

Mathistad Testing Summary

Purpose

The purpose of the testing was to determine the degree of communication between the middle member of the Bakken (MB) and the Three Forks Sanish (TFS) across the lower Bakken Shale. Understanding the degree of communication is important in determining the number of wells needed and where they should be drilled to optimize recovery from each zone. This work tested the degree of communication between wells drilled directly over or beneath an existing producer in the Bakken or TFS zones. The degree of communication determines whether one well will adequately drain both zones.

Results and Application

The test consisted of drilling the Mathistad #2 in the middle member of the Bakken above the Mathistad #1, an existing TFS producer. Pressure data, frac fluid tracers and oil samples were gathered as part of the project. The analysis shows a TFS well alone would not recover a significant portion of the Middle Bakken reserves. Results show that the #2 fractured into the #1 wellbore in all frac stages, but even with the well to well communication, the #2 is estimated to recover an additional 400 MBO over the base case of only drilling and producing the Mathistad #1. Pressures measured in the #1 showed communication from at least 12 of the 14 stages and fluid tracers recovered in the #1 production showed frac fluid from all 14 of the #2 frac stages.

Analysis of the oil samples showed no major differences in the oils sampled. Oil compositions from multiple Bakken and TFS wells showed more areal variation in the same zone than the variation in samples from separate zones in the same location.

History matching the pressure and production data in the reservoir simulator allows it to be used to forecast different operating scenarios. The different scenarios investigated showed the Mathistad #2 will recover additional oil but the optimum recovery is obtained by staggering wellbores 660' apart in the Bakken and TFS zones. This means wellbores in the same zone will be 1320' apart for optimum recovery and economics.

A key parameter in the history matching is the vertical permeability between zones. History matching shows that prior to fracture treating the Mathistad #2, the vertical permeability between the Middle Bakken and TFS is only .01 microDarcies. This allows some pressure communication but not enough to adequately drain the other zone with only one well. The modeling showed it takes at least 5-6 months of production to begin to fully recognize the effect of vertical permeability.

Hydraulic fracture modeling showed the fracture treatments would be contained in zone at initial reservoir pressures. However with pressure depletion the fracture model showed the fractures would grow from the Bakken to the TFS. The pressure data and fluid tracer data support this model result.

Mathistad Communication Testing

Purpose

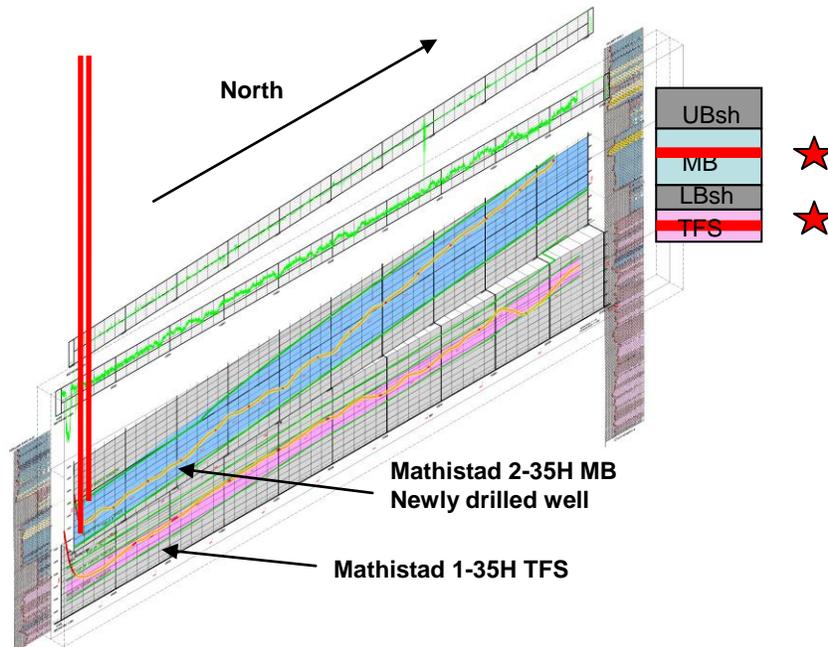
The purpose of the testing was to determine the degree of communication between the middle member of the Bakken (MB) and the Three Forks Sanish (TFS) across the lower Bakken Shale. Understanding the degree of communication is important in determining the number of wells and where they should be drilled to optimize recovery from each zone. This work tested the degree of communication between wells drilled directly over or beneath an existing producer in the Bakken or TFS zones. The degree of communication determines whether one well would adequately drain both zones.

Results

The analysis shows a TFS well along would not recover a significant portion of the Middle Bakken reserves. Results show that the #2 fractured into the #1 wellbore in all frac stages but, even with the well to well communication, the #2 is estimated to recover an additional 400 MBO over the base case of only drilling and producing the #1. Pressures measured in the #1 showed communication from at least 13 of the 14 stages and fluid tracers recovered in the #1 production showed frac fluid from all 14 of the #2 frac stages.

Testing and Analysis

The test consisted of drilling the Mathistad #2 in the middle member of the Bakken above the Mathistad #1 which is a TFS producer. Figure 1 shows the well trajectories in yellow.



The Mathistad #1 had produced from June 2008 until May 2009 before it was shut in to measure pressure response from drilling and completing the #2. The #2 was hydraulically fractured June 15th -17th 2009 and put on production June 19th. Pressure

data was gathered from both wells through October 2009 after the wells were returned to production. Pressure and production data was used to history match a simulation model of the 1280 acre spacing unit. This model was used to forecast recovery from the two wells and compare to the forecasted recovery from the #1 assuming the #2 was not drilled. The difference in model forecasts through 2029 is over 400 MBO.

Data Collection

Oil samples were collected from Bakken and TFS producers operated by Continental Resources Inc. in October 2008. Simulated distillation compositions from these oil samples were included in this data submittal. Oil compositions were analyzed for the Mathistad #1-35H in the October 2008 sampling. Additional oil samples were gathered in January 2010 from the Mathistad #1 and #2. No significant differences in compositions are seen between the Bakken and TFS oils. There appears to be more variation in oil by area than between zones. Figure 2 shows the plot of oil compositions by well.

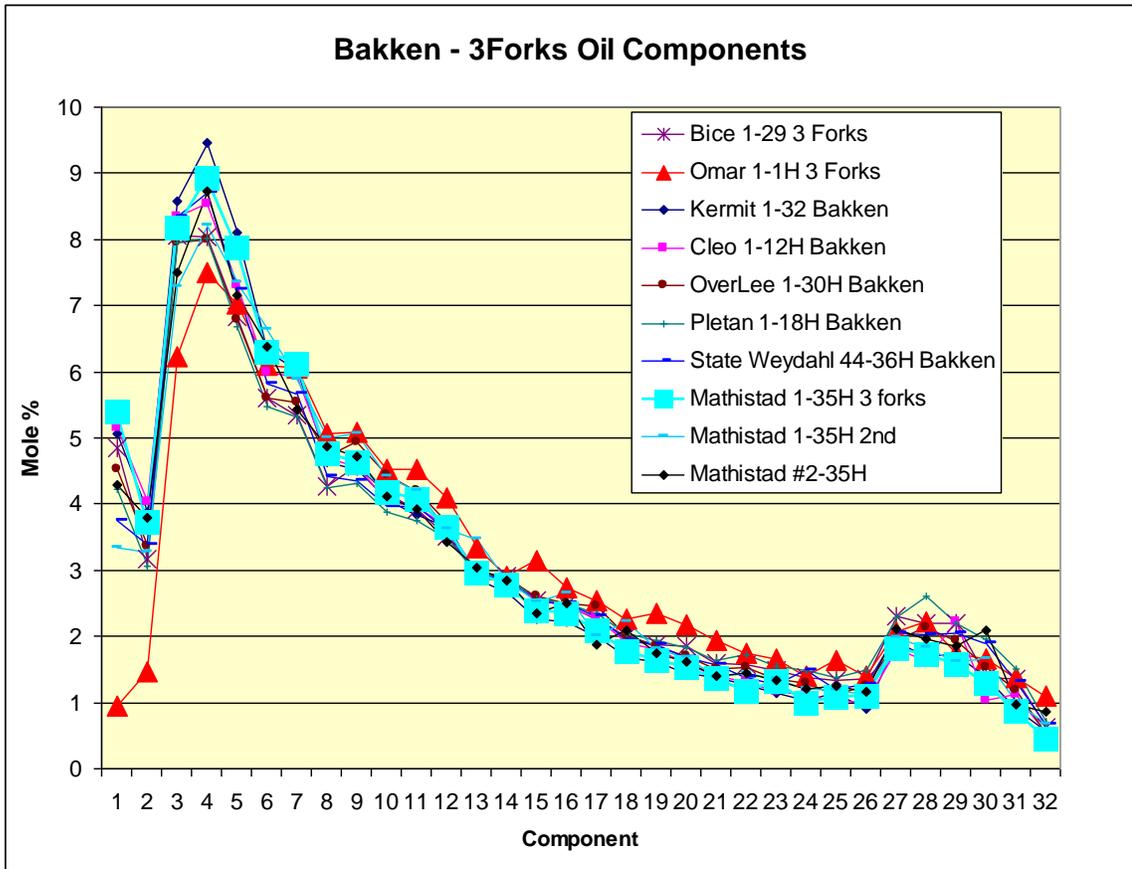


Figure 2 Bakken and TFS oil compositions

Pressure data from the Mathistad #1 gathered prior to the start of funding consisted of flowing BHP in November 2008 after about 6 months of production. As part of the testing program, additional pressure data was collected from May through October 2009. This data along with daily and sometimes hourly rates are submitted as part of this project.

Before the #2 lateral entered the Bakken formation, BHP gauges were run in the #1 and it was left shut in during the entire drilling of the #2 lateral. Before the #2 was fraced June 15th-17th, the BHP gauges in the #1 were retrieved and then rerun to monitor the frac of the Bakken in the #2 well. BHP gauges were left in the #1 until July 17th but the gauges quit recording on July 9th. Gauges were pulled and rerun in the #1 until July 31st 2009 when the well was put back on pump. Additional fluid levels and a buildup were collected with an acoustic well sounder through October 2009.

BHP gauges were run June 19th 2009 following the frac in the #2 and prior to beginning flowback. These gauges were pulled and rerun on June 24th, July 21st and July 28th. Additional flowing BHP data was collected from the #2 through October 2009.

Simulation

History Matching

History matching of the Mathistad #1 was performed using Tempest simulation software from Roxar Inc. The grid consisted of 5 layers with 35 x 70 grids to represent a 1280 acre spacing unit. The only BHP data prior to the start of May 2009 was a flowing BHP taken November 12-21, 2008. The initial pressure was estimated at 6250 psi based on general Bakken DST measurements and fracture treatment data and analysis. Pressure data about 25 miles south in December 2009 prior to beginning completion of the Bice #2-29H measured pressure in the middle Bakken of 7250 psig. Adjusting the initial pressure in the simulator upward would result in a slight lowering of reservoir permeability and decreased drainage area. Therefore the pressure initially estimated of 6250 psig is being used in the simulation.

Values for reservoir properties were estimated from offset logs in adjacent sections. The layer values for porosity were 6%, 6%, 9%, 6%, and 13% for the upper Bakken through the Three Forks. Water saturation values were 10% in the shale and 30-40% in the non shale intervals. Initial reservoir permeability is estimated at .001 md with adjustments to this made at the time of the fracture treatments in the grid blocks adjacent to the wellbore. Permeability adjustments are made in addition to the usage of planar hydraulic fractures extending from the wellbore at each of the mechanically isolated fracture stages. The planar fractures are given conductivity and fracture half lengths to describe the fractures effect on flow from the grid blocks to the wellbore.

Simulation of the Mathistad #1 was begun prior to the drilling and completion of the #2 with only the fracture treatment data, daily production and wellhead pressures and the extended flowing BHP data from the #1. The simulation showed that the history match was sensitive to the vertical permeability between the Bakken and TFS. The average vertical permeability from the history match was determined to be .01 microdarcys (10^{-5} md). Using higher vertical permeability caused the model producing pressure to be higher than the November 2008 measured BHP data showing there is a very limited communication between the Bakken and TFS zones following the completion of the Mathistad #1.

The Mathistad #1 was fraced with 10 stages isolated by 9 swell packers over the length of the lateral. Each frac stage in the model is represented by an approximately equally spaced frac with a 1000' fracture half length and conductivity of 1000 mdft. In

addition, the permeability of a grid block containing a wellbore was increased to .15 md and the permeability of the three adjacent grid blocks was increased from .001 to .01 md with the rest of the grid blocks remaining at .001 md. The resulting history match is shown in figures 3-6 with model values shown in red and the actual values shown in green.

Figure 3 shows the model BHP matches well with the actual data for the Mathistad #1 including the pressures measured during the frac of the #2. From beginning production until the frac of the #2 the production from the #1 matches well with the 10 planar fractures and the enhanced permeability along the lateral. After the frac of the #2 however a skin factor of 7 was used to obtain the flowing BHP during August-November 2009. This skin was removed after the wellbore cleanouts of both wells in November 2009. The #1 reported drilling numerous hard spots and tight spots with almost continuous sand circulated to surface. Following the cleanouts the skin was removed and the model appears to be matching the well data again.

Model GOR behavior is shown in Figure 5. The match of model and reported GOR is good with this model setup. Other models without the near wellbore permeability modification did not match the GOR behavior as well.

The modeled water cut in the Mathistad #1 from August until November 2009 is significantly lower than actual after the #2 frac. During this same time period the modeled water production from the #2 is too high by the same amount as the #1 is too low. Even though the pressure match is obtained for the #1 from the injection of frac fluid in the #2 there does not appear to be enough water transmitted to the TFS interval. This effect apparently is due to wellbore plugging following the frac of the #2. After a wellbore cleanout of both wells in November the model is able to match the water cuts in both wells again.

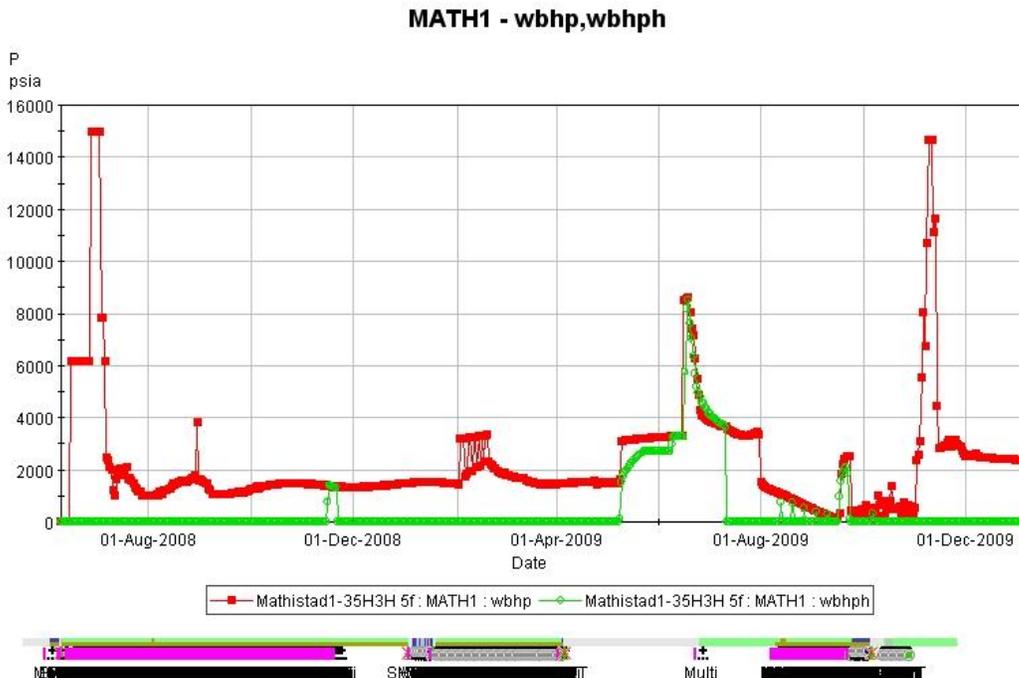


Figure 3 Comparison of measured and model BHP.

MATH1 - wlpr,wlprh

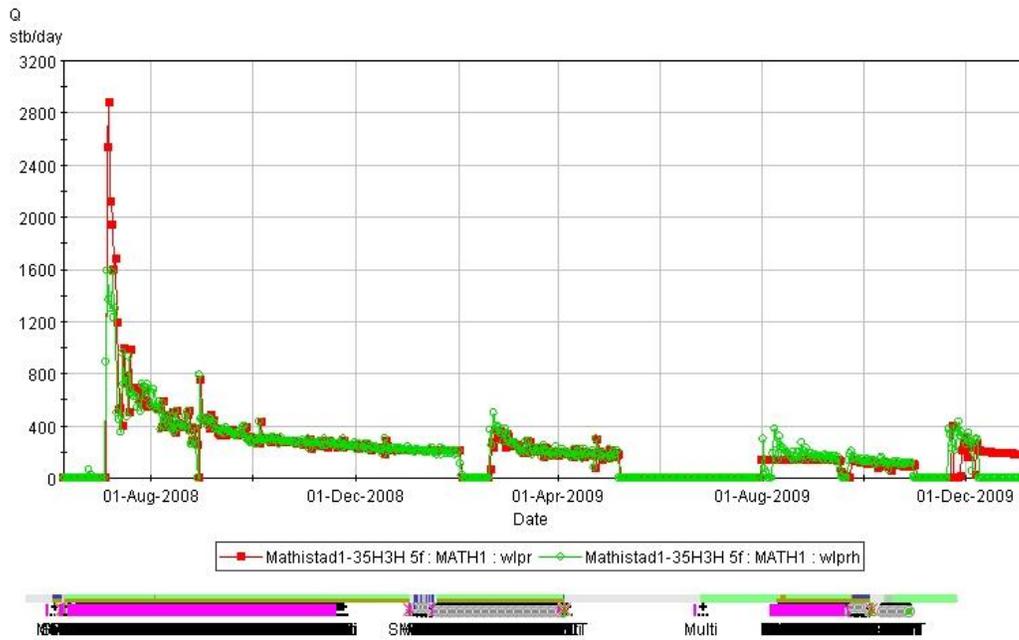


Figure 4 Liquid Production

MATH1 - wgor,wgorh

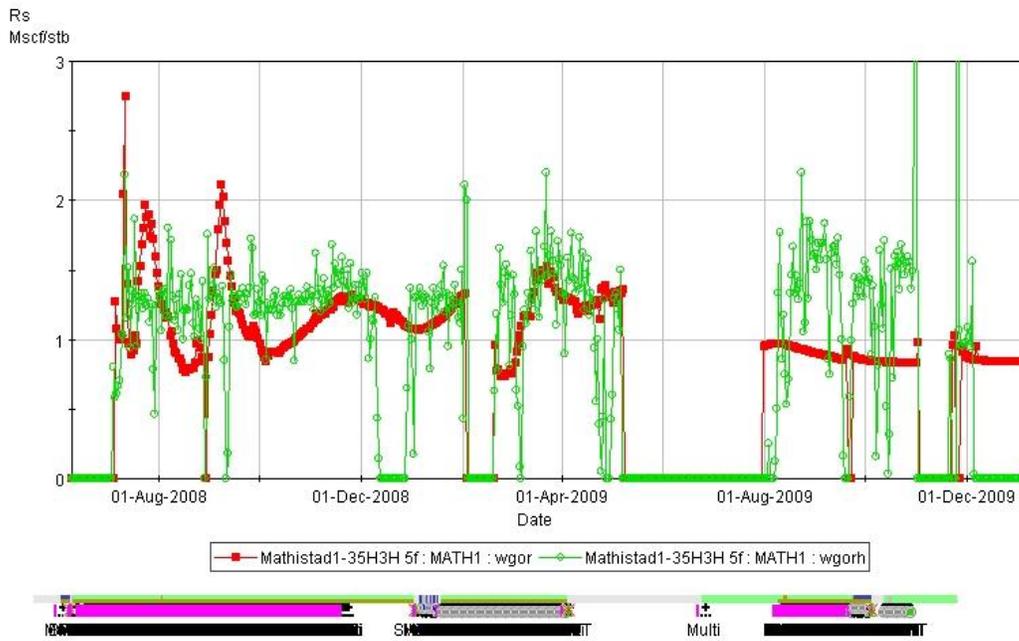


Figure 5 GOR

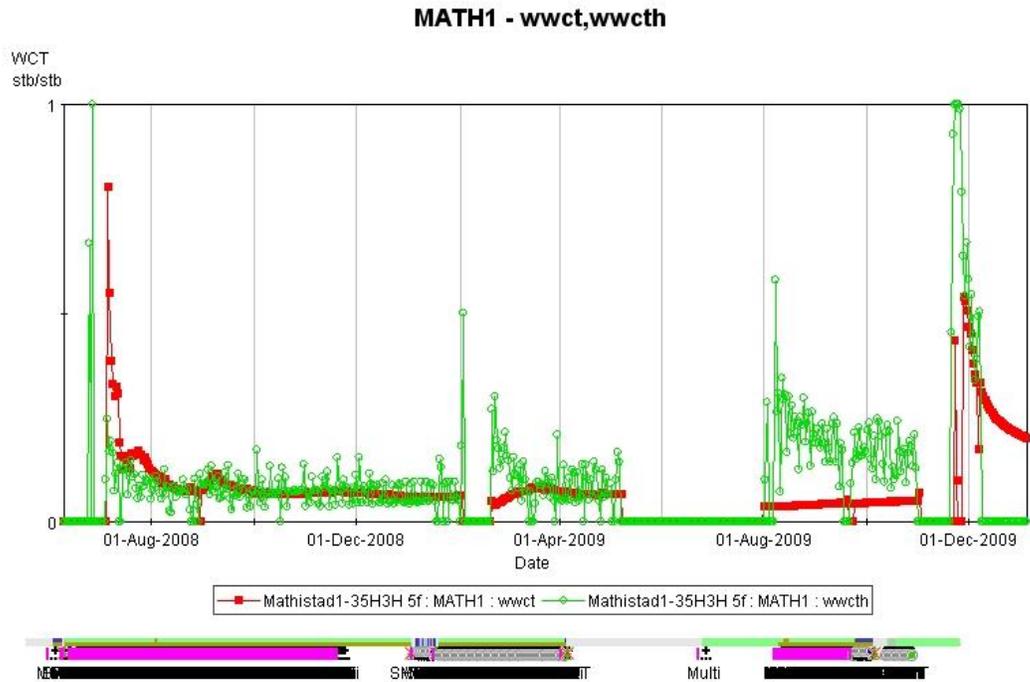


Figure 6 Water cut match except following the #2 frac until the November cleanout.

Figures 7-10 show the history match of the Mathistad #2. The biggest difference for the modeling of the #2 was the fractures were setup as longitudinal fracs instead of transverse as in the #1.

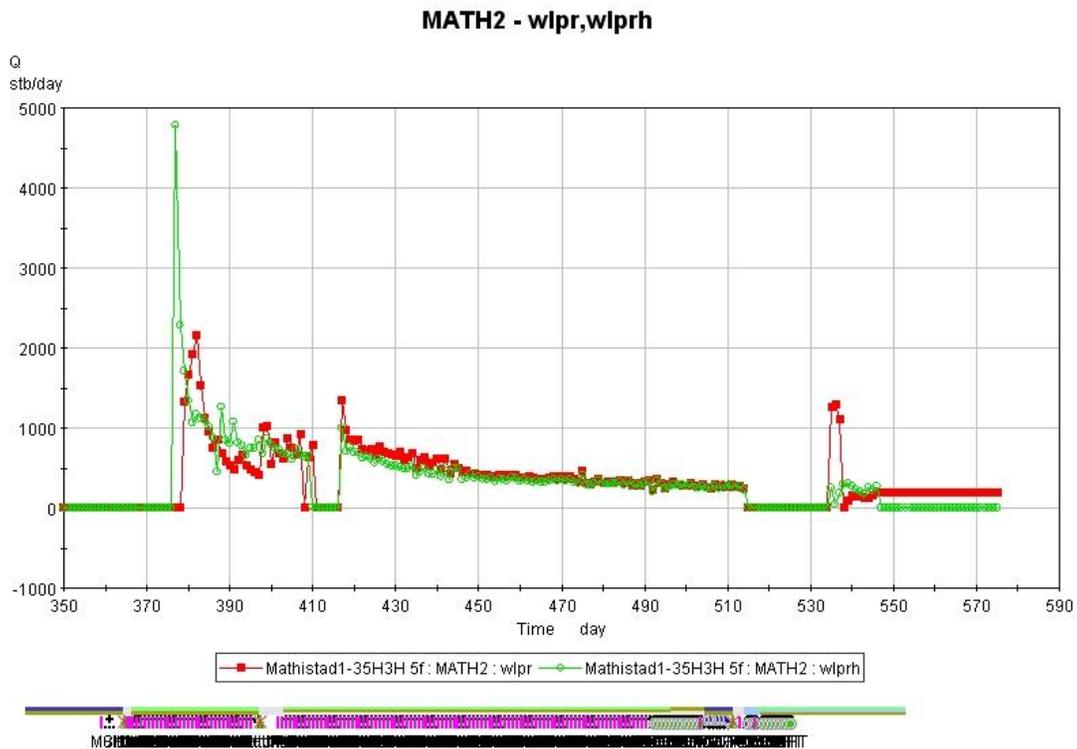


Figure 7 Liquid production rate comparison of the Mathistad #2.

MATH2 - wbhp,wbhph



Figure 8 BHP match of the Mathistad #2.

MATH2 - wgor,wgorh

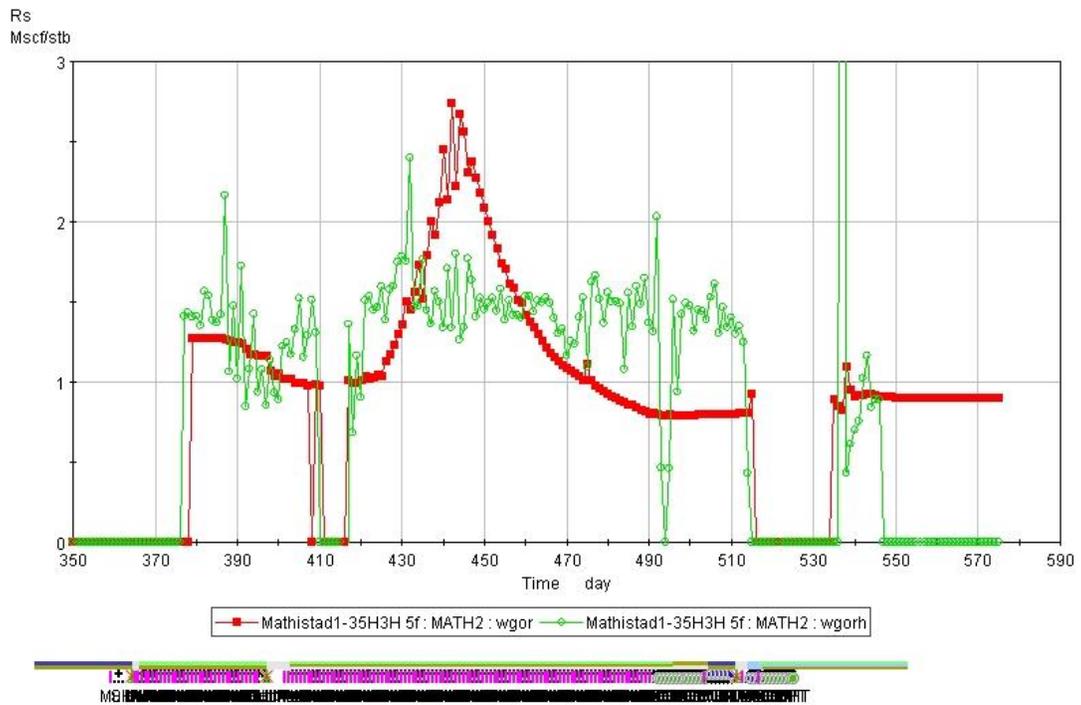


Figure 9 Mathistad #2 GOR match.

MATH2 - wwct,wwcth

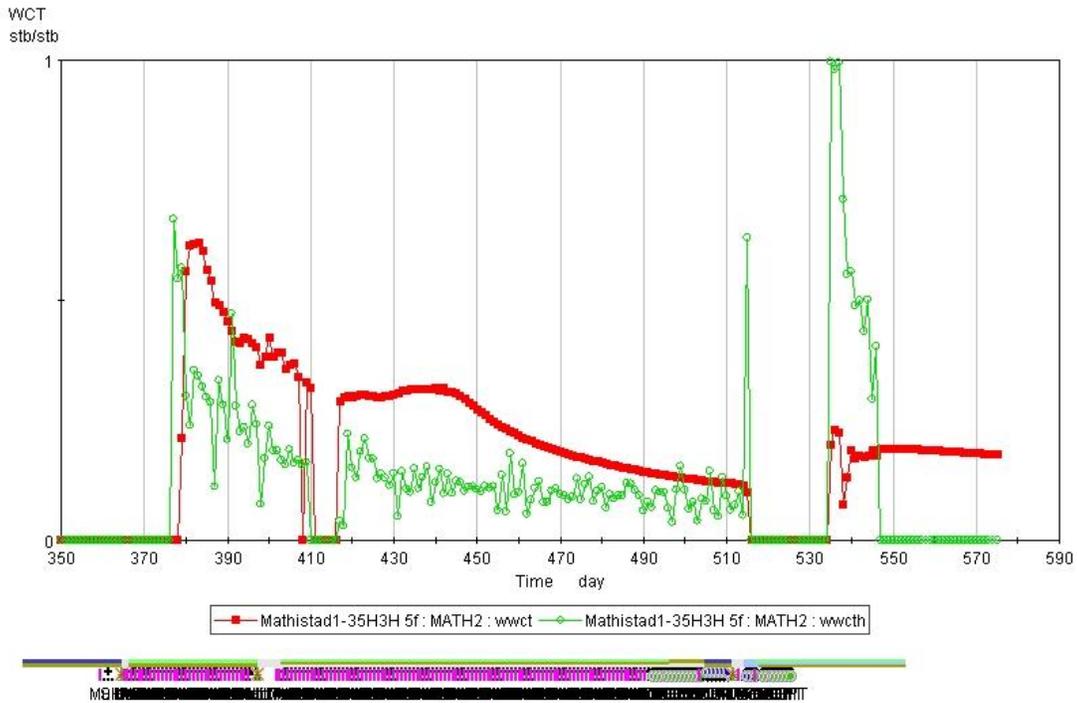


Figure 10 Mathistad #2 Water cut comparison.

#2 Fracture Treatment

The fracture treatment of the Mathistad #2 was pumped June 15th-17th 2009 with BHP gauges in the Mathistad #1 to monitor pressure during the 14 stage fracture treatment of the #2. 12 of the 14 frac stages appear to be seen during the fracturing. Figure 11 shows the bumps in the pressure in the Mathistad #1 during the fracturing.

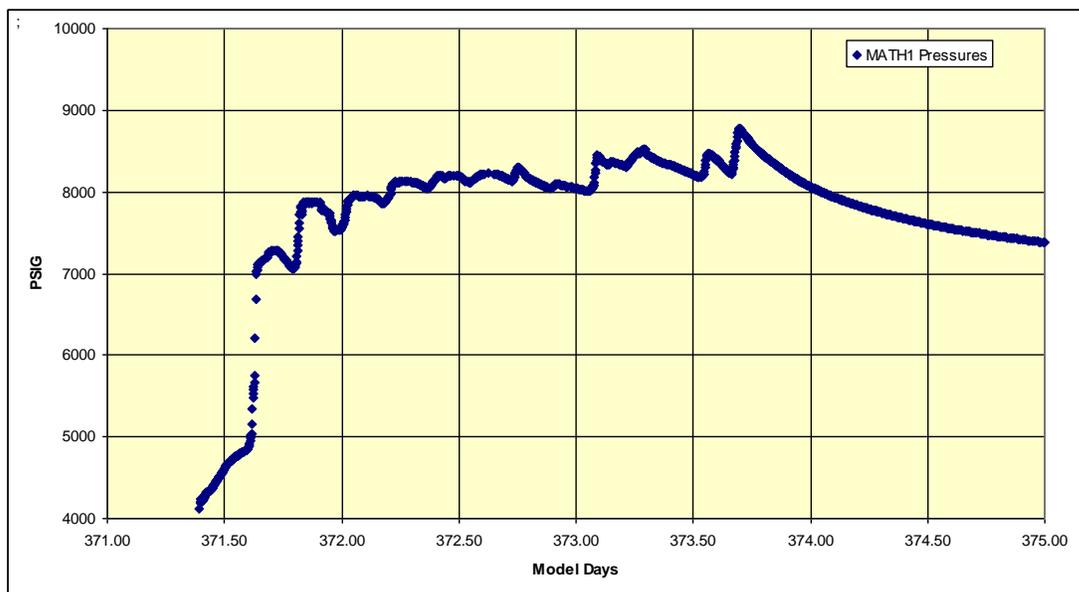


Figure 11 Mathistad #1 BHP during the #2 frac showing bumps in pressure from the 14 frac stages.

The 14 stages were mechanically isolated using swell packers spaced along the lateral. Each stage except 7 and 8 had a different fluid tracer added to the fracturing fluid to monitor the fracture stage ability to contribute to production and determine which stages broke through to the #1. Subsequent production from each well showed all of the tracers present in each wellbore showing all 14 stages communicated to the TFS and #1 wellbore during the fracturing treatment. The fracture communication could be expected due to the pressure depletion in the TFS around the #1 wellbore by the 11 months of production.

Fracture modeling showed a major difference in fracture growth when modeled with and without the pressure depletion. Without pressure depletion the fracture model showed the fracture stayed in the Bakken without breaking into the TFS. However, using the same fracture model and having pressure depletion in the TFS showed the frac would grow down and the proppant would be present from the Bakken to the TFS. The propped fracture length is 250', about the same distance as the ends of the #1 and #2 laterals are apart.

Following the #2 frac, BHP gauges were used to monitor the pressure during production following the frac. BHP gauges were run in the #2 with the tubing and the #1 was left shut in. The #2 began flowing back on June 19th. Figures 12-13 show the pressure data from the #1 and #2. The BHP in the #1 reflects the pressure falloff from the #2 frac even before the gauges were run in the #2. The pressure falloff in the #1 and #2 is very similar after the #2 gauges were on bottom until the #2 began production.

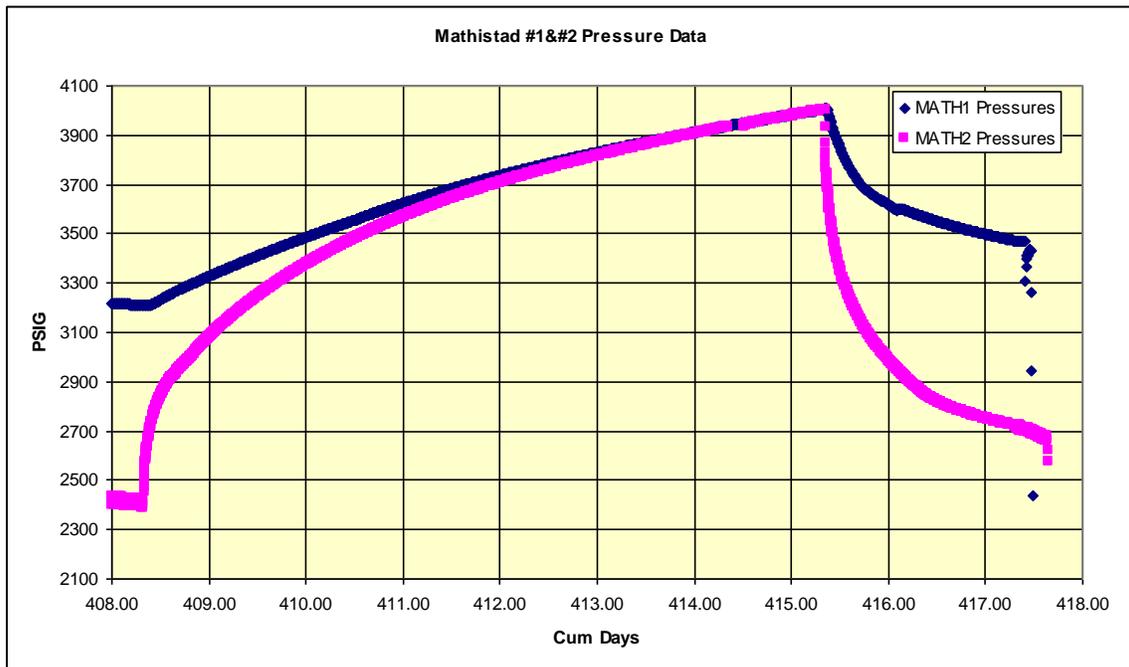


Figure 12 #1 and #2 pressure response from shutting in the #2 and returning it to production.

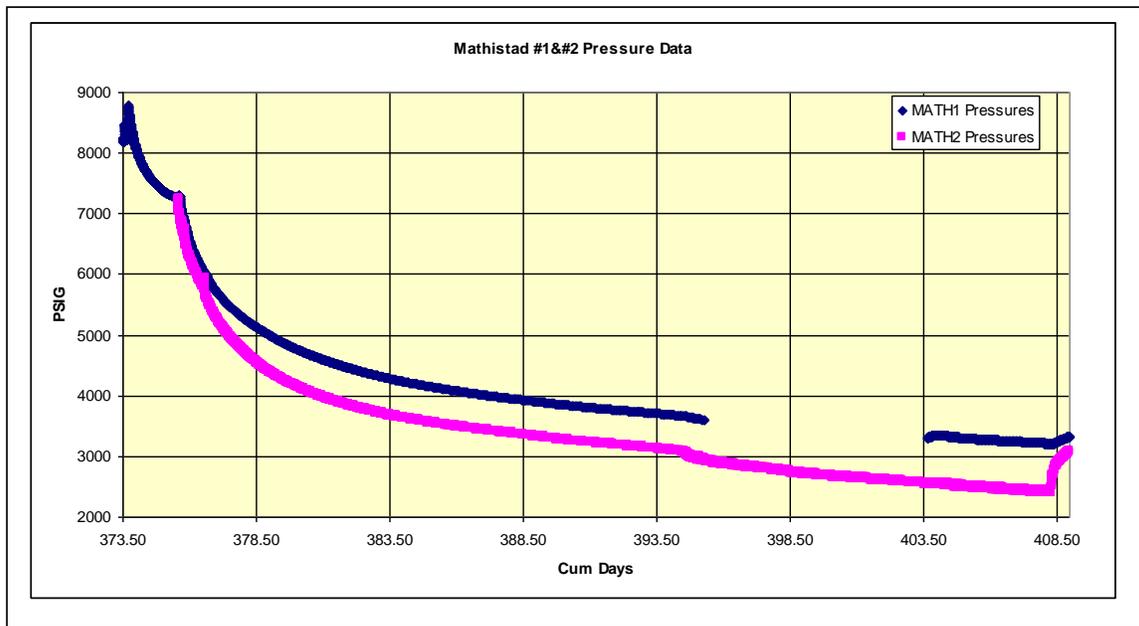


Figure 13 #1 & #2 Pressure data during flowback of the #2

Optimum Spacing

The communication between the Mathistad #1 and #2 is apparent from the tracer and pressure data presented. However the communication before the #2 completion and frac appears very limited so the question is “How much incremental production will the #2 or additional infill wells provide?”. To address these questions the simulation model was used to project recovery under two different scenarios. The first scenario projected recovery both wells producing. The second scenario was a projection of the Mathistad #1 assuming the #2 had not been drilled. The recovery of the Mathistad #1 was determined by running the model through 2029 with a minimum BHP. Predicted recovery is over 500 MBO at the end of the model run. This compares to about 900 MBO for the continued operation of the #1 and #2 giving an incremental recovery from the #2 of 400 MBO. The ultimate recovery will be highly dependent on the relative permeability to oil and gas as significant gas saturation is developed when the reservoir drops below the bubble point pressure. Therefore the absolute values projected for recoverable reserves are subject to more error than the relative error between cases.

Optimum spacing was evaluated by using the model with hydraulic fractures and permeability adjustments as in the Mathistad #1. The base model of the #1 was replicated to represent infill wells and used to predict recovery for additional wells to determine the spacing for optimum economics.

The model shows recovery is maximized and still economic by drilling wells 1320’ apart in the same zone and 660’ apart in different zones. This would allow drilling 7 wells per 1280 acre spacing unit if 660’ setbacks from the lease line are used. Unusually large hydraulic fractures or natural fractures could cause some localized pressure depletion in new infill wells. The relatively high permeability flow path connection (compared to the unstimulated areas of the reservoir) would cause measured pressures to be low in new wellbores. However the well bore pressure in the new well could continue

to build as crossflow occurs all along the new wellbore into the high permeability flow path connecting the old and new wells.

Initial pressure and production data from wells drilled at 660' in the Middle Bakken offsetting TFS completions show different ranges of communication. Some wells showed almost no communication between zones with apparent initial reservoir pressure of 7250 psi or higher. Other wells showed the Bakken had been communicating to the TFS but only along a portion of the lateral. In these cases the second well showed pressure increasing even while the first well was still producing with a high permeability connection. When the fluid in the tubing was dumped on the formation in the first well the pressure responded quickly showing a high permeability connection. This pressure behavior indicates areas of higher pressure were crossflowing along the lateral repressuring the portion of the lateral in the Middle Bakken that had been partially depleted.

Conclusions

Conclusions from the analysis of the data gathered as part of this project are as follows.

1. There is very limited communication between the Bakken and TFS reservoirs at the Mathistad location prior to fracturing in a pressure depleted area.
2. Enough additional reserves will be produced from a second well completed directly above or below the first to be economic, even with high permeability fractures communicating between the wells.
3. Fracture communication may exist in a limited area due to natural or hydraulic fractures, but significant additional reserves can still be developed for up to 7 wells per spacing unit.
4. Pressure depletion can create significant hydraulic fracture growth between zones over a short distance. It might be possible to produce the incremental reserves of the second well from the first well after the second well is stimulated.
5. No distinguishable differences exist between the Bakken and TFS oil to separate the zones.

This report was prepared by Continental Resources, Inc. pursuant to an agreement with the Industrial Commission of North Dakota, which partially funded the report. None of Continental Resources, Inc. or any of its subcontractors, the Industrial Commission of North Dakota or any person acting on behalf of any of them:

- (A) Makes any warranty or representation, express or implied, with respect to the accuracy, completeness, or usefulness of the information contained in this report, or that the use of any information, apparatus, method, or process disclosed in this report may not infringe privately-owned rights; or
- (B) Assumes any liabilities with respect to the use of, or for damages resulting from the use of, any information, apparatus, method or process disclosed in this report.

Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the Industrial Commission of North Dakota. The views and opinions of authors expressed herein do not necessarily state or reflect those of the Industrial Commission of North Dakota.