FIRST SOLUTIONS TO PROBLEMS AND ISSUES WHEN HYDRAULICALLY FRACTURING THE AVALON SHALE

Bouhala, Khaled, Alarbi Nasraldin, Namvar, Mahdi and Sevilla, Mauricio,
Halliburton Energy Services

ABSTRACT
Recent activity in the Avalon Shale play, an upper member of the Leonard series in southeastern New Mexico[1], has opened up a new horizon for production from an unconventional formation. Key to the potential success of the Avalon Shale play will be the ability to adapt and refine horizontal completion methods and stimulation techniques. The effectiveness of hydraulic fracture stimulations is critical for optimal economic production of this natural gas and oil shale play. The initial stimulation methods used for the early wells in this play have revealed several challenges while hydraulically fracturing the Avalon Shale interval. Some of the issues are high treating pressure, near wellbore tortuosity, early fluid leak off, natural fractures, and a propensity for sand-outs that lead to shorter effective fractures and wellbore damage.

This paper will present field case study demonstrating most of the previously mentioned problems and issues with hydraulically fracturing in the Avalon Shale and the steps that were taken to remedy them.

INTRODUCTION

Hydraulic fracturing has become the completion of choice when stimulating unconventional resources. It has proven successful to commercialize tight formations by creating a permeable pathway for the hydrocarbons to flow into the wellbore. The Avalon shale is one example of these unconventional formations. The Avalon shale is an oil & gas shale formation in the Permian Basin located in southeastern New Mexico and spread across Eddy, Lea & Chaves counties; it also extends to west Texas[2]. The Avalon shale lies above in the Bone Spring formation and it is comprised of series of individual sandstone zones separated by carbonaceous and shaley siltstones ranging in depth from 6,500 to 9,000 feet [1]. The production from this formation consists roughly of one third crude oil, one third natural liquid gas and one third dry gas [2].

To reach a maximum production from the Avalon shale formation the wells are horizontally drilled and hydraulically fractured. The TVD ranges between (6500'-7500') followed by horizontal section reaching an average of 13,500' MD, completed with (5,5"OD-N80/P110) casing and divided to 13-16 fracture sections on the horizontal part in a depth of 8000' to 13500' MD.

FIELD CASE STUDY

For a typical Avalon shale formation fracturing treatment behavior (figure1), the treating pressure reaches approximately 7000 psi at 80 bpm by pumping water comingled with friction reducer additive starting the proppant treatment with linear gel followed by crosslinked fluid stages; this will bring the treating pressure down to ~ 4800 psi, due to the increase of fluid efficiency by adding the crosslinked fluid and creating a dominant fracture.

Keeping the treating pressure at low levels is vital as it facilitates to pump with the highest possible treating rates, which would extend the geometry of the fracture to cover the maximum of the pay zone and, thus, gain the most production out of the treated formation. Low treatment pressures can also help minimize the casing and tubing string cost by selecting a cheaper tubular grade based on the achieved lower treating pressure limitations. That will have a cost reduction impact on the operating companies drilling and completion expenditures.

Maintaining low treating pressures can be more challenging with the presence of fine natural fractures; which is the case in a lot of sections in the Avalon shale formation. That leads to high fluid leak off into the formation, which lowers the fracturing fluid efficiency resulting in high treating pressure (figure 2). Considering the type of rock and its high stresses, reducing the treating rate can help to reduce the treating pressure, However, at the same time, it will have a negative effect on the fracture geometry by failing to cover the most possible of the target reservoir zone and, consequently, diminishing the prospected post treatment production.

In this studied field case linear gel with a viscosity of 11 cp was used in sand slug (the first stage of the). Treating with linear gel is problematic especially in environments with severe leak off properties. Linear fluids tend to easily imbibe into the formations with the presence of natural fractures. That results in a failure to generate a dominant fracture due to the random distribution of the fracture fluid efficiency between the numerous natural fractures. Another issue associated with such environments is the inability to place proppant slug with the use of large mesh proppants, 20/40 in this case, in small natural fractures.

The same high treating pressure behavior was observed when treating with a crosslinked fluid comingled with a the proppant size slug .The crosslinked fluid could enhance the fluid efficiency by reducing the leak off. However, a dominant fracture was still not created. If it had, a pressure decrease would have been noticed. Being too big to fit in the fine fractures, the proppant used in the proppant slug didn’t help alleviate the severity of the high treating pressure problem as it was not able to plug the natural fractures and totally eliminate the fluid leak off problem.

When changing the sand slug design from linear gel with 20/40 mesh size proppant to crosslinked fluid Comingled with stages of 100 Mesh sand slug, a dramatic treating pressure decrease from 7600 to 4700 was achieved (figure 3). That is attributed to the better fluid efficiency of the crosslinked system as well as to the placement of the smaller proppant inside the fine natural fractures and plugging them aiding to reduce fluid leak of into these fractures. The treating pressure started to decrease as soon as the sand slug stages got in contact with the formation allowing the increase of treating rates to maximize the fracture geometry to optimal levels enhancing expected production.

CONCLUSION

In this work a field case study was done on a fracture treatment in the Avalon shale formation to analyze some of the issues that contribute to the high treatment pressure encountered during the pumping process which prevents to pump by high enough rates to create optimum fracture geometry. That includes the presence of natural fractures, the high fluid leak off rates and their consequences. The proposed remedy to the problem comprises of the use of a crosslinked fluid system and smaller mesh size sand in the sand slug. That will help improve the fluid efficiency by plugging the fine natural fractures to reduce fluid leak off.

The optimized fracture design on the Avalon shale, that takes into account the mentioned parameters, would help to increase the Post treatment production level. Furthermore, it will help to optimize the tubular selection during the drilling phase and the horse power needed for fracturing treatment. In addition to that, down time or delays caused by problems related to high treating pressure during the pumping process will be avoided. All that leads to decrease in the operator companies drilling and well completion expenditure and make the fracturing treatment more profitable.

REFERENCES

1- http://oilshalegas.com/avalonshale.html
2- http://avalonshale.com/

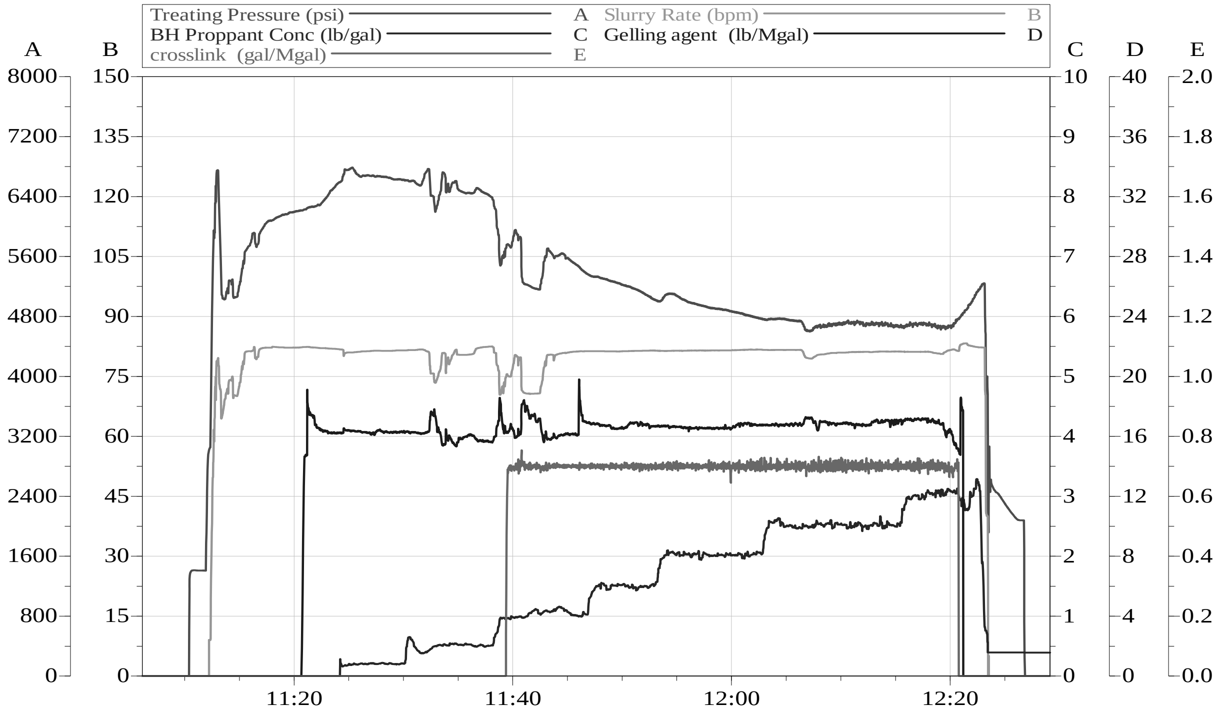

Figure 1 - Avalon Shale Typical Fracture Treatment

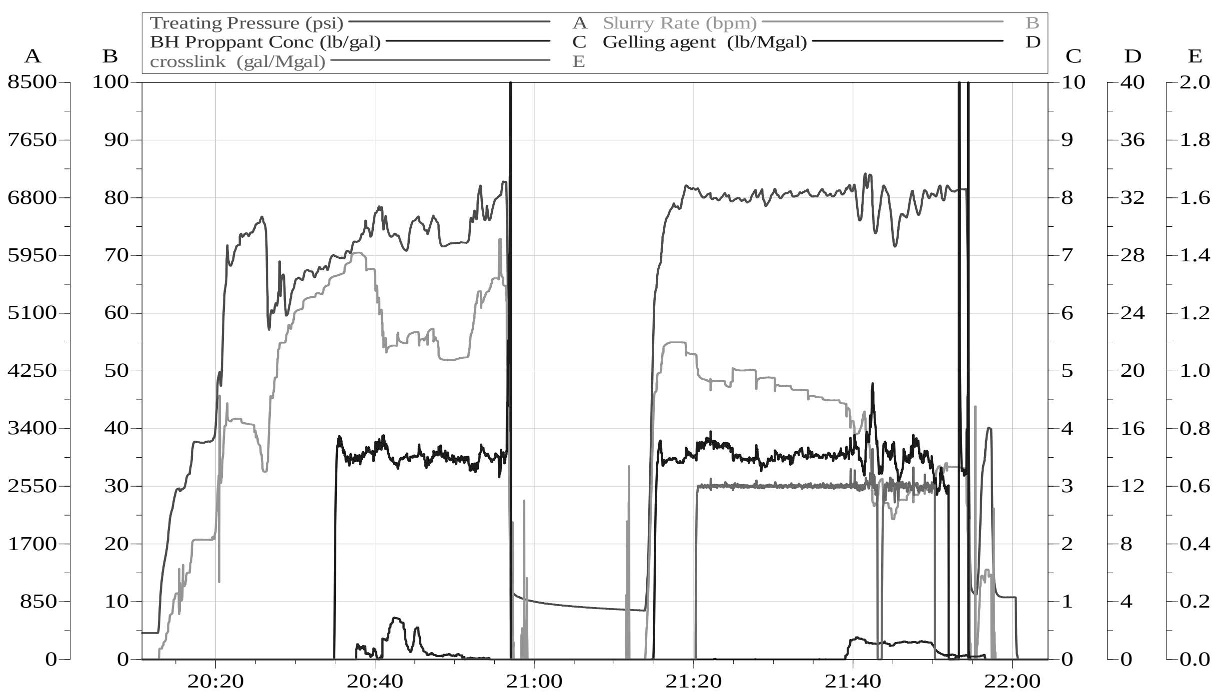

Figure 2 - Avalon Shale Fracture Treatment With 20/40 Prop Slug

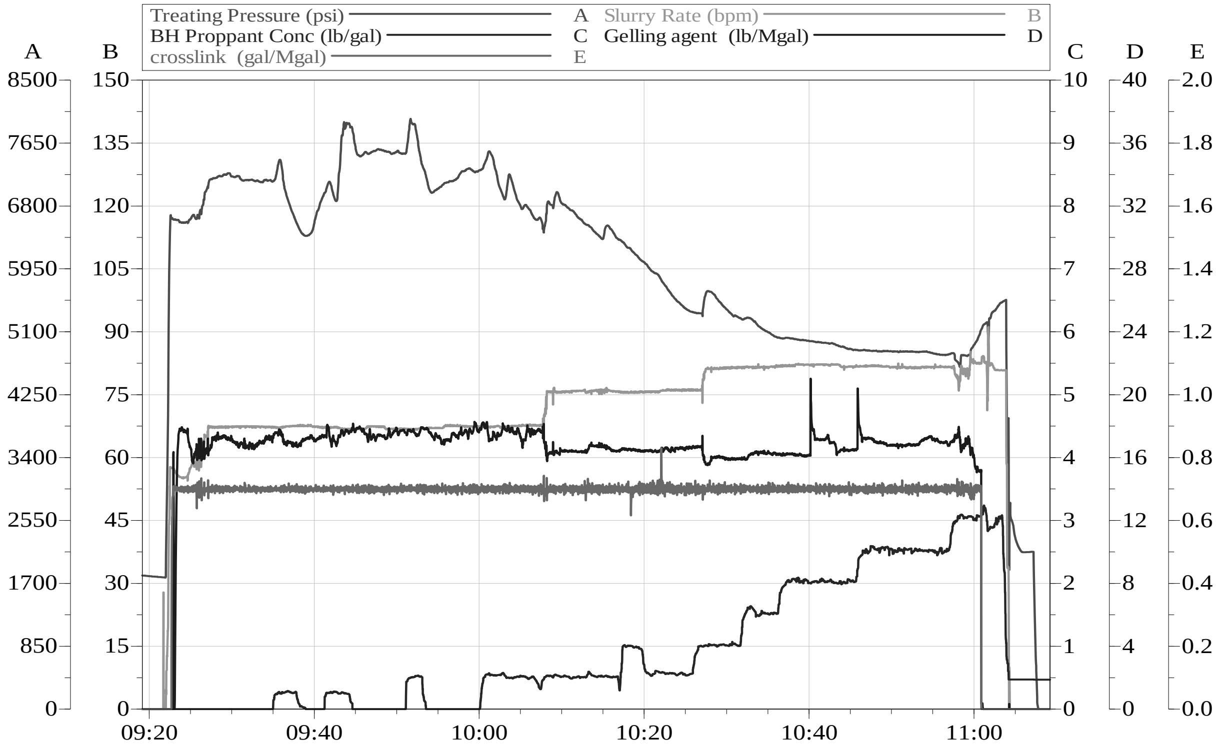

Figure 3 - Avalon Shale Fracture Treatment With 100 Mesh Prop Slug