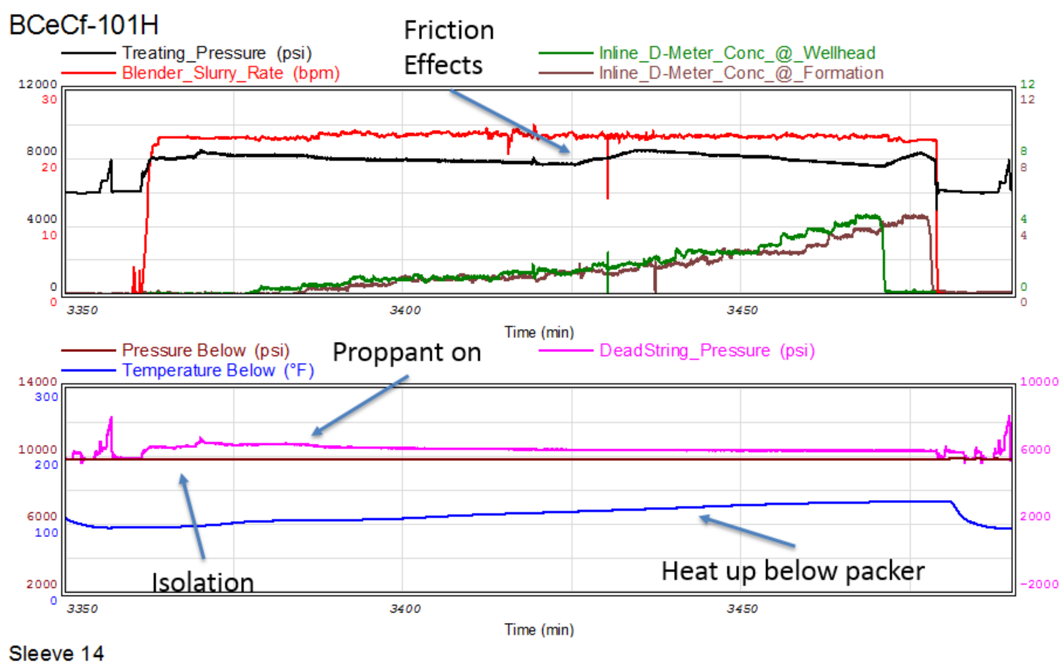


Figure 9. *Example of good pressure isolation – Sleeve 14.*

In the evaluation of near wellbore restriction and more specifically near field fracture complexity, the bottomhole treating pressure proxy, deadstring pressure, is utilized. Ideally, a rate step down test would be employed to determine the makeup of the near wellbore restriction (fracture complexity vs port/perf restriction). However, now rate step down tests were utilized during the treatment of either well. However, the principal of the rate step down test can be applied since we have a reliable indication of bottomhole treating pressure throughout the completion of BCeCf-101h. Any change in the deadstring pressure due to rate change is generally a function of a near wellbore restriction. If the pressure changes occur at higher injection rates, the near wellbore restriction is going to have a fracture complexity component in it. If the pressure changes at lower injection rates, the near wellbore restriction is going to be more dominated by port/perf restriction. This is highlighted in Figure 10.

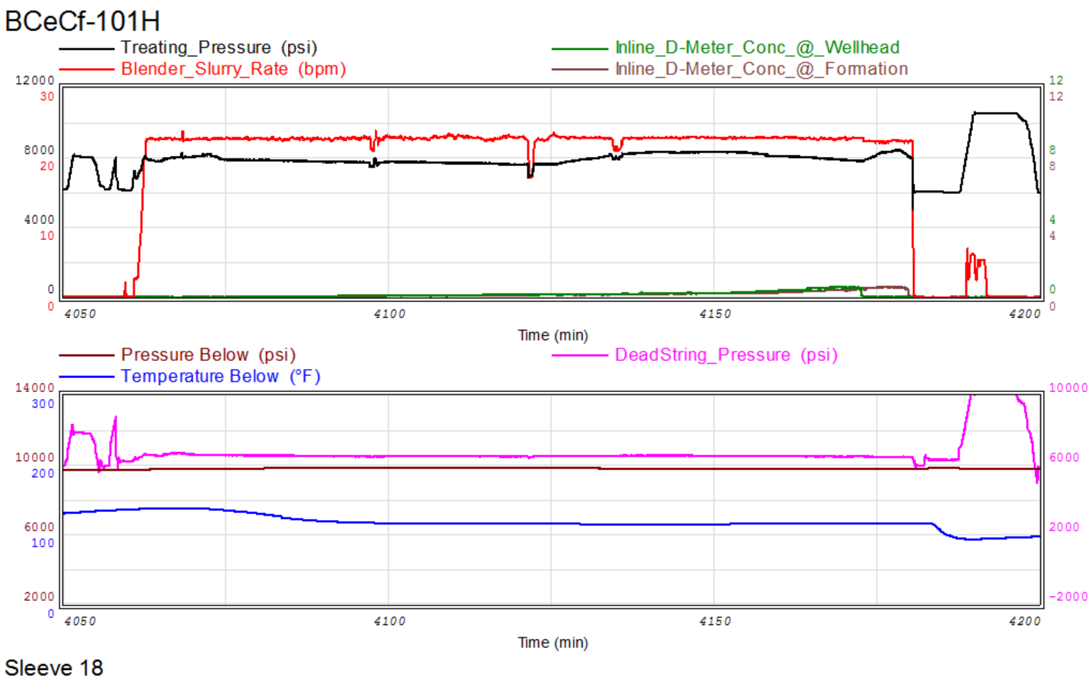
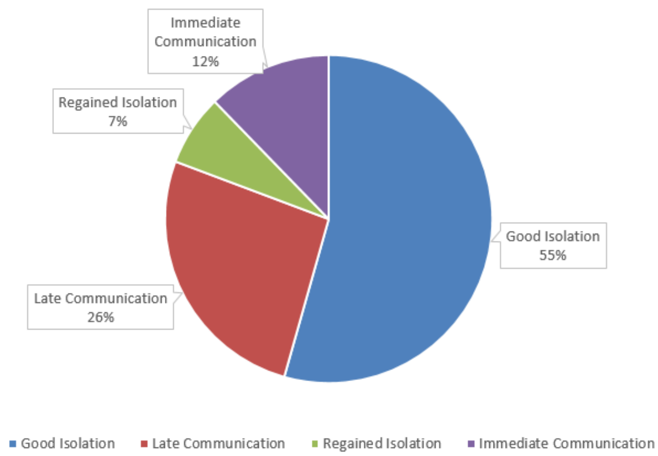


Figure 10. *Example of change of injection rate effect on bottomhole treating pressure. Notice that the rate changes at the higher injection rates have a minimal effect while there is marked change when injection is ceased. Note a) that the total near wellbore restriction is small and b) this restriction appears to be more port restriction dominated – Sleeve 18.*

Each stage of the BCeCf-101h well was analyzed for pressure isolation, near wellbore restriction/fracture complexity, and proppant placement. This evaluation utilized the combined gauge data, frac data, and coil tubing pressure data as discussed. As seen in Figure 11, the pressure isolation was not perfect during the treatment of this well, overall, the pressure isolation between stages was reasonable. Most of the pressure communication occurred late in the treatment, most was slight in nature as indicated by a relatively large pressure differential between the zone being treated and the previously treated zones, and four stages regained pressure isolation during the treatments resulting in little to no proppant bridging. These are all indications of new fracture growth during the treatment.



Good Isolation	Late Communication	Regained Isolation	Immediate Communication
31	15	4	7

Figure 11. *Pressure isolation evaluation of BCeCf-101h*

In addition, the near wellbore restriction was evaluated to generally be relatively moderate early in the treatments declining during the treatments. Fracture complexity was interpreted as being minimal during the 101h treatment. Generally, there was a minimal amount of proppant bridging. This is a good indication that proppant distribution into the created fracture was generally good.

Discussion

While there are some differences in the treatments between the two wells, the biggest difference is the completion methodology. While the 102h well doesn't have any bottomhole gauge or deadstring data, there is no strong indication that the amount of fracture complexity or proppant bridging is significantly different than the 101h well. However, there is no way to evaluate zonal isolation in the 102h well. Furthermore, there is no way given the data set to, evaluate the exact placement of the treatments in the 102h well.

COMPLETION COSTS

Comparative completion costs between the 101h and 102h wells were screened in order to include only those expenditures directly associated with the specific completion methodology employed. This included the costs of coiled tubing, sleeves, BHA rental, pumping, wireline services and other items that were directly related to the completion method. The cost of proppant and other variable costs not associated specifically with the style of completion were not included in the totals. Bundled costs described above are presented in Table 3, indicating a savings of approximately 9% for the comparable pinpoint costs vs the MCPP completion costs.

BCeCf-101h Costs (Pinpoint)	BCeCf-102h Costs (MCPP)
90.8%	100%

TABLE 3. *Comparison of bundled completion costs*

PRODUCTION ANALYSIS DISCUSSION

Production Evaluation – Basic Comparison

Both wells navigate the same section of Vaca Muerta Formation (S2A) and the length of the drain is similar (1500m). Comparison of oil and gas production (unnormalized) shows similar profiles with the 101h (pinpoint) well performing slightly better (Figure 12)

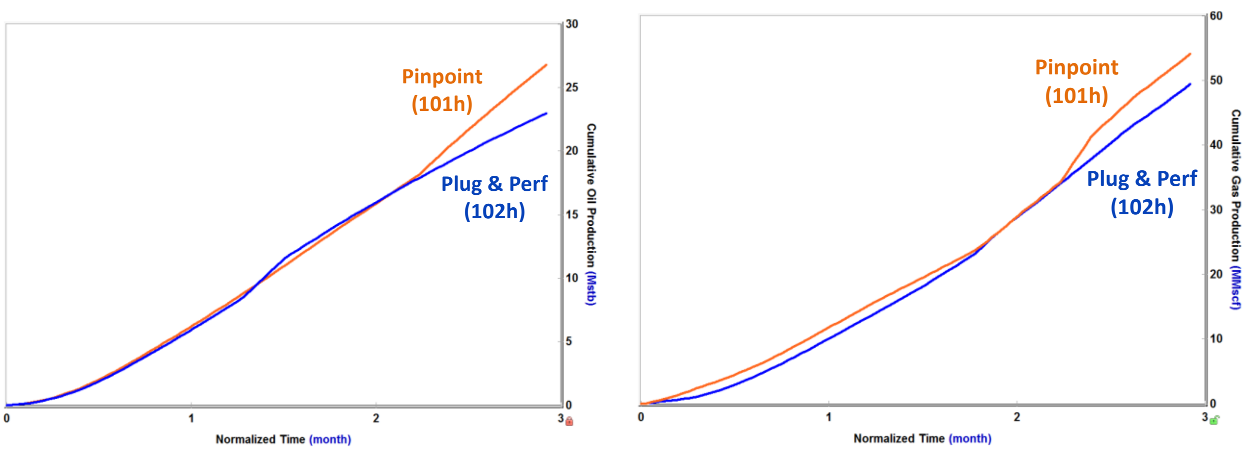


Figure 12: *Comparison of oil and gas production volumes – 101h vs. 102h*

Figure 13 compares flow rate and pressure between the two wells. Both wells exhibit a choke change, increasing drawdown (at different times in their production history). It should be noted that the flowing pressures are measured at surface in these wells, and both produce naturally through casing (no tubing installed). This reduces confidence in calculated bottomhole pressures significantly. In reality, the true bottomhole flowing pressures may be a lot higher than what they are calculated to be, which can have major implications to the results of the RTA work.

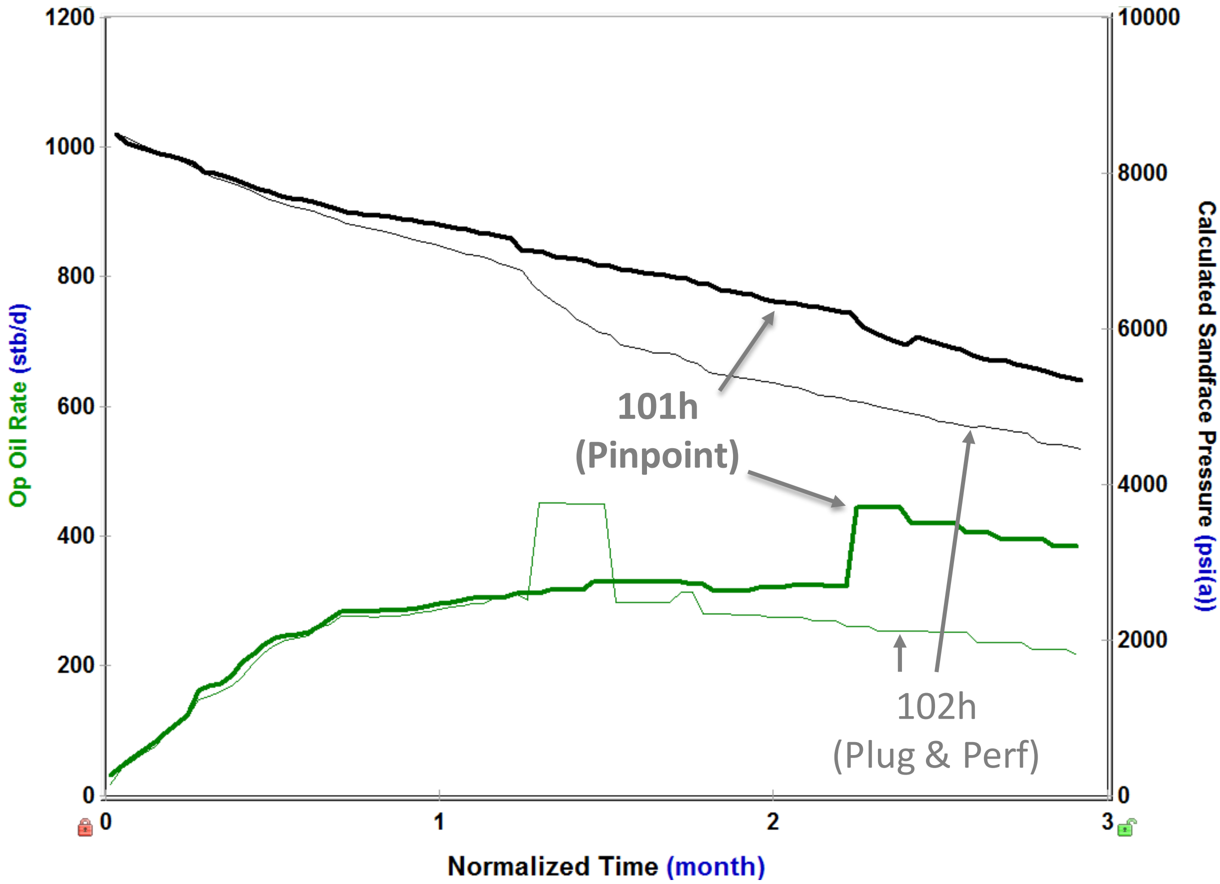


Figure 13: *Comparison of production rate and calculated bottomhole flowing pressure – 101h vs. 102h*

RATE TRANSIENT ANALYSIS

Background

Rate transient analysis (RTA) is used to understand dominant drive mechanisms and characterize dynamic reservoir and completion parameters in a producing well, based on detailed analysis of rate and pressure.

The RTA performed in this study includes linear flow specialized plot analysis and flowing material balance (FMB) analysis. These techniques yield bulk reservoir and completion performance parameters, as well as qualitative descriptions of flow regimes and production drive mechanisms. The bulk interpretations are validated with a history match of the well performance data, based on representative reservoir models.

The linear flow specialized plot is a good objective indicator of completion effectiveness, based on early well performance data (both rate and flowing pressure). This plot identifies transient linear flow and quantifies the product of total connected fracture area and square root of matrix permeability$(A\sqrt{k})$. In the study of an adjacent well pair, it can usually be assumed that permeability is the same, and therefore total fracture area can be estimated. It also quantifies the apparent fracture conductivity, which can be influenced by propped fracture conductivity, convergence skin, fracture face skin, proppant embedment, fines migration, phase trapping and other phenomena.

The flowing material balance (FMB) analysis focuses on the late-time flow behavior, quantifying the contacted Original Oil in Place (OOIP). In ultra-tight reservoirs, this analysis is usually indicative of the hydrocarbon pore volume in contact with the productive fracture network – often called the stimulated reservoir volume (SRV).

A more comprehensive summary of standard RTA techniques, models and conventional workflow is presented by Anderson and Mattar (2003). An RTA methodology for shale wells is provided by Anderson et al. (2010).

The Vaca Muerta is highly over-pressured and thus there is an expected dependence of rock compressibility and permeability on effective stress. With this consideration in mind, the parameter representing pressure dependent rock properties in RTA (the gamma function) is set as an assumed value, based on the evaluators' previous experience in dealing with Vaca Muerta wells. Thompson et al. (2010) and Okouma et al. (2011) provide details for identifying stress-dependent permeability in abnormally-pressured shale well production data sets, provide a workflow for calibrating the pressure-dependent permeability relationship (from build-up data), and demonstrate its impact on production forecasting and reserves.

Interpretation of Bulk Parameters

Comparison of the linear flow specialized response for the 101h and 102h wells is shown in Figure 14. The slope of this plot is used to calculate the inverse of the total connected fracture area. The upward deviation from straight line behavior indicates the onset of fracture interference (which will lead to the eventual depletion of the SRV). From Figure 14, we can see that the 101h (pinpoint) well has more connected fracture area (approximately 40% better than the 102h well).

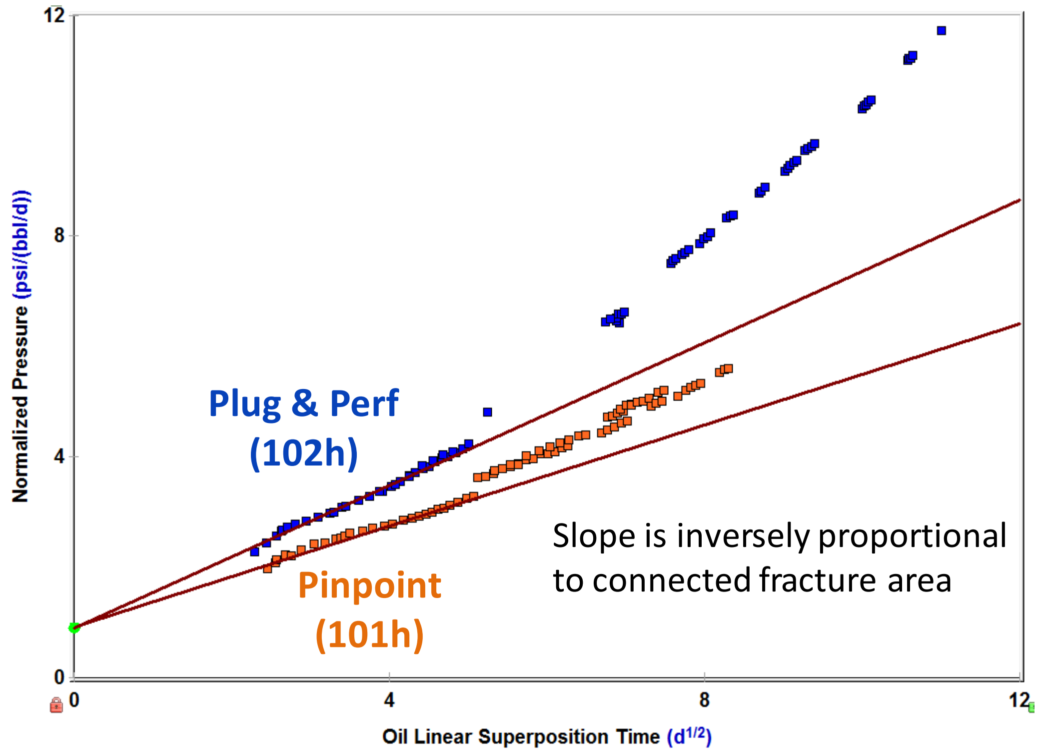


Figure 14: *Linear flow specialized plot analysis – 101h vs. 102h*

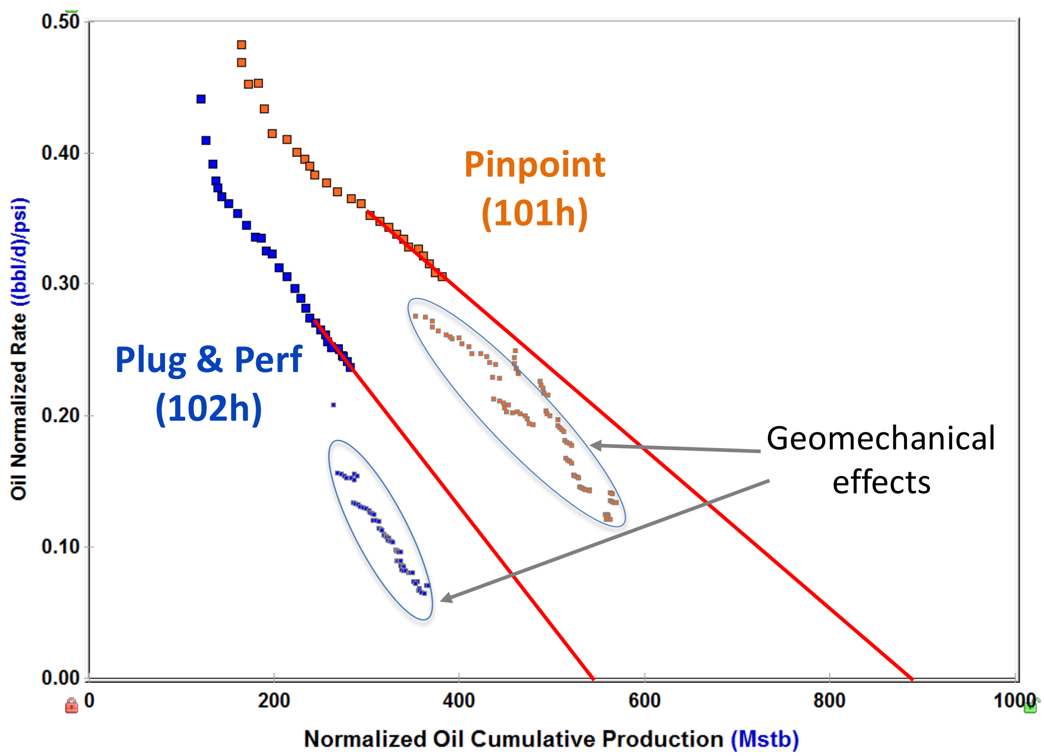


Figure 15: *Flowing material balance analysis – 101h vs. 102h*

Figure 15 compares the flowing material balance response between the 101h and 102h wells. Extrapolation of this plot yields a rough estimate of SRV. Quantitatively, these SRV estimates are only approximations, and should not be relied upon solely. However, as a relative comparison, they are useful to demonstrate which well has been successful in stimulating a greater hydrocarbon pore volume. In this case, the 101h (pinpoint) well has stimulated about 60% more hydrocarbon pore volume than the 102h well. Another important observation from the FMB plot is the obvious productivity loss that occurs in both wells after the choke is opened. This is very likely attributed to geomechanical forces, which cause the fracture conductivity (and to a lesser degree the matrix permeability) to decay as a result of compaction, as the pore pressure decreases.

Production Simulation – Benchmarking Well Performance

The Enhanced Fracture Region (EFR) model by Stalgorova and Mattar (2012), shown in Figure 16, has proven to be a suitable model for simulating production from a multi-stage fractured horizontal well in an ultra-tight reservoir. This model assumes uniform, planar parallel hydraulic fractures that are perpendicular to the horizontal lateral. Each primary hydraulic fracture is surrounded by a limited region of enhanced permeability that can be used to simulate fracture complexity. The flow capacity and volume of the enhanced region are usually defined through the history matching process. It should be noted that, in this study, all production modeling was performed using a numerical (finite difference) model to account for multi-phase flow in the reservoir.

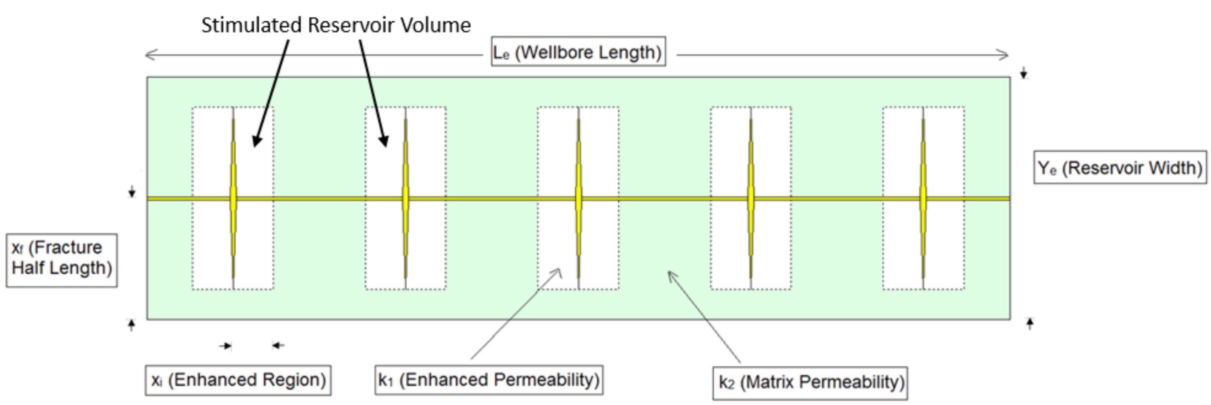


Figure 16: *Enhanced fracture region model (Stalgorova and Mattar, 2012)*

Figure 17 shows the model history match for the 101h (pinpoint) well. We will refer to this as the "benchmark model". In Figure 18, the 102h well performance is compared against the benchmark model, accounting for differences in lateral length, stage count and entry point spacing. Fracture properties (length and conductivity) are assumed to be identical between the two wells. It is clear from Figure 18 that the benchmark model outperforms the 102h well. The cumulative difference in oil production over the time period of interest (5 months) is 11,358 STB. Another way to state this result is that if the 102h well had been completed as a pinpoint well, with all other things being equal, it would have produced 11,358 STB more oil over the first 5 months. Of course, we are assuming that the geological and geomechanical overprint is identical for these wells. If this were not the case, then the benchmark model would have to be normalized for any other measured differences in the reservoir and/or completion.

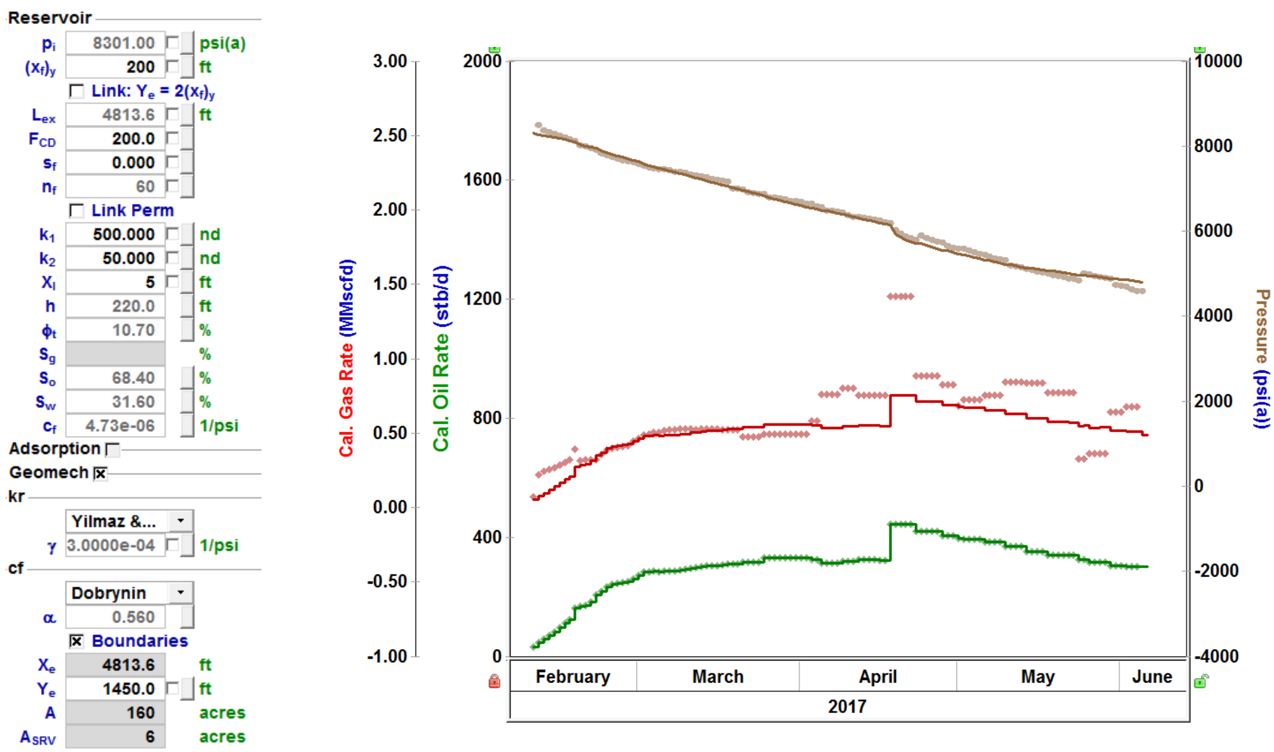


Figure 17: *Numerical model history match of 101h (pinpoint) well production data*

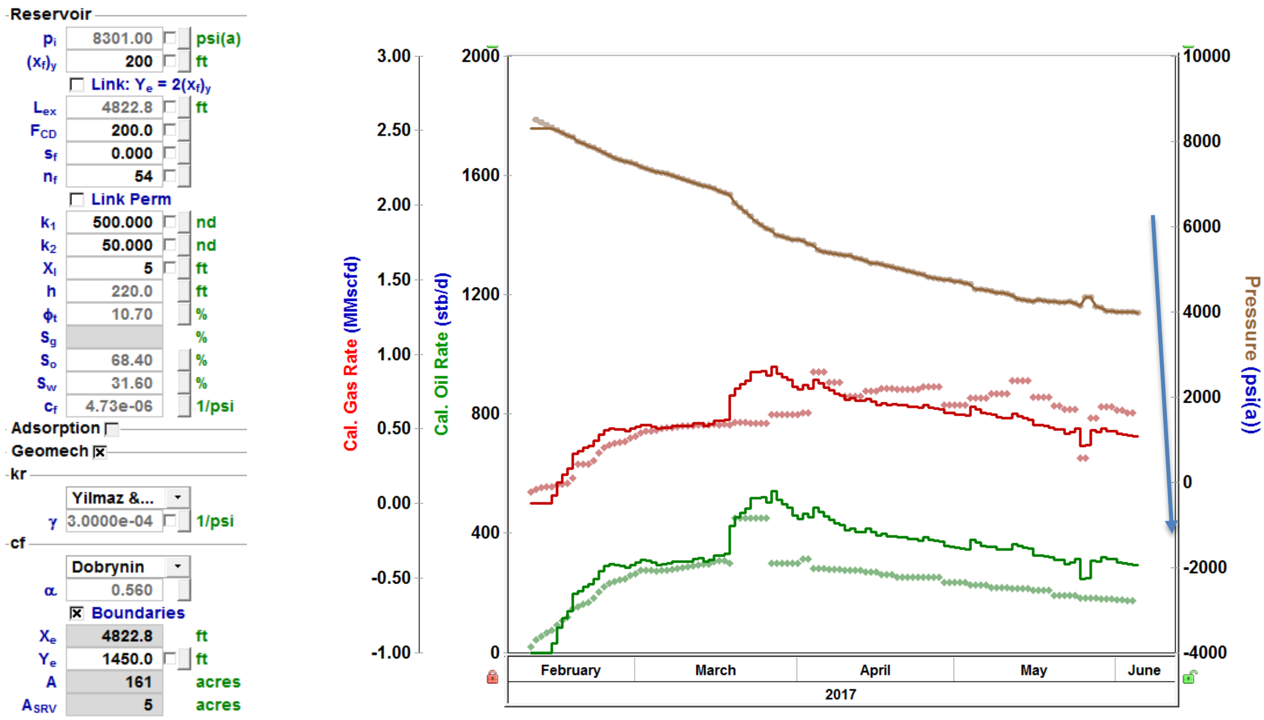


Figure 18: *102h (Plug & Perf) well performance compared to benchmark model*

PINPOINT OPPORTUNITIES

Benchmarking analysis of the application of uniformly spaced pinpoint stimulations in the 101h horizontal well indicates a more effective stimulation vs. a comparable multi-cluster plug & perf (MCPP) completion applied to the 102h well. The obvious inference is that the 100% placement efficiency achieved in the pinpoint completion method has resulted in a significant impact on the uniformity and distribution of the stimulation fluids & proppants employed. Non-uniform breakdown pressures and stress shadows causing interference between perf clusters are typically considered to be the sources of poor cluster efficiency in MCPP completions. In contrast, the pinpoint stimulation method may offer a unique venue through which the stress shadow effects between stages might be used to advantage, with the potential to further enhance SRV and well production. Several researchers and authors have theorized on the potential for stress-shadow effects to positively impact closely spaced frac stages by enhancing fracture complexity. In theory, this is operationally achieved through the non-sequential placement of fracture stages, a process that is not feasible with any ball-drop or MCPP completion. Pinpoint completions that employ closeable frac sleeves represent a new practical method for facilitating the placement of fracture stages in any desired sequence. Specifically, the engineered placement of a frac stage in between two previously placed stages may hold the potential for enhanced fracture complexity, greater fracture height growth, both potentially having a positive impact on well performance. This “next step” in understanding the full potential of pinpoint completions provides a new opportunity to advance the science of horizontal multistage completions, and the economic value of unconventional reservoirs.

CONCLUSIONS

The two well comparison of MCPP and Pinpoint completion methods in the Vaca Muerta shale indicates both a cost and production advantage for the pinpoint style completion. Rate Transient Analysis indicates that the production improvement is associated with a larger SRV generated by the pinpoint stimulation treatment. This is presumably associated with the 100% cluster efficiency produced by the pinpoint completion, with an assumed lower cluster efficiency in the MCPP completion. The opportunity to realize additional SRV enhancements may reside in the application of frac sequencing, a process uniquely facilitated by the pinpoint completion method. Greater pinpoint completion experience and data collection in the Vaca Muerta play will continue to improve well results, EUR, and optimal return on capital.

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Nomenclature

ct	=	total compressibility, psi -1
□	=	*porosity*
FBHP	=	*flowing bottomhole pressure*
FCD	=	*dimensionless apparent fracture conductivity*
FMB	=	*flowing material balance*
h	=	*net thickness, ft*
k	=	*permeability, md or nd*
Np	=	*cumulative oil production, Mstb*
OOIP	=	*original oil in place, Mstb*
Pi	=	*initial reservoir pressure, psi*
pwf	=	*bottomhole flowing pressure, psi*
q	=	*flow rate, stb/d or Mscf/d*
SRV	=	*stimulated rock volume*
xf	=	*fracture half length, ft*