URTEC-208282-MS

Automated Well Performance Diagnostics in Unconventional Reservoirs: A Multi Basin Study for Early Time Production Optimization

Darryl Tompkins, Oladapo Adejare, Marci Kerls, Adam Swartley, and Christina Costello, Revo Testing Technologies

This paper was prepared for presentation at the SPE/AAPG/SEG Asia Pacific Unconventional Resources Technology Conference to be held virtually on 16–18 November, 2021.

Abstract

Many operators have struggled to determine an optimum draw down strategy during the initial production period (flowback). Most that we have encountered rely on an analysis of the data after the initial production period when it’s too late to mitigate any loses in well performance. This paper will examine the use of an Automated Performance Diagnostic ("APD") application to detect changes in well performance in real time during the early production period and alert operators when there is a problem. Examples from multiple basins will show how the application is used in different reservoirs and how it can be connected to an automated choke system and artificial lift system to optimize both early time and late time well performance. Rate Transient Analysis will be applied to synthetic data generated from numerical models to demonstrate the correlation between observed loses in well performance using well known analysis methods and the APD application. Next, the APD application will be applied to field data with known decreases in well performance encountered during the initial production period. Finally, the APD application will be applied in real time during the initial production period to guide surface operations to optimize well performance. The APD application identified all known instances of well performance loses in both the synthetic and field data even identifying some that were previously unknown. In field testing the APD application was not only able to determine decreases in well performance to avoid production loses but it could quickly identify improving well performance which allowed some wells to have the choke opened faster than the operators had previously done. The APD application has been able to evaluate well performance in real time in all tested basins. It is the belief of the authors that the application should work in any basin globally. When combined with an automated choke systems and artificial lift the APD application can be expanded to field wide optimization.

Introduction

Over the year's various authors have described diagnostic methods and guidance for improving unconventional well productivity through draw down optimization during the initial production period. (Crafton 2008, Okouma Mangha 2011, Deen 2015, Tompkins 2016, Mirani 2018, Rojas 2018, Kumar 2018, Lerza 2018, Yingkun Fu 2019, Wijaya 2020). However, one of the biggest issues with implementing any of these methods is knowing exactly when to increase draw down and by how much during the initial production period. This paper will demonstrate an automated well performance diagnostic application that can be used to assess changes in well performance in real time. This application gives operators the ability to determine the effect of draw down on well performance to determine if additional draw down can be applied.

Unconventional well performance is commonly assessed using Rate Transient Analysis ("RTA") straight-line diagnostic methods to determine reservoir and fracture parameters. Diagnostic plots for radial, bi linear, linear, and boundary dominated flow are used to determine permeability, fracture area, fracture conductivity and volume in place from the slope of straight-line trends of the data (Dake 1978, Wattenbarger 1998). These parameters can then be used to compare how good one completion design and / or reservoir is relative to another. As an example figure 1 shows how a straight line is fit to the linear trend of the Rate Normalized Pressure ("RNP") vs √time and the slope of the line is used to determine $A\sqrt{k}$. The $A\sqrt{k}$ parameter is commonly used as a well performance metric where lower slope = higher $A\sqrt{k}$ = better well performance.

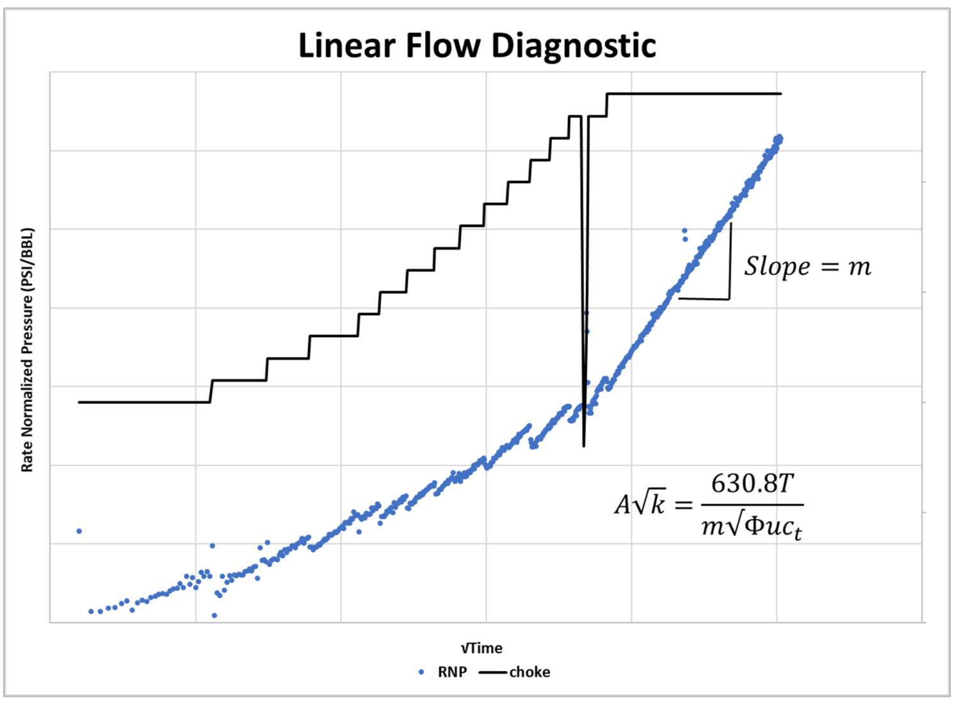


Fig. 1- Linear Flow Diagnostic Plot showing location of linear trend to determine slope for calculation of well performance parameter A√k

A major drawback of RTA workflows is they are very time consuming and nearly impossible to use in real time. Additionally, current diagnostic methods fail to adequately address the dynamic nature of unconventional reservoirs. The APD was created to see how reservoir and completion performance parameters change in real time to alert operators to changes in subsurface conditions that affect well performance as they are occurring. This gives operators the ability to manage surface equipment in real time to optimize the draw down during the initial production period.

Concept

One of the primary assumptions for APD is that quick changes in rate and pressure caused by changes in choke size, ESP frequency, gas lift injection rate, etc. introduce new rate and pressure transients into the reservoir and the rate and pressure response associated with each transient is a function of the key reservoir and completion parameters which can be obtained from straight line diagnostic methods.

Deen (2015) illustrated how the well performance (determined from a linear flow diagnostic plot) increased with each new transient created from each choke change. Tompkins (2020) demonstrated that when the right data acquisition methods are used during the initial production period the correct transient response could be identified and analyzed. From the work of these authors we hypothesized that with good quality data RTA straight line diagnostic methods could be automated to see changes in well performance in real time. From here a proof of concept plan was developed to validate the APD. First we analyzed field test data manually with straight line diagnostic methods to demonstrate how the APD works. Next, we automated the manual workflow and tested it on numerical models to see if it could identify known decreases in well performance. Finally, we tested the APD on field test data with known decreases in well performance.

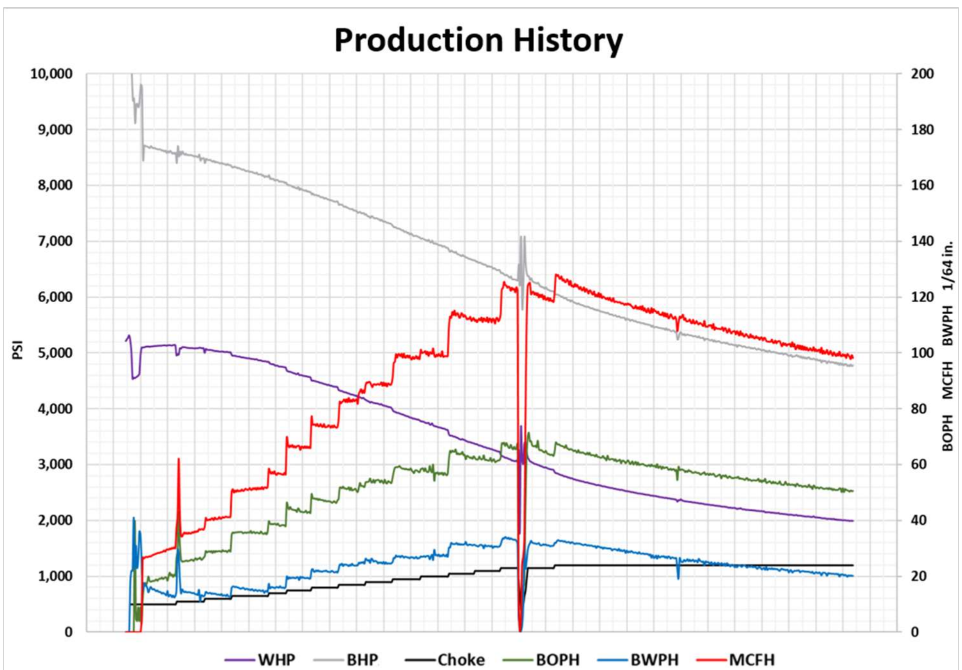
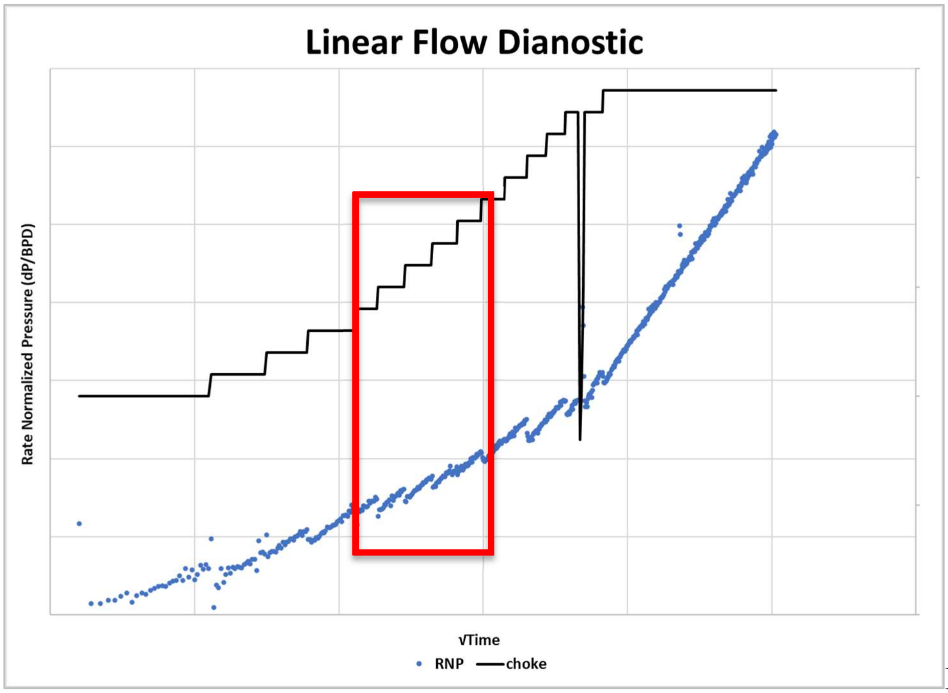


Figure 2 - Production History for multistage horizontal well completed in South Texas Eagle Ford formation

In figure 2 is the production history for a multistage horizontal well ("MSHW") completed in the South Texas Eagleford formation and figure 3 is the linear flow diagnostic plot for the same well.

When the data is of sufficient quality each transient can be identified and analyzed to determine the magnitude of performance changes. When the data is not of sufficient quality the reservoir response may be hidden by data noise and identification of the correct straight-line trends in initial production data can be impossible (Tompkins 2020).



D

Figure 3 - Linear flow diagnostic plot showing the area outlined in red that is expanded in figure 4

Figure 4 is the expanded section of figure 3 outlined in red. From this expanded section there is a noticeable change in the trend of the data associated with each choke change and the reservoir response can be clearly identified within each transient. When straight line diagnostic methods are applied to each transient the change in well performance from one choke to the next can be determined.

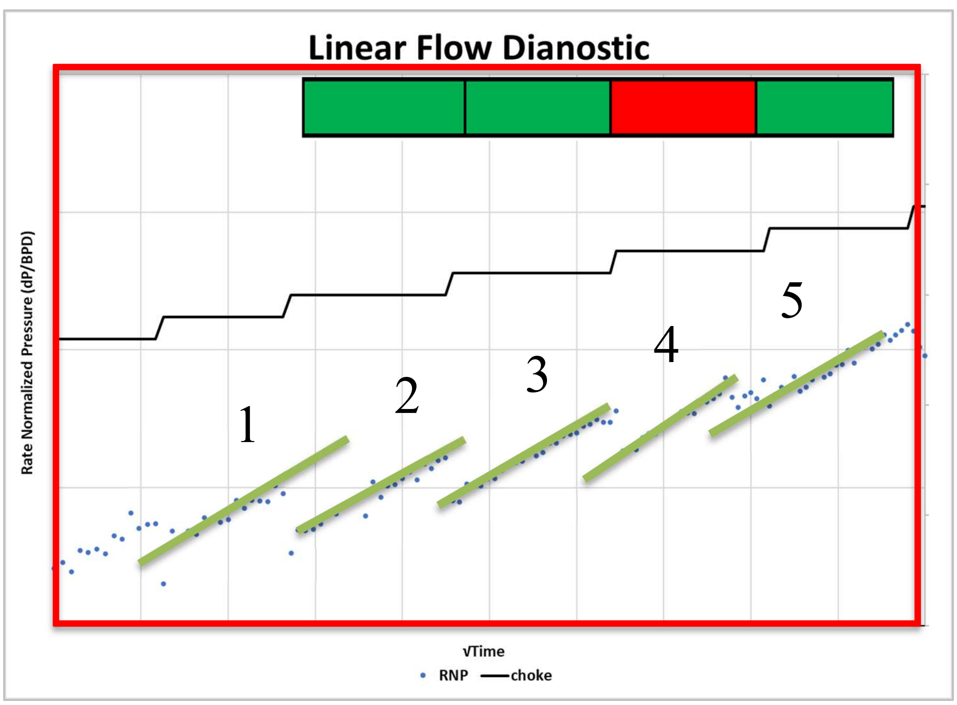


Figure 4 - Expanded section of figure 3 showing identification of each transient

Table 1 provides a summary of the $A\sqrt{k}$ parameters from each transient as well as a color to indicate if the parameter has increased/stayed the same (Green), small decrease (yellow), or decreased (red). When the colors representing the change in performance are plotted above the data in figure 4 a clearer picture begins to emerge detailing how the well's performance is changing in the subsurface in real time with each choke change.

Transient #	$A\sqrt{k}$	Color
1	100000	n/a
2	107000	
3	111000	
4	92500	
5	110000	

Table 1 - $xf\sqrt{k}$ values determined from linear flow straight line analysis applied to each transient

With this concept now clearly defined the next step is to automate the process in the APD application.

Validation with Numerical Model

In order to test and validate the APD application a numerical multiphase infinite conductivity fracture model was constructed using the parameters shown in table 2. It should be noted that for the first test of the APD the exact model parameters are not particularly important. The objective here is to create an ideal model with parameters that would be expected in an unconventional reservoir and completion but without any performance losses. This will help to validate that the APD application is functioning correctly under ideal circumstances before progressing on to more complicated scenarios.

Numerical Simulation Parameters		
Fracture model	Infinite Conductivity	
Fracture half length	300	ft.
Fracture height	350	ft.
Fracture mid-point height	150	ft.
Fracture width	0.004	in.
Fracture angle	0	deg.
Well length	350	ft.
Perforation length	350	ft.
Initial pressure	8000	psi.
Initial GOR	1200	scf./bbl.
Initial water sat.	0.6	
Reservoir type	Homogeneous	
Transmissibility	1.75	md.*ft.
Permeability	0.005	md
Thickness	350	ft.
Porosity	0.05	

Table 2 - Numerical simulation parameters

Figure 5 shows the numerical model and the pressure distribution after the first simulation to create ideal production data. The purpose of showing the model here is to demonstrate that this is a simple numerical model with none of the complexities found in more advanced models.

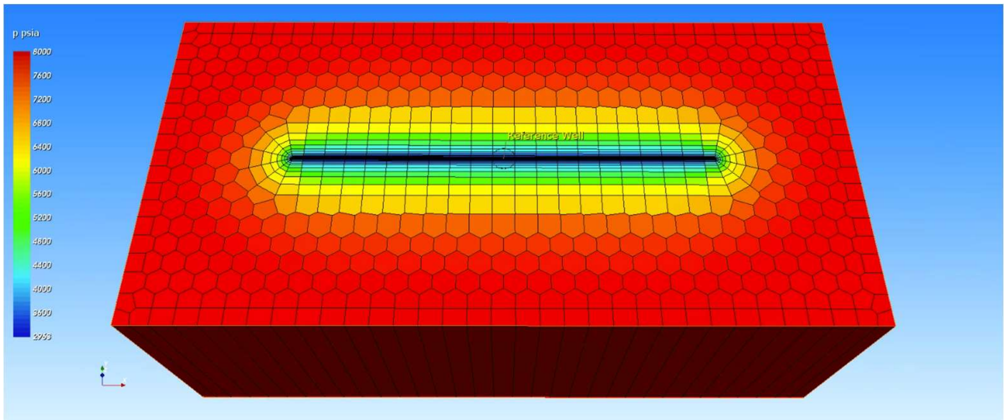


Figure 5 Numerical model of single fracture showing pressure distribution

Figure 6 shows the production data generated from the numerical model. This data was then put into the APD application to verify that it would not identify any decreases in well performance. At the top of the production history in figure 6 is the output from the APD application. Here, we see it is all green indicating that every hour the analytical model was matched to the data the well's performance improved.

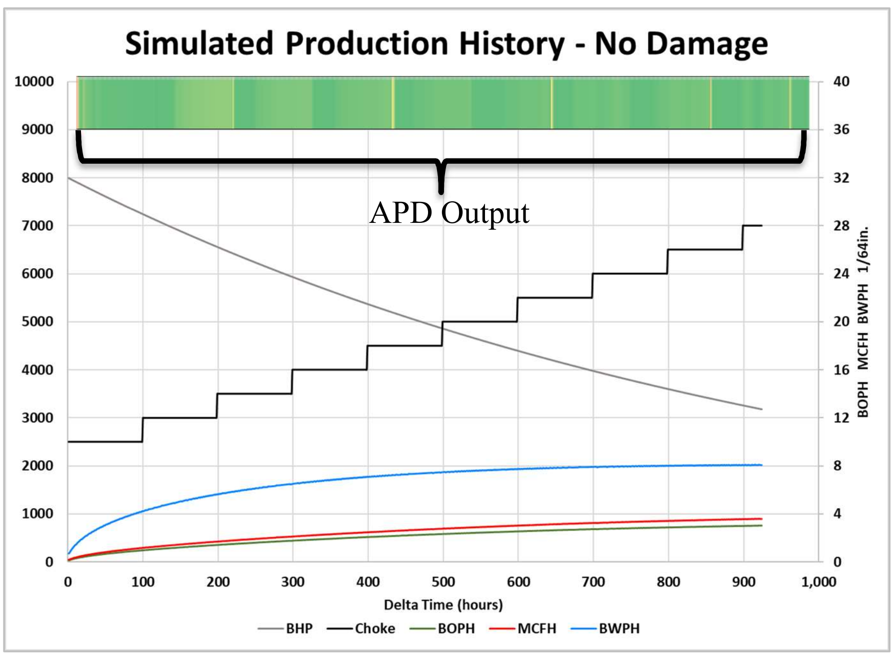


Fig. 6 Simulated multiphase production history generated from numerical model with APD application output at the top of the plot

Next an oil rate measurement error is simulated to see if the APD application is sensitive enough to identify the time period where the simulated oil rate measurement error occurred. At a delta time of 400 hrs. the oil rate is reduced quickly until a delta time of 700 hrs. when it returns to normal. The green dotted line shown during that period indicates what the oil rate should have been if it was correct. Measurement errors like this can be caused by debris getting stuck in a turbine meter, improper gauging of tanks, and improper in-situ calibration of the oil rate measurement device. At the top of the production history plot is the APD application output. During the period the oil rate was reduced (simulating an oil rate measurement error) the APD output turns yellow indicating the well performance has slightly decreased.

We have found rate measurement errors to occur quite often during the initial production period and it helps to use the production ratio's plot and QA/QC procedure discussed by Tompkins (2020) to verify rate measurement errors. Additionally, APD application worked very well for indicating "caution" when it turned yellow. This is not usually an indication of a sustained loss in well performance but instead is most often an indication of small intermittent decreases in well performance and rate/pressure measurement errors.

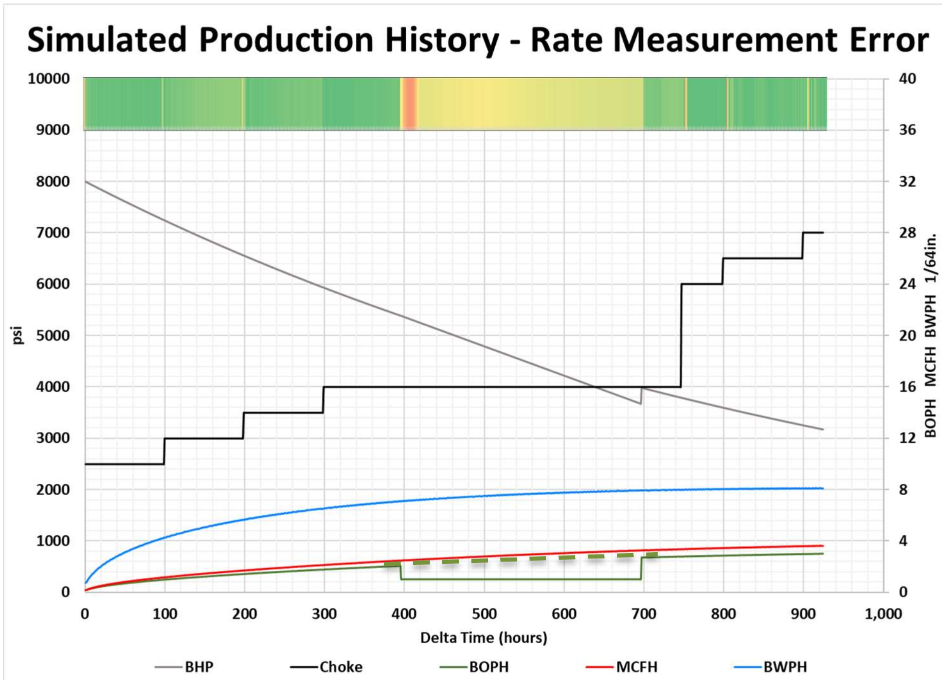


Figure 7 - Simulated production history with oil rate measurement error from 400 hrs. to 700 hrs. .

Finally, in figure 8 is the simulated production history of a well with a sustained decrease in well performance.

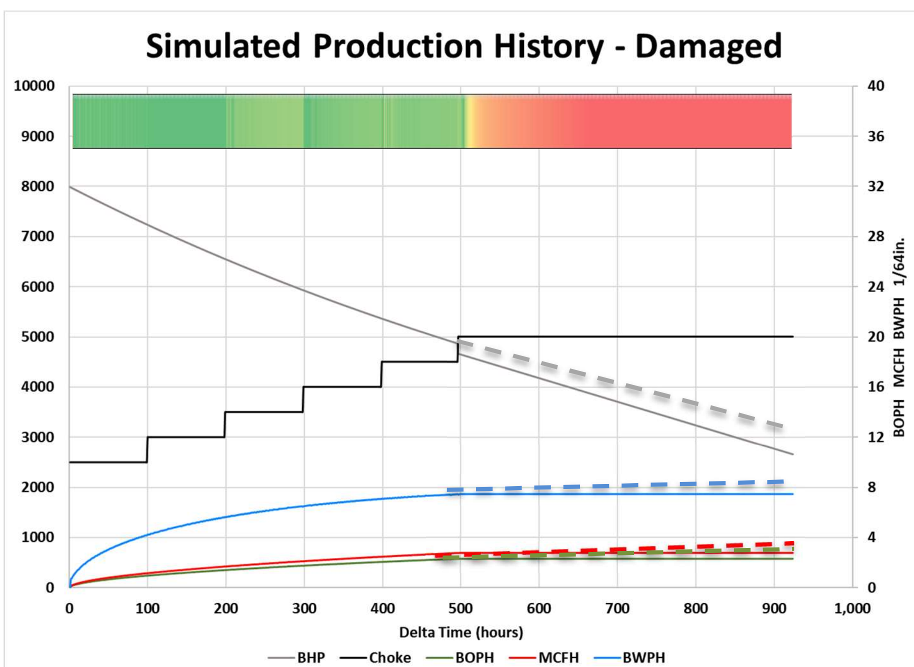


Figure 8 - Simulated production history for a well with a sustained decrease in performance at 500hrs

At 500hrs there is a decrease in BHP of 200 psi when the choke is increased to 20/64”. At the same moment the rates stop increasing for the remainder of the test. The dotted lines indicate what the rates and pressure would have been if there was no decrease in well performance at 500 hrs. As can be seen from the APD application output at the top of the production history plot in figure 8 the color is red indicating a decrease in well performance when the choke is increased to a 20/64” choke at 500 hrs. as expected.

Validation with Field Data

Once the APD application had been tested and verified on simulated data from the numerical model it was tested on field data sets similar to the simulated cases. Figure 9 is the production history from the same MSHW in the Eagleford formation shown in figure 2. For this case the data was assessed manually each day to determine the change in well performance. The choke was changed approximately every 24 hrs. to allow for a smooth, consistent data set to aid in the manual interpretation. Although the results of the manual assessment aligned with the APD application the definition seen in the APD application was surprising. The manual assessment provided 26 separate diagnostic evaluations (1 for each day). However, the APD application provided over 640 (one every hour). There were several spots where the APD application indicated very subtle and short periods of decreasing well performance shortly after some choke changes. There were no sustained decreases in well performance identified with the manual analysis or the APD application.

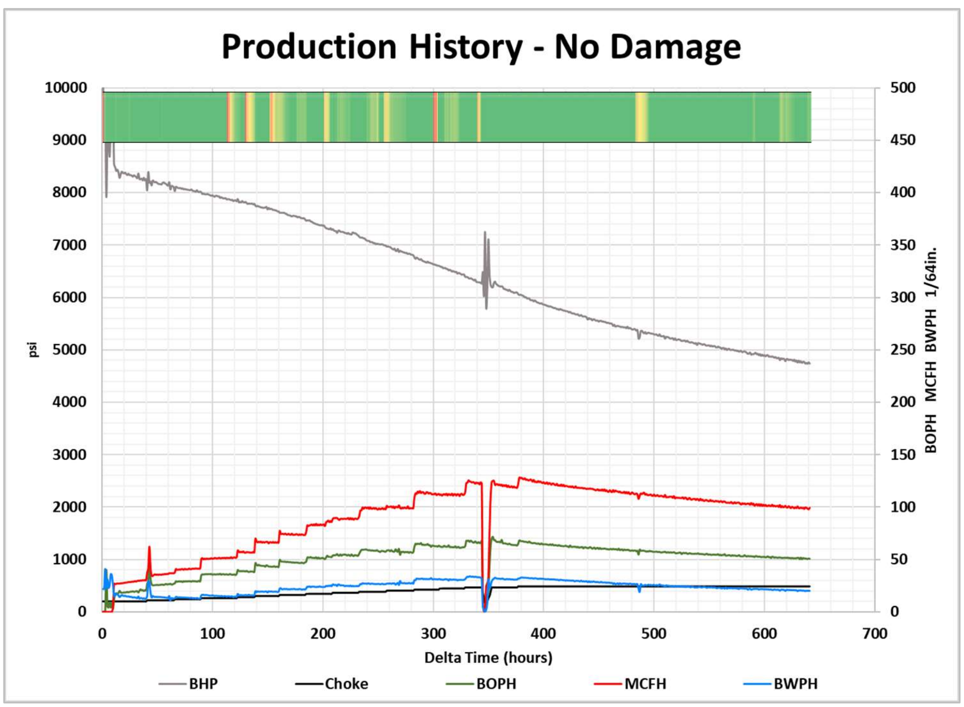


Figure 9 - Production history from Eagleford well with no decreases in well performance during initial production period

For the next test with field data figure 10 shows the production history for a MSHW well in the Delaware basin Wolfcamp formation of West Texas with a known water rate measurement error. Tompkins (2020) demonstrated that when there is a change in 2 of the production ratio trends for an oil well flowing at a bottom hole pressure greater than the saturation pressure the common phase between the 2 production ratio trends is the phase with the measurement error. Figure 11 shows the production ratios with a change in the Gas-Water Ratio (“GWR”) and Water-Oil Ratio (“WOR”) trend (starting at approximately 275 hrs.) seen in the area outlined with the red box. The common phase between GWR and WOR is water indicating that there is a water rate measurement error that starts when the GWR and WOR trend changes. The dotted lines indicate what the GWR and WOR would have been if the water rate measurement was accurate. At approximately 475 hrs. the water meter was fixed and the water rate measurement error is corrected.

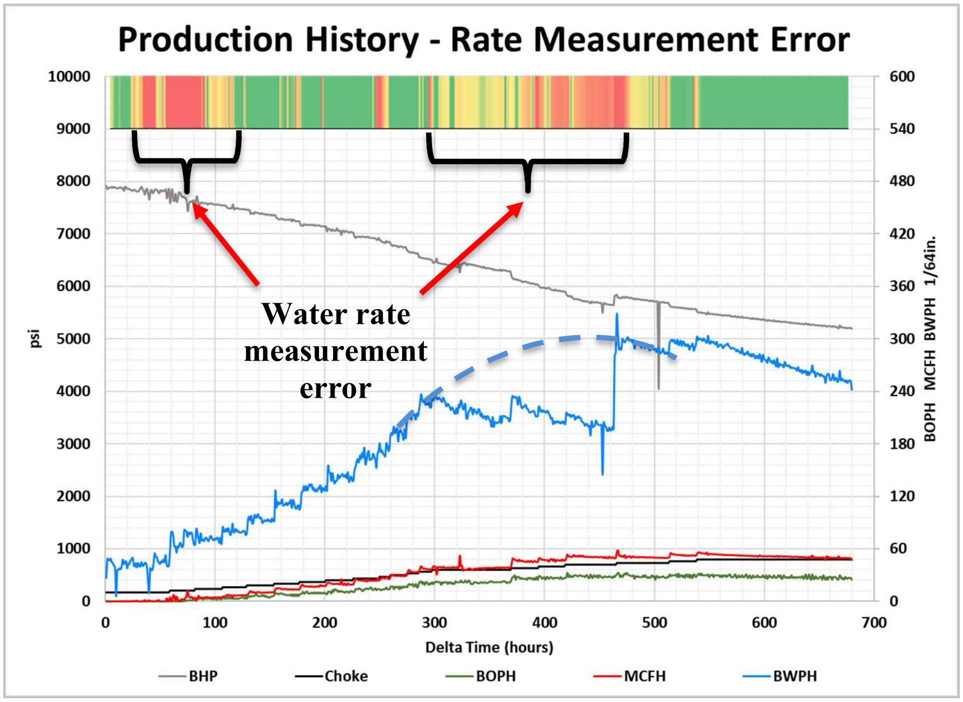


Figure 10 - APD application identifying water rate measurement error from approximately 275 hrs. to 475 hrs.

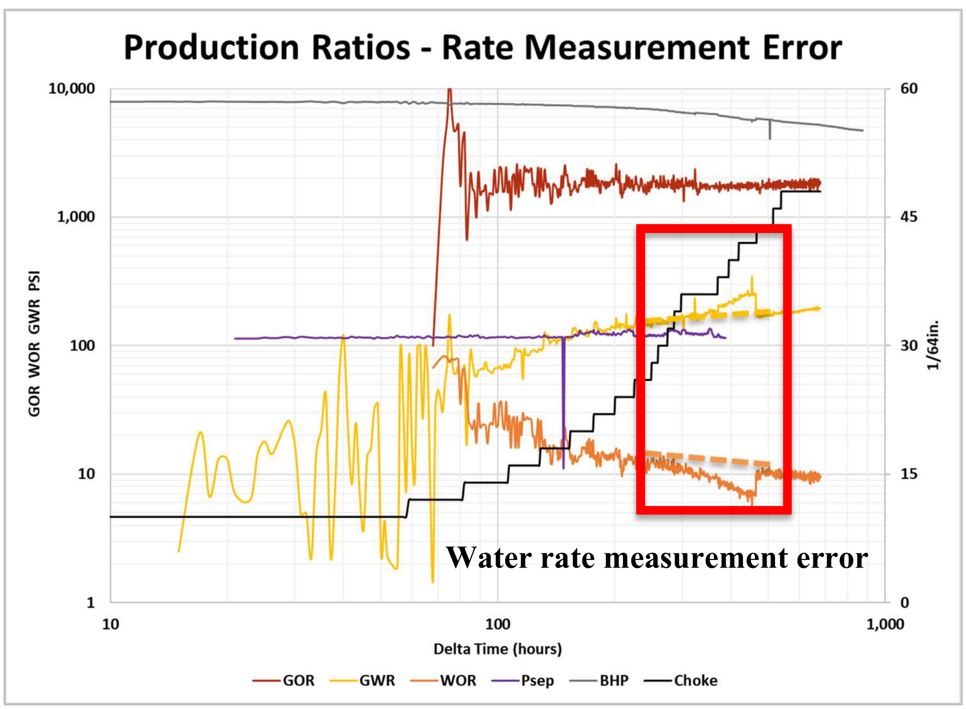


Figure 11 - Water rate measurement error identified by change in GWR and WOR trends

In the production history shown in figure 10 the APD applications output can be seen at the top of the plot where there is an indication that performance is decreasing where the water rate measurement error is occurring. Initially the APD output turns yellow and then starts to turn red as the rate measurement error gets worse. The dotted blue line in figure 10 indicates what the water rate should have been if the water rate had been measured accurately during that period. Once the water rate measurement error at is resolved the APD application turns yellow and then green and remains green for the rest of the test indicating increasing well performance.

Additionally, APD also an indicated a decrease in performance at the start of the test that was not seen with the manual interpretation. This is likely due to a water rate measurement error early in the test. This is a common occurrence usually caused by poor water rate measurements from manual measurement of water tanks referring to as "tank strapping" prior to flowing through separation equipment.

Next, are 2 field tests that were used to validate the APD for decreases in well performance. The APD was applied to the data sets to determine if it could identify the areas of decreasing well performance that had previously been identified with manual RTA straight line methods. In the first data set shown in figure 12 shows is the production history for a MSHW landed in the wet gas window of the Eagleford formation of South Texas. At approximately 150 hrs. into the test shortly after the choke was increased from an 18/64 inch to a 20/64 inch the bottom hole pressure started to decline rapidly. RTA of the data indicated a large decrease in well performance likely caused by sand that plugged off part of the lateral. As differential pressure across the sand plug increased it eventually broke free at approximately 200 hrs. into the test. At the top of figure 12 is the APD output indicating a decrease in well performance when the sand plug formed in the lateral. After the sand plug is cleared the APD indicates a sustained decrease in well performance for the duration rest of the test.

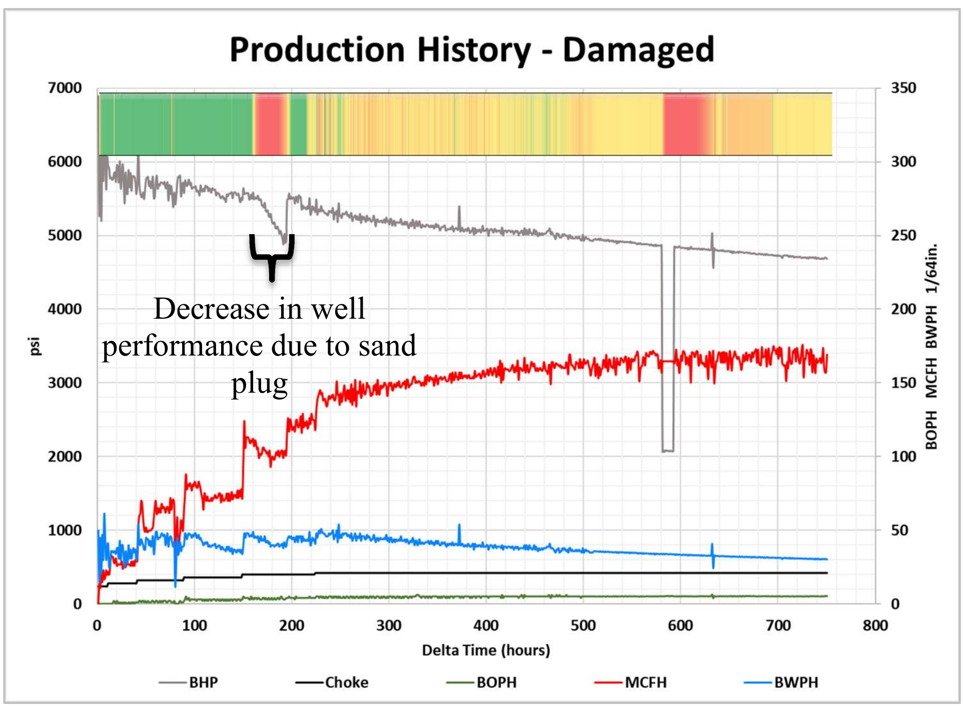


Figure 12 - Production history for a well with known decrease in performance identified with APD

The second data set with a known decrease in performance is shown in figure 13. This test data is from a well in the Delaware basin Wolfcamp formation of West Texas. In an effort to improve the initial production an aggressive draw down was applied to the well. At 380 hrs. into the test the choke was increased quickly from 54/64 inch to 2" over 48 hrs. and the draw down increased from 68 psi/day to 370 psi/day. Additionally, the sand rate increased from 1 gal/hr. to 10 gal/hr. RTA of the data indicated a decrease in well performance starting 420 hrs. into the test. The APD output is shown at the top of figure 13. With this data set the APD not only identified the section of the data confirmed with RTA to have a sustained decrease in well performance but it also identified several other sections with rate measurement errors and intermittent decreases in well performance.

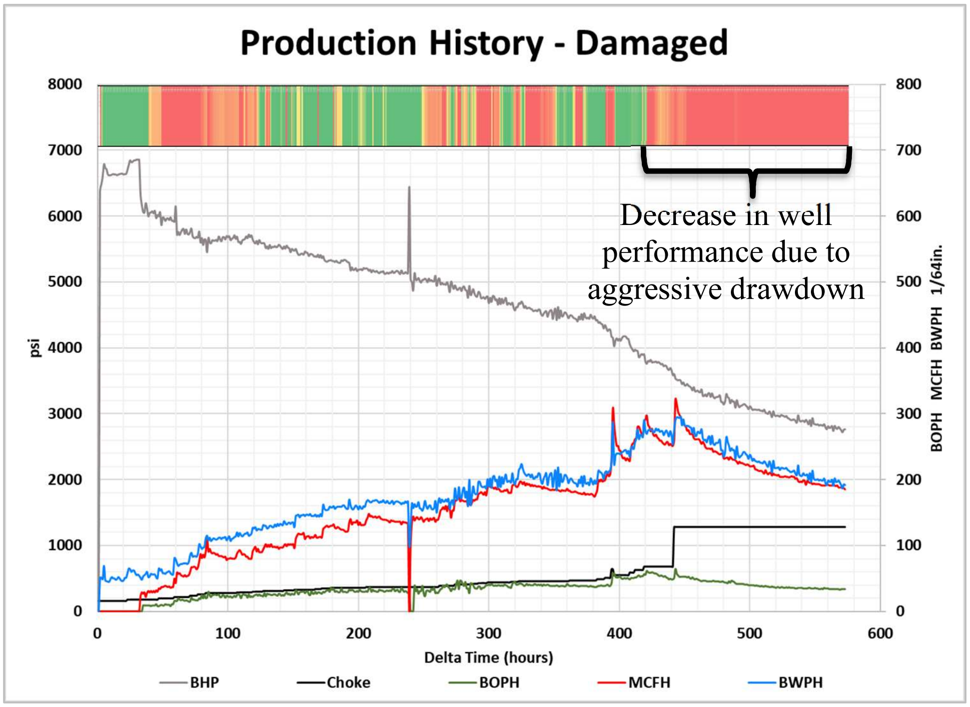


Figure 13 - Production history for a well with a known decrease in well performance from aggressive drawdown

Once the APD was validated with the numerical model and field test data it was applied in real time to optimize the drawdown during the initial production period of a newly completed well.

Real Time Well Performance Optimization

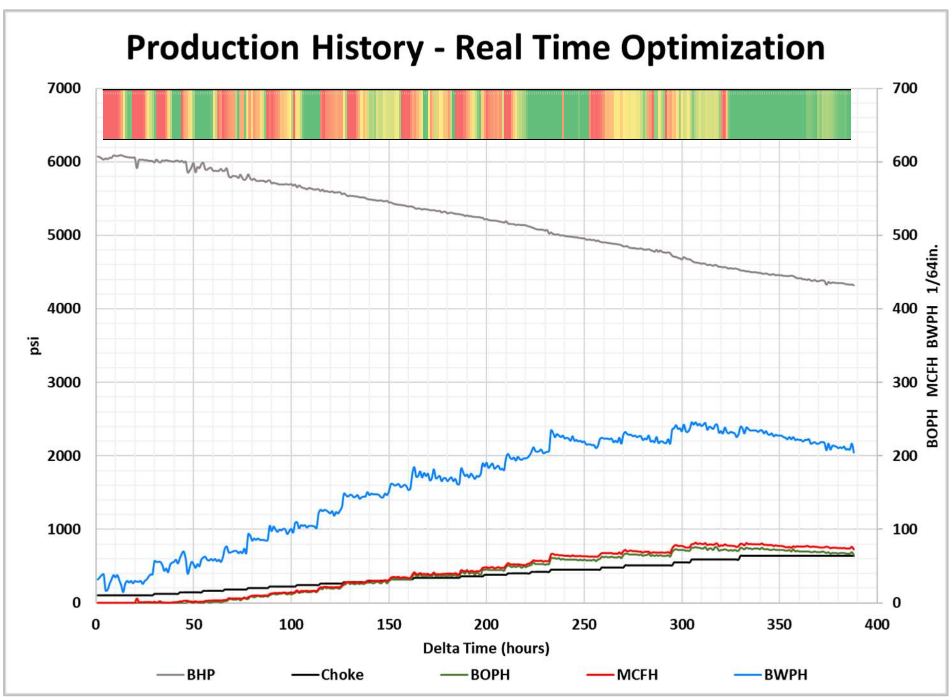


Figure 14 - Production History with performance optimized in real time with APD application

The final test for the APD was to evaluate how effective it would be with real time well performance optimization. The objectives of this test were to decrease the initial production (flowback) period and decrease the time to maximum rate without any sustained decreases in well performance.

Figure 14 shows the production history for well in the Delaware basin Wolfcamp formation. The choke was increased each time the APD indicated well performance was increasing (APD turns green). In this test the well performance decreased after almost every choke change but then started to increase again shortly after (usually within 24hrs). The APD tool reduced the average time of the initial production period and the average time to maximum production by 20% and no sustained decreases in well performance were identified.

Discussion

When the APD was applied to field test data the real potential became very apparent. When doing the analysis manually with RTA software it took about 30 minutes to upload the data and evaluate the well performance. Practically speaking, it is hard for one engineer to do this multiple times a day on multiple wells. The APD did the evaluation in real time every hour of the day which dramatically reduced the time spent on well performance evaluations during the initial production period. Additionally, APD application provided a superior level of detail into how well performance changes during the initial production period that has not been seen before.

From the test in figure 9 there were several spots between 100 hrs. and 200 hrs. where the well performance dropped briefly just after the choke was changed. We think this might be associated with wellbore storage dissipation that occurs directly after choke changes. We have seen this occur on other test always lasting less than 24 hours and usually less than 4 hours. When this is seen we have waited until the APD application indicated the performance was increasing before increasing the drawdown more.

The field test data from figure 12 was an interesting case where there was confirmation from RTA of a decrease in performance when the bottom hole pressure rapidly decreased. However, the sustained decrease in well performance that occurred after the sand plug cleared was not easily identified with RTA but was identified by the APD. We think the sand plug may have formed close to last few heel stages and the drawdown the followed (approximately 500 psi in total) was applied very quickly to these stages and permanently decreased the performance of those stages. If the APD tool had been used in real time on this data set the decreasing well performance could have been identified immediately and the drawdown adjusted to mitigate the impact of the sand plug on long term performance.

After seeing how the APD application identified decreasing well performance associated with rate measurement errors, wellbore obstructions and aggressive drawdown strategies the real time optimization test seemed like the next logical step. In all the tests leading up to this point we had seen a period of decreasing well performance following each choke change that appeared to increase in duration further into the test. With this in mind we wanted to test the APD in real time as if it was connected to the choke system and controlling it directly. To do this we simply increased the choke in the real time test (for the well in figure 14) each time the APD indicated well performance was increasing and we kept increasing the choke until we didn’t see the well performance increase much after 24 hrs. This helped us test the concept of an automated choke system or artificial lift system that would change its operating parameters in real time to optimize production. Below in figure 15 is a flow chart detailing how the APD could be integrated with an automated choke system or artificial lift.

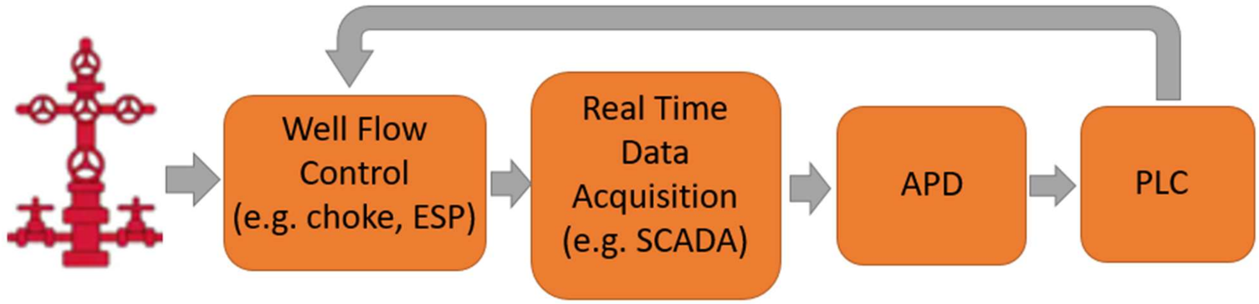


Figure 15 - Flow diagram for integration of APD with auto choke or artificial life

Conclusions

The hourly resolution of the results from automated performance diagnostics gives operators' the ability to optimize well performance in real time in a manner not possible with manual analysis.

The Automated Performance Diagnostic (APD) application identified all known instances of well performance loses in both the synthetic and field data and even identified some that were previously unknown, such as wellbore storage dissipation.

In field testing the APD application identified decreases in well performance that would have prevented production loses and also quickly identified improving well performance which allowed some wells to have their chokes opened faster than the operators had previously done.

Finally, the integration of the APD with an automated choke or artificial lift system was discussed and the concept was tested by increasing the choke on a well at the same time it would have been changed automatically had it been part of an automated choke system.

References

Crafton, J.W. 2008 Modeling Flowback Behavior or Flowback Equals Slowback. Presented at SPE Shale Gas Production Conference, July 23-25. SPE 119894 https://doi.org/10.2118/119894-MS

Dake, L.P., 1978 Fundamentals of Reservoir Engineering, Elsevier, New York

Deen, T., Daal, J., Tucker, J. 2015 Maximizing Well Deliverability in the Eagle Ford Shale Through Flowback Operations. Presented at SPE Annual Technical Conference and Exhibition. Houston, Texas, USA, September 28-30. SPE-174831-MS. https://doi.org/10.2118/174831-MS

Fu, Y., Dehghanpour, H., Motealleh, S., Lopez, C.M., Hawkes, R., 2018 Evaluating Fracture Volume Loss During Flowback and its Relationship to Choke Size: Fastback vs Flowback. Presented at SPE/AAPG/SEG Unconventional Resource Technology Conference, Houston, Texas, USA 23-25 July. URTeC 2903105 https://doi.org/10.2118/195595-PA

Kumar, A., Seth, P., Shrivastava, K., Sharma, M.M., 2018 Optimizing Drawdown Strategies in Wells Producing from Complex Fracture Networks. Presented at SPE International Hydraulic Fracturing Technology Conference and Exhibition. Society of Petroleum Engineers. SPE-191419-18IHFT-MS. https://doi.org/10.2118/191419-18IHFT-MS

Lerza, A., Rojas, D., Liang, B., 2018. Defining the Optimal Drawdown Strategy in the Vaca Muerta Formation. Presented at Unconventional Resources Technology Conference. Society of Exploration Geophysicists, American Association of Petroleum Geologists, Society of Petroleum Engineers. URTEC-2880115-MS. https://doi.org/10.15530/URTEC-2018-2880115

Mirani, A., Marongiu-Porcu, M., Wang, H., Enkababian, P., 2018. Production-Pressure-Drawdown Management for Fractured Horizontal Wells in Shale-Gas Formations. SPE Reserv. Eval. Eng. 21 (03), 550–565. https://doi.org/10.2118/181365-PA

Okouma Mangha, V., Guillot, F., Sarfare, M., San, V., Ilk, D., Blasingame, T.A., 2011 Estimated Ultimate Recovery (EUR) as a Function of Production Practices in the Haynesville Shale. Presented at SPE Annual Technical Conference and Exhibition. Society of Petroleum Engineers. SPE-147623-MS. https://doi.org/10.2118/147623-MS

Rojas, D., Lerza, A., 2018. Horizontal Well Productivity Enhancement through Drawdown Management Approach in Vaca Muerta Shale. Presented at SPE Canada Unconventional Resources Conference. Society of Petroleum Engineers. SPE-189822-MS. https://doi.org/10.2118/189822-MS

Tompkins, D., Sieker, R., Koseluk, D., Cartaya, H. 2016. Managed Pressure Flowback in Unconventional Reservoirs: A Permian Basin Case Study. Presented at SPE/AAPG/SEG Unconventional Resources Technology Conference, San Antonio, Texas, USA, 1-3 August. URTEC-2461207-MS https://doi.org/10.15530/URTEC-2016-2461207

Tompkins, D. 2020. Initial Production Testing Measurement Diagnostics. http://revotestingtech.com/initial-production-testing-measurement-diagnostics/

Tompkins, D., Kerls, M., Adejare, O., 2020. An Examination of the Effects of Surface Data Acquisition Methods on Well Performance Evaluations and Completion Optimization. Presented at SPE/AAPG/SEG

Unconventional Resource Technology Conference, Austin, Texas, USA, 20-22 July. URTeC 2515 https://doi.org/10.15530/urtec-2020-2515

Wattenbarger, R.A, El-Banbi, A.H., Villegas, M.E., Maggard, J.B. 1998. Production Analysis of Linear Flow into Fractured Tight Gas Wells. SPE-39931-MS https://doi.org/10.2118/39931-MS

Wijaya, N., Sheng, J.J., 2020 Probabilistic Forecasting and Economic Evaluation of Pressure Drawdown Effect in Unconventional Oil Reservoirs Under Uncertainty of Water Blockage Severity. Published in Journal of Petroleum Science and Engineering 185 (2020) 106646 https://doi.org/10.1016/j.petrol.2019.106646