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Remediation of Long-Term Production Deferrals from Formation Damage in a Depleted Transylvanian Sandstone Reservoir

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Abstract

The work completed was a comprehensive approach of understanding and treating formation damage to further redevelop a mature asset through successful remediation operations. The identification of skin was completed with slickline techniques and reservoir and production flow profile monitoring. Primary formation damage mechanisms were naturally occurring scales in the near wellbore, damage caused by water blockages and workover fluids. Redesigned completion fluids, acid pumping and innovative coiled tubing tools were used in the remediation works which were all firsts in the basin. A modified decline curve analysis technique was used to economically justify treatment of nearly all wells in the field and led to substantial production increases.

In 2003, an Association was formed to manage a mature Romanian gas field producing since 1970. Production skin was evident and in 2010 a well failed due to halite formation. Consequently, liquid and solid sampling tools were deployed within suspect wellbores. In 2010, a new workover fluid formulation was introduced but despite improvements formation damage was still induced. From 2010 to 2013, there had been an increased focus on understanding and treating calcite, halite and water block damages to boost field-wide productivity.

Formation damage was observed as being both naturally occurring and induced in the field. An initial assessment and pilot treatment of 10% of the wells led to a near 40% incremental gain in those wells. After which, the campaigns were further expanded to over 75% of the field. Technically, the investigation into formation damage changed the development plan for the field going forward. Operationally, the intervention procedures introduced were new to the basin and have been adopted by the Association's partners in other assets.

A major limit on ultimate recovery from depleted hydrocarbon reservoirs is declining well productivity. Salt formation, scale deposition, and water blockage restricts flow, reducing production rates and ultimate recovery of reserves. Therefore, economic formation damage management is an essential tool for extending field life, increasing profitability, and improving recovery of aging assets. Impressive results led to a strategic shift in local field production management and the techniques are useful worldwide in similar fields.

Introduction

In Laslau Mare, as in many depleted gas fields worldwide, proper brownfield management is the key to extending returns from aging assets. As wells reach economic producing limits inexpensive but effective techniques are needed to enhance production and ultimate recoverable reserves. As reservoir pressures deplete, natural causes of formation damage in the form of calcium carbonate (calcite), halite salt or water blockages can defer production. Also, through the course of workover campaigns, formation damage can be induced from the use of completion and workover fluids which are in extreme overbalance with the depleted reservoir. As the potential energy of the wellbores is greatly decreased, often a well is not capable of clearing itself from these various types of formation damage. Flowrate restoration requires identification of the issue at hand, quantification

of the residual potential in the completion and proper execution of economically justifiable interventions aimed at remediation.

The sedimentation in the Laslau Mare area was deep marine in Badenian, going to turbiditic-marine in Lower Sarmatian (Buglovian) to shallow marine in Upper Sarmatian. According to this, the formations from Badenian are very tight, siltstones with higher shale content and low porosity-permeability. Also, the shallow layers are characterized by channels and smaller sand bodies that have good porosity-permeability. The intermediate layers, are more continuous sandstone layers, with quite homogeneous property distributions. Although the depositional environments and properties changed, the range of permeability leans toward tight gas with a lower minimum around 0.01 mD up to a maximum average around 4 mD. Approximately 50 active wellbores target the above zones with perforation intervals averaging approximately 50 to 75m of net perforations in a typical producing package.

Extent of Known Damage

When Romgaz and Schlumberger formed an Association based on production gain sharing, it was generally accepted that the majority of underperformance was due to water loading in the wellbore from the low permeability flow environment. However, when recompletion campaigns began, a mixture of calcite and halite scales were also found to have been forming in the tubing **(Fig. 1)**.

Fig. 1-- Evidence of Scale Found During Workover Operations

Initially, the damage was thought to have been localized as evidence was only found in a few wellbores. By 2010 many of the subsurface recompletion candidates had been intervened and a greater focus was placed on existing completion enhancement. A cost effective solution was needed to investigate if deposits found in the tubing could also be forming elsewhere in the wellbore potentially plugging off the perforations and formation. Therefore a slickline intervention campaign was completed which focused on pressure and temperature surveys in conjunction with sample retrieval tools (sand bailers and tubing cutters). The pressure and temperature surveys proved that water loading was still a persistent problem despite aggressive chemical surfactant treatment programs. The slickline retrieval tools discovered samples of calcium carbonate scale and salt and across perforated intervals proving the existence of precipitates not only in the tubing but within the perforations and potentially into the formation **(Fig. 2)**.

Fig. 2 -- Evidence of Scales Recovered Using Slickline

Once it was discovered that water, calcite and halite were all deferring gas production, a methodology was required for quantitatively predicting what residual potential existed. Many methods could be used; however the reservoir models were built on logs more than 30 years old and were often missing key information needed to accurately determine flowing potential. Thorough core analysis was also lacking, so the best method left would be based on production history matching and decline curve analysis. A traditional decline curve analysis is based on assumptions which do not necessarily hold true in Laslau Mare. Bottomhole pressure is not constantly monitored with downhole gauges, therefore bottomhole conditions are typically extrapolated from surface pressures. This became unreliable in cases of scale formation or wellbore water loading as the frictional flowing losses and fluid column will increase the effective bottomhole flowing pressure beyond a linear relationship. Assuming the productivity index and reservoir pressure of a certain well are both constant then increases in bottomhole pressures will result in decreased gas flow rate as shown in the flow equation

$$Q = PI \times (P_r^2 - P_{wf}^2)$$

where Q is flow rate, PI is productivity index, Pr is reservoir pressure, and Pwf is bottomhole flowing pressure. Any change in the wellbore, especially liquid loading, will occur at a faster rate than the depletion of the reservoir pressure so a normal decline curve analysis will be artificially faster and show less remaining potential in the well than is actually available. If post-intervention potential is underestimated, enhancement opportunities may seem uneconomical. This will lower the economically recoverable reserves as wells suffering from formation damage will be abandoned prematurely rather than being stimulated. Therefore, a solution which could identify and account for underperformance while still accurately predicting post-intervention production was needed.

To make a modified decline curve which was applicable for the depleted gas field, the data first had to be made as accurate as possible. It was found that monthly production data was subject to many artificially imposed spikes. Many flowrate increases/decreases were actually antiquated accounting practices which discounted gas from wells while being produced to underground storage and then re-allocated the gas whenever it was released back into the national grid. Also seasonal variations in surface sales line pressure directly impacted well performance which could show rapid decline during one part of the year followed by a negative decline during another. Therefore, annual production data was used to smooth out the monthly variations and reduce the number of ignored outliers which made for a more comprehensive decline curve analysis.

The next step was to determine when the well started to underperform. As mentioned some wells had physical deposition of calcite or halite in the tubing and plugging the perforations or were full of water. Each leads to a higher bottomhole flowing pressure and decreased gas flow rate which under-represents the inflow potential of the well. If one tried to match the decline curve to include the production history where the well was water loaded it would lower the overall residual potential after intervention. However, the production history during underperformance is still relevant as the reservoir is driven by natural gas depletion drive, therefore omitting the cumulative flowing volume would lead to overly optimistic potential left in some wells and could negatively impact the overall economics of any remediation campaign.

The greatest accuracy was achieved by accounting for the full flowing history of the well while focusing the decline curve baseline solely on periods of pseudo steady-state flow with consistent bottomhole pressures. This was attained by focusing the analysis on periods of time where surface line pressures were relatively stable: no drastic gas/water ratio changes were observed nor were any major changes in surface well choke sizes made. A decline curve was generated which could represent how the well should have produced had it followed a normal decline without significant increases in bottomhole pressure or damage to the formation. The well's "normal" decline was then compared to the actual production with a focus on the cumulative volume of hydrocarbon produced after underperformance began. Once the area under the "normal" decline curve is the same as the actual cumulative production volume one can estimate what the daily production could be by using the daily rate associated with that point in time. This is assuming that only the candidate well is responsible for the depletion of the reservoir in that area, no production interferences. This daily rate could then be projected to current time, with the remainder of the "normal" decline, to provide a gas rate forecast.

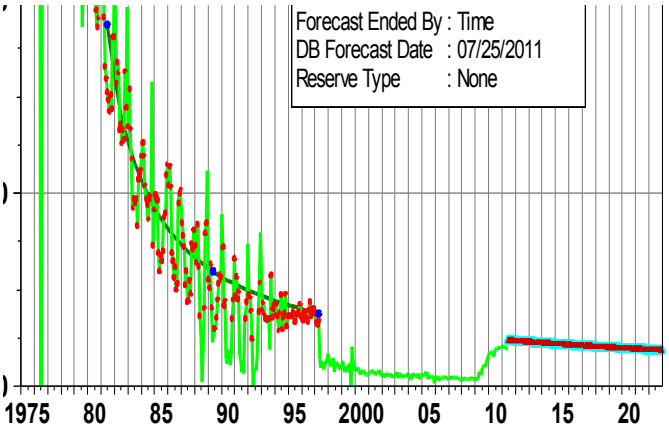

Fig. 3 -- Normal Decline Curve Analysis (No Potential)

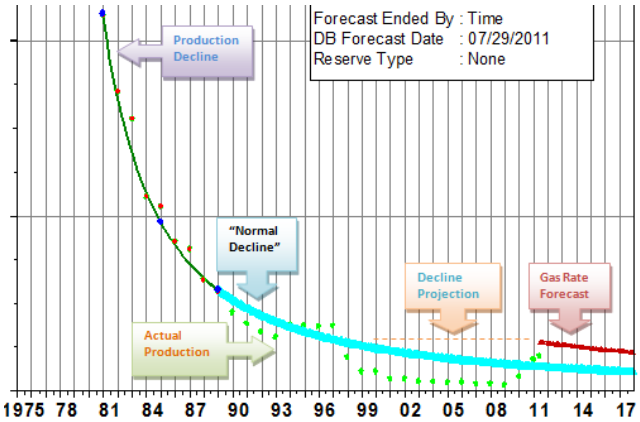

Fig. 4 -- Modified Decline Curve Analysis (Residual Potential)

A side-by-side comparison of the normal versus modified decline curves is shown in Fig. 3 and Fig. 4. The first well, when analyzed under normal decline curve analysis techniques (even while discounting the obvious underperformance from 1997 to 2010) shows that the well is producing at approximately the forecasted rate so there is little economical intervention potential remaining. The second well, which is analyzed using the modified decline curve analysis techniques discussed above, suggests that the cumulative volume produced after 1988 (when the well stopped declining in a normal way) would have been reached in ~1998 had it followed the "normal" decline. The average daily rate associated with that point in time is then projected to current time and compared to the actual daily production. In this case, the analysis technique suggests that there is still residual potential remaining in the well even though recent activities had already multiplied gas production many times over in recent years.

Naturally Occurring Formation Damage

Decline curve analysis alone could not determine what type of formation damage was actually hindering well performance. As previously mentioned the workover observations as well as the slickline intervention campaigns made it obvious what the damage mechanisms were in some wells; however, in other cases decline curve analysis showed wells to have a lot of potential without any physical evidence of damage in the wellbore. In these cases, the damage is most likely localized in or behind

perforations. Chemical analysis of all recovered samples point to calcite and halite as the main scale deposits within the field and it was well known that water holdup also hindered well performance. Core analysis showed that the sandstone cementing material is, on average, approximately 25% calcium carbonate. This is an abundant source for produced water to carry and eventually deposit calcite as pressure/temperature evolution shifts the equilibrium beyond normal saturation in water. For halite, the marine depositional environment explains why water in certain areas of the field has 125+g/ml sodium chloride concentrations in surface samples. Although there are varying levels of sodium chloride from one zone to the next, given the correct conditions, pressure and temperature changes could again lead to precipitation before or after the perforated intervals.

Imposed Damages

Studying the evolution of the reservoir is typically carried out via production logging and pressure buildup analysis. Both methods are generally considered safe for brown fields as long as post-build-up the pressure release is controlled in a way that will not cause mobilization of fines, creation of hydrates or the like. Fines and hydrates are not a prevalent issue for Laslau Mare, however the buildup tests have proven to be detrimental to flow rate in a few cases. The first example is of a typical buildup test where the well has a pressure gauge set in the well then production was fully shut in. After a shut in time of 4 days, determined by the differential pressure buildup overnight, the well is put directly back into production. The pressure recording device showed that both before and after shut in, the well showed no signs of wellbore water loading as shown in Fig. 5.

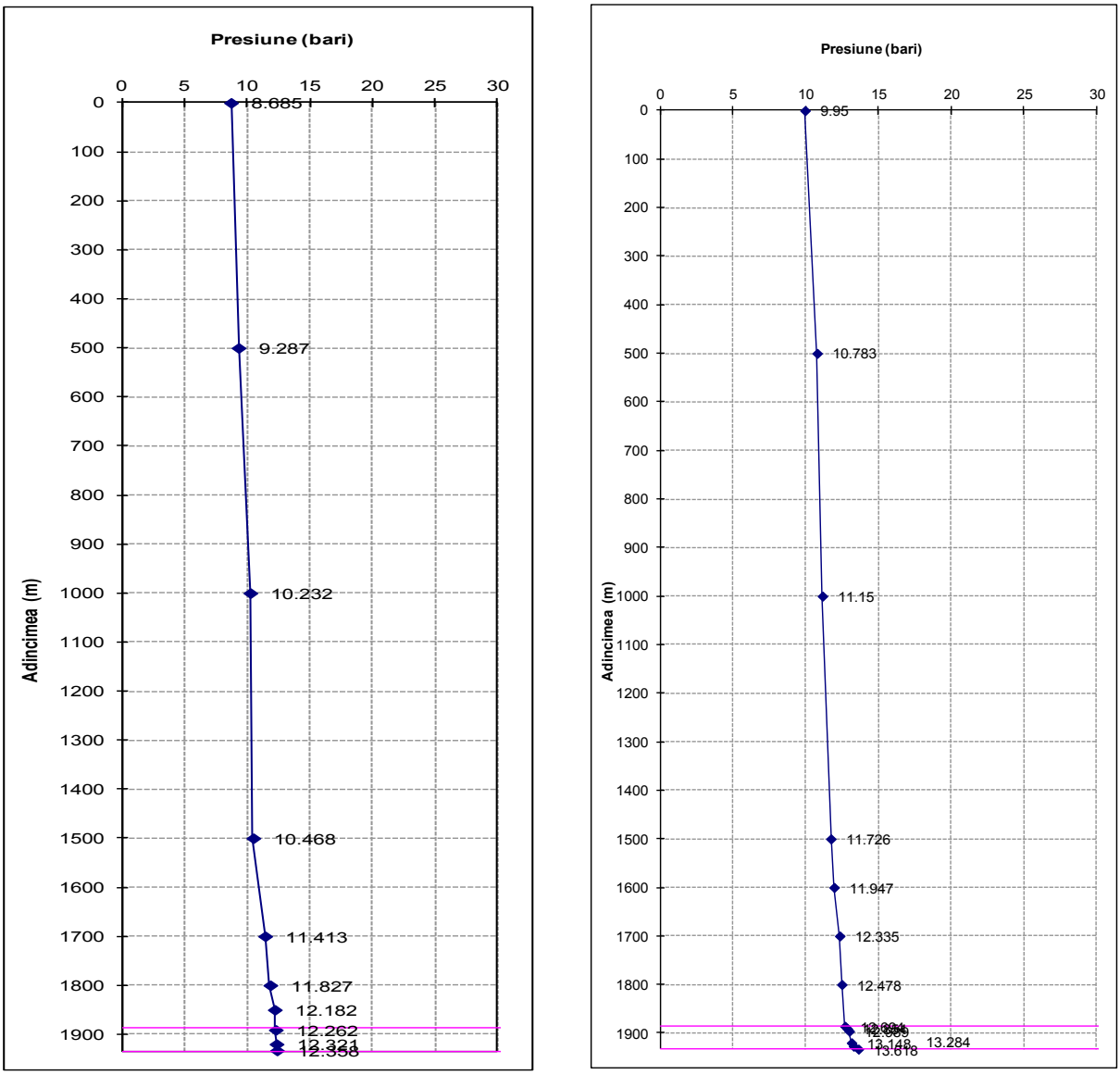

Fig. 5 -- Pressure Gradient Survey Before and After Shut In Conditions

Assuming that the near wellbore region of the reservoir was re-energized by the extended reservoir during shut in period one should expect a slight increase in daily production over a short period of time as the near wellbore region re-depletes the stored pressure. However, the result after shut in was exactly the opposite. As shown in Fig. **6**, the well took nearly six months to return production to pre-intervention rates. The water production is also of note. Although the well was not filling with water, it was slugging water to surface periodically compared to the more stable gas and water production that was occurring prior to shut in.

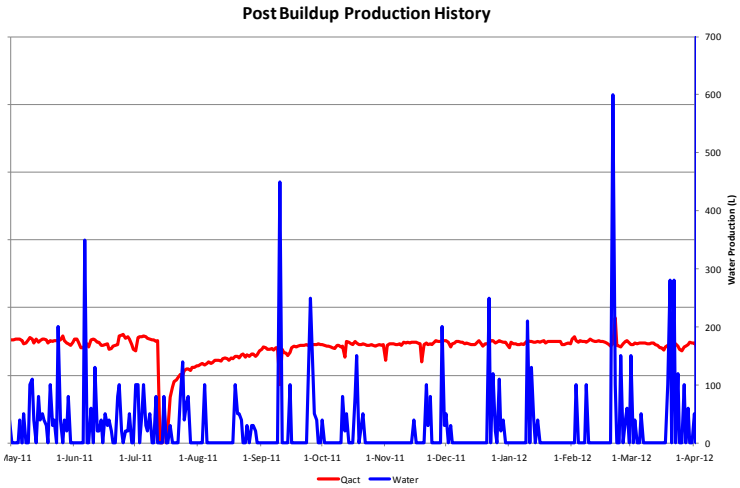

Fig. 6 -- Post Pressure Buildup Production History

The 180-day buildup is extreme considering no kill fluids were used and that only reservoir hydrocarbons and water which should be relatively inert were interacting with the near wellbore region. During workover operations, in order to safely access a well, a kill fluid is needed to control any hydrocarbon inflow from the reservoir. In the basin the typical kill fluid used was a brine containing potassium chloride to reduce clay swelling tendencies. As mentioned, Laslau Mare is quite a depleted brown field (30% of original reservoir pressures in most cases) and a full column of brine is sufficient overburden to easily induce losses to the formation. After workover campaigns were completed in 2009 and 2010, the interventions were seemingly failures, with initial post workover rates much lower than expected. The root cause of this failure was discovered to be that in some cases as much as 100m3 of workover fluids were lost to the formation.

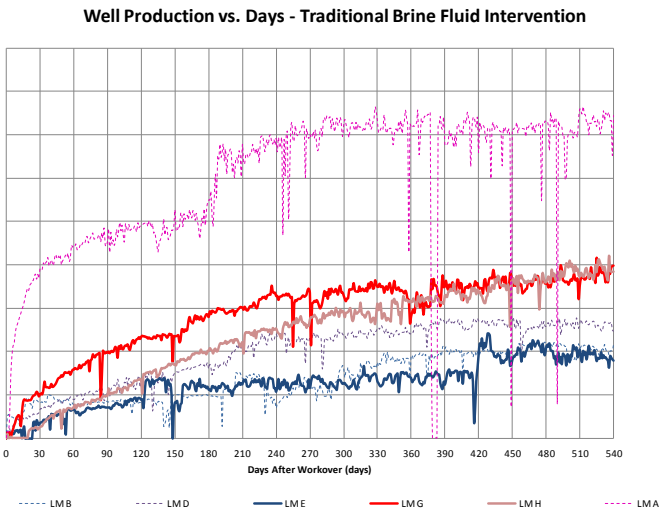

Fig. 7 -- Formation Damage Caused by Traditional Workover Brine Systems

The excess lost workover fluid led to cleanup periods of the wells which were in some cases more than two years long as demonstrated in Fig. **7**. The assumption at the time was that flooding of the near wellbore region was the sole cause of this formation damage. Therefore, it was decided that (for the first time in the basin) a designer workover fluid using a calcium carbonate loss control matrix should be introduced. The calcium carbonate matrix would form a filter cake across the exposed reservoir sections and only spurt losses should be induced into the reservoir. Once this specialized workover fluid was

introduced, it was seen as an operational success. Workovers were executed using 200+ bar of overpressure while realizing no more than a few hundred liters of losses in the best case scenarios. The expectations were high that upon putting the well back on production the deferrals experienced from extended cleanup would be eliminated.

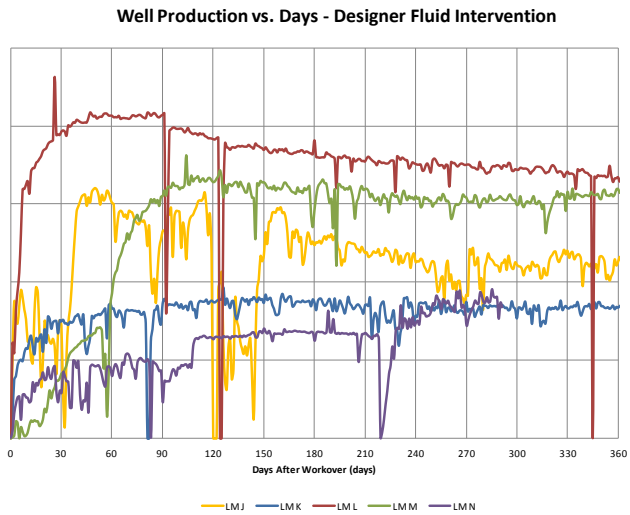

Fig. 8 -- Formation Damage Caused by Designer Workover Fluid Systems

Although the carbonate matrix reduced losses, wells still experienced clean up periods. Most wells stabilized between 100 to 120 days before plateauing or beginning declines. This is similar to that of pressure build up tests and suggests that there is still some type of formation damage occurring even with the loss control matrix in use. However, it is obvious that the designer workover fluid is much better for the recovery of the reservoir in comparison with the original system. The theory is that although wells are killed without inducing losses (using the carbonate matrices or during pressure buildups) the loss of a pressure differential across the perforated zone allows for capillary forces to raise the near wellbore water saturation. These capillary forces are sufficiently strong compared to the reservoir pressure and may be blocking off gas production. One more example that this type of damage may be occurring is underbalanced perforating operations.

When perforating a new zone in an existing wellbore, the local procedure is to perforate at- or (preferably) under-balanced. The idea being that it provides the least damage to the reservoir and gives the operation the best chance for success. However, as before in workover operations there is still a cleanup period necessary before full gains are realized.

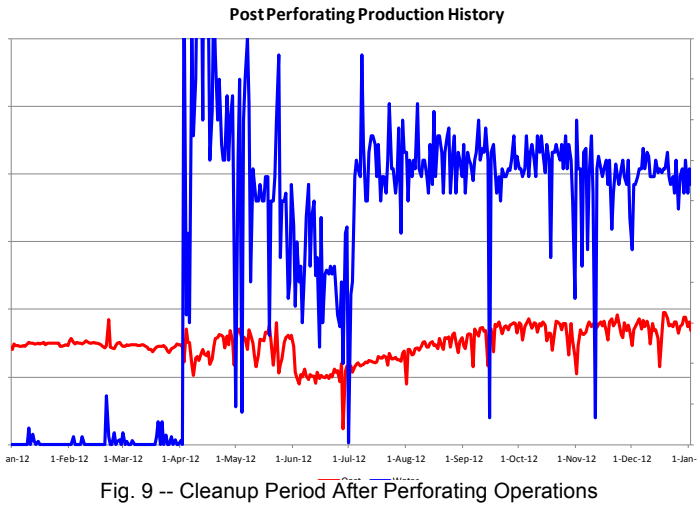

Fig. 9 -- Cleanup Period After Perforating Operations

The production graph in Fig. **9** is typical of wells in Laslau Mare. Although operations are performed in underbalanced conditions, a higher than average water rate is experienced which declines then plateaus followed by a slowly increasing gas rate. After 120 to 180 days, the gas rates will stabilize as the formation damage cleans up.

The phenomenon that best explains the damages associated with the above induced damages would be a persistent water block from high capillary forces (Mahadevan and Sharma 2005). Given the low permeability environment and highly depleted reservoir conditions, it is likely that the capillary forces in the rock which once were easily overcome by the force of gas behind them have slowly become more dominant. There are mathematical models, (Mahadevan and Sharma 2007), which also help explain why, over longer periods of time, these blockages eventually clean themselves up. The best explanation may be that as gas is produced through an interval adjacent to a water block, the dry gas is able to evaporate some of the water held up in the near wellbore area. This process continuously repeats itself, slowly changing the relative permeability of gas in the near wellbore reservoir. As long as the well is producing water to surface it can further establish relative gas permeability to the zone and eventually clear the water block.

Procedurally Speaking

As previously mentioned, some wells showed physical signs of scale, halite or calcite or water blockages. Others were predicted to have been underperforming based solely on the modified decline curve analysis without physical signs of an issue. Therefore, the best solution to treat wells without physical evidence in the wellbore was to find a treatment solution that could address all three damage mechanisms.

To treat calcite, typically acidizing is performed using hydrochloric acid (HCl) which has a good dissolution rate for calcium carbonate in general. When HCl was applied in Laslau Mare however, post-acidizing flow rates were unchanged and chemical analysis post acidizing showed that the acid solution did little to dissolve any calcium scales. Samples of recovered scales were then sent to laboratories where it was discovered that a treatment using a designer organic acid (a clay-stabilized, iron (III)-inhibited, formic acid) was a best-fit solution for the calcite deposits. This designed acid could then be diluted with stabilized water so that it could be used to dissolve the halite salt deposits as well. The solution was considered safe for the formation as it was stabilized against clay swelling. Only basic original core analysis existed, and the core storage facility had been flooded from a fresh water stream making Laslau Mare specific fluid compatibility (especially clay swelling) studies unreliable.
The use of a formic acid solvent does have some drawbacks. The diprotic acid reaction with calcite is reversible to some extent, meaning that the precipitate can reform once dissolved (Alkhaldi 2009). Also, the reaction is slower when compared to the reaction of HCl with calcite. The key to speeding up the dissolution of calcite and halite, while maintaining as much solute in solution as possible, is to keep unspent solution in contact with precipitates.

To adapt for use of a formic acid base a new type of acidizing procedure had to be created. Hydrochloric acidizing had previously been performed by using coiled tubing to place a small amount of acid across the perforated interval where it was left to soak for three hours before being kicked off and neutralized at surface. For the formic acid jobs, the provider of the acid suggested that we adopt a policy they use in other fields, which involves filling the well with acid solution, circulating the acid and monitoring returns. Once returns suggest that acid is not being spent, the well is then kicked off and returned to production. This procedure would not usually be possible for a significantly depleted reservoir however, as the overburden pressure imposed from a full wellbore would cause the treatment to uncontrollably inject itself into the reservoir. As mentioned in workover experiences, any great volumes of liquids uncontrollably lost to the reservoir could lead to water blockages which could cause more production hindrance than the presence of calcite and halite.

The procedure was modified to avoid imposing an overburden on the reservoir. The amount of treatment solution was calculated based on the area of interest with respect to the expected bottomhole pressure during treatment. The volumes were always kept sufficiently low to be either at balance or underbalanced with respect to the formation. Since less volume was used and returns could not be continuously monitored on surface, it was necessary to allow for a greater soak time to achieve similar dissolution rates with the weaker formic acid. The treatment was either pumped with coiled tubing or without depending on the completion design. The first step was to unload any liquid in the wellbore using nitrogen. After which acid was pumped into the wellbore and was agitated using leftover nitrogen in order to speed up initial reaction chemistry. This helps reaction kinetics by keeping the freshest acid in contact with scale deposits as much as possible when the acid is at its strongest concentrations (Alkhaldi 2009). Afterwards, the treatment solution was left to soak overnight (which was possible since it was inhibited against reaction with the tubulars). The next day the solution was recovered on surface by pumping nitrogen again and samples were taken to the lab for analysis and improvement. As this technique evolved over time, after recovery of the final liquid treatment volume, any excess nitrogen was injected into the reservoir. The injection was performed to try and create a higher relative permeability to gas and treat any imposed water block that may have formed.

Pilot Study to Full Field Implementation

The first study of the technique in Laslau Mare was to test the treatment on wells which showed physical signs of scale in the wellbore. This afforded the opportunity to test both the treatment technique in parallel with the decline curve analysis. We were able to investigate the wells with slickline post intervention to determine if the wellbore had been significantly cleared of deposits and also to see if post-treatment rates suggested by the decline curve technique were attained. The initial campaign occurred slowly over the course of 2011 to allow for continuous learning as the technique was applied and sample returns were analyzed. From the seven wells that were treated over the course of that year the campaign achieved an incremental hydrocarbon gain nearing 40% above and beyond what the wells were previously producing. Because the interventions were optimized to minimize costs and were shown to be quite successful for gaining incremental production the overall campaign achieved an over 300% return on expenditures within the first year. Return on investments were calculated based on a stable flowing period prior to intervention without being normalized for either general changes in field pressure or the natural decline of the well over time. Therefore there are some spikes in the incremental rate that are not necessarily representative of true well performance. Rates prove that the wells are quite responsive to changes in gas sales delivery pressures, suggesting that a downhole choke (scale) is not the main limiting force on the reservoir. This was agreed upon between Association partners as indisputable proof of the technique's performance as it takes away any presumed pressure effect or baseline declines.

The pilot study proved a success for both the treatment technique and the decline curve analysis tool's ability to forecast post intervention flow rates. Therefore in 2012 a decision was made to implement the technique wherever the modified decline curve analysis tool suggested that incremental gas potential merited intervention, even in the cases where no physical evidence of scale existed. Since the procedure did not just target calcite scale, but also halite and water loading/blockages it was successful in treating many wells which were impaired by formation damage even though no physical signs could be recovered and tested. During 2012, 24 decline curve analysis candidate wells, nearly 50% of the field, were acidized using the afore mentioned techniques. Within four months, the campaign began generating positive cash flow for the Association and the full campaign performance peaked with an incremental gain of over 30% above baseline before the end of the year. Not only was the full campaign seen as a success but it should be noted that nearly 70% of the individual candidates were economically enhanced. Some wells even experienced a near 100% incremental gain for hydrocarbon production. The first year returns were nearly 400% for the full scale campaign. Combining the results of 2011 and 2012 and extending them out over the remaining life of the Association contract shows the true impact of the technique. Future production was declined using a 30% year-on-year production decline from current rates (compared to the normal 10% decline associated with the full field decline) as scales may reform in the future. Despite the accelerated decline the campaign shows a near 25:1 return on investment before project end (PE), Fig. **10**. This was considered a great success for a field which has been in production for nearly 40 years and was previously thought to have been near its producing potential.

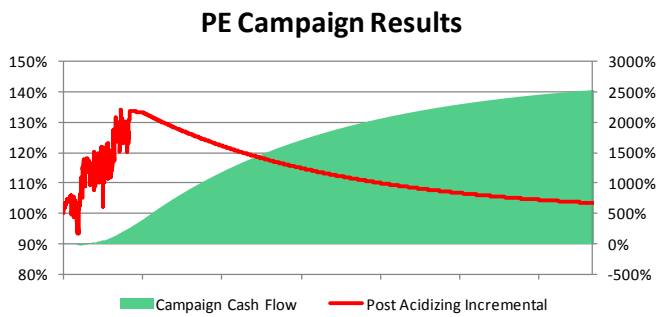

Fig. 10 – Project End Decline Curve Analysis Acidizing Campaign Results

New Technology Improvements

Although the techniques and methodologies introduced were firsts in the basin, the technology foundation was basic. Treatments focused only on the wellbore tubulars and a very minimal radius behind the perforations. As previously discussed, uncontrollable losses of treatment fluid may have been as detrimental as the initial formation damage itself. Therefore, there was apprehension over pushing too much treatment fluid into the reservoir without a way to control its placement. However, there were candidates for which it seemed necessary to treat not only the wellbore but also deeper into the perforations. In a few cases there was a history of where the calcium carbonate workover fluid was used beyond normal operating boundaries. In two cases there were issues: once getting a rig in place after the well was killed and the kill fluid polymers started to break down and once the time needed to complete the operation extended beyond what was expected. Even after re-perforating it

was evident that the wells were heavily damaged by the workover fluids because post-intervention flow rates were almost zero from wells that were previously average to slightly above average in the field.

Remedial acidizing was performed on both wells as was the recommendation of the workover fluid specialists. Using the normal technique previously described, the acid treatment was placed in the perforated interval, agitated, left to soak overnight and was then kicked off. However, the acidizing was able to restore only a portion of the well's production. Upon researching, a tool was discovered which could use dynamic high-amplitude pressure pulsing to evenly treat perforation intervals (Wang et al 1998). This tool is more commonly used in heavy oil production wells and for waterflood optimization, but could also be deployed via coiled tubing in Laslau Mare. Lab testing of the tool made it seem very effective at uniformly treating the reservoir even behind the perforations, Fig. **11**. Some marketing information from the company showed that the treatment liquid could be injected using minimal volumes and pressures since the tool creates the pressure pulsing using differential pressures across the tool face not overall pressures in the wellbore. This principle helped minimize leak-off. Also, since the tool is designed to enhance production via excitation of the reservoir it was thought that the pulsing could help reduce capillary forces and prevent significant water blockages after treatment placement.

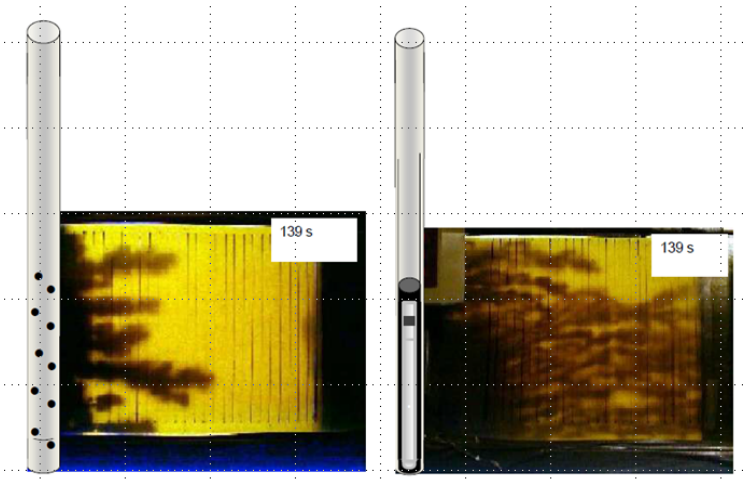

Fig. 11 -- Normal Treatment Distribution (Left) Versus Pulsed Treatment Distribution (Right)

As the case in the two wells previously damaged by the workovers was dire, it was considered a no loss situation to trial the tool in the field. It would be clear if the pressure pulses could further stimulate the wells above and beyond the normal acidizing procedures as they had already been treated using the normal procedure. Also, since the wells were already known to have higher potentials and were severely damaged, it reduced the production risk if the application didn't perform as expected and caused any temporary water blocks. Both wells were considered very successful applications of the new technology. Although Well A did not have its full production restored after intervention, the well's performance increased by almost 70% compared to the basic acidizing technique. This well had previously been damaged not only by the workover fluid but also by a shallow freshwater leak in the wellbore, so the true extent of formation damage in this well is not fully known. However, in Well B, the extent of damage was considered to be limited to the workover fluids and the pulsing acidization was able to enhance production by over 50% compared to traditional acidizing and restored production to pre-workover rates, Fig. **12**. Immediate production restoration was not obtained however, so water blocks were not fully treated but the results were still positive enough to apply the technology in other wells in the field.

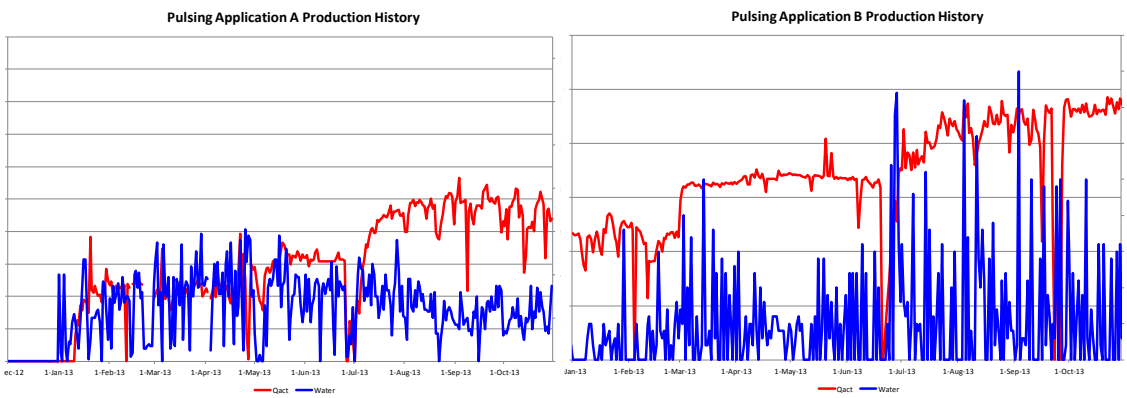

Fig. 12 -- Pulsating Tool Application Pilot Test Results

Based on the pilot tests, the pulsating tool was further applied four more wells in the field and in 2013, a further seven wells were treated without coiled tubing making it impossible to apply the pulsating tool. After three years, and an advancement in the technologies applied, nearly 80% of Laslau Mare was treated for various formation damages using specialized acidizing techniques.

Another technology (which was also a first in the basin) was applied directly to clear water blocks. In wells which were treated with acidizing and either had no positive response, or even a negative response, it was thought that the near wellbore water blockages could be restricting the potential of the wells to produce. It was thought that the driving force behind the water block was the combination of low permeability and low drawdown pressures from depletion of the reservoir. Wellhead compression was introduced to help lower bottomhole flowing pressure and increase differential pressure from the reservoir to the wellbore. Compression was applied in nearly 40% of the field from 2010 through 2013. One example of clearing a water block is in **Fig. 13**. It can be seen that the initial compression installation in September lead to a small increase in gas production followed by a steady decline as liquids could not be lifted from the wellbore (the well was not liquid loaded based on slickline measurement). However in October there seemed to be a fundamental change in the performance as liquids started being produced to surface. After another month there was a breakthrough and the well quickly doubled in gas flow rate to the operating capacity of the machine with increased water production. The compressor was then moved to another well, and the gas production tapered off a little but maintained a 50 to 60% increase compared to the pre-compression flow rates.

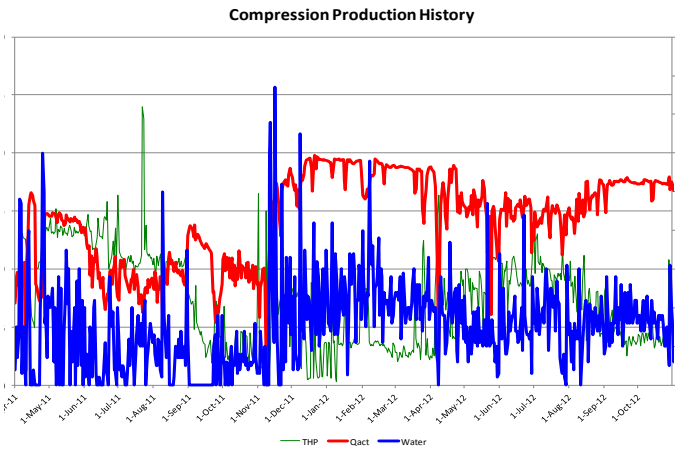

Fig. 13 -- Effect of Compression Clearing Water blocked Reservoirs

Field Wide Impact

Treatment of formation damage in Laslau Mare proved to be a large-scale campaign over the course of a year. Up to the date of this paper's publication, nearly every well in the field has been treated to some extent for remediation of formation damage (either naturally occurring or artificially imposed). The impact of treating formation damage in Laslau Mare is shown in Fig. **14**. Overall, the Association was very successful in identifying production enhancement opportunities using acidizing techniques or compression. Treatment of formation damage currently accounts for nearly 15% of the full field daily production and over 20 % of the Association incremental daily production, generating exemplary returns on investment.

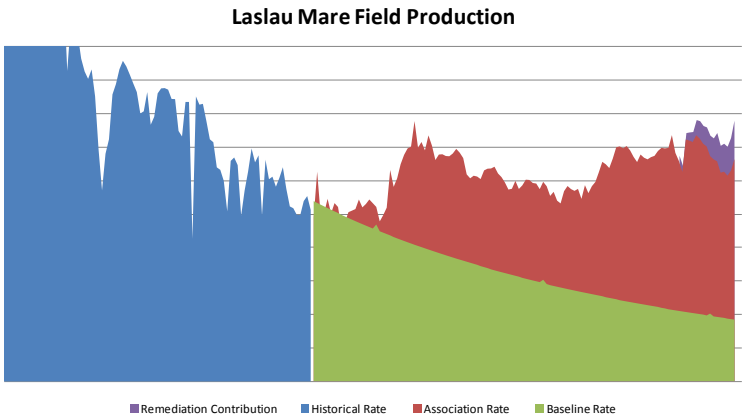

Fig. 14 -- Contribution of Formation Damage Treatment to Field Production

Future Implications

Based on the previous success of treating formation damage in Laslau Mare the plan going forward is to look at new technologies which could further enhance current techniques. This includes the use of new technologies, such as surface tension reducers, which could help chemically treat water blockages. It also includes the expansion and re-use of existing technologies such as the compressors and pulsating tools to further stimulate wells which were previously unsuccessful using traditional tools or in wellbores showing signs of calcite/halite re-deposition. Investment into formation damage remediation will continue to be a focal point of the annual maintenance operating budget in Laslau Mare.

Conclusions

- Laslau Mare is a depleted gas field, exhibiting signs that formation damage is impairing the daily production in the field.
- Formation damage is both naturally occurring and artificially imposed in Laslau Mare.
- Prediction of the severity of well underperformance and residual production potential was accurately performed using a modified decline curve analysis technique for candidate selection.
- Using designer carbonate matrix workover fluids cut post intervention cleanup time in half. Introduction of a formulated formic acid enhancement solution was also very successful in clearing out wellbore deposits and cleaning the perforations. Both techniques resulted in increased well performance and high returns on investment.
- New pulsating tools were successfully trialed and proved to further enhance production, especially where traditionally formation damage remediation techniques were not sufficient.
- Compression is a successful tool in clearing persistent water blockage from wells and can be a great tool for enhancing production in aging gas fields.
- A focused approach to treating formation damage in brownfields can lead to significant incremental production gains.
- Formation damage remediation will continue to be a focus in Laslau Mare, with further trials of new technologies and expansion of existing successes.

Nomenclature

Q = flow rate
PI = productivity index
Pr = reservoir pressure
Pwf = bottomhole flowing pressure

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