Successful applications of continuous diversion during acid treatments in carbonate reservoirs

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Abstract

In offshore southern Mexico, production from limestone and dolomite formations derives from naturally fractured zones. During stimulation treatments, in addition to the reservoir's characteristics, the completion design can play a significant role in planning an effective acidification. A typical completion includes a large reservoir zone exposed from 80 to 140 m and sometimes can be near a water zone, meaning that the necessary distribution of the stimulation fluids into the net pay can be difficult, but not impossible.

Open hole logs are a useful diagnostic tool to identify the net pay zones throughout the long sections of exposed reservoir. With this basic information, it is possible to estimate the interval to be stimulated. In a naturally fractured reservoir, the implementation of chemical diversion is common; however, in cases of high conductivity, the use of in-sequence diversion steps, such as pumping two different systems, can improve diversion. Typically, one of the diverters is a controlled viscosity fluid and the other is a hydrophobically modified polymer (HMP).

In 2014, more than 35 wells have been treated with the presented acidizing technique, which has permitted the operator to perform effective acid stimulations. Due to the higher effectiveness of the treatments pumped, providing better diversion effects than those with just the use of an HMP diverter system, it was possible to stimulate other zones with permeability variation along the interval. Many of the wells evaluated resulted in a 50-fold increase of the oil production rate, showing, in some cases, reduced water cut and, in other cases, maintaining the water rate production.

This paper describes the learning curve to achieve increased production by combining two diverter methods during stimulation treatments, in high-pressure/high-temperature (HP/HT) offshore wells. This technique is widely used in marine region of Mexico, executing during the period 2020-2021, 72 wells with this diversion technique in different fields.

Keywords: Continuous diversion, carbonate, HP/HT, naturally fractured.

Aplicaciones exitosas de divergencia continua durante tratamientos ácidos en yacimientos de carbonato

Resumen

En el sur de México, las formaciones productoras son formaciones de caliza y dolomía naturalmente fracturadas. Durante los tratamientos de estimulación, además de las características del yacimiento, el diseño de la terminación puede desempeñar un papel importante en el diseño de una acidificación eficiente. Una terminación típica incluye una gran zona de yacimiento expuesta de 80 a 140 m y, a veces, puede estar cerca de una zona de agua, lo que significa que la distribución necesaria de los fluidos de estimulación en el espesor neto puede ser difícil, pero no imposible.

Los registros de agujero descubierto son una herramienta de diagnóstico muy útil para identificar las zonas de capacidad productiva neta en los largos tramos de yacimiento expuestos. Con esta información básica, es posible estimar el intervalo que debe estimularse. En un yacimiento naturalmente fracturado, la aplicación de la divergencia química es común; sin embargo, en casos de alta conductividad, el uso de divergencia en secuencia, como lo es el bombeo de dos sistemas diferentes, puede mejorar la colocación final de fluidos. Normalmente, uno de los desviadores es un fluido de viscosidad controlada y el otro es un polímero modificado hidrofóbicamente (HMP).

En 2014, se han tratado más de 35 pozos con esta técnica de divergencia en la acidificación, lo que ha permitido al operador realizar estimulaciones ácidas eficaces. Debido a los resultados de los tratamientos bombeados, donde se ha proporcionado mejores efectos de divergencia, que aquellos con el solo uso de un sistema desviador HMP, ha sido posible estimular otras zonas con variación de permeabilidad a lo largo del intervalo. En muchos de los pozos evaluados se consiguió multiplicar por 50 la tasa de producción de petróleo, mostrando, en algunos casos, una reducción del corte de agua y, en otros, el mantenimiento del gasto presente de producción de agua.

Este artículo presenta una nueva técnica de divergencia en tratamientos de estimulaciones para yacimientos naturalmente fracturados, permitiendo con ello, lograr que los sistemas ácidos y no ácidos, contacten nuevas zonas de la roca, y así una mayor longitud de estimulación en el intervalo a estimular y mejorando la productividad de los pozos. De igual manera, describe la curva de aprendizaje para lograr un aumento de la producción mediante la combinación de dos métodos de divergencia durante los tratamientos de estimulación, en pozos marinos de alta presión/alta temperatura (HP/HT). En el periodo de 2020 a 2021, fueron ejecutados 74 pozos con esta técnica de divergencia en la región marina de México en diversos campos del área.

Palabras claves: Divergencia continua, carbonato/dolomía, HP/HT, naturalmente fracturado

Introduction

The use of diversion in naturally fractured carbonates sometimes is considered a very difficult stimulation stage to achieve. However, after many field applications, a diverter combination has demonstrated that it is possible to redirect different acid stages during a stimulation treatment. One of the questions frequently asked is if it is necessary to add a diverter stage during a treatment, why is a separate diversion stage performed? It looks like a simple answer, but it depends on the variations that may be present in reservoir permeability, variations in reservoir pressure, skin due to specific damage, or if it is needed to avoid stimulating a specific zone (water), or combination of zones.

To apply any diversion, it is important to consider the factors that could affect the divergence. The most appropriate divergence method for a particular situation depends on many factors, including but not limited to the specific completion, shot density of perforations, the fluid type that was produced or injected after treatment, cement integrity, reservoir permeability and bottomhole pressure and temperature. For the cases in study in this paper from 2015-2017, the reservoir permeability of the fracture system is around 99 mD to 500 mD obtained from buildup test. More recently, in 2020-2021, the range of formation permeability of the case studies has been extended from 1 mD to more than 1 Darcy.

With that in mind, it is important to consider the types of diverters that are available in the market. The following are the most common systems used in the Gulf of Mexico marine operations:

- Viscous fluids
- Foams

And available for uncommon operations:

- Degradable particulate-diverting agents
- Ball sealers[1]

The subject of this paper is to present the alternative achieved when two chemical systems are combined, that become a viscous fluid solution using a relative permeability modifier and a fracturing fluid.

Experimental tests

As a first approach, the two diverters were tested with different protocols. The relative permeability modifier was evaluated to verify the restriction that an HMP system offers to water-based fluids. The experimental test consists in preparing a cylinder with 20/40 mesh sand at the top of the arrangement, **Figure 1**, and measuring the time to expend 10 ml of water, after which the HMP system is followed by water again. A restriction was observed in the flow of the final water stage after the HMP was placed in the sand pack. This system is adsorbed and changes the effective permeability of that zone. **Table 1** shows the results of the test.

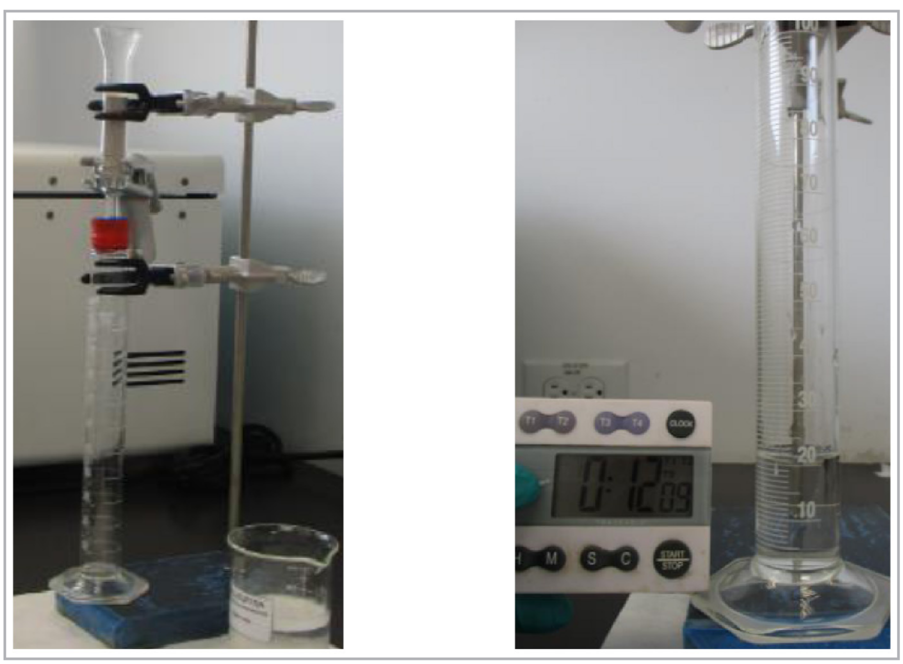

Figure 1. Arrangement to evaluate the transit time of HMP system.

Stage	System	Quantity (ml)	Temperature (°C)	Time (min:sec)
1	Water	10	25	2:21
2	HMP system	10	25	12:09
3	Water	10	25	4:44

Table 1. HMP system evaluation results.

The column test presented above, is the standard test to demonstrated how the HMP affects the subsequent aqueous fluid pumped, that in this case is the highly viscous fluid and acid stages, affecting the transit time from 12:09 minutes to 4:44 min in this case. In field cases, this temporally delay in the transit time (divergence effect) of the fluids through the zone treated, has been demonstrated with an increasing of surface and bottomhole pressure[2].

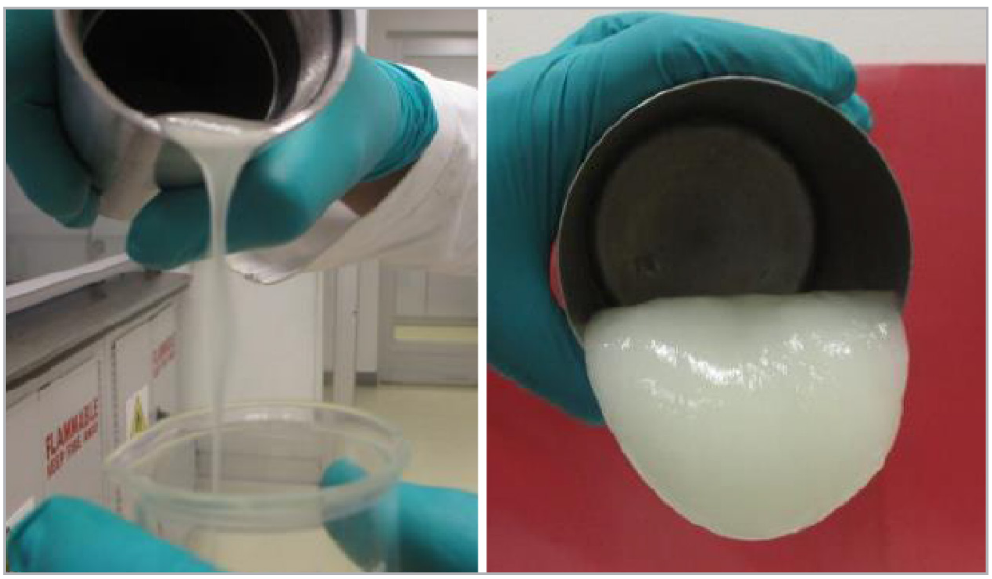

Figure 2. Highly viscous system (HVS) previous to activation (left) and after activation (~1500 cp viscosity), (right).

The second test performed was the fluid test, or rheological test evaluation, to verify the break time of the highly viscous system. The test was carried out at 120°C and 420 psi. Basically, the fluid is exposed to these conditions to activate it until it reaches a high viscosity (~1500 cp), **Figure 2**. This viscosity is maintained during a regulated time based on the fluid design, and after the pumping time the fluid is broken.

Figure 3 shows the rheological profile achieved with this design. It is important to verify the fluid behavior with this test because the action of this system is temporary, and it should be returned to a low viscosity to facilitate the final return flow after stimulation.

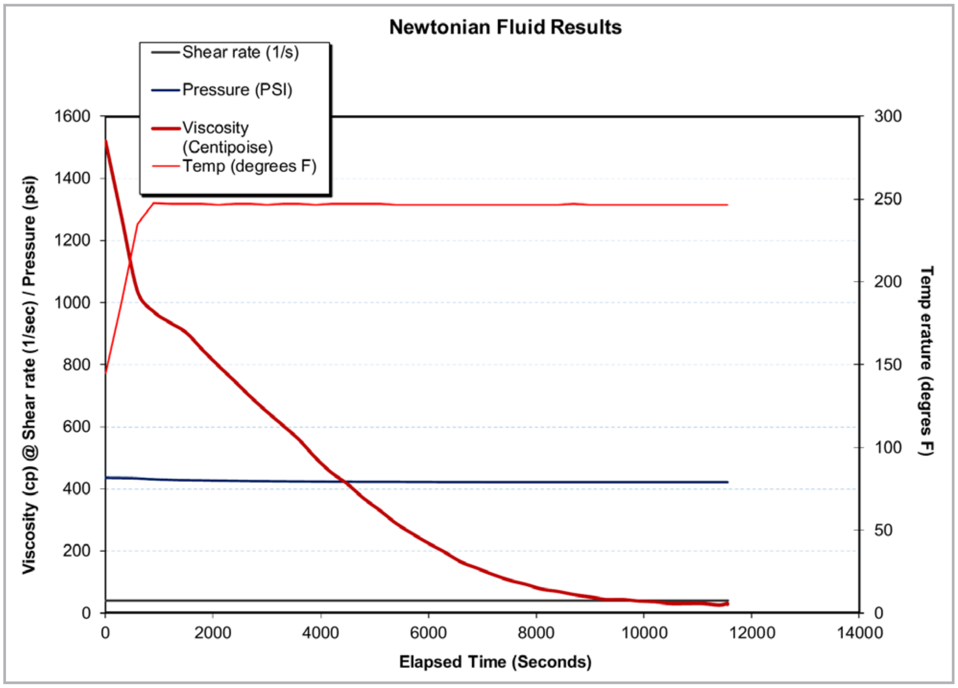

Figure 3. 25 #/Mgal highly viscous fluid control and break test control.

When these systems are combined, the results are a double chemical diversion acting to ensure selectively targeted new hydrocarbon-producing zones are acidized. The HMP system helps to divert the subsequent acid stage to other zones. In this case, the highly viscous fluid follows the HMP system during the stimulation sequence to help achieve a double diversion effect. **Figure 4** represents the effect of the HMP system. The polymer attaches to the surface of the rock as it enters the formation matrix by simple electrostatic attraction (black continuous line at the bottom). Once the polymer attached to the surface of the rock, it selectively reduces the permeability to water-based fluids (represented in gray dashed lines). The hydrophobic modification of the water-soluble polymer allows multiple layers of the polymer to build up because of the association of the hydrophobic groups[3] (circled red).

Figure 4. The hydrophobic modifications allow the polymer to build up because of the association of the hydrophobic groups, (SPE 165091)[3].

Field application

In 2014, a combination of chemical diverters was applied to enhance the stimulation of large-exposed sections in naturally fractured reservoirs. With the passage of time, it has been verified that the combination in-sequence of the two-divergent processes described, has resulted in an increase in production in more than 70% of the cases of the sample studied, which represents 36 study wells from 2015 to 2017, **Figure 5**. The 27% of the wells with no change in production were identifies common reservoir characteristics such as higher permeability more than 400 mD and BHT more than 160 °C. However, since 2020 there are field evidence than demonstrated that in wells with more than 1 Darcy it is possible to achieve an improvement in oil production post stimulation using this diversion technique, but it is not subject of this study. The following three relevant cases of the application of this technique in offshore wells located in the Bay of Campeche, Mexico, describe implementation of a stimulation pumping schedule with the sequence presented in **Table 2**.

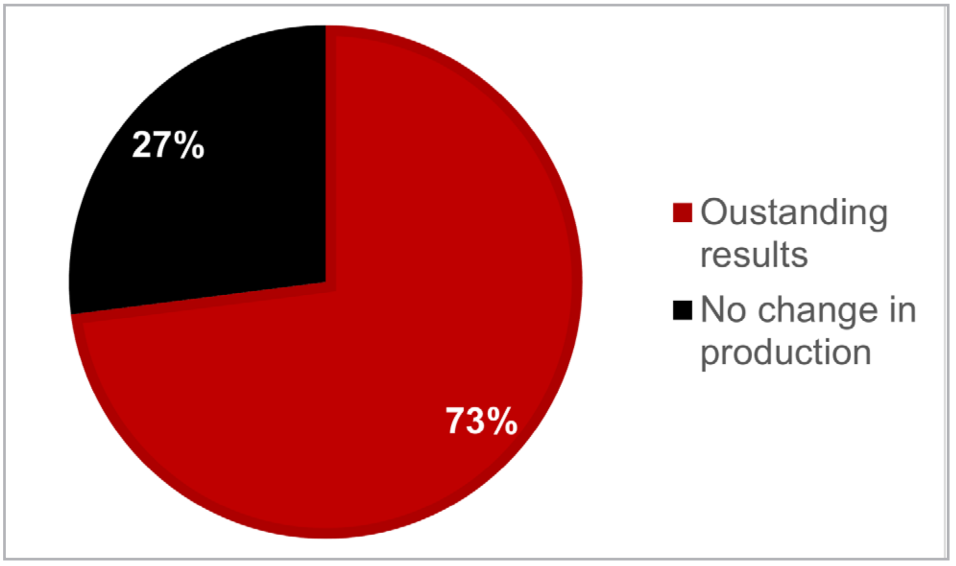

Figure 5. Combined Divergence Case Statistics, (2015-2017).

Stage	Fluid	Volume (m^3)
1	Solvent	20.0
2	Retarded Acid system 1	10.0
3	Retarded Acid system 2	8.0
4	HMP diverter	8.0
5	Highly viscous fluid	8.0
6	Retarded Acid system 1	15.0
7	Retarded Acid system 2	9.0
8	Solvent	14.0
9	Nitrogen (if needed)	2924

Table 2. Example of the pumping schedule.

During the period 2020-2021, more than 70 wells, were executed in marine region of Mexico. The **figure 6**, shows the volume ratio pumped in those wells using a 62% of the highly viscous fluid pumped versus 38% of HMP fluid, during the same stage of continuous diversion.

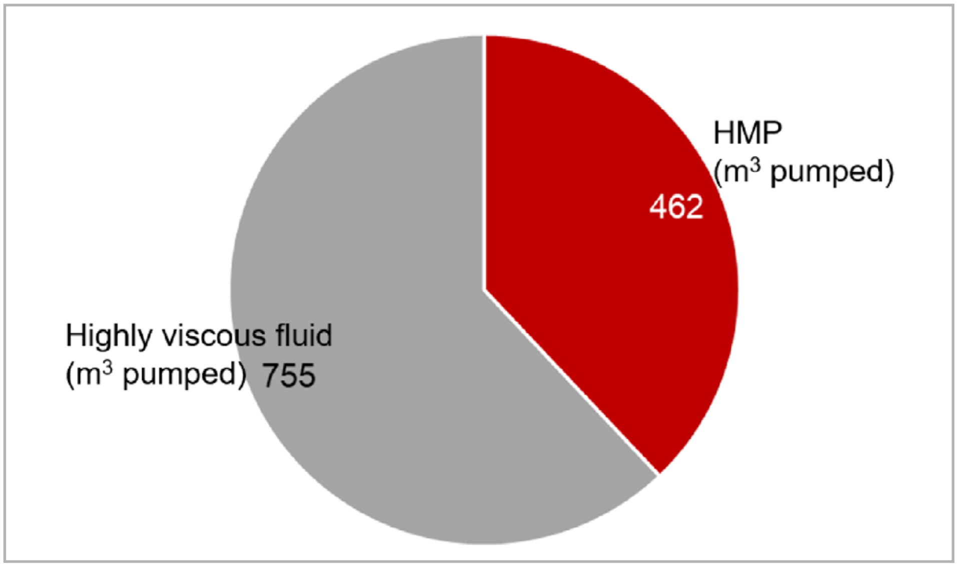

Figure 6. Combined Divergence Case Statistic, volume in cubic meters pumped (2020-2021).

Case 1. Well A

Well A is an oil well completed in a carbonate reservoir with a bottom-hole temperature (BHT) of 180ºC, porosity of 7.03%, water saturation of 11%, permeability of 213 md, reservoir pressure of 728 kg/cm^2, wellhead pressure of 400-500 kg/cm^2, gas oil ratio of 764 m^3/m^3. The completion was through a 5-in slotted liner, exposed to 100 meters of reservoir, **Figure 7**.

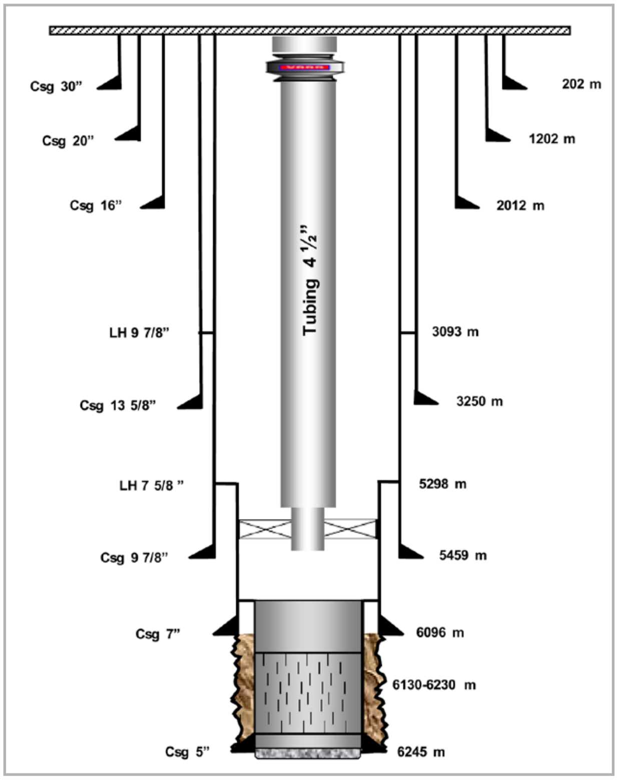

Figure 7. Well A schematic.

The acid job was executed using 118 m^3 of retarded acid systems, 60 m^3 of solvent system, 20 m^3 of HMP system, and 20 m^3 of highly viscous fluid. The pumping rate was from 7 to 17 bpm and the maximum treating pressure was 8,500 psi. Although it is difficult and inaccurate to verify the divergence effect with only the wellhead pressure, the data during the pumping of the stimulation in events 12 and 13 marked in the grey box of **Figure 8**, showed an increase in pressure from 2,900 to 4,700 psi observed during the arrival of the downhole divergence.

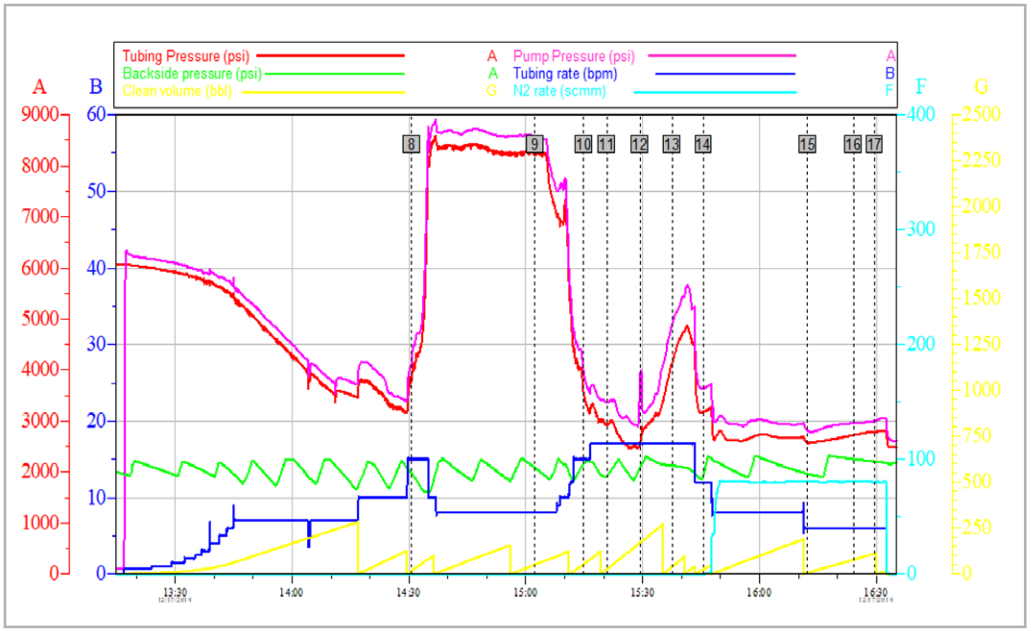

Figure 8. Treatment plot for Well A with HMP+highly viscous diverters.

Results

With this treatment, the production was enhanced from 3,600 bpd to 10,000 bpd. One of the keys of the success in this job was the in-sequence diversion with the HMP system and the highly viscous fluid to improve diversion between the target zones.

Case 2. Well P

This well was stimulated as a part of the final phase of the completion. During the drilling phase, a total of 1364 m^3 of inverted mud was lost into the formation even though the production rate in the well was measured before stimulation at 2,300 bopd through a 1-in. choke. In this case, the well completion was a 7-5/8-in. cemented liner with 25 m of perforated zone, **Figure 9**. The reservoir characteristics are a lithology of 31% calcite, 64% dolomite, 5% mixed layer clays, a bottomhole temperature of 164°C, a reservoir pressure of 303 kg/cm^2, a permeability of 800 mD, porosity of 10% and a water saturation of 12%.

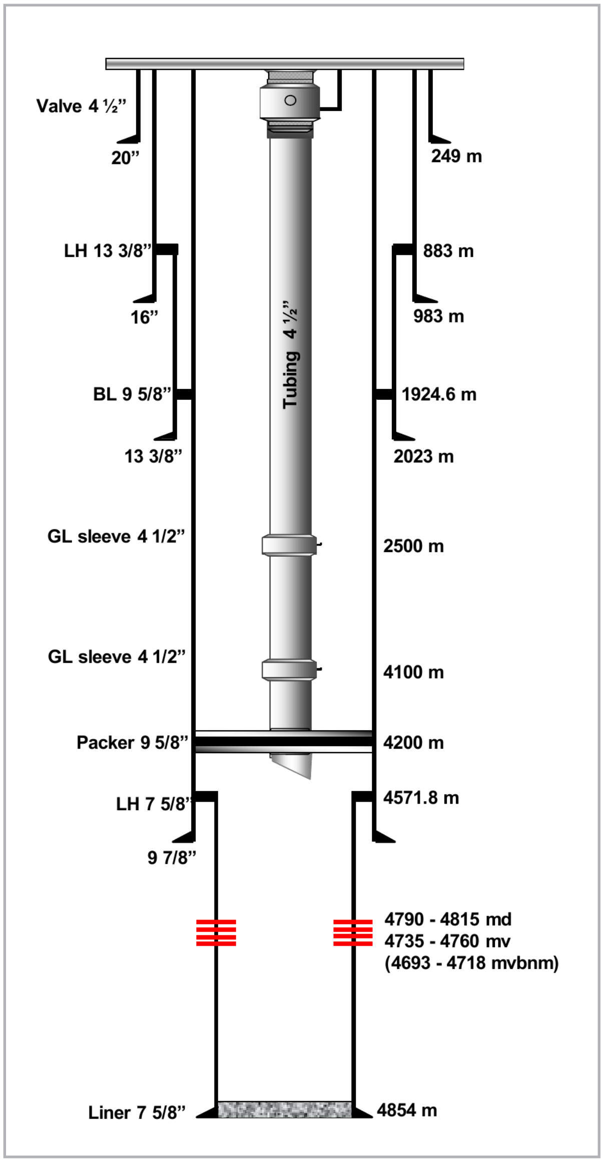

Figure 9. Well P schematic.

As part of the completion schedule, an acid stimulation was planned for pumping 60 m^3 of solvent, 28 m^3 of retarded acid blend, 15 m^3 of HMP diverter, and 15 m^3 of highly viscous fluid. During most of that part of the treatment, nitrogen was pumped in, commingled with the stimulation systems, at a pump rate of 150 scm/min. **Figure 10** indicates the treatment graph of this job.

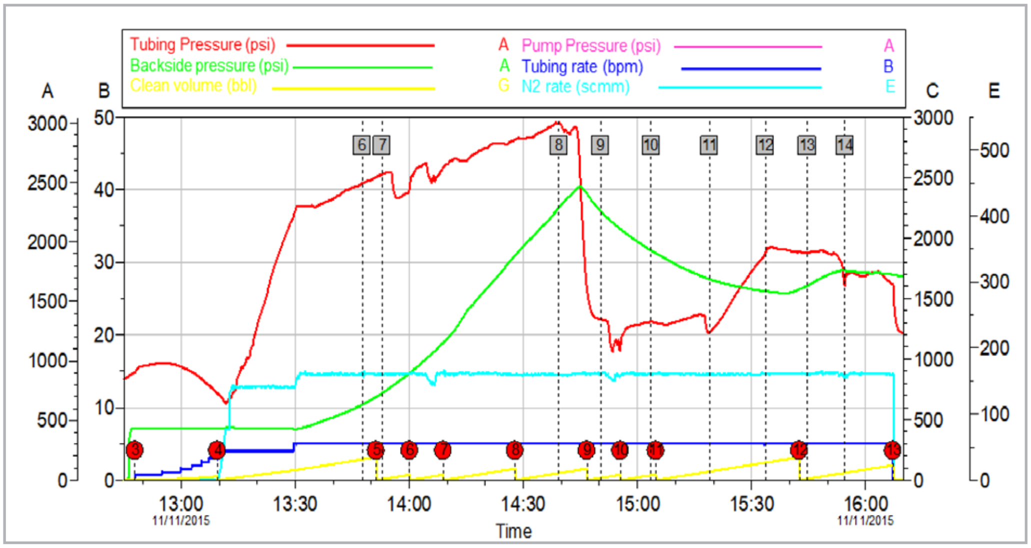

Figure 10. Treatment plot for Well P with HMP diverter+highly viscous fluid.

Results

After the treatment, an oil production rate of 8,500 bpd through a 1-inch choke was reported.

Case 3. Well A2

Well A2 was drilled and completed in January 2017 with a cemented 7-in. casing and 3 ½ - 4 ½-in. production tubing with the objective to produce a carbonate formation in the cretaceous formation at 5,582 m – 5,632 m depth, **Figure 11**. This formation has a permeability of 178 md, porosity of 5%, a water saturation of 30%, a bottomhole temperature of 155°C, and reservoir pressure of 998 kg/cm^2.

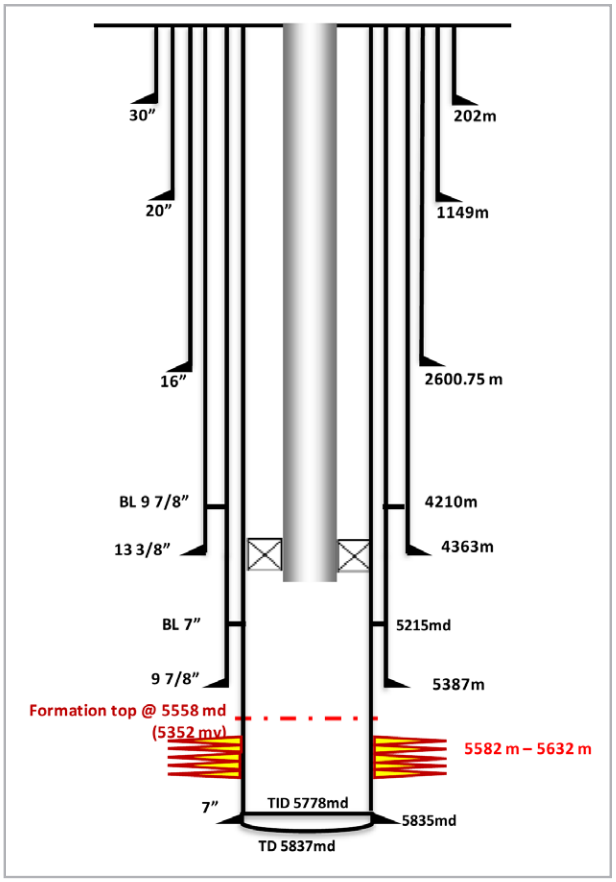

Figure 11. Well A2 schematic.

As part of the completion, a near wellbore stimulation was executed because it was reported that 2639 m^3 of inverted fluid loss started at a depth of 5610 md and continued up to 5837 m. The last 22 m of the interval of interests are within this loss zone. After this treatment that included 7 m^3 of HMP diverter and 8 m^3 of highly viscous fluid, an estimated oil production of 16,688 bopd with 1-1/4-in. choke was reported. In April 2017, another acid stimulation was required including 43 m^3 of solvent, 39 m^3 of retarded blend acid, 7 m^3 of HMP system, and 8 m^3 of highly viscous fluid. The pumping rate during the job was from 6 to 14 bpm with a maximum surface treating pressure of 9,100 psi, **Figure 12**.

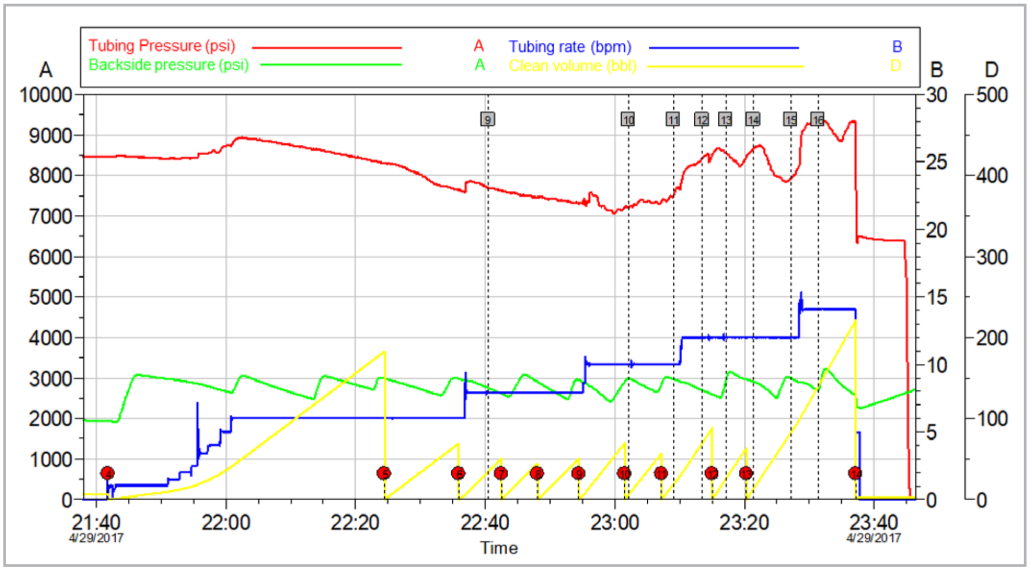

Figure 12. Treatment plot for Well A2 with two diverters, (stages 12 and 13).

The results of this second treatment were estimated based on the wellhead pressure and productivity analysis to be 18,307 bopd, through the same 1-1/4-in. choke.

Case 4. Well O

Well O, is an oil well located in marine region of Mexico with a lithology in the Upper Jurassic formation (JSK) with mostly carbonate (87% Limestone) and bottom hole temperature up to 253 °F. The well was completed in open hole (4,294-4,403 md). The challenge was to inject the fluids into the best potential zones of the 109 meters of open hole. In October 2020, a matrix stimulation was executed using 30 m^3 of solvent system, 90 m^3 of retarded acid and a 10 m^3 of HMP + 15 m^3 highly viscous fluid as diverters, in **Figure 13**, it is circled the stage at surface of the diversion stage arriving at reservoir.

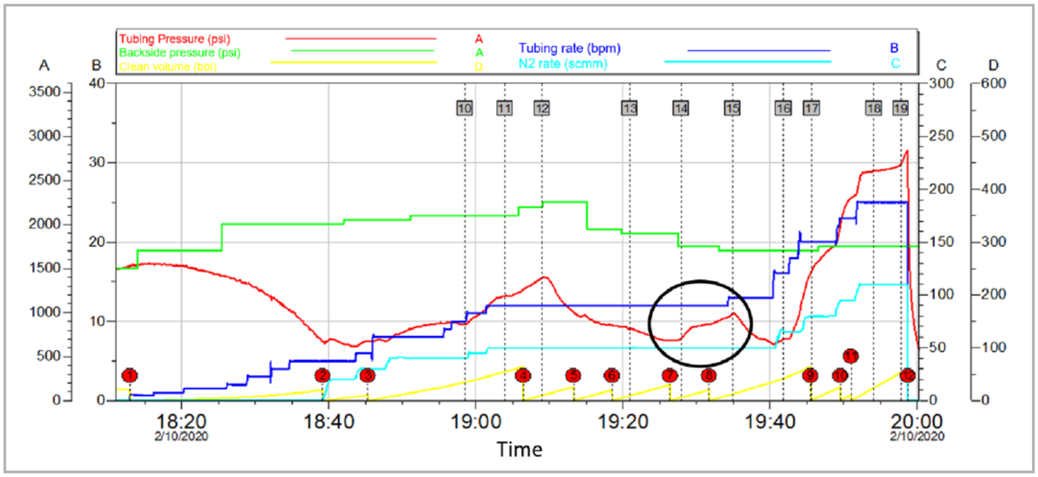

Figure 13. Treatment plot for Well O with one diversion stage, (stages 14 and 15).

Before the intervention the well O produces 3438 bpd, after stimulation the oil production was 5285 bpd. **Table 3**, resumes the results obtained after the stimulation job

Date	Choke (IN)	Production (bpd)	Water Cut (%)
Before treatment (bpd)	1	3438	0.4
After treatment (bpd)	1	5285	0.6

Table 3. Well O results after stimulation treatment.

Case 5. Wells I-1 and I-2

The well cases I-1 and I-2, are examples of the continuous implementation of this diversion technique, expanding the formation permeability range of use from the previous cases. In **table 4.**, there are a resume of the reservoir characteristics of these two cases.

Parameter		Well I-1	Well I-2
BHT	(psi)	3,483	3,417
BHP	(°C)	132	132
Porosity	(%)	6.2	6
Water Saturation	(%)	17	12.3
Permeability	(mD)	11.2	2.98

Table 4. Well I-1 and I-2 reservoir characteristics summary.

In **Figures 14 and 15**, the data during the pumping of the stimulation in events 13-14 and 17-18 marked in the grey box, showed an increase in surface treating pressure during the arrival of the downhole divergence. In both cases the pumping rate remained constant and could be a reflect of the effect of diversion in each stage. The better way to verify if this behavior is because of the diverter effect, is with bottomhole pressure.

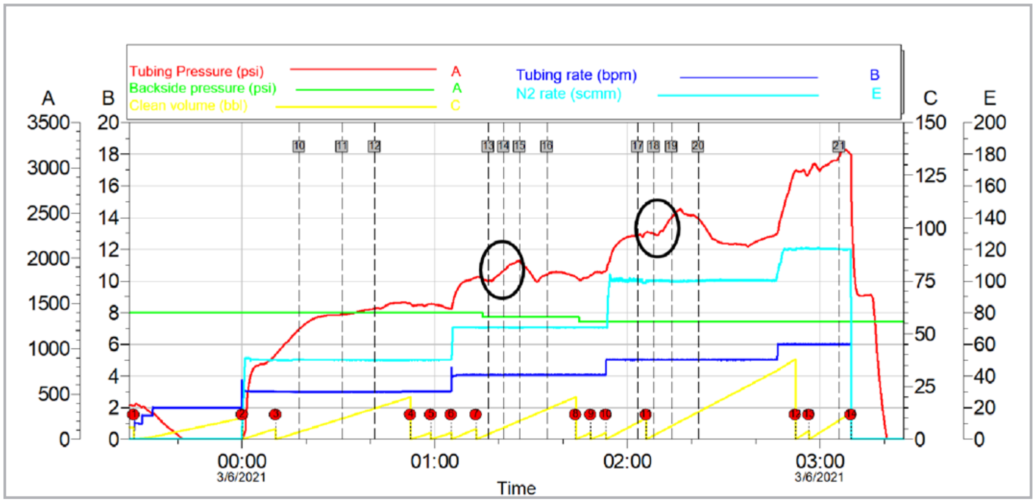

Figure 14. Treatment plot for Well I-1 with two diverters, (stages 13-14 and 17-18).

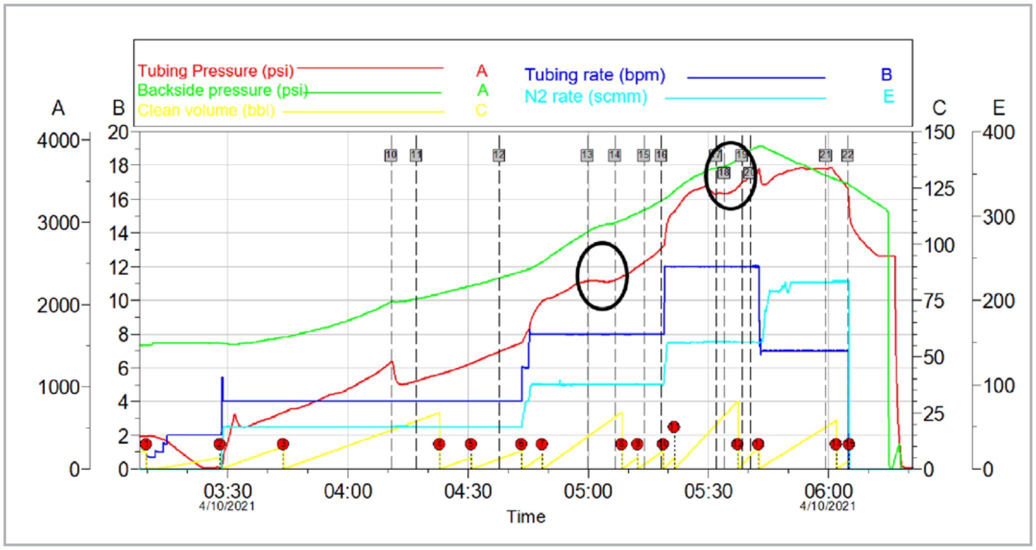

Figure 15. Treatment plot for Well I-2 with two diverters, (stages 13-14 and 17-18).

Table 5 shows the results of both wells, where the continuous diversion was used in both cases, with two stages of the diversion technique.

Well	Date	Before			After			
		Choke θ (in)	Q_o (bopd)	W (%)	Choke θ (in)	Q_o (bopd)	W (%)	ΔQ (bopd)
Well I-1	6-Mar-21	-	-	-	1	3395	-	3395
Well I-2	10-Apr-21	5/8"	796	7.7	5/8"	4760	7.7	3964

Table 5. Well I-1 and I-2 results after stimulation treatment

The evaluation of in-sequence chemical diverters in several assets in the marine region of Mexico has been followed through time. **Figure 16** shows a compilation of the cases with available data after treatment with this technique.

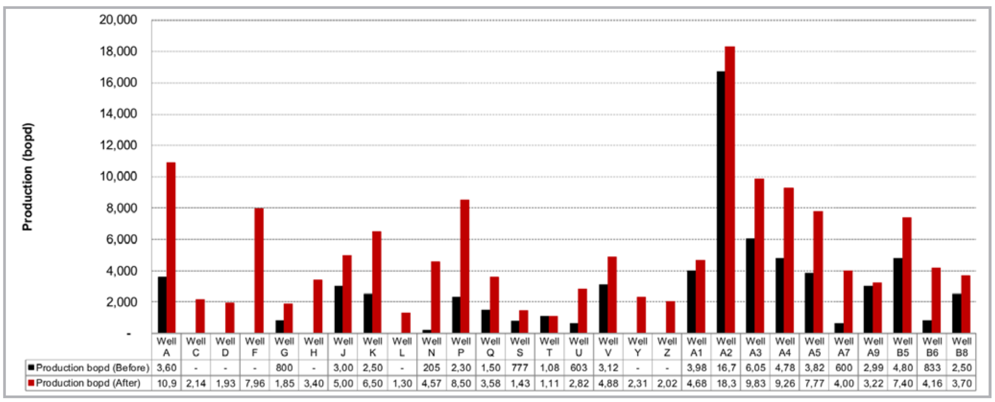

Figure 16. Case summary of production results of in-sequence diversion application.

Finally, the implementation of this diversion technique represents an improve in the cost of the diverters implemented in Marine Region of Mexico, with a reduction of the total cost even considering that two different systems are necessary to create the diversion stage. Comparing the diverters available and commonly used in marine region of Mexico **Table 6**, shows that the cost of the continuous diversion is very competitive with a total price per cubic meter lower than other conventional diverters available.

Nro	Diverters availables	Cost [USD/m³]
1	Diverter 1	3,000.00
2	Diverter 2	3,500.00
3	Diverter 3	2,906.16
4	Diverter 4	2,906.16
5	Diverter 5	3,000.00
6	HMP (hydrophobically modified polymer)	2,590.00
	HVS (Highly viscous system)	218.66

Table 6. Comparisons of cost of different diverters available.

Conclusions

The following conclusions are a result of this work:

1. From 2015 to 2017, more than 35 wells are being executed with the use of in-sequence diversion and over time, this diversion technique have been expended to use in a variety of scenarios, including new completions, workovers to abandoned, add new intervals, and periodic acid treatments.

2. For the cases in study in this article from 2015-2017, the reservoir permeability of the fracture system is around 99 mD to 500 mD obtained from buildup test.

3. From 2020 to 2021 more than 70 wells were stimulated with continuous diversion during acid treatments. The permeability range of the 2021 case study is between 2 to 11 mD obtained from log analysis.

4. The continuous diversion during acid treatments had been evaluated in field, in wells with reservoir permeability more than 1 Darcy.

5. The effect of reduction in water effective permeability facilitates the highly viscous fluid action and has been evaluated in laboratory through the column test and transit time of both fluids.

6. The wells in this study present a bottomhole temperature up to 180°C and a reservoir pressure up to 998 kg/cm^2; however, the use of this technique in stimulation has been proven in well with BHT of 120°C and reservoir pressure of 127 kg/cm^2.

7. During 2015-2017 history cases, was identified that the 27% of the wells no presented change in production. These wells presented common reservoir characteristics, such as higher permeability more than 400 mD and BHT more than 160 °C.

8. Up to a 50-fold increase of the oil production rate has been achieved.

Nomenclature

bpd	Barrels per day
bopd	Barrels oil per day
bpm	Barrels per minute
°C	Celsius degrees
cp	Centipoise
HMP	Hydrophobically Modified Polymer
HP/HT	High pressure / High Temperature
HVS	Highly viscous system
in	Inches
m	Meters
md	Millidarcies
ml	Milliliters
min	Minutes
scm/min	Standard cubic meter per minute
sec	Second
#/Mgal	Pound per thousand gallons

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Semblanza de los autores

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Egresado de la licenciatura en Ingeniería Petrolera por el Instituto Politécnico Nacional en el año 2004 y Maestro en Ingeniería por el Instituto Mexicano del Petróleo en 2007.En el año 2008 ingresa a Petróleos Mexicanos en el Activo Integral Litoral de Tabasco de la Región Marina Suroeste, asignado al área de Ingeniería de Yacimientos. De 2009 a 2011 laboró en Superintendencia de Productividad de Pozos como Ingeniero analista-operativo de pozos fluyentes. De noviembre de 2011 a febrero de 2017 laboró en la Subdirección de Desarrollo de Campos como encargado del área de Productividad de Pozos y posteriormente como Coordinador de Diseño e Ingeniería de Proyectos en la Gerencia de Proyectos Aguas Someras. De febrero de 2017 - abril 2018 laboró en la Gerencia de Operación de Alianzas y Asociaciones de la Subdirección de Producción Bloques Aguas Someras AS02. En mayo del 2018 se reintegra al Activo Integral de Producción AS02-04 como Superintendente de Caracterización Dinámica y de enero de 2019 a la fecha es Superintendente de Productividad de Pozos, a partir de diciembre del 2020 es Encargado de la Coordinación del Grupo Multidisciplinario de Administración de Yacimientos del Activo de Producción Litoral de Tabasco.

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Egresada de la Facultad de Ingeniería de la Universidad Nacional Autónoma de México, donde obtuvo el título de Ingeniera Petrolera en 1996. En el periodo 2000-2002 realizó estudios de postgrado en la misma institución, con especialidad en Ingeniería de yacimientos. Ingresó a Petróleos Mexicanos en 1997 en el área de productividad de pozos del Activo Integral Litoral de Tabasco de la RMSO.

De 1999 a 2010 se desempeñó como especialista de yacimientos, alcanzando el puesto de Superintendente de Ingeniería de yacimientos y líder de proyectos en el Activo Integral Litoral de Tabasco de la RMSO. En 2011 cubrió el puesto de Coordinador de Diseño de Proyectos en el mismo Activo. Posteriormente, en septiembre del mismo año, se integró a la Subdirección de desarrollo de campos, en donde fue Líder de proyecto y Coordinador de diseño e ingeniería de proyectos. En 2015 es nombrada Gerente de Proyectos de Aguas Someras de la Subdirección de Desarrollo de Campos, para posteriormente ser Administradora el Activo de Producción Samaria-Luna, Administradora de Activo de Producción de Litoral de Tabasco y Administradora del Activo de Producción Bellota-Jujo, donde se desempeña actualmente.

Saraí Santos Ramírez

Es egresada de la Facultad de Química de la Universidad Nacional Autónoma de México, donde obtuvo el título de Ingeniera Química. En el periodo de 2006-2008 realizó estudios de Maestría en Ingeniería Química en la Universidad Nacional Autónoma de México, con especialidad en Ingeniería de Procesos. De 2008 a 2013 se desempeñó como ingeniero de campo en el área de estimulaciones para la Región Marina de México. De 2013 a 2020 se ha desempeñado como ingeniera de diseño para el área de estimulaciones, fracturas y control de agua en la Región Marina, trabajando en los diferentes Activos: Cantarell, Ku Maloob Zaap, Litoral de Tabasco, Abkatun Pol Chuc y Exploratorios.

Katya Campos Monroy

Realizó sus estudios de Ingeniera de petróleo en la Universidad de Oriente, Anzoátegui Venezuela; trabaja en Halliburton, en el área de Production Enhancement (Estimulaciones) como asesor técnico con más de 17 años de experiencia. Enfocada en estimulaciones de yacimientos naturalmente fracturados en diseño de acidificación y fracturamiento acido. Amplia experiencia en diseño de acidificación en arenas, control de agua y gas y fracturamiento hidráulico apuntalado. Ha trabajado en la región Sur y Marina de México, y por tres años en Bogotá, Colombia. Actualmente se desempeña como asesor técnico en la región Marina de México.