

Respuesta a Requerimientos

1	Datos del Solicitante			
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Dirección:		CARRERA 11 NO. 86-53, PISO 6	Domicilio/País de constitución:	COLOMBIA - CUNDINAMARCA - BOGOTA D.C.
Identificación:				
☒ CEDULA DE CIUDADANIA ☐ EMPRESA EXTRANJERA ☐ PASAPORTE		☐ CEDULA DE EXTRANJERIA ☐ NIT		
Número:		66783790-		
2	Dato de la Creación			
Identificación de la Creación		No. de Certificado	Vigencia	No. de Expediente Tipo Trámite

MÉTODO PARA INCREMENTAR LA PRODUCTIVIDAD DE LAS FORMACIONES DE HIDROCARBUROS UTILIZANDO FLUIDO QUE CONTIENE AGENTE DE ENLAZAMIENTO CRUZADO ORGANOMETÁLICO E INHIBIDOR DE ESCAMAS DE ÓXIDO		000000		16051487	PCT-PATENTE DE INVENCION CAPITULOS I Y II
3	Texto de la Comunicación	Se anexa memorial de respuesta a Oficio de Forma No. 3289, junto con nuevo pliego reivindicatorio conformado por 23 reivindicaciones y dos artículos informativos.			
4	Anexos				
☒ Anexos					

P-11315

SUPERINTENDENCIA DE INDUSTRIA Y COMERCIO
DIRECCIÓN DE NUEVAS CREACIONES

E. S. D.

Re: Expediente No. **16-051.487**

Solicitud de patente a nombre de **BAKER HUGHES INCORPORATED**

Yo, CAROLINA DAZA MONTALVO identificada como aparece al pie de mi firma, domiciliada en la Carrera 11 No. 86-53, piso 6, obrando como apoderada de la sociedad BAKER HUGHES INCORPORATED, domiciliada en Houston, Texas, Estados Unidos de América, solicitante de la patente de la referencia, en respuesta al oficio No. **3289** notificado por fijación en lista el 05 de abril de 2016, relacionado con los requerimientos formales de la solicitud, atentamente me permito presentar la siguiente información:

1. Reivindicaciones

En relación con las objeciones sobre falta de claridad de las reivindicaciones me permito informar que, con fundamento en la facultad que confiere el artículo 34 de la Decisión 486 al solicitante para modificar la solicitud de patente en cualquier momento del trámite, presento junto con este memorial nuevo capítulo reivindicatorio, el cual consta de 23 reivindicaciones y reemplaza completamente el capítulo presentado anteriormente. En el nuevo capítulo reivindicatorio se realizaron las siguientes modificaciones:

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- 1.1** Considerando las amables sugerencias del examinador, se han modificado las reivindicaciones independientes de método para señalar las etapas y condiciones de las mismas. Igualmente, se ha introducido el conector “caracterizado por”, con el fin de dividir estas reivindicaciones en preámbulo y parte caracterizadora.
- 1.2** Del mismo modo, el nuevo pliego reivindicatorio no comprende las expresiones “que se puede someter a enlazamiento cruzado” (el agente es traducido ahora como “polímero viscosificante reticulable”) y “aproximadamente”.

En cuanto a estas modificaciones, me permito decir que las mismas no amplían de ninguna manera la materia objeto de la presente solicitud y se realizaron con el ánimo de superar las objeciones de claridad planteadas por el examinador en su concepto técnico.

En relación con el número de reivindicaciones, atentamente indicamos que no se requiere el pago de tasas por reivindicaciones adicionales, toda vez que el nuevo pliego reivindicatorio contiene el mismo número de reivindicaciones que el inicialmente presentado.

2. Claridad y concisión de las reivindicaciones

Respecto a las objeciones de claridad, el solicitante manifiesta que mediante las modificaciones realizadas en el capítulo reivindicatorio quedan subsanadas la totalidad de las objeciones, de modo tal que las nuevas reivindicaciones proporcionan claridad y concisión a la invención descrita, siguiendo las recomendaciones realizadas por el examinador en su concepto técnico.

En particular, como se indicó anteriormente, las reivindicaciones independientes de método están caracterizadas por una secuencia de etapas y condiciones. De otro lado, estas reivindicaciones indican claramente dónde inicia la parte caracterizadora.

Igualmente, el nuevo pliego reivindicatorio no contiene las expresiones “que se puede someter a enlazamiento cruzado” y “aproximadamente”.

Por lo anterior, las nuevas reivindicaciones son más claras y concisas.

No obstante lo anterior, es deseo del solicitante poner de presente lo siguiente:

Las reivindicaciones recitan el transporte de un inhibidor escamas de óxido dentro de un gel, en donde el gel se forma en presencia del inhibidor de escamas de óxido, a partir de la interacción de un polímero viscosificante reticulable y un agente de reticulación. Las reivindicaciones por lo tanto recitan un agente de reticulación organometálico en combinación con un inhibidor de escamas de óxido. El solicitante declara específicamente en el párrafo 0005 de la descripción, que los inhibidores de escamas de óxido tradicionales no son eficaces cuando se usan con el agente de reticulación organometálico ya que el gel resultante es inestable. Bajo las condiciones de temperatura y presión de la operación de fracturación, el gel debe ser lo suficientemente estable para transportar el agente de sostén en las fracturas creadas o agrandadas. Por lo tanto, la esencia de la invención del solicitante es el hallazgo de que los inhibidores de escamas de óxido reivindicados se pueden usar con un agente de reticulación organometálico, en donde el gel resultante exhibe una alta estabilidad.

El problema estado de la técnica, como se referencia por el solicitante en el párrafo. 0005 es bien conocido. Para mejor referencia del examinador se adjuntan los siguientes artículos:

- ✓ D.V. Satya Gupta, Mike Brown, Steve Szymczak, "A 5-Year Survey of Applications and Results of Placing Solid Chemical Inhibitors in the Formation via Hydraulic Fracturing"; SPE 134414; September 19-22, 2010; Florence, Italy; y
- ✓ Leonardo Maschio, Bilu Cherian, Bernard Lungwitz, Michael Tyndall, Marieliz Garcia, and John Longwell, "Optimization of a Scale Treatment in the Uinta Basin - A Case History"; SPE 107993; April 16-18, 2007; Denver, Colorado.

Ambos documentos discuten los problemas de incompatibilidad de los inhibidores de escamas de óxido en fluidos de fracturación reticulados.

Esta información es importante a la hora de comprender la invención, la cual se ha definido con mayor claridad en el nuevo pliego reivindicatorio.

Ahora bien, el examinador considera que expresiones "polímero viscosificante" y "agente de enlazamiento cruzado (reticulación)" no son claras. A este respecto, se desea indicar que la descripción contiene ejemplos de "polímeros viscosificantes" en las páginas 2, 18 y 19. De hecho, una fórmula se presenta en la página 19. Igualmente, ejemplos de "agentes de enlazamiento cruzado (reticulación)" se encuentran en las páginas 2, 13, 14 y 15. Sin embargo, estos son sólo ejemplos dentro de un sinnúmero de polímeros viscosificantes y agentes de reticulación organometálicos que son conocidos en la técnica para crear un gel para fondo de pozo. En nuestra opinión, la limitación de las reivindicaciones a los agentes de reticulación organometálicos y agentes viscosificantes ejemplificados limitaría indebidamente el alcance hasta el punto que perdería todo su sentido, ya que podría eludirse fácilmente mediante el uso de un agente de reticulación organometálico o polímero viscosificante no recitado específicamente por solicitante. En este sentido, es importante notar que la reivindicación 19 define los polímeros viscosificantes preferidos y referencia el agente de reticulación organometálico como uno que contiene Zr, Ti, Al o Sb como metal.

Por lo anterior, la persona del oficio normalmente versada en la materia comprendería dichos componentes, lo cuales están además indicados con mayor detalle en las reivindicaciones dependientes.

El examinador también considera que las expresiones "derivados celulósicos", "un ion de metal polivalente", "hidroxilo", "carboxilo", "sulfato", "sulfonato", "amino" y "amido" son muy generales. Las especies adecuadas de "un ión de metal polivalente" se recitan en la página 13, párrafo 32 de la descripción. Además, un "grupo hidroxilo, carboxilo, sulfato, sulfonato, amino o amido" como un derivado de un polímero reticulable se hace referencia en el párrafo. 00039. Por su parte, los derivados celulósicos adecuados se mencionan en los párrafos 00041-00045. Todos estos términos son bien reconocidos por las personas del oficio normalmente versadas en la técnica de prestación de servicios de petróleo y gas en los pozos. Al igual que en el caso anterior, la limitación de las reivindicaciones a los componentes ejemplificados limitaría indebidamente el alcance hasta el punto que perdería todo su sentido, ya que una persona del oficio normalmente versada en la materia sería

capaz de encontrar alternativas que no hayan sido específicamente recitadas por el solicitante.

El examinador también indica que la expresión "polímero viscosificante que se puede someter a enlazamiento cruzado" es inaceptable. En el nuevo pliego reivindicatorio esta expresión ha sido traducida con mayor claridad como "polímero viscosificante reticulable". Adicionalmente, las nuevas reivindicaciones recitan la reacción de reticulación entre el polímero viscosificante reticulable y el agente de reticulación. Por ello, se considera que esta expresión es clara y concisa.

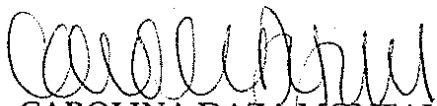
Finalmente, el examinador afirma que la frase "prevenir y/o inhibir la formación de escamas de óxido en el pozo y/o formación" es inaceptable. Como se ha indicado anteriormente, la invención del solicitante yace en el hallazgo de que los inhibidores de escamas de óxido reivindicados se pueden usar con agentes de reticulación organometálicos. Cuando se bombean, se previene la formación y/o se inhiben las escamas de óxido debido al bombeo del fluido. Por ello, se considera una información relevante que debe ser incluida en las reivindicaciones, además de proveer mayor claridad al objeto reivindicado.

Del mismo modo, el pH y la viscosidad son características técnicas medibles, que permiten definir una condición técnica de método o un rasgo técnico de un producto, por lo que se consideras aceptables, claros y concisos.

En consecuencia, nos permitimos informar que las nuevas reivindicaciones 1 a 23 se ajustan a las disposiciones del artículo 30 de la Decisión 486/00 y que las objeciones formuladas por el examinador se ven superadas.

Habiendo atendido cabalmente las objeciones presentadas por ese Despacho en el oficio No. 3289 notificado por fijación en lista el 05 de abril de 2016, solicito atentamente sea tenida en cuenta la información aquí presentada y continuar con el trámite de la presente solicitud.

Señor Director,



CAROLINA DAZA MONTALVO

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ANEXOS

- Nuevo capítulo reivindicatorio que incluye 23 reivindicaciones.
- Copia del Artículo: D.V. Satya Gupta, Mike Brown, Steve Szymczak, "A 5-Year Survey of Applications and Results of Placing Solid Chemical Inhibitors in the Formation via Hydraulic Fracturing"; SPE 134414; September 19-22, 2010; Florence, Italy.
- Copia del Artículo: Leonardo Maschio, Bilu Cherian, Bernard Lungwitz, Michael Tyndall, Marieliz Garcia, and John Longwell, "Optimization of a Scale Treatment in the Uinta Basin - A Case History"; SPE 107993; April 16-18, 2007; Denver, Colorado.

P-11315
Reivs. Modificadas
20/05/2016

REIVINDICACIONES

1. Un método para fracturar una formación calcárea o silíceo que contiene hidrocarburos penetrada por un pozo caracterizado por lo siguiente:

(a) bombear en el pozo a una presión suficiente para crear o agrandar fracturas en la formación calcárea o silíceo que contiene hidrocarburos, un fluido de tratamiento de pozo que comprende:

(i) un polímero viscosificante reticulable;

(ii) un agente de reticulación organometálico que contiene un ion de metal polivalente; y

(iii) un inhibidor de escamas de óxido seleccionado del grupo que consiste de sulfonatos de polivinilo, un ácido poliacrilamidometilpropano sulfónico, carboximetil inulina y poliacrilatos sulfonados así como las mezclas de los mismos;

(b) formar un gel que contiene el inhibidor de escamas de óxido después del paso (a) por medio de la reticulación del polímero viscosificante reticulable y el agente de reticulación organometálico;

(c) transportar el inhibidor de escamas de óxido en el gel dentro de la formación;

(d) prevenir y/o inhibir la formación de escamas de óxido en el pozo y/o formación con el inhibidor de escamas de óxido transportado.

2. El método de acuerdo con la reivindicación 1, caracterizado porque el ion de metal polivalente es seleccionado del grupo que consiste de Zr, Ti, Al y Sb así

como las mezclas de los mismos.

3. El método de acuerdo con la reivindicación 1, caracterizado porque el inhibidor de escamas de óxido es un sulfonato de polivinilo que tiene un peso molecular promedio en número desde 500 hasta 100.000.

4. El método de acuerdo con la reivindicación 1, caracterizado porque el inhibidor de escamas de óxido es un ácido poliacrilamidometilpropano sulfónico que tiene un peso molecular promedio en número desde 500 hasta 200.000.

5. El método de acuerdo con la reivindicación 1, caracterizado porque el inhibidor de escamas de óxido es carboximetil inulina que tiene un peso molecular promedio en número desde 500 hasta 30.000.

6. El método de acuerdo con la reivindicación 1, caracterizado porque el inhibidor de escamas de óxido es un copolímero de poliacrilato sulfonado que tiene un peso molecular promedio en número desde 500 hasta 30.000.

7. El método de acuerdo con la reivindicación 1, caracterizado porque el metal polivalente del agente de reticulación organometálico es titanio.

8. El método de acuerdo con la reivindicación 1, caracterizado porque el metal polivalente del agente de reticulación organometálico es circonio.

9. El método de acuerdo con la reivindicación 3, caracterizado porque el pH del fluido de tratamiento de pozo está entre 3 y 12.

10. El método de acuerdo con la reivindicación 9, caracterizado porque el pH del fluido de tratamiento de pozo está entre 3 y 6.

11. El método de acuerdo con la reivindicación 4, caracterizado porque el pH del fluido de tratamiento de pozo está entre 3 y 12.

12. El método de acuerdo con la reivindicación 5, caracterizado porque el pH de la composición de tratamiento de pozo está entre 8 y 12.

13. El método de acuerdo con la reivindicación 6, caracterizado porque el pH de la composición de tratamiento de pozo está entre 8 y 12.

14. El método de acuerdo con la reivindicación 1, caracterizado porque la formación de escamas de óxido es además prevenida y/o inhibida en la sarta de tubos, tubería de revestimiento, tuberías, bombas o válvulas localizadas en el interior del pozo.

15. El método de acuerdo con la reivindicación 1, caracterizado porque el polímero viscosificante reticulable contiene uno o más grupos funcionales seleccionados del grupo que consiste de hidroxilo, carboxilo, sulfato, sulfonato, amino y amido así como las mezclas de los mismos.

16. El método de acuerdo con la reivindicación 1, caracterizado porque el polímero viscosificante reticulable es seleccionado del grupo que consiste de derivados celulósicos, almidón, gomas de galactomanano, xantano, carragenano, poliacrilamida, alquilpoliacrilamidas, poliacrilamida parcialmente hidrolizada o un copolímero de acrilamida y ya sea un acrilato o ácido acrilamidometilpropano sulfónico así como las mezclas de los mismos.

17. El método de acuerdo con la reivindicación 16, caracterizado porque el polímero viscosificante reticulable es seleccionado del grupo que consiste de hidroxialquil celulosas, alquilhidroxialquil celulosas, carboxialquil celulosas, guar no derivatizado o un guar derivatizado así como las mezclas de los mismos.

18. El método de acuerdo con la reivindicación 17,

caracterizado porque el polímero viscosificante reticulable es un guar derivatizado seleccionado del grupo que consiste de hidroxipropil guar, hidroxietil guar, hidroxibutil guar y carboximetilhidroxipropil guar así como las mezclas de los mismos.

19. Un método para inhibir o controlar la deposición de escamas de óxido en un pozo o en una formación subterránea penetrada por un pozo durante la fracturación de la formación subterránea, el método caracterizado por lo siguiente:

(a) bombear en el pozo a una presión suficiente para crear o agrandar una fractura un fluido de tratamiento, en donde el fluido de tratamiento comprende:

(i) un polímero viscosificante hidratable que es guar no derivatizado o un derivado de guar o una combinación de los mismos;

(ii) un agente de reticulación organometálico que contiene un metal seleccionado del grupo que consiste de Zr, Ti, Al y Sb así como las mezclas de los mismos; y

(iii) un inhibidor de escamas de óxido seleccionado del grupo que consiste de sulfonatos de polivinilo que tienen un peso molecular promedio en número desde 500 hasta 100.000, un ácido poliacrilamidometilpropano sulfónico que tiene un peso molecular promedio en número desde 500 hasta 200.000, una carboximetil inulina que tiene un peso molecular promedio en número desde 500 hasta 30.000 y poliacrilatos sulfonados que tienen un peso molecular promedio en número desde 500 hasta 30.000 así como las mezclas de los mismos;

(b) formar un fluido de tratamiento de pozo viscoso estable por medio de la interacción del polímero viscosificante y el agente de reticulación organometálico en presencia del inhibidor de escamas de óxido; y

(c) transportar el inhibidor de escamas de óxido en una zona específica de la formación sujeta a fracturación.

20. El método de acuerdo con la reivindicación 19, caracterizado porque la viscosidad del fluido de tratamiento de pozo viscoso estable después de la interacción del polímero viscosificante hidratable y el agente de reticulación organometálico es mayor a 500 cP a 100 seg^{-1} a una temperatura mayor a 150°F .

21. El método de acuerdo con la reivindicación 20, caracterizado porque la viscosidad del fluido de tratamiento de pozo viscoso estable después de la interacción del polímero viscosificante hidratable y el agente de reticulación organometálico a temperaturas mayores a 250°F a 100 seg^{-1} es de 800 a 900 cP.

22. Un método para inhibir o controlar la deposición de escamas de óxido en un pozo o en una formación subterránea penetrada por un pozo durante una operación de fracturación hidráulica, el método caracterizado por los siguientes pasos:

(A) bombear en el pozo a una presión suficiente para crear o agrandar una fractura cerca de las regiones del pozo de la formación subterránea un fluido de tratamiento de pozo, en donde el fluido de tratamiento de pozo comprende:

(a) un polímero viscosificante reticulable seleccionado del grupo que consiste de guar no derivatizado, derivados de guar, derivados de celulosa y poliacrilamida así como las mezclas de los mismos;

(b) un agente de reticulación de circonio o titanio; y

(c) un inhibidor de escamas de óxido seleccionado del grupo que consiste de:

(i) sulfonatos de polivinilo, el pH del

fluido de tratamiento de pozo estando entre 3,0 y 12,0;

(ii) un ácido poliacrilamidometilpropano sulfónico, el pH del fluido de tratamiento de pozo estando entre 3,0 y 12,0;

(iii) una carboximetil inulina, el pH del fluido de tratamiento de pozo estando entre 8,0 y 12,0; y

(iv) un poliacrilato sulfonado, el pH del fluido de tratamiento de pozo estando entre 8,0 y 12,0; y

(B) transportar el inhibidor de escamas de óxido en un fluido gelificado en una región cercana al pozo, el fluido gelificado siendo formado por la interacción del polímero viscosificante reticulable y el agente de reticulación de circonio o titanio en presencia del inhibidor de escamas de óxido; y

(C) inhibir o controlar la formación de escamas de óxido cerca de las regiones del pozo de la formación subterránea con el inhibidor de escamas de óxido.

23. Un método para fracturar una formación calcárea o silícea que contiene hidrocarburos penetrada por un pozo caracterizada por lo siguiente:

(a) bombear en el pozo a una presión suficiente para crear o agrandar fracturas en las regiones cercanas al pozo de la formación calcárea o silícea un fluido de tratamiento de pozo, el fluido de tratamiento de pozo comprende:

(i) un polímero viscosificante reticulable;

(ii) un agente de reticulación inorgánico; y

(iii) un inhibidor de escamas de óxido seleccionado del grupo que consiste de sulfonatos de polivinilo, un ácido poliacrilamidometilpropano sulfónico,

una carboximetil inulina, poliacrilatos sulfonados así como las mezclas de los mismos; y

(iv) un agente de sostén

(b) formar un fluido gelificado a partir del fluido de tratamiento de pozo del paso (a);

(c) transportar el inhibidor de escamas de óxido en el fluido gelificado es una zona específica dentro de la formación; y

(d) prevenir y/o inhibir la formación de escamas de óxido en el pozo y/o formación sujeto a fracturación con el inhibidor de escamas de óxido.



SPE 134414

A 5-Year Survey of Applications and Results of Placing Solid Chemical Inhibitors in the Formation via Hydraulic Fracturing

D.V. Satya Gupta, SPE, J. Mike Brown, SPE, and Steve Szymczak, SPE, BJ Services Company

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This paper was prepared for presentation at the SPE Annual Technical Conference and Exhibition held in Florence, Italy, 19–22 September 2010.

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Abstract

Solid chemical inhibitors placed in the formation during hydraulic fracturing have provided inhibition protection for up to five years. Deepwater operators, especially, desire longer inhibition periods. This paper provides a summary on treatment results over five years and over 1500 wells. It covers inhibition for scale, paraffin and asphaltene either as a single application or as a multiple product application. These applications have been in various formations including deepwater, tight gas and coal bed methane formations. The longest documented treatment has been in the ground for over five years.

Placing a solid chemical inhibitor into the formation via the fracturing process requires a product that is compatible with the fracturing fluid, does not adversely affect conductivity and provides long term inhibition through the controlled release of the inhibitor into the produced fluid. The solid inhibitor is added to the fracturing proppant. Primarily this is a mass-balance process by which a finite amount of inhibitor desorbs over time. The goal is to maximize the inhibitor loading, minimize the chemical release rate without negatively impacting the stimulation.

In the treated wells inorganic and organic deposition has been arrested for extended periods when compared to alternative liquid addition applications. Solid scale inhibitors have been the most common treatment and are monitored through residual analysis. The paraffin and asphaltene inhibitors are monitored through comparative testing. The paper details both the time and the cumulative production that has flowed through the respective proppant packs.

Wells that are scheduled for hydraulic fracturing and that display tendencies for organic and/or inorganic deposition are candidates for solid chemical placement during the fracture. The results from over 1500 wells indicate that this method for deposition inhibition reduces intervention costs and lowers lifting costs.

Introduction

This paper follows up on work presented on this topic in earlier papers, Szymczak (2006), Gupta (2008), Gupta (2009) and Smith (2009). It presents an update for the industry on a production chemical technology by which a chemical inhibitor is adsorbed onto an inert, proppant-sized, solid particle to form what is characterized as a solid inhibitor. This material is then added to the proppant during a hydraulic fracture, frac pack, high rate water pack or gravel pack. When fluid is produced the inhibitor desorbs into its respective solubilizing liquid. The solid inhibitors for scale, corrosion, salt or biocidal action desorb into the produced water. In the absence of water flow they remain intact on the solid matrix. The solid inhibitors for paraffin or asphaltene desorb into the hydrocarbon phase. The purpose of the solid chemical additive is to provide long term inhibition for mineral and/or organic deposition. The measure of success for long term life is a function of time or cumulative volume of treated fluid. The wells with the longest continuous scale treatment were treated with the solid scale inhibitor in May of 2005. For over five years these wells have been producing without any scale related well failures and without any supplemental addition of scale inhibitor. The well with the highest cumulative water production has produced in excess of 2.0 millions bbls of produced water without scaling problems. For paraffin the longest producing well produced for 29 months before it was determined that the paraffin inhibition characteristics had diminished below the effective level. Its cumulative oil production was 40,000. The longest and highest producing well treated with the solid asphaltene dispersant has been in the ground for over six months. It continues to show evidence of asphaltene dispersion. Its cumulative oil production is at 500,000 bbls. In all over 2,000 wells have had the

solid inhibitor product added during the hydraulic fracture process. Of these over 90% used the solid scale inhibitor. See Table 1 for a summary of the longest time period and highest cumulative throughput.

Current research is underway to improve the characteristics of the solid substrate. One effort is aimed at adding compressive strength without sacrificing absorbency. The other effort is to expand the chemicals available in the solid form. Progress in these areas will be the subject of future publications.

By adding the product during the fracture, the chemicals are present at the initial point of pressure drop in the formation. This occurs at the fracture/formation interface. An inhibitor dissolved in the oil or water phase in the proppant pack optimizes the inhibition potential throughout the formation, at the near well bore, in the production tubulars and throughout the surface facilities. In one anecdotal incident an operator reported a cessation of the SWD (salt water disposal well) acidizing program once the solid scale inhibitor was in use in the newly fractured wells. The value of a deposition mitigation program is seen in reduced LOE (lease operating expense) and reduces NPT (non-productive time), thus improving lease economics.

A fracture fluid has several functions, all of which need to be accomplished within a relatively short time. The fluid must offer viscosity and then break the viscosity. It must control fluid leak off. It must maintain a prescribed pH range in order to achieve the viscosity. Any additional chemical component added to a fracture fluid must be examined for any potential incompatibility with the fracture fluid. For that reason all solid production chemicals added to the fracture are routinely examined for fluid compatibility. In addition to the fluid compatibility the solid chemical additive must not adversely affect the fracture conductivity. For that reason the product is tested and evaluated at system closure pressures using accepted API testing procedures.

Specialty production chemicals have traditionally been added to a production stream in order to inhibit, scavenge, disperse, resolve, kill or perform other functions that relate to the economical production of hydrocarbons. The production chemicals described in this paper are designed to inhibit scale and paraffin and disperse asphaltenes (Note: although asphaltenes are colloids and technically are not inhibited like paraffins, the industry uses the term asphaltene inhibition. Technically these products are asphaltene dispersants).

These production chemicals are efficient at ppm (parts per million) dosages. In a traditional continuous feed application these chemicals are typically used in the range of 10-200 ppm, although higher rates can be considered normal. When these chemicals are applied as a bulk fluid, either as a squeeze or added to a fracture, there is little control over the release rate as measured through subsequent residual testing. Maschio (2007) discusses liquid production chemicals that were introduced into fracture fluids as a means to transport the production chemical into the formation to enhance performance. Norris (2001) reports that liquid chemicals flow back at higher than necessary rates. This has been an accepted consequence of adding liquid chemicals in a bulk phase.

Contrarily, Gupta (2008) reports that the chemicals adsorbed onto a solid desorb at a rate that is close to the MIC (minimum inhibitor concentration; sometimes this threshold level is reported as MEC - minimum effectiveness concentration). In that regard it is similar to having a controlled release rate in the formation. Thus, for an equal amount of chemical, the solid chemical has a longer expected life because of the low desorption rate. The reason has to do with the adsorption characteristics of the native formation versus a solid specifically selected for its absorbency qualities. Whereas the release rate of the liquid additive is determined by the flow rate of the produced fluids, the release rate of the adsorbed chemical is determined by the desorption characteristics of the solid. Lab and field data conclusively demonstrate the significant difference in the relative flow rates. These studies show the difference can be greater than one order of magnitude. In the case of a deep water well or a well that presents a logistical challenge for an intervention, an extension of one or two years before an intervention is required can have significant and beneficial impact on the cost of operations.

Statement of Theory and Definitions

The addition of a solid material to a proppant can affect the overall performance of the proppant. If the purpose of the proppant is to achieve and maintain a conduit for the flow of produced fluids, then the introduction of a solid chemical should not negatively affect the flow of those produced fluids. In order to assure that there is no harm done by this solid chemical, the system must be tested for crush and conductivity.

The adsorption of a liquid chemical onto a solid particle must be done so as to assure slow release (as opposed to no release or burst release, i.e. a high initial release upon contact with the solvent – oil or water). The product must show chemical inhibition capability after having gone through the manufacturing process. This is accomplished through a lab test called the pore volume displacement test. The solid inhibitor is mixed with sand and placed in packed column of known liquid volume space. The liquid volume of the column is a pore volume. Water or oil, depending on the inhibitor, is displaced through the column and the volume of fluid is measured. After a prescribed number of pore volumes a fluid sample is taken and measured for residual chemical inhibition efficacy. Figure 1 compares the scale inhibitor residual from 3 pore volume tests. It shows the significance drop in the residual value of the liquid chemical versus the two solid chemicals. The liquid chemical and chemical used in Solid Inhibitor 3 are the same chemistry.

In the fracture, the solid product must be added with the proppant at the prescribed rate in a continuous manner and at a steady rate. The objective of the addition rate is to assure equal distribution throughout the fracture. The efficiency of the inhibitor in the fracture is a function of the surface area exposed to the solvating fluid and the degree to which the solid has crushed under closure pressures. It is not sufficient to say that the average addition rate was 2% by weight of proppant. If that average had a rate deviation as high as 5-10%, then the integrity of the job could be compromised. It is theorized that high addition rates will result in crush and fines generation that will negatively impact conductivity and will expose more particle surface area that could result in a higher than expected desorption rate. It should be noted that all of the products described herein use the same inert substrate as the solid particle. There has been no observation of any physical characteristic difference between the scale, paraffin and asphaltene solid inhibitors when exposed to the crush and conductivity testing. In the charts and graphs supporting this paper the crush and conductivity data may refer to results for the scale inhibitor. That is only because the early work was done when that was the only commercial product. Subsequent comparative tests show no physical response differences as a function of what particular chemical is adsorbed onto the substrate. The solid is inert and retains its size and shape for the life of the well. In that respect the solid substrate is similar to the proppant used in the fracture. Figure 2 shows the results of a crush test run at four different closure pressures. As expected the percent of fines increases as the pressure increases. Figures 3-6 show the conductivity and permeability results for the solid product added at 1% and 2% by weight of proppant.

Once the product has been placed and the well is on production it is necessary to take regular samples in order to test the efficacy of the product as an inhibitor. For the scale inhibitor the residual is measured as a function of phosphorous in the water. For the paraffin inhibitor the residual is measured against an untreated sample in a comparative test in a cold-finger test. For the asphaltene inhibitor the residual is measured against a blank in a forced aliphatic solvent precipitation test.

There are two measures by which one can evaluate the value of a solid inhibitor placement. Both have merit and relevance to an operator. These are length of time and cumulative treated production. The treatment period has relevance from the standpoint of daily well operations and chemical program maintenance. In the case of the sixteen Appalachian wells shown in Table 2 the length of treatment carried more importance than the cumulative barrels of water treated. These wells are in remote locations and are not visited on a regular basis by the field pumpers. For a traditional continuous, surface scale inhibitor application each well would require a containment basin, a chemical tank, a pump, a power supply system and tubing to feed the chemical from the pump to the well. Such a system requires regular and frequent oversight. If such a well site is only visited once a week, and if a pump was off for a week due to a mechanical problem, then the well would not receive the critical scale inhibitor treatment. Scenarios such as this would lead to an increase in the well failure rate and to an increase in operational expense.

For the Appalachian wells the solid scale inhibitor provides long term (5 years and counting) scale inhibition and eliminates the need for frequent well site inspection and program maintenance. Maintenance consists of collecting a water sample on a regular basis so that the water can be analyzed for scale inhibitor residual and reported to the customer.

The focus on cumulative water is most important for operations where a surface treatment is impractical, where scale forms at the perforations, where the cost of a surface program is higher than the solid treatment, and/or in a case where the cost of intervention is high. In Table 2, the California wells are an example of scale forming at the near well bore such that chemical from a traditional surface treatment could not inhibit scale formation. In these wells the operator has reported anecdotal information where it appears that the wells treated with the solid product see higher production than the comparable offset wells without the solid inhibitor added to the fractures. The supposition is that the chemical is inhibiting the formation of scale in the formation and at the near well bore such that the permeability is better than for wells that do not see the inhibitor at the near well bore.

The two deep water wells shown in Table 2 are cases where the high cost of an intervention made it financially beneficial to spend the extra money on the solid inhibitor at the time of the frac pack in order to extend the period of time before an intervention was required. In this case the high cost of a deep water rig mobilization for an acid job was cost prohibitive when compared to the solid inhibitor alternative. The operator for the GOM Well 1 (see Table 2) reported that the well had produced a total of 3.5 million bbls of water as of June 2010. Although our inhibitor residual data shows an undetectable level of scale inhibitor residual after 2.0 million bbls the well has continued to produce without a scaling incident. The water production that has occurred after the residual reading was undetectable is not an indication of the scale inhibitor continuing to work, but it may indicate that the water chemistry, temperature or pressure has changed so as to have reduced the scaling tendency from its original values to the present.

Description and Application of Equipment and Processes

The solid chemical description and application covers the following process: manufacturing, packaging & transportation, application and the residual inhibitor testing.

In order to manufacture a solid product from a liquid chemical and an inert solid carrier the liquid must be blended with the solid to assure thorough, consistent and complete adsorption of the chemical onto high surface area of the solid substrate. The solvent is removed. The result is a chemical-laden solid particle in which the entire chemical component is 100% active, i.e. all of the non-active material in the liquid chemical has been removed.

The product is packaged in 50 lb. bags for ease of shipment and handling. The package and the transportation methods must ensure that the product is not subject to degradation due to over-burdening that would result in premature crush. When the product arrives at its final destination the percentage of fines should not exceed the allowable limit as set by internal specifications.

The product is added as a dry additive to the fracture. The addition of dry ancillary products and chemicals is an accepted and normal practice in the hydraulic fracturing business. Since the addition of the product must be done at a prescribed rate (currently the weight percent to proppant is in the 1-2% range) the dry add equipment must be capable of adding the dry product at the prescribed rate throughout the fracture process. When the proppant rate increases the dry add rate needs to increase and vice versa when the proppant feed rate is reduced. At the end of the job the operator should be able to demonstrate that the dry product was fed within allowable feed rate tolerances throughout the process.

Once the product has been added and the fracture treatment is complete, the well goes onto production. It is at the point that the fracture fluid has completed its respective job, i.e. assure the placement of the proppant with minimal fluid leak off, and that the production chemical begins its job. Operators employ the solid inhibitor because they either know there will be deposition problems or because they suspect there will be problems and decide to take preventive measures. In either case the efficacy of the product needs to be measured. As stated above the samples (water and/or hydrocarbon) are collected at the well head and are sent to the lab for residual testing. Several residual test results over time will establish a residual trend for that particular application. The residual trend is the monitoring method for estimating the life of the chemical in that well.

Presentation of Data and Results

This section will present data from specific wells treated with either a solid scale inhibitor, solid paraffin inhibitor or solid asphaltene inhibitor.

Scale Inhibition: Previous SPE papers reported on the development of a chemical laden inert solid used for the inhibition of mineral scale in producing wells. Szymczak (2006) presented the initial findings on the scale inhibitor residuals from wells that had been fractured with the solid chemical blended with the proppant. At that time the two initial wells had been under production for approximately one year. In all only ten wells had been treated with this product up to this time. See Table 2 for a summary of the 26 wells treated with the solid scale inhibitor. These are the same wells reports earlier in Gupta (2008). Although these are only 26 out of over 2,000 wells that have been treated, they were chosen to provide continuity from a previous reporting and to allow the reader to compare the results from two years ago to the present.

In Gupta (2008) scale inhibitor residual data was presented from those two wells, fourteen other CBM wells, eight wells from California and two deep water Gulf of Mexico wells. At that time the two original CBM wells had been producing for over three years and still showed adequate scale residuals. The CBM wells had low water production rates. The California had water production in the 100 BWPD range. The two GOM wells produced 3500 BWPD. At that time all wells showed adequate scale inhibitor residuals.

This current paper includes an update on all of the twenty-six wells highlighted in Gupta (2008). All of the land wells (16 CBM and 8 California) are still producing, and, except for one well, still show acceptable inhibitor residual levels. None of the wells have had scale related failures. Although these are only a small sample of the more than 2,000 wells that have been treated using the product, we have updated the data to provide continuity from the previous reporting and to allow the reader to compare the results from two years ago to the present.

The sixteen CBM wells only produce approximately 5 BWPD. Thus for any particular solid scale inhibitor loading one would expect sufficient chemical for several years. The two wells first reported upon in Szymczak (2006) have now produced for over five years without incident. There is one anomaly in the data. Appalachia Well #4 shows the scale inhibitor residual to be below the detectable limit. There is nothing out of the ordinary about this well. Also there have been no scale related issues with the well. This is one of the earlier wells (fractured in September 2005). The operator has indicated there may have been an issue with the fracture such that not all of the solid inhibitor may have been placed where it was intended. For now this well is viewed as an anomaly and not as an indication of a trend towards accelerated inhibitor depletion. Based on a mass balance calculation these wells should have scale inhibition for well over ten years.

The eight California wells produce in the range of 40-130 BWPD. They have been producing for over four years and show cumulative water production in the range of 50,000 to 200,000 bbls. Based on a mass balance calculation these wells should have scale inhibition for up to seven years depending on the initial loading.

As reported in Gupta (2008), the two deep water Gulf of Mexico wells (Well #1 and #2) had produced cumulative water totals of approximately 1.4 and .8 million barrels, respectively. The most recent data presented in Table 2 shows that Well #1 has produced in excess of 2 million bbls of water. Well #2 has been shut in and has not produced an appreciable amount more than in 2008. For Figure 7 is graph of Well #1 plotting the scale inhibitor residual against the cumulative water production. Somewhere between 1.4 and 2.4 million bbls of water the scale residual dropped below the detectable limit. By extrapolating the intersection of the residual curve with the MIC line at 1 ppm it appears that the cumulative water production at that time was approximately 2.0 million barrels. One can not say conclusively that the scale inhibitor had any residual effectiveness during this time, but there are no reports of scale related well problems. (Note: in Table 2 of SPE 115655 the initial production dates of GOM 1 & 2 was given as 4/26/07. It was actually 4/27/06)

Paraffin Inhibition: In Smith (2009) data for Well B 13 was presented along with four other wells in the Permian Basin that were fractured with the solid paraffin inhibitor particle. The cumulative oil production for Well B 13 is shown in Figure 8. Crude samples from this well were periodically gathered and tested. The test was a comparative pour point test in which the treated sample was compared against the blank. Because of the chemical nature of the paraffin inhibitor it is difficult to analyze for this organic molecule in a crude oil. That is why a comparative performance method is used. For 29 months the treated sample showed a pour point markedly better than the blank. Starting with a sample gathered in month 29 there was little difference between the treated and untreated samples. It was determined that the paraffin inhibitor had desorbed to a point where it no longer provided paraffin inhibition. Once notified the operator made provisions to use other means to inhibit the produced paraffin.

Asphaltene Dispersion: To date less than five wells have been fractured using the solid asphaltene dispersant product. Of these only one has produced for an appreciable amount of time. This is the first public reporting of data from a well treated with the solid asphaltene dispersant. The subject well is a deep water well in the Gulf of Mexico. It is labeled Well 6460. Figure 9 shows the production data and asphaltene residual data for this well. It produces approximately 3100 BOPD. Over six months it has produced 500,000 bbls of oil. During that time six oil samples were collected and analyzed for the percent asphaltene in the crude. Because the dispersant used for the solid asphaltene product is an organic it is difficult to analyze for the presence of the particular dispersant molecule. For that reason the estimate of residual life for the solid product is based on an indirect method, i.e. forced precipitation of the asphaltene using an aliphatic solvent. The supposition is that if there is asphaltene presenting the crude sample then the asphaltene did not deposit in the well. Of course, this is not a guarantee that deposition is not occurring. That why it is important to establish a trend line and to check with the operator regarding well production and pressure changes. The trend line together with well reports can give some degree of assurance that asphaltene deposition has been mitigated. This is the same approach one is forced to use for a continuous application of an asphaltene dispersant. Work is planned to come up with an analytical method by which a positive identification of the asphaltene dispersant could be made.

Conclusions

Over 2000 wells have been fractured with a solid chemical inhibitor blended into the proppant. Of these, over 90% have used the solid scale inhibitor. The remaining 10% are made of up paraffin and asphaltene applications. In order to qualify as a bona fide additive the solid product must pass certain tests. These include tests related to the fracture fluid, i.e. rheological compatibility, crush and conductivity. The product must also pass performance tests, i.e. a low desorption rate from the inert solid matrix and performance in the system as an inhibitor. The evidence shown in this paper and in earlier related papers substantiates the viability and performance of this chemical technology.

There is only one occasion in the life of a well where it is desirable to add copious amounts of water. That is during the fracture. The development and use of these solid inhibitors takes advantage of that one time injection of water. Using the water and proppant as a delivery system the products are placed deep in the formation. Based on the production volume of the well these inhibitors can provide protection from organic and inorganic deposition for years. In turn an operator is presented with a technology that can prevent or delay the need for a costly intervention to remove scale, paraffin or asphaltenes. By saving on work over costs that operator has more funds available to develop new fields and increase reserves.

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Tables

Table 1: Longest Run Time & Highest Cumulative Production for Solid Inhibitors		
Solid Inhibitor	Longest Period in the Ground	Highest Cumulative Treated Production
Scale	60 Months for Wells in Appalachia	Approximately 2,000,000 bbls water in Deep Water GOM Well
Paraffin	29 Months for Well B 13 in Permian Basin	Approximately 40,000 bbls oil for Well B 13 in Permian Basin
Asphaltene	6 Months for Well 6460 in Deep Water GOM	Approximately 500,000 bbls Oil for Well 6460 in Deep Water GOM

**Table 2: Solid Scale Inhibitor Loading for 26 Treated Wells
Sorted by Cumulative Bbls of Water Produced**

Well Location	Well Reference	Initial Production Date	Latest Sample Date	Months in Ground	Latest Inhibitor Residual (ppm) below MIC	Pounds Solid Inhibitor in Frac	BWPD	Cumulative Bbls Water Produced
GOM	1	4/27/2006	10/4/2009	41	below MIC	62	2781	2,441,769
GOM	2	4/27/2006	3/26/2008	23	3.9	74	2158	712,303
California	8	6/1/2006	5/19/2010	48	1	460	135	192,780
California	1	9/6/2006	5/19/2010	44	6	495	134	178,622
California	3	9/6/2006	5/19/2010	44	3.9	450	112	149,296
California	2	9/6/2006	5/19/2010	44	4.8	450	106	141,298
California	5	12/1/2005	5/19/2010	54	2	200	83	133,464
California	4	12/1/2005	5/19/2010	54	2	200	67	107,736
California	7	7/6/2006	5/19/2010	46	3.2	970	57	79,401
California	6	12/1/2005	11/30/2009	48	3.5	200	39	56,121
Appalachia	1	5/23/2005	5/23/2010	60	11	800	5	8,700
Appalachia	2	5/24/2005	5/24/2010	60	20	800	5	7,630
Appalachia	3	9/30/2005	3/23/2010	54	6	550	5	8,065
Appalachia	4	9/30/2005	3/23/2010	54	below MIC	800	5	8,065
Appalachia	5	10/1/2005	3/23/2010	54	5	550	5	8,060
Appalachia	6	7/20/2006	3/23/2010	44	11	840	5	6,615
Appalachia	7	7/26/2006	3/23/2010	44	20	1520	5	6,585
Appalachia	9	8/24/2006	3/23/2010	43	10	1375	5	6,445
Appalachia	10	9/6/2006	3/23/2010	43	15	880	5	6,385
Appalachia	11	9/27/2006	3/23/2010	42	9	1100	5	6,280
Appalachia	12	11/3/2006	3/23/2010	41	3	1580	5	6,100
Appalachia	13	11/6/2006	3/23/2010	41	21	1225	5	6,085
Appalachia	14	1/15/2007	3/23/2010	38	15	1580	5	5,740
Appalachia	15	2/2/2007	3/23/2010	38	15	1750	5	5,655
Appalachia	16	2/21/2007	3/23/2010	37	12	624	5	5,560
Appalachia	8	8/16/2006	8/20/2009	36	10	1400	5	5,420

Figures

Figure 1

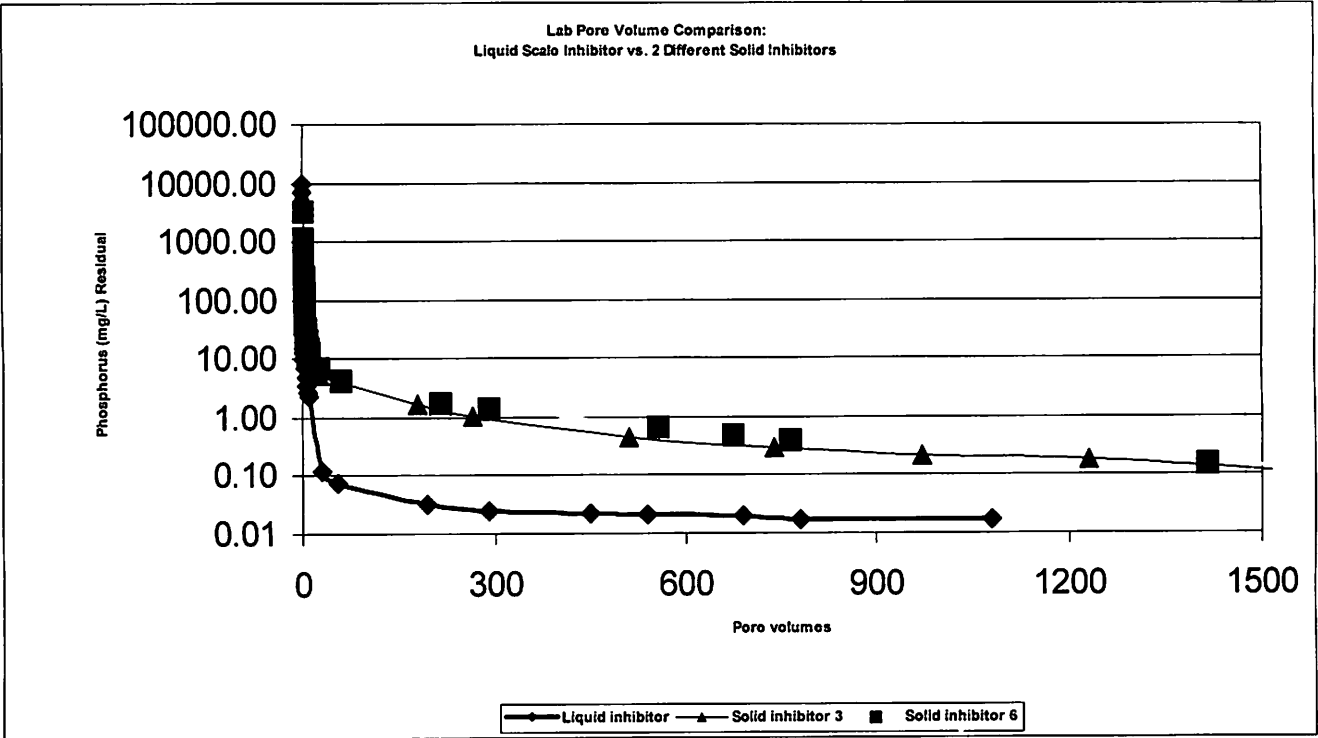


Figure 2

CRUSH DATA - 20/40 CARBOHSP + SOLID SCALE INHIBITOR

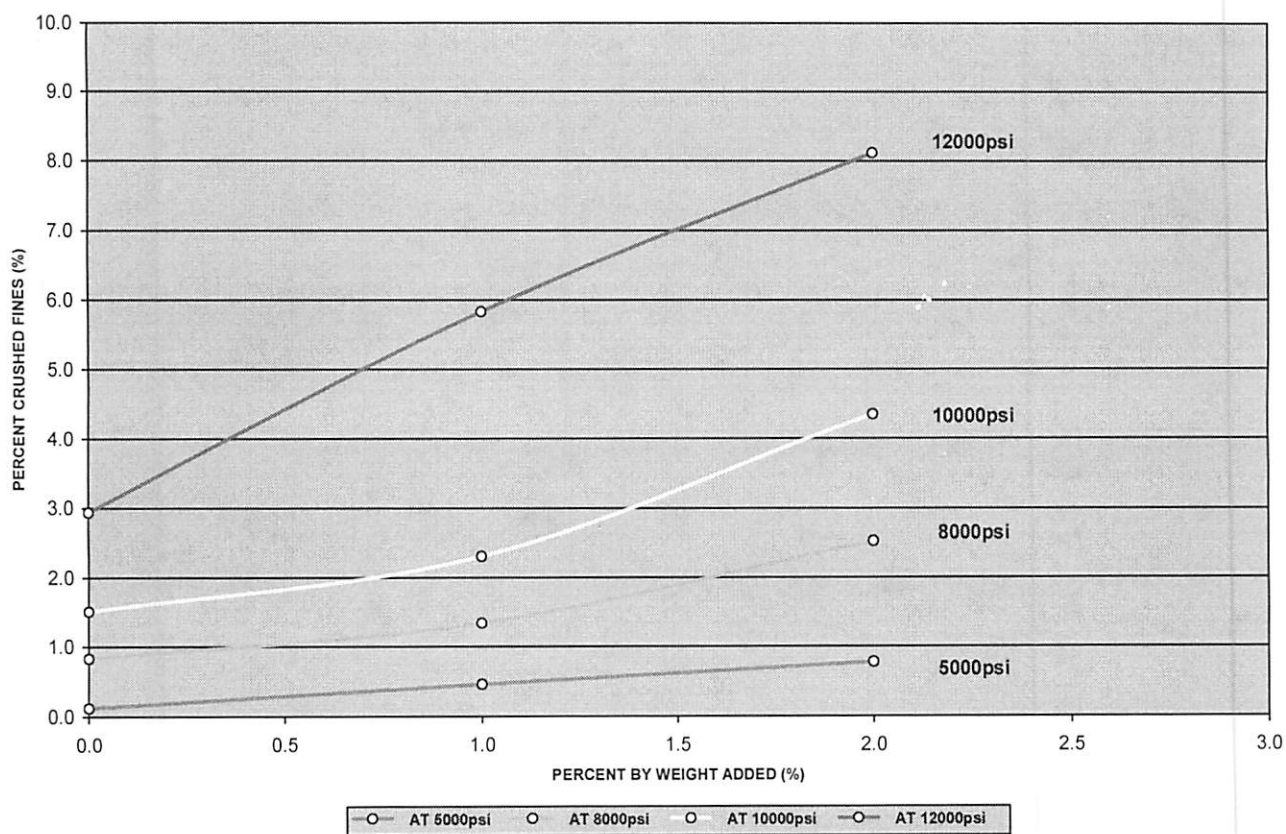


Figure 3: CONDUCTIVITY DATA FOR 20/40 Proppant
+ 1% by weight scale inhibitor composite at 250F and 2lb/sqft

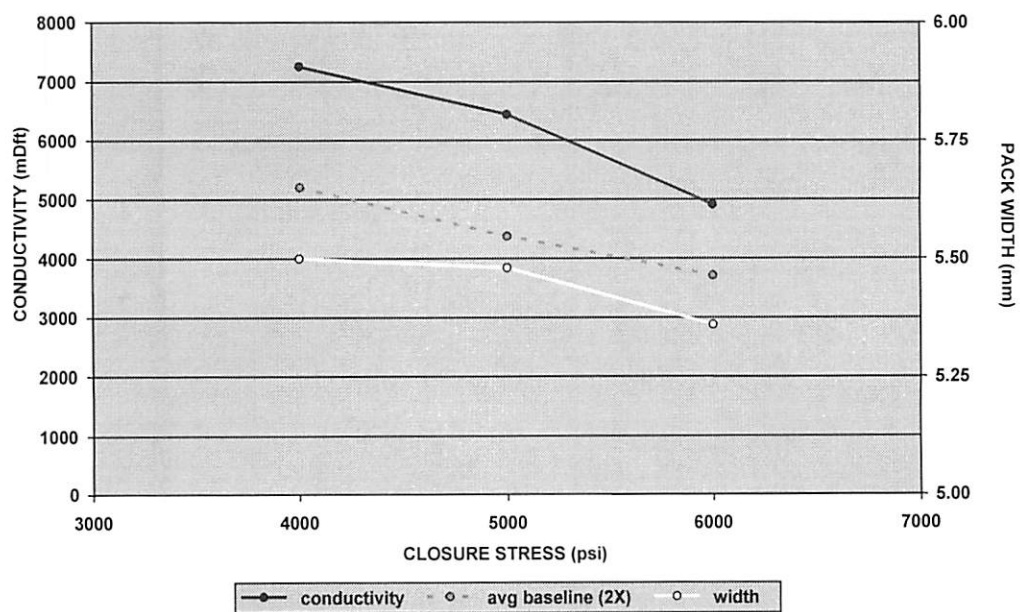


Figure 4: PERMEABILITY DATA FOR 20/40 Proppant
+ 1% by weight scale inhibitor composite at 250F and 2lb/sqft

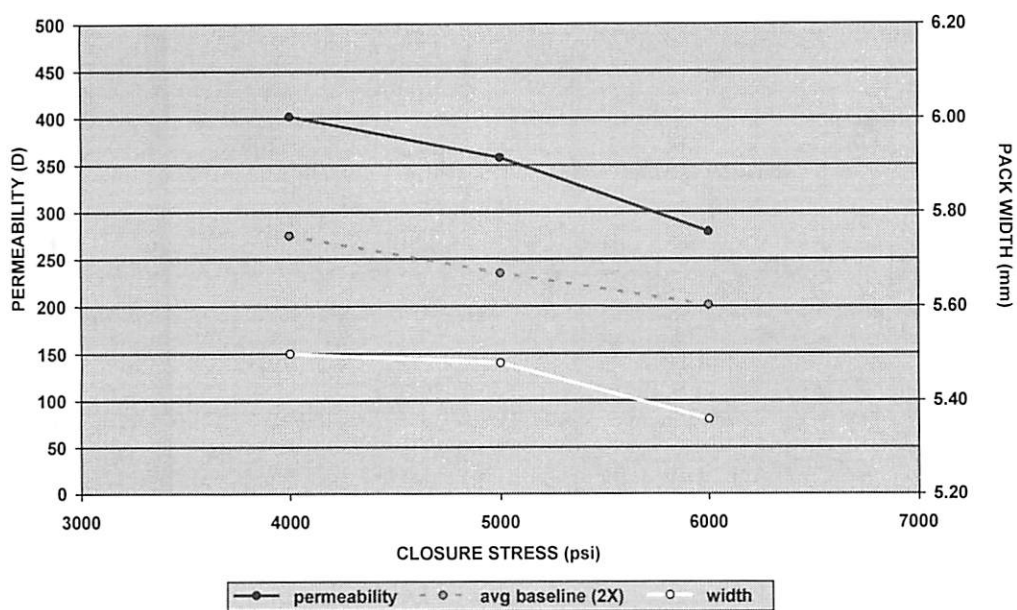


Figure 5: CONDUCTIVITY DATA FOR 20/40 Proppant
+ 2% by weight scale inhibitor composite at 250F and 2lb/sqft

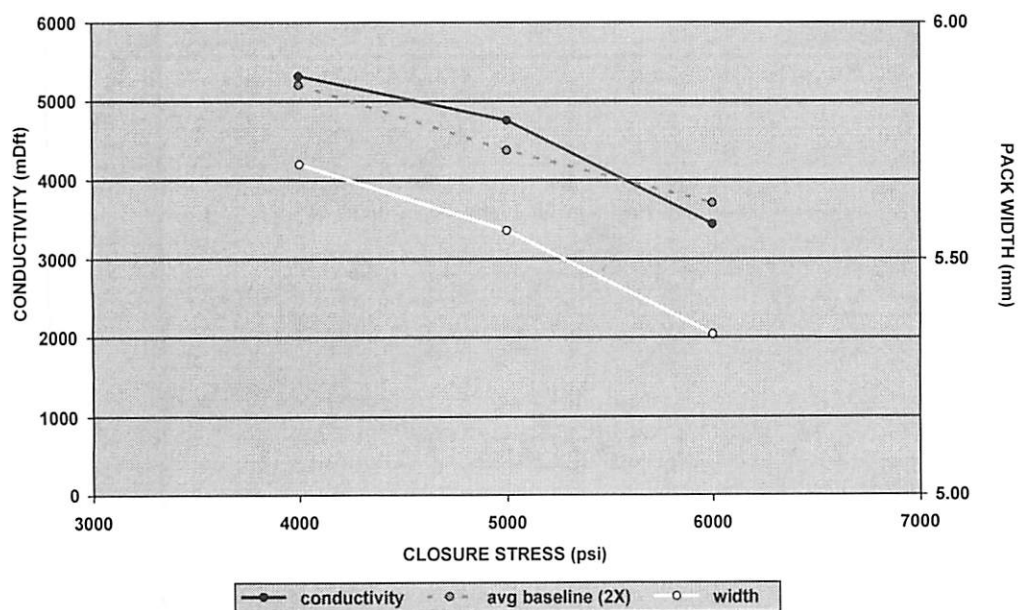


Figure 6: PERMEABILITY DATA FOR 20/40 Proppant
+ 2% by weight scale inhibitor composite at 250F and 2lb/sqft

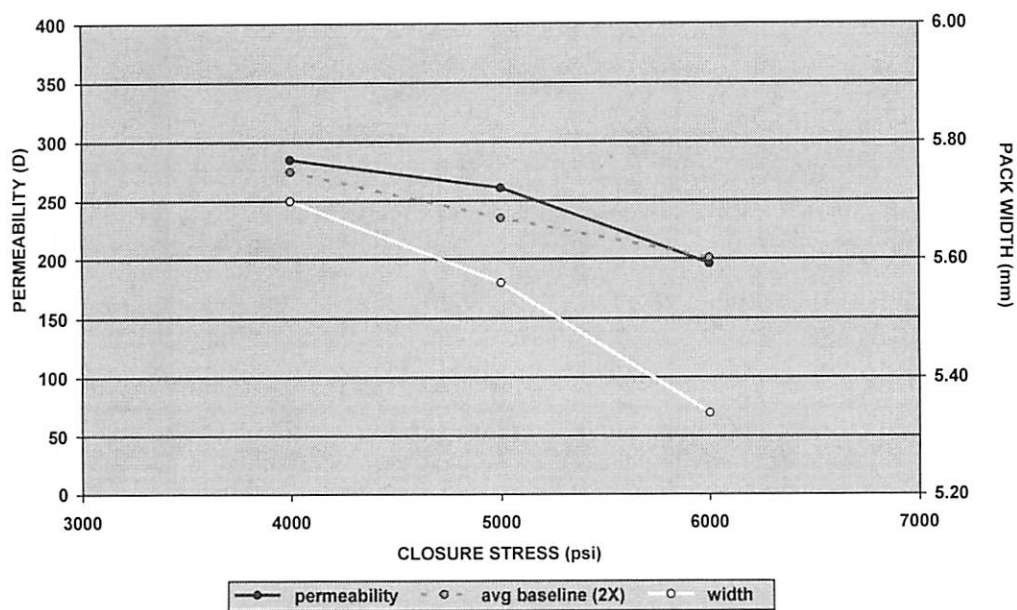


Figure 7

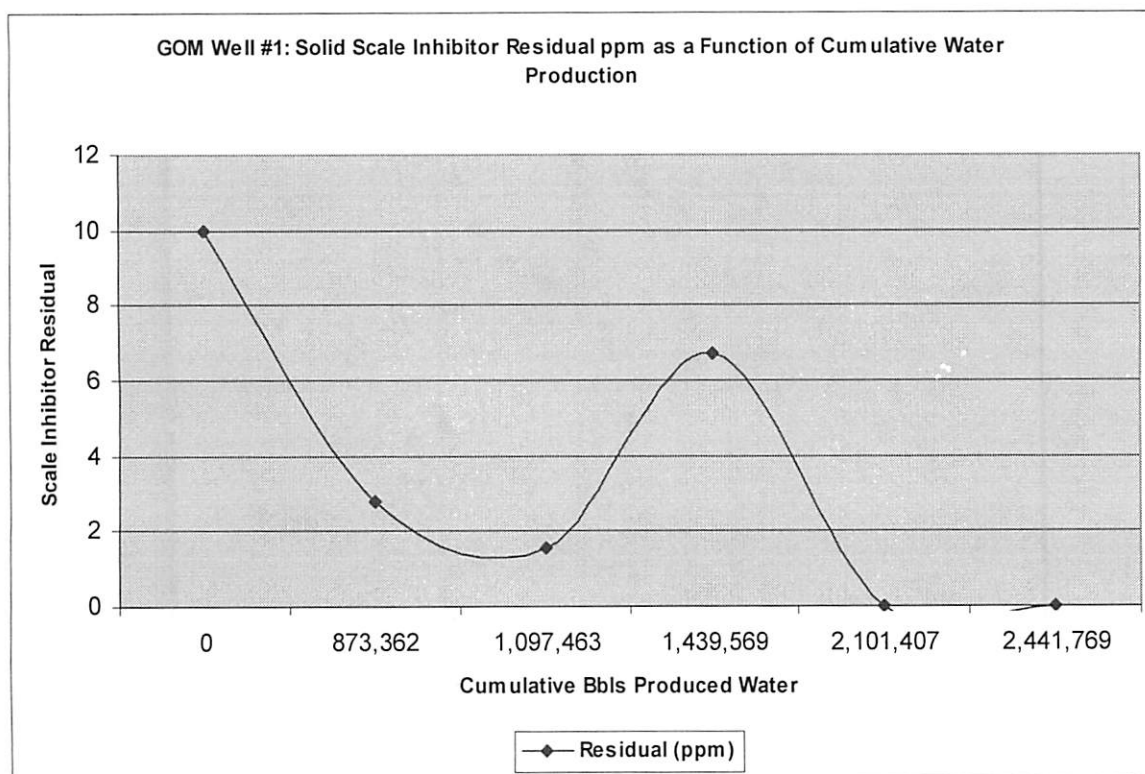


Figure 8

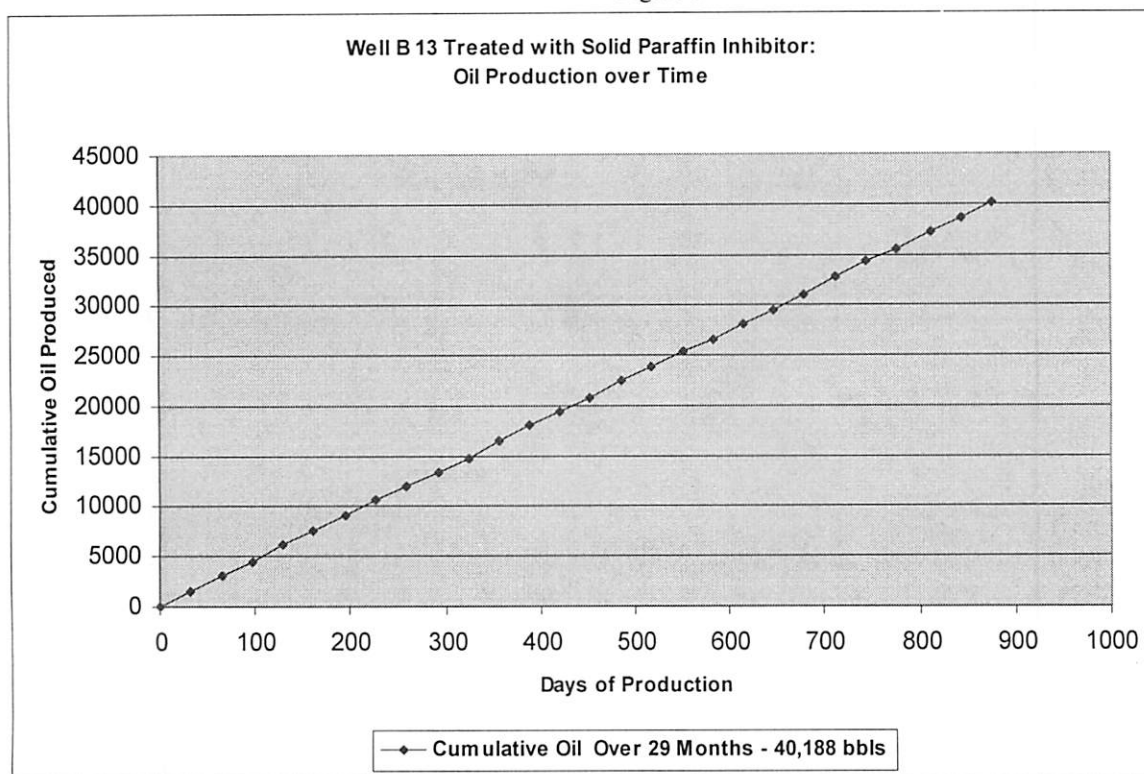
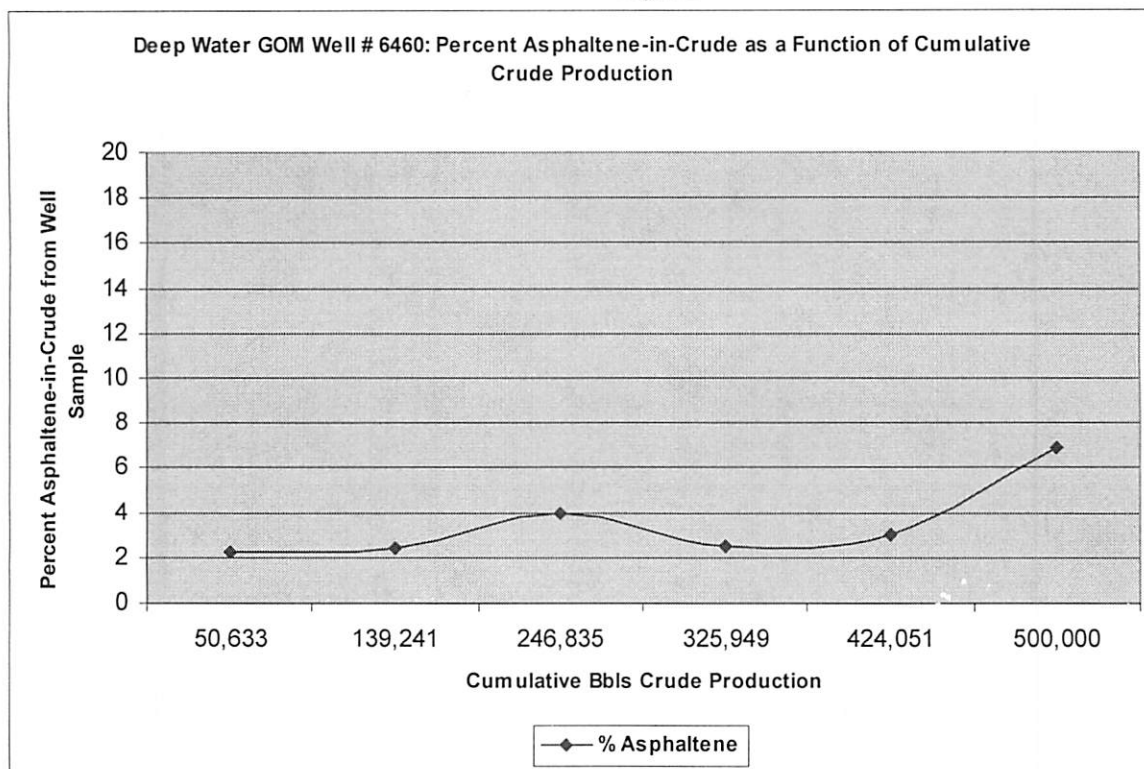


Figure 9





SPE 107993

Optimization of a Scale Treatment in the Uinta Basin—A Case History

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Abstract

The precipitation and accumulation of scale deposits is a major concern for production companies in the Uinta Basin. Since 2003, conventional hydraulic fracturing treatments with scale inhibitor pumped simultaneously as an additive have been offered to this region. This service proved to be very effective in the Permian Basin using borate crosslinked fracturing treatments (with scale inhibitor concentrations as low as 5 gal/mgal). However, these design criteria and formulation of the scale treatments had to be changed significantly to be effective in the typical Uinta Basin gas well environment: low permeability (<0.1 md), multi-layered, commingled gas reservoirs. Typically, a well completed and placed on production without any scale inhibitor in the Uinta Basin may show signs of scale buildup in as little as 30 days. The effects of the scale accumulation can be seen everywhere from an exaggerated production decline to scale deposition on production equipment. This paper outlines the learning procedure and present designs, testing and monitoring results from scale treatments together with a case study from the Uinta Basin.

Introduction

The purpose of a scale inhibition treatment is to prevent the formation of inorganic scale deposits such as sulphate and carbonate scales throughout the production system. Typically, if formation water enters the production system, scaling can be initiated by the pressure/temperature drop or mixing of incompatible water fractions. This scale deposition yields to a variety of problems ranging from plugging the formation pores/proppant pack and perforations to the reduction of pipe diameters. Typical scale deposits found in the Uinta basin are shown in the **Figs. 1 and 2**. Scaling in the upper production system (tubing, surface facilities) can be easily controlled by the continuous injection of scale inhibitors. However, the prevention of scale at the reservoir level (such as reservoir

matrix, fracture surface and proppant filled fracture) is more challenging due to the lack of accessibility. To overcome this problem, a scale inhibitor squeeze treatment was developed to effectively place a scale inhibitor in the near wellbore region¹.

A variety of squeeze techniques for applying scale inhibitors during the stimulation process have been described in prior studies². It has been shown that most of the scale inhibitors studied were not compatible with the crosslinked fracturing fluid and this resulted in low gel strength even at inhibitor concentrations of 5 ppm or less. Therefore, the scale inhibitors in this study were introduced into the pre-pad of a fracturing job.

In a properly executed treatment the scale inhibitor should:

- cover the entire length of the propped fracture (as opposed to a squeeze treatment, which only penetrates into the critical matrix);
- have thermal stability at formation temperature and;
- have long lasting retention characteristics to ensure sufficient protection time.

The efficiency of a scale treatment can be estimated by the scale inhibitor return profile. When the inhibitor concentration is less than a certain threshold, the Minimum Inhibitor Concentration (MIC), the scale protection becomes ineffective and a retreatment is necessary. However, the task of predicting the treatment-life of an inhibitor squeeze is difficult in a multi-layered commingled system due to commingling of different water types and the challenges involved in the predictability of water production.

This paper presents the applications of a phosphino-polyacrylate scale inhibitor (PPASI) in the stimulation of multi zone gas wells. Specifically described is the monitoring of scale inhibitor return and the design optimization.

Geology

The major section of the Uinta Basin is located in northeastern Utah, with a small portion in northwest Colorado. This basin is a major depositional basin that subsided during late Cretaceous through Tertiary time, when the North Horn through Duchesne River Formations was deposited. The basin is bounded on the north by the Laramide east-trending Uinta uplift and the Uinta Basin boundary fault, on the east by the north-trending Douglas Creek arch, on the west by the Sevier north-trending Charleston-Nebo thrust (that extends into the basin) and on the south by the Laramide north-trending San Rafael and northwest-trending Uncompahgre uplifts. The basin is an asymmetrical syncline with the deepest end in the north central (Fig. 3).³

The majority of the study was focused on the Riverbend field and some analysis has also been done in the Natural Buttes field. This paper focuses on three major formations (Fig. 4): Wasatch (Porosity (ϕ_{avg}) = 11%, Water Saturation (S_w) = 55%, Avg Net = 90 ft), Mesaverde (ϕ_{avg} = 11%, S_w = 47%, Avg Net = 250 ft) and Blackhawk (ϕ_{avg} = 12%, S_w = 42%, Avg Net = 57 ft). Reservoir pore pressure gradients range from 0.46 psi/ft in the Wasatch to 0.56 psi/ft in the Blackhawk. Typical fracture gradients ranging from 0.7 to 0.95 psi/ft and Young's Moduli range from 3-7 million psi.³

Methodology and Design

When a model-based approach⁴ is utilized to not only predict water productive zones, but also to ensure that fracture growth into sands with high water saturations (and mobile water) is limited or prevented (through the development of a mechanical earth model), an optimization program can be implemented to design and effectively treat scale. The majority of this study focuses on scale treatment optimization using this methodology.

Fracturing treatment designs for the Uinta Basin largely employ gel loadings below 20 lbs/mgal for temperatures approaching 200°F (93°C). When a fracture fluid system is used at its upper temperature limit, significant gel degradation at these low gel loadings can be observed when an alien chemical is introduced that may interfere with the crosslink mechanism. This is true for the scale inhibitor studied, even though the same inhibitor is compatible with the same fracturing fluid system at higher gel loadings. Thus, inhibitor placement as well as concentration had to be modified.

Following a scale inhibitor placement treatment, the inhibitor flows-back with the produced water and its presence prevents the precipitation of scale. Analysis of inhibitor returns has shown fluctuations in the short-term readings, whereas a consistent trend is observed over the longer term (months). When the scale inhibitor returns are fluctuating, a good practice is to closely monitor the inhibitor returns for three consecutive months. Only if the inhibitor levels in the return are below the MIC for the three consecutive months, a new treatment should be considered. Besides estimation of the treatment life span, field monitoring is useful to optimize placement parameters such as shut-in periods, post flush volumes and adsorption mechanisms in wells with multiple zones. The dominant placement mechanism for the typical scale inhibitor is based on an adsorption process where the chemical is adsorbed on the rock matrix. Alternatively, a precipitation mechanism can be used for inhibitor placement which is believed by some authors to yield a longer lasting retention.⁵⁻⁹ In this case, the inhibitor reacts with an activator forming a gel glaze covering the formation and the proppant pack. This glaze aids in the retention especially for wells producing gas at high rates. Following a treatment, the initial production shows typically a high concentration of non reacted inhibitor returns. Later, the scale inhibitor returns are leveled indicating the release of the inhibitor controlled by its adsorption/desorption kinetics. Typical lifetimes of this fracture while treating for scale can range from several months to well over a year depending on factors such as water

production and precipitation and/or adsorption on the rock/proppant matrix.

Testing: Dynamic Tube Blocking Experiments. The Dynamic Tube Blocking Apparatus (DTBA) is shown schematically in Fig. 5.

The test procedure is described as follow: To avoid premature scaling of the water, a synthetic mixture of the scaling water was prepared by separating the salts in separate cation and anion fractions. The cation fraction was generated with chloride counter ions and the anion fraction was prepared with sodium counter ions. These waters were made up separately, filtered to 0.45 μ m and adjusted to the appropriate pH using sodium hydroxide and acetic acid. Tests were carried out at the stipulated pH upon mixing of the two brines. Anion and cation waters were pre-heated to the test temperature of 200°F and then pumped through a capillary (0.8 mm diameter) upon immediate co-mingling of the two solutions. A pressure increase indicates scale build-up on the interior surface of the coil, while pressure taps ahead of and behind the coil measure the differential pressure to ascertain when scale deposition has occurred. Scale inhibitor was added to a batch of anion solution to give a stock of anion brine with a high concentration of scale inhibitor. This stock was blended with pure anion solution to give the correct concentration of scale inhibitor in the combined water system after mixing with the cation solution. The inhibited water was flowed through the dynamic loop and the concentration of scale inhibitor was then decreased until control of scaling was lost. The dynamic efficiency test cannot exactly reproduce field conditions, and is, at best, a semi-quantitative technique. It does, however, allow relative comparison of inhibitor performance, and provides an approximation of the likely MIC required for the chemical in the field.

Scale Monitoring. Two methods were used to monitor the scale inhibitor returns: A spectro-photometric procedure analyzing the polyacrylate content in PPASI utilizing a transmissibility change as a function of the PPASI content. The major advantage of this method is that it requires relatively simple analytical equipment. The second method uses Inductive Coupled Plasma (ICP) spectroscopy to selectively monitor the phosphor content in PPASI. The ICP testing is more accurate, but it requires complex equipment and therefore cannot be used in a field laboratory.

Placement. The observation of high fluid efficiencies and long closure times of the cross-linked systems, impact of the inhibitor of the fracturing fluid rheology and the use of rate-transient analysis methods^{4, 10} has lead to the introduction of the scale inhibitor in the pre-pad where the inhibitor is placed in a non-wall building inefficient fluid to ensure that the fracture face is in contact with the inhibitor and its effectiveness maximized. The inhibitor is added to the pre-pad stages in concentrations up to 18 gal/mgal. Of paramount importance is the analysis of the step-down diagnostics tests prior to the introduction of the scale inhibitor. In multi-layer treatments using limited entry techniques, large breakdown pressures may limit the effectiveness of the inhibitor treatment placement if careful designs are not applied. Most simulators

used in fracture simulation do not account for differences in initiation pressures when numerous sand bodies are stimulated. Geo-mechanics modeling with image log data to identify and model breakouts and drilling induced fractures together with drilling data has been incorporated successfully in some basins to predict large initiation pressures.

Production Evaluation. Production data was analyzed using a rate-transient based analysis for fractured wells to evaluate reservoir and fracture properties.¹⁰ This technique can be used to obtain quantitative estimates of the reservoir effective permeability, effective fracture half-length, and average fracture conductivity (provided certain flow regimes or limits of the flow regimes are exhibited in the production data) together with production history match. Generally, performing this kind of studies in the Uinta Basin is extremely challenging because of the multiple layer producing at the same time. However, when production logs are available, production allocation techniques using pressure traverse calculation that honor material balance are used to create a unique pressure and rate history for each individual zone. Individual transient for each reservoir unit/ flow unit is then created for rate-transient analysis. Once the estimates of fracture and reservoir parameters are obtained, a production history match is then performed on the individual stage and a commingled wellbore; then a multi-layer model is built to match the production history.

Results and Discussion

Experimental Testing. Four water samples were used to determine the MIC by Dynamic Tube Blocking testing. The representative water compositions of the tested samples are listed in Table 1. It is noted, that in the water samples 3 and 4 have additional 200 ppm Ba^{2+} and Sr^{2+} ions added to represent the worst case scenario. Water samples collected on the surface may not be representative, because some of the ions can be already removed by scaling. Also, the analysis of the scale residue as shown in Figs. 1 and 2 revealed the presence of calcium carbonate (CaCO_3) and barium sulfate (BaSO_4) scale in approximately 16:1 ratio. In a typical test procedure the blank times without the scale inhibitor were determined. Fig. 6 shows the differential pressure plots while flowing synthetic produced water 1 through the coil at 200°F (93°C) and with 894 ppm bicarbonate. Under these conditions, the average blank time was determined to be 66 minutes and so the scale inhibitor must prevent scale deposition (determined to be a rise in dp of 1 psi) for a period of 198 minutes (3 times the scale blank). The bicarbonate level was increased from 447 ppm to 894 ppm in order to achieve a blank time in a reasonable period of time. The exponential pressure curves generated during the blank stages are typical of scale formation within a narrow bore coil. Fig. 7 shows the differential pressure plots when synthetic Vernal produced water 1 with 894 ppm bicarbonate is forced through the coil at 200°F (93°C) with PPASI present. As the concentration of PPASI is dropped less than 0.5 ppm, scale control is lost resulting in an increase in differential pressure as scale is deposited within the coil. The MIC determined for PPASI using water 1 is therefore, 0.5 ppm. Given the higher level of

bicarbonate used to create any scale in the system, the MIC in the field for brine 1 will be less than 0.5 ppm.

The results of the DTBA test for all water samples are shown in Table 2. The results indicate the required MIC for the water samples 1 and 2 is 0.5 ppm and 1 ppm respectively. Water samples 3 and 4 with additional Barium and Strontium ions require a MIC of 40 ppm. They also represent the worst case scenario. Because analytical detection of the inhibitor below 5 ppm is difficult, a MIC of 5 ppm was proposed for the field monitoring

Field Monitoring. The typical effluent profile of the scale inhibitor in a treated multiple-zone well is shown in Fig. 8 using the spectro-photometric analytical method. The results are showing the fluctuations of the inhibitor returns. The MIC concentration dropped for three months from 4 ppm to slightly above 1 ppm before finally returning to 4 ppm but no evidence of scale was observed. This observation confirms the practice of monitoring the inhibitor returns at least for three consecutive months.

A comparison of the sample analysis with the ICP method was performed and shown in Table 3. At scale inhibitor returns above 2 ppm both methods lead to similar results. However, at returns below 1 ppm, both methods show a significant deviation, which can be attributed to the analytical error or unidentified components in the produced water affecting the accuracy of the methods. Therefore, even if inhibitor returns below 1 ppm may provide efficient scale protection, the analytical detection of the inhibitor becomes unreliable. Protection times seen in the area using this method are well over one year.

Production Analysis. Exaggerated declines observed through decline-curve analysis (exponential decline) can be attributed to scale build-up observations from production logs across the perforation and through significant reduction in gas production through the observed perforations (Figs. 9, 10 and 11).

Early in the field development, six wells were completed without the use of a scale inhibitor. Scaling problems were recognized early through exaggerated production declines and subsequent intervention from production logs. Offset wells were selected for analysis based on well-location, geological-members, log data quality and availability of production log data. Offset well groups that were stimulated with and without scale protection were selected for comparison. Since a vast amount of pressure, rate, production log and single layer testing data is available and a model (petrophysical and mechanical) based approach was used in the field to calibrate models to data, uncertainty in matching the older scaled-up wells was reduced.

Case History. Offset wells that were completed in marine sands only (and that did not commingle the fluvial section of the well) were selected for comparison (Fig 9). Since a scale inhibitor was not introduced into "Well 1" scaling was evident early in the well's life. Scale was evident on the production log run after 65 days of production (Fig. 12). The observed differences between the open-hole and the cased-hole gamma ray indicate the build-up of a radioactive substance with time

(most likely BaSO₄ scale).

Rate-transient methods were used to analyze the pressure and rate data for the marine sand (generated using production log data and a pressure traverse calculation and material-balance calculation).^{4, 10} As is shown in Fig. 13, the well that was treated with scale inhibitor exhibited clear fracture flow regimes and a production history match was performed to determine fracture and reservoir properties (fracture half-length, conductivity, and permeability). The match on the offset, unprotected well was not as simple; no clear formation linear fracture-flow regimes were visible and thus fracture pressure history match results and bi-linear flow-regime results were used as estimates and bounds for the production history match. History match using analytical models (Fig. 14) could not match the entire production history and thus it is evident that conductivity, perforation tunnel size or permeability is changing as a function of time due to a damage mechanism like scale (evident from the production log analysis). The analytical history model match indicates that whether all initial fracture properties (conductivity and length) and reservoir parameters (permeability) remained the same throughout the 60 days, the decline typical of the red curve would be observed. Therefore, the presence of scale inhibitor yields in an extra 4 MMScf of gas after 60 days. Thus, if the scale deposition is modeled in the fracture (since the majority of the pressure drop will be across the fracture face), as conductivity reduction, then simulations indicate that the conductivity is halved in the fracture during this production period due to scale, see Table 4 and Fig 15.

Conclusions

Laboratory tests were used to determine an initial scale treatment strategy in the Uinta Basin. In addition, monitoring the inhibitor returns together with the production analysis is used to optimize the field treatment plan. Since production comparison amongst offset wells is a difficult task in multi-layered commingled systems (with fluvial and marine sequences), the incorporation of a calibrated petrophysical and mechanical model (that incorporates geological differences) is of importance to understand and detect the presence of scale in the development of a scale prevention program. The only two wells where the analytical model could not match the production decline are the wells in which the scale inhibitor was not used and scale was observed. This analysis has been confirmed by workovers done on these wells to remove the scale build up. The following conclusions can be drawn from the laboratory study and the production comparison case history:

- The Minimum Scale Inhibitor concentration was determined by dynamic tube blocking tests with field water samples. This method proved to be reliable in estimating the actual scale tendency under field conditions.
- Monitoring of the actual inhibitor returns confirmed the practice to observe the returns for at least three consecutive months prior to considering re-treatments.
- Sharper than normal declines (modeled with conductivity decline) were observed and quantified (in terms of

production loss) in unprotected wells.

- Production logs suggest scale at the perforations and possibly inside the fracture proppant pack.
- With time, scale will probably form in the tbg/csg/surface equipment.
- Scale growth in this area is fast (~60 days).
- Scale inhibitors have proven to be successful in delaying and in some cases preventing scaling problems.

Nomenclature

<i>csg</i>	= Casing
<i>dp</i>	= Differential pressure [psi]
<i>DTBA</i>	= Dynamic Tube Blocking Apparatus
<i>FG</i>	= Fracture gradient
<i>K</i>	= Permeability
<i>K_f^{rw}</i>	= Fracture conductivity [md*ft]
<i>K_x</i>	= Formation permeability [md]
<i>ICP</i>	= Inductive Coupled Plasma
<i>lb</i>	= Pounds
<i>md</i>	= Millidarcies
<i>mgal</i>	= Thousand gallons.
<i>MIC</i>	= Minimum Inhibitor Concentration
<i>MMScf</i>	= Million standard cubic feet
<i>PL</i>	= Production log
<i>PPASI</i>	= Phosphino-polyacrylate scale inhibitor
<i>P_{wf}</i>	= Bottomhole flowing pressure
<i>QAQC</i>	= Quality control, quality assurance
<i>S_w</i>	= Water saturation
<i>tbg</i>	= Tubing
<i>X_f</i>	= Fracture half length [ft]

Acknowledgments

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Ion	Water 1	Water 2	Water 3	Water 4
Unit	mg/l	mg/l	mg/l	mg/l
Na	8976.5	28214.4	3943	0
Ca	677	4169	160	321
Mg	67	50	0	0
K	61	600	0	0
Sr	52	143	252	342
Ba	42	21	242	221
Cl	15189	56593	6310	11131
SO ₄	17	4283	325	200
HCO ₃	447	0	244	366
pH	6.6	6.0	7.0	7.0

Table 1: Brine chemistry of the water samples used for the DTBA tests. 200 ppm of Ba and Sr were added to Water Samples 3 and 4.

Water Sample	PPASI-MIC [ppm]
1	<0.5
2	1
3	40
4	40

Table 2: Summary of MIC's determined by dynamic loop tests.

Produced Water Sample	Spectrophotometric Acrylate Testing [ppm]	ICP Testing [ppm]
1	2.73	2.42
2	2.56	2.28
3	0.6	1.37
4	0.6	1.72
Base line (Tap Water)	1	0.98

Table 3: Summary of scale inhibitor return analysis using produced water field samples

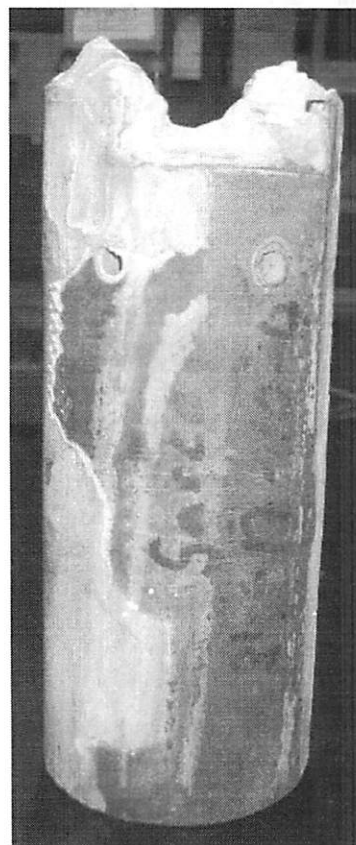


Fig. 1: Scale deposits typically found in the Uinta Basin.

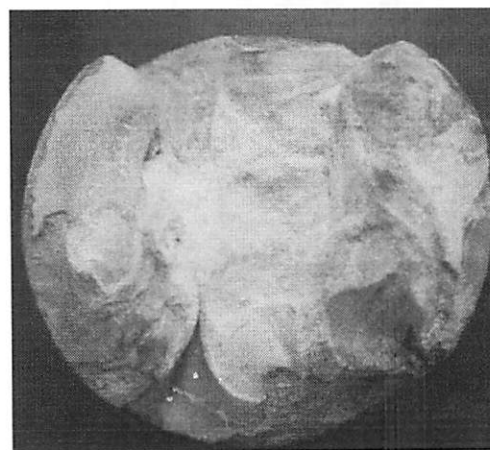


Fig. 2: Scale deposits typically found in the Uinta Basin (top view).

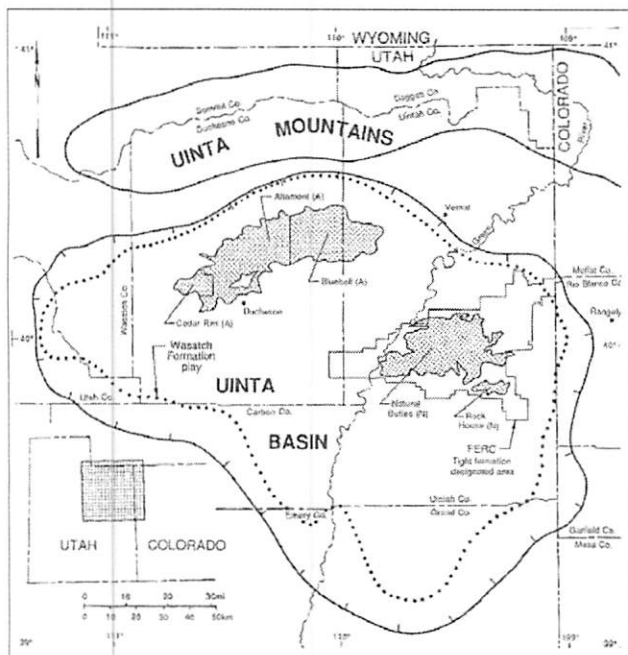


Fig. 3: Uinta Basin geology map.

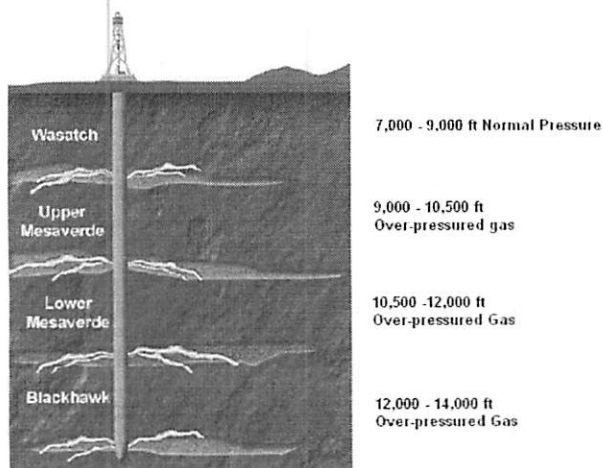


Fig. 4: Graphical representation of formation used in this study.

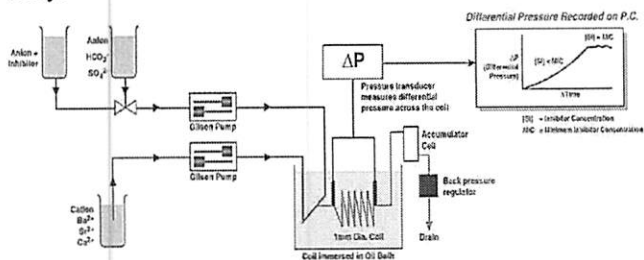


Figure 5: Schematic of Dynamic Tube Blocking Apparatus (DTBA) to determine the Minimum Inhibitor Concentration (MIC).

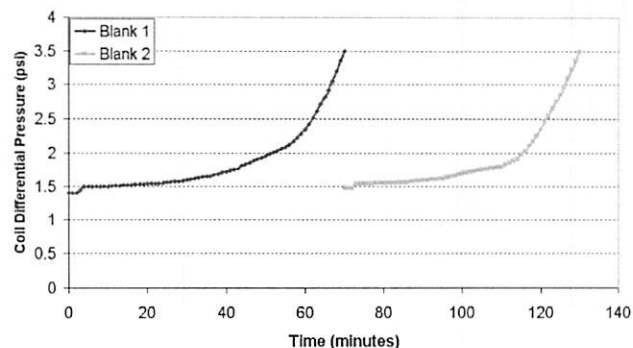


Fig. 6: Blank test with produced water.

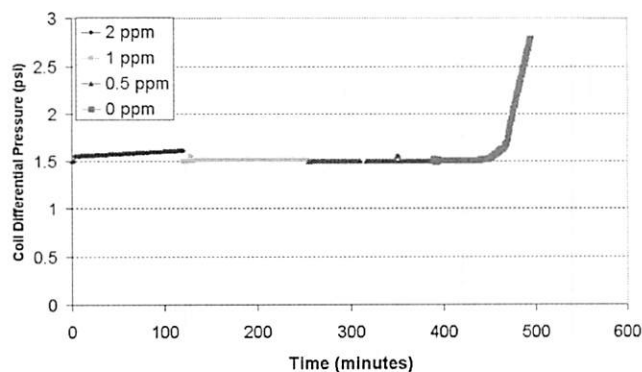


Fig. 7: Determination of the MIC with produced water. Below 0.5 ppm, scale control is lost as indicated by the increase of differential pressure.

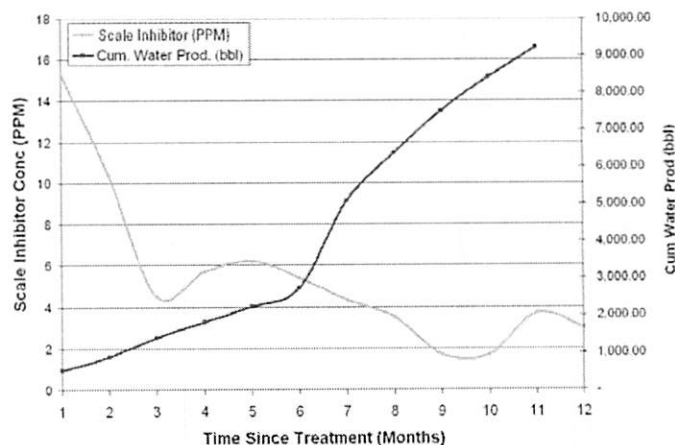


Fig. 8: Orange line: typical inhibitor flowback analysis [ppm]; Blue line: cumulative water production [bbl].

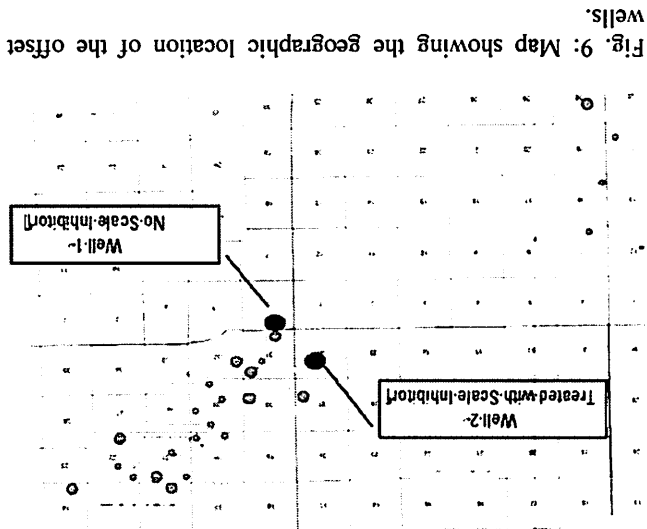


Fig. 9: Map showing the geographic location of the offset wells.

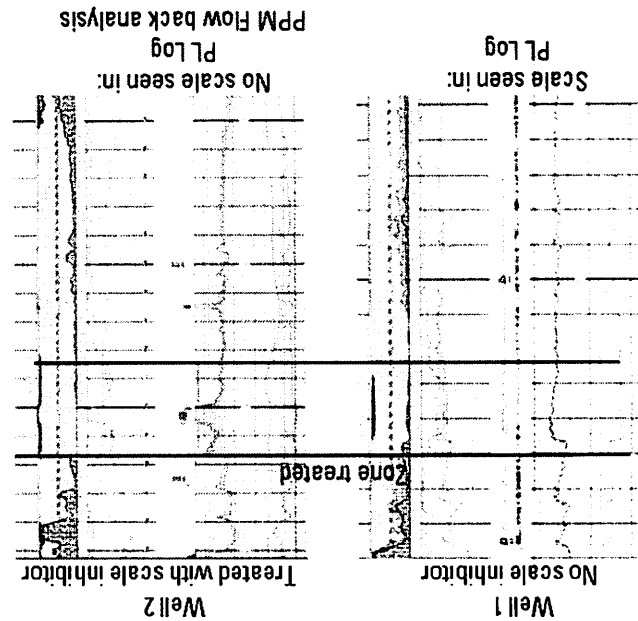


Fig. 10: Logs from the untreated and treated wells.

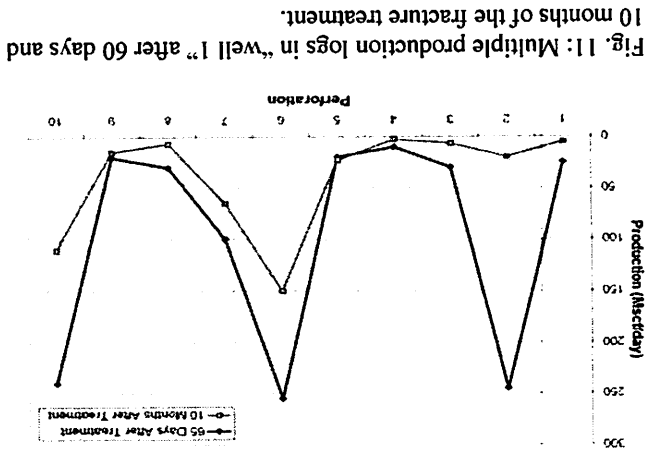


Fig. 11: Multiple production logs in "well 1" after 60 days and 10 months of the fracture treatment.

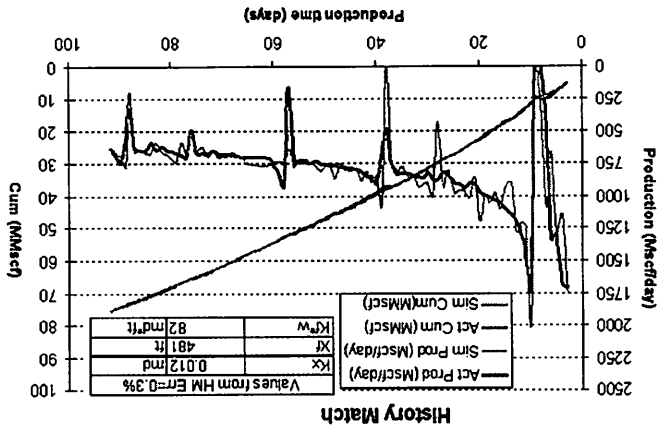


Fig. 12: Production log in the zone of interest after 65 days of production.

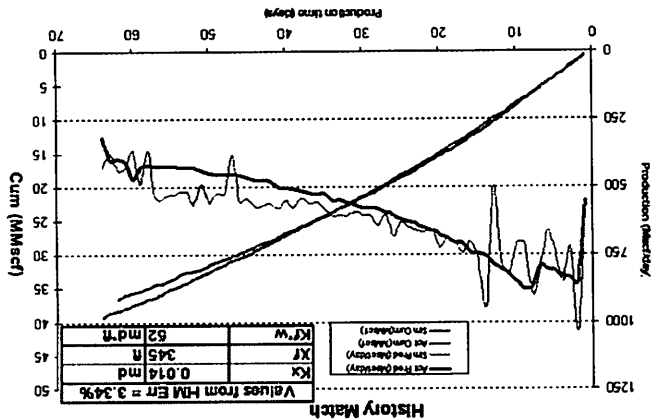
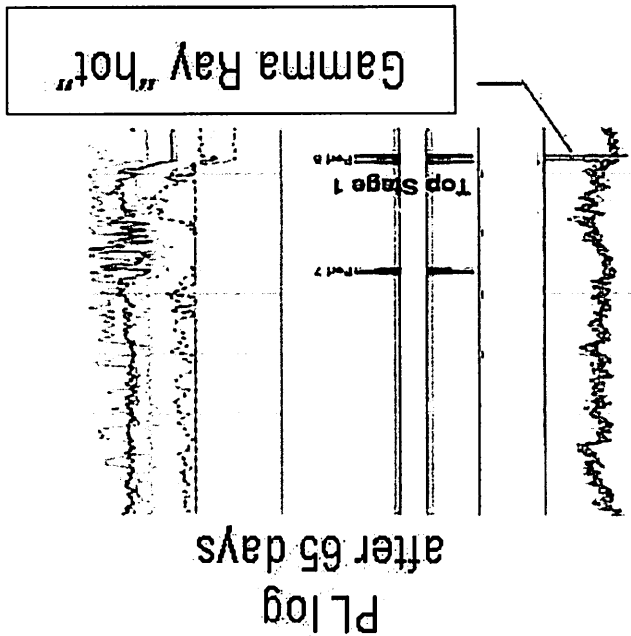


Fig. 13: Production history match for protected well.

Fig. 14: Production history match for the unprotected well.



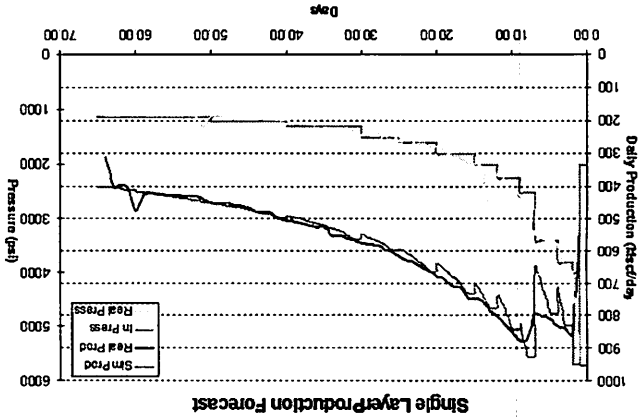


Fig. 15: Production overlay by matching bottomhole flowing pressure.

Time	Cond (md*fi)	Days	fi	md*fi
1	355	65		
2	355	65		
4	355	65		
6	355	65		
8	355	65		
10	355	65		
12	355	65		
15	355	65		
20	355	65		
25	345	65		
30	345	55		
40	345	42		
50	345	38		
60	345	32		
65	345	30		

Table 4: Conductivity used to match real production in Fig. 15. Fracture conductivity was reduced to half after 60 days of production.