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Preventing Sustained Casing Pressure in Shale Wells

N. Kyle Combs, Fred Sabins, Jeff Watters, and Larry T. Watters, CSI Technologies

Abstract

The primary objective of this study is to identify and implement methods to mitigate sustained casing pressure (SCP) in shale wells. As part of a Research Partnership to Secure Energy for America (RPSEA) sponsored project, an extensive study was undertaken to evaluate SCP occurrence and develop methods to prevent gas communication.

An initial study of cementing materials and operations confirmed SCP occurrence around 50%, but provided no definitive identification of mechanisms. An in-depth analysis, extended to include data from drilling, completion, and production operations, revealed the actual SCP occurrence to be higher. The analysis also provided specific details regarding cause.

Two separate mechanisms were identified as contributing factors to SCP: short-term gas migration and cement seal failure caused by post-cementing operational stresses. It was found that both mechanisms occurred at an equal percentage and independent of the other. Furthermore, the analysis revealed information on cement design and placement that could not have been found using any other method. Modified cement composition and operational procedures were developed based on results of the in-depth analysis. These modifications were implemented and results show SCP occurrence was significantly reduced.

Introduction

Shale plays continue to extend technical, engineering, and operational boundaries of the U.S. land-based upstream petroleum industry. This unconventional hydrocarbon source provided opportunity to increase domestic production as well as technical challenges to produce quickly, economically, and safely. Overcoming these technical challenges resulted in specialized drilling and completion techniques (pad drilling or factory-style drilling) (Trevino 2014), long lateral well bores, and multiple fracturing treatments per well. These innovations allow shale operators to drill and complete economically and react quickly to market drivers; in effect becoming lean "swing producers" as described by Krane and Agerton (2015).

Demand for natural gas from unconventional resources has increased dramatically and has driven the development of these unconventional plays. Natural gas production in the U. S. rose from 1.73 TCF in 1999 to 13.64 TCF in 2015 (Statista 2015). The U.S. Energy Information Administration (EIA) predicted a 56% increase in domestic natural gas production between 2012 and 2040, most of which is expected to come from shale gas, see Figure 1 (AEO2014). Wellbore and cement sheath integrity will be critical to the safe development and production of these resources, and to minimizing the environmental impact of these wells.

The intense drilling activity, new drilling and completion methods, unconventional high-pressure formations, long horizontal sections, and multiple, large-volume fracturing treatments increase challenges for constructing and producing wells with minimum environmental or safety impact. One fundamental petroleum industry HSE issue is sustained casing pressure (SCP). SCP is the presence of measurable annular pressure at the wellhead that returns after being bled down. While SCP is not an indicator of well failure, it is an indicator that there is a potential issue with long-term well integrity. SCP has been a prevalent oil and gas industry issue since the early 1940's, but the impact of SCP on long-term life of shale wells coupled with environmental concerns have created major concerns in most shale gas plays.

SCP symptoms develop as early as during cementing operations and can happen any time during the lifetime of the well, including years after completion. Signs of early gas migration during or immediately after cementing operations include gas bubbling or an increase in pressure at the surface. Short-term gas migration mechanisms comprise cement slurry gelation and fluid loss during setting. SCP that occurs later in the life of the well often indicates long-term gas migration issues caused by physical damage to the cement or casing from post-cementing operational stresses. Parameters that affect the risk of long-term gas migration are cement mechanical properties, cement ductility, and drilling fluid filter cake removal prior to cementing. A common challenge with addressing both short-and long-term gas migration is that each shale play is different, so the application of cement systems and cementing best practices needs to be tailored for expected well conditions in that particular area.

RPSEA sponsored a long-term study of SCP in shale plays focused on the development of methods to remediate or prevent gas communication. One phase of the project involved in-depth study of SCP in a typical shale region including monitoring well performance through cementing, completion, and production. Based on this operational and performance review, the next action involved identification of SCP sources and causes along with methods to alleviate them. Finally, implementation of the revised methods would be tracked to determine the level of success achieved. This paper presents results of that study.

A representative shale play was selected for the study. Average incidence of SCP after cementing in this play was approximately 50%. However, initial review of cementing practices revealed no glaring errors in procedure or materials. Next, historical well data of SCP occurrence from the shale were collected for cementing, completion, and production operations. Data included well architecture, cement designs, and stimulation and cementing programs from wells both with and without SCP to identify trends and target areas for improvement. This data also helped classify the type, timing, and magnitude of gas communication.

This fundamental root-cause analysis identified two distinct barrier failure mechanisms that were not evident during normal performance monitoring and cement testing. By expanding the monitoring, trends in both short and long-term SCP related to cement function were identified along with protocols to alleviate the cementing performance issues.

The results of the root-cause analysis lead to modifying the cementing procedure. This included changing cementing composition as well as operational placement. The revised program provided cement with improved short-term gas migration control as well as improved mechanical properties to withstand stresses of post-cementing operations.

Revised cementing procedures were monitored and documented to ensure that design protocols were implemented properly and to capture performance results for evaluation. These results were then compared to pre-modification statistical SCP occurrence to determine if the changes made were effective.

SCP Identification

In order to determine how to prevent sustained casing pressure (SCP) from occurring in shale wells, it must first be understood where and how SCP occurs. SCP is the result of fluid or gas flow through the annular cemented regions. This is commonly known in the industry as gas or fluid migration. There are several different mechanisms but they mostly fall into two categories: short and long-term.

Background of SCP Mechanisms

Short-term gas migration describes gas flow that occurs while the cement is still liquid or transitioning from a liquid to a solid. This is typically during the first few hours after placement up to a few days at most. Sabins, *et al*. (1980) lists the controlling mechanisms that govern short-term gas migration as gel strength development within the cement slurry, pressure differential between initial hydrostatic pressure and formation pressure, fluid loss from the cement into the formation, and volume loss during hydration.

Short-term gas migration is prevented by cement composition and placement design optimizations. Using rigorous lab testing, cement can be designed to have adequate fluid loss control, quick transition time, and low hydration volume reduction (HVR). In addition, the total vertical height of the slurry in the annulus can be reduced so that the hydrostatic pressure exerted by the fluid column above the cement is larger and the overall pressure reduction across the cement is lowered.

Evaluation methods for assessing the severity of a well's short-term gas flow potential along with the predicted success of a cement composition designed for the well conditions also quantifies the prospect of short-term gas-flow. Sutton and Ravi (1989) presented one such metric as a dimensionless scaling factor that quantifies the likelihood of short-term gas flow occurring in a particular well, termed Gas Flow Potential, (GFP). GFP relates the maximum possible pressure reduction that can occur in a cement column as a result of cement fluid volume loss and static gel strength development. GFP also provides a metric for a well-cement system's risk of suffering short-term gas migration. The basic theory of the factor accounts for the effects of overbalance pressure, well dimensions, volume losses and gel strength development. All this reduces to a simple ratio of:

$$\mathrm{GFP} = \frac{1.67 \times \frac{L}{D}}{P_{OB}}$$

Where:

- L is the length of the slurry column in feet
- D is the diameter of the annulus in inches
- P_{OB} is the initial overbalance pressure at the gas producing zone

This relatively easy to obtainable information yields a GFP value usually ranging from 0 to 10. Cement design procedures are dictated by the magnitude of GFP:

- GFP = 0 – 3: Low Gas Flow Potential
- GFP = 3 – 8: Moderate Gas Flow Potential
- GFP > 8: High Gas Flow Potential

GFP directs the cement design process to a fit-for-purpose approach toward cement design. Once the potential for gas flow is quantified, the cement composition can be tailored with the right properties to prevent short-term gas migration. These theoretical short-term gas migration factors can be easily applied to specific field applications. The analyses performed for the wells during this investigation revealed the importance of dealing fully with short-term gas migration while simultaneously evaluating the cement system's long-term resistance to gas flow.

Long-term gas flow describes gas flow that begins weeks or months after the cement has been placed, and is caused by very different mechanisms than short-term gas migration. It is often referred to as gas leakage as opposed to gas migration and is usually caused by inadequate mechanical properties of the cement, poor drilling fluid removal during placement, shrinkage of the set cement, damage of the cement sheath due to subsequent well operations, or some other type of long-term degradation. Long-term gas leakage is usually much less severe than short-term gas migration, but is still an issue that must be resolved.

For the purposes of this report, cement integrity was found to be the long-term mechanism most prevalent. Goodwin and Crook (1990) describe in detail how cement integrity can be damaged or completely destroyed by thermally or hydraulically induced pressure extremes or pressure cycles during the well operations after a cement has been placed and allowed to set. During post-cementing operations extreme forces can be exerted along the cement sheath, such as those forces from drill pipe whip and temperature or pressure fluctuations from stimulation operations. Should the force exerted exceed the mechanical properties of the set cement, damage or deformation could be induced along the casing to cement interface, allowing fluid to flow. Pressure cycling can also cause failure to the bond at the cement to casing interface even if the maximum pressure exerted is less than the mechanical property limit of the cement.

Long-term gas leakage is prevented by the optimization of cement mechanical properties or well operations. Mechanical properties of the set cement can be tailored to prevent damage or deformation during post-cementing operations. In addition, operations to place the cement can be optimized by enhancing mud removal capabilities of the spacer or wash fluids pumped before the cement. In addition to cement optimization, post-cementing operations may potentially be optimized to exert less force, but still perform the task they are required.

These two types of gas migration are quite different and are resolved by focusing on different characteristics of the cement design and operations. In order to determine what must be done in a particular area, it must first be understood in great detail what type of gas migration is occurring. The following sections describe this type of in-depth analysis that was performed on a shale play that was having moderate to severe SCP issues, starting from the most basic of observation studies and cement testing followed by an in-depth root-cause analysis, all of which were necessary to determine what problems were present and what solutions needed to be implemented.

Initial Field Study

The project started by conducting an initial field study of the subject shale play consisting of onsite observations of cementing operations and the study of current well architecture. Information was collected for approximately 75 wells, evenly distributed over three distinct sections of the shale actively being developed between 2006 and 2013. For each section, 15 to 20 wells with SCP along with five wells without SCP were chosen to review in further detail. The wells were studied on an individual basis and as a whole to evaluate both local phenomena and formation wide trends.

Cementing and casing data reviews revealed that a typical well was initially drilled to 1,000 ft and a 9.625 in surface casing was cemented in place. This was followed by continued drilling to a total vertical depth between 2,500 and 4,500 ft TVD, and horizontally approximately 5000 ft. A 5.5 in casing string was then cemented in place. Top of cement (TOC) was brought to surface on all strings as per current regulations. On the production casing strings, a lead/tail cement system was used with the 14.2 lb/gal tail cement being brought to the 45° angle section of the wellbore, resulting in approximately 150 to 200 ft of tail cement above the shale formation. The remaining depth of production casing was cemented with a lead cement system having a density ranging between 10.8 to 12.8 lb/gal. These low density cement systems were used to keep losses from occurring during cementing operations as a result of being required to bring TOC to surface.

It is important to note that from looking at drilling data for these wells, it was discovered that high pressure sand zones were frequently encountered above the shale targeted for production. These sand zones frequently produced water or gas shows while drilling and are believed to be the source of the annular pressure.

Gas flow potential (GFP) was calculated at several points along the vertical section of the wellbore using the data supplied; since there was only a single density fluid in the vertical annulus, the GFP was constant at 2.85. This value is within the low range, but it is very close to the moderate potential for short-term gas migration.

Review of the hydraulic fracturing operations job reports provided pressures and stage information for the multiple stimulation treatments performed on each well. Pressure exerted on the casing during testing was typically 9,000 psi. The wells were stimulated using a standard plug and perf method with fracturing fluid pumped downhole through the 5.5 inch production casing. Anywhere from 10 to 15 stages were commonly pumped, with maximum pressures during each stage averaging around 4,500 psi.

Cementing design and operational post job reports showed that there were no major or easily identifiable trends that explained why there was SCP on some wells and not on others. Density variations were within acceptable limits during placement, and the majority of the jobs were performed successfully with no unplanned shutdowns.

The results from the initial field study indicated that SCP was occurring, but there was no explanation as to why it was occurring nor any insight given into the magnitude or time of the occurrence. There were no major issues being experienced while drilling or cementing these wells, and the results showed that there was very high variability, even within pads, in regards to SCP occurrence. Something else was needed to help identify where the problem was.

Initial Cement Testing

The cement systems being used were rigorously tested to determine if they were capable of withstanding short and long-term gas migration. This includes both testing of the liquid slurry and as it transitions to a solid as well as the long-term mechanical properties and durability of the set cement. While both systems were heavily tested, special focus was paid to the lead systems being used as they were the system that was covering the likely source of the annular pressure.

In general, standard tests described by API RP 10B-2 were performed along with more specialized mechanical property testing. The tests included free fluid, fluid loss, rheology, thickening time, ultrasonic cement analyzer (UCA), and various settling tests. Results for some of these tests can be seen in Table 1. The mechanical properties and cement durability tests ran were Young’s Modulus, Poisson’s Ratio, tensile strength, anelastic strain, and annular seal durability.

Ultimate compressive strength (UCS), Young’s Modulus, Poisson’s Ratio, and anelastic strain tests were performed using a standard load frame equipped with LVDT’s. Loading for UCS was at a rate of 35psi/sec until failure. To determine Young’s Modulus and Poisson’s Ratio, the sample was cycled from 5% to 50% of the UCS for three cycles before ending the test. The sample was fitted with LVDTs to determine radial and axial deformations during loading. For UCS, Young’s Modulus, and Poisson’s Ratio, values were taken on samples cured under bottom-hole temperatures and pressure for 1, 7, and 14 days.

The anelastic strain test setup is similar to the Young’s Modulus and Poisson’s Ratio testing, except the load is cycled 25 times as opposed to three. The amount of deformation that occurs per pressure cycle is calculated. Anelastic strain samples were cured for 7 days.

Annular seal testing was performed on the cement systems as well. The test method and apparatus used for this project is similar to what is described in detail by Sabins (2004), with a few modifications as follows: A specialized cell used for this test consists of a one inch steel pipe centered in a three inch steel pipe. Cement is then poured into the annulus created by the two pipes and allowed to cure at BHST for seven days. To test, a small amount of gas is applied to the bottom of the annulus, and the inner pipe is pressure cycled between 0 and 10,000 psi. When gas flow is detected at the top of the annulus, the annular seal has failed and the test is complete. From the number of cycles the slurry takes to fail, the total energy absorbed can be calculated.

The gel strength transition (GST) is the time it takes for the cement to develop gel strength from 100 $lb_f/100ft^2$ to $500lb_f/100ft^2$. During this time the cement begins to self-support, reducing the amount of hydrostatic pressure exerted on the formation, which can allow gas to enter the cement matrix and migrate toward surface. If this transition period is too long, the hydrostatic pressure of the cement column can drop below the formation pressure and can result in the gas creating permanent pathways to surface allowing gas to migrate indefinitely. Shorter gel transition times reduce the chance of those pathways forming. Typical industry best practice recommendations are that this time is 45 minutes or less.

The lead cement system does not solely cure at downhole static temperatures, so testing at lower temperatures of 92˚F (temperature at 1000 ft TVD) and surface temperature (80˚F) show how the GST time varied with temperature. The results can be found in Table 2. At 92˚F the transition time doubled and at 80˚F it was more than 3 times the time recorded at 132˚F. This means that along the vertical section of the wellbore, the time that fluid flow can occur while the cement is setting is increased, thus increasing the chance for flow pathway creation.

The lead systems had very low compressive strengths and the strength development was very slow, even at BHST as seen in Table 3. The table also shows how at lower temperatures in the higher vertical sections of the well, the compressive strength was even slower to develop and was significantly lower. This shows that the lead cement systems were overall very weak, even in best case scenarios of bottom-hole conditions.

The anelastic strain testing results displayed in Table 4 for the lead slurries show the deformation of the cement systems when cyclically loaded. Relatively speaking the values for slope and percent per cycle are high. In addition to the anelastic strain, the annular seal testing results in Table 4 show that under annular cyclical applied energy, the cement systems failed immediately. This is very significant in that is shows the drastic inability of the lead system to maintain any seal integrity, even under the slightest of post cementing operational stresses.

Initial Study Results

The initial field study and cement testing showed that there was the potential for SCP to occur. This is evident by the test results of the cement being used as well as the SCP occurrence noticed during observation and architectural study. However, there was still no sufficient data that showed when, how, and why the SCP was occurring in the first place. At this time, it was known that the problem existed, and that there was potential for both short and long-term migration to occur.

Something else was needed that could show all the details of the problem and aid in the identification of the root-cause of the problem. Without a proper identification, only guessing could be used to determine a solution. If a proper solution was to be determined, a thorough analysis that combined the data from drilling, completion, and production operations into a single analysis must be done.

In-depth Root-cause Analysis

In order to properly address the questions still remaining after the initial field study and cement testing, an in-depth analysis was performed by combining data from drilling, completion, and early production operational reports. This was a daunting task as the metrics and terminology used by the various departments differed greatly. This is also an uncommon practice in the industry as cross-over between departments is not often observed due to the differences in driving factors and motivation.

Information for a statistically significant number of wells drilled over a 6-month period was gathered to quantify the probability of SCP occurrence and to assess operational triggers associated with SCP. Data gathered for each well included SCP incidence, magnitude, and timing; as well as lead production string cement density, top of cement, time interval in days between cementing and fracturing, and the number of fracturing stages. SCP occurrence statistics and influence of well operations indicated from the data set are summarized below.

SCP was categorized according to four classifications:

N-N: No SCP pre- or post-frac
N-Y: No SCP pre-frac, but SCP noted post-frac
Y-Up: SCP detected pre-frac with pressure increasing post-frac
Y-Down: SCP detected pre-frac with pressure decreasing post-frac

Study well percentages by category for overall SCP occurrence are presented in Figure 2. The analysis indicated that 86.5% of wells drilled manifested SCP of some magnitude. 36.7% of study wells with no SCP exhibited signs of SCP occurrence after fracturing operations. 49.8% of study wells exhibited SCP prior to fracturing; and all of those wells were affected by stimulation operations. Prior to this analysis, it was estimated that less than 40% of the wells in the area had SCP. The true occurrence percentage would have never been known if not for this study. This spread of SCP occurrence and timing indicated that both short-term and long-term migration mechanisms were present.

A quarter of the wells in this study exhibited SCP pre-frac with the magnitude decreasing after fracturing. At first glance, these data seem to indicate that the fracturing treatment alleviated the SCP problem. In fact, reduction in SCP magnitude does not indicate that the seal breach created by gas flow after cementing was restored (even partially) by stimulating the well. The presence of SCP confirms that the flow path is still open. Reduction in magnitude could result from opening flow paths to low-pressure zones that become new annular gas flow destinations. In any event, no indication of reducing or eliminating the breached annular seal is supported by the lowering of SCP magnitude. This category of well performance was considered to be indicative of a seal failure resulting in an SCP issue.

Bringing lead cement slurry to surface on production strings is standard practice for many different shale plays, including the one that was studied for this project. However a small number of wells in the study underwent lost circulation or fall back during cementing, so top of cement was not at surface. Upon further inspection, SCP occurrence in wells with shortened lead cement columns was found to be significantly lower than for those with TOC at surface. Additionally, SCP occurrence prior to fracturing was lower with shortened cement column as indicated by the total percentage values in the N-N and N-Y categories. The results are detailed in Figure 3.

This pre-frac decrease in SCP associated with shortened cement column supported the improvement of short-term gas migration control. Gel strength development’s effect on hydrostatic pressure transmission and associated gas influx is lessened by a shorter column of gelling cement. As this theory would predict, the shortened column decreased pre-frac SCP. Post-frac SCP occurrence, however, was not affected by the column height decrease. This indicates that the lead cements were still susceptible to stress-induced long-term gas leakage.

The data obtained by the root-cause analysis successfully identified the problem and presented the information needed for a potential solution. Without the analysis, it would not have been known that both migration mechanism types were so prevalent nor that there was such a high occurrence of SCP. Using this data, a potential solution could be developed to aid in SCP prevention.

Solution

Using the root-cause analysis information, a solution was developed and implemented. This solution was two-fold; it involved changing both the operational design and the cement system design.

Leaving TOC below Surface

Operationally, the change included leaving TOC below surface as opposed to filling the annulus to surface with cement. The depth of the TOC was determined mostly by the depth of the target zone, but could also be determined by any issues or gas pockets encountered during drilling. By leaving cement below surface, a constant hydrostatic pressure in the form of a non-setting fluid column can be kept above the cement and thusly, the risk of short-term gas migration can be reduced significantly. This is backed up by cementing ideology as well. Even though it seems counter-intuitive, leaving cement below surface can actually prevent SCP. The equation for gas flow potential shown earlier can be used to prove this theory as well. This equation shows that by having a shortened cement column, less reduction in hydrostatic pressure is experienced and thus the GFP is lowered. An example of how this is possible is shown in Appendix A.

A lowered top of cement will also allow for a higher density, more competent cement system to be used throughout the critical part of the wellbore. This would aid in reducing the occurrence of both short and long-term gas migration. Another benefit of keeping cement below surface involves remediation of SCP. Should SCP develop despite the preventative measures put in place here, a lowered top of cement would allow for many more remediation options than there would be if top of cement were brought to surface.

New Cement Design for Lowered TOC Operation

With the lowered TOC now allowing for a higher density, more competent cement system to be used in the vertical section of the wellbore, it was determined that the best option from an operational and economic standpoint would be to use a single cement system as opposed to a lead/tail design. Recommendations for developing this cement were determined by industry accepted cementing best practices, and the data obtained from the initial study of the project, i.e. the energy analysis and GFP calculations. From a mechanical property standpoint, these criteria are also supported by SPE 1913405 (McDaniel 2014) and the report from the BSEE project E14PC00037 (Sonnier 2015) which describe how operational acts of completion greatly affect well integrity and what can be done to improve cement design to aid in mitigating those affects. The recommended criteria are displayed in Table 5.

The cement system developed was essentially the tail cement system that was being used prior to the operational change with some small modifications that were made to allow for an increase in fluid loss and free fluid control as well as lower the GST. With a more competent 14.2 lb/gal cement system being placed across any potential shallow gas pockets or small producing formations above the target shale, there is an obvious improvement over the lightweight systems that were previously covering these sections. Table 6 shows the results of the short-term gas migration testing performed. The lower temperature corresponds to a shallower well and the higher temperature corresponds to a deeper well. As can be seen, there is a major reduction in fluid loss and free fluid as compared to the results of the lead system that was previously covering the critical sections in the vertical wellbore. This in itself will significantly aid in short-term gas migration mitigation. Additionally, a major increase was seen in compressive strength and other mechanical properties due simply to the increase in density, these results can be seen in Table 7.

Results of Modified Cementing Procedure

Once the cementing program improvements were designed and substantiated via engineering analysis, personnel observed field implementation of the new cementing procedure for 6 months (equal time period to the first statistical analysis and field observation periods).

Operationally, the reports from the field observation were very good. With the use of a single cement system, the operations were simpler. Although no major operational issues were noted prior to the change, simplification usually results in smoother operations. There was a small concern that there would be losses due to the use of a higher density cement than prior to the operational change; however, no major losses were noted, even in areas that were known to have the potential for losses. This is also supported by the work shown in Appendix A.

Additionally, each well cemented following the revised procedure was monitored weekly for detection of pressure increase in the production casing annulus. This initial monitoring prior to stimulation of the wells targeted occurrence of SCP resulting from short-term gas migration. Table 8 shows the SCP occurrence as number of wells per pad with pressure on the production casing annulus. These data provide comparative information to assess the effectiveness of the revised cementing program in preventing SCP due to short-term migration (prior to stimulation). A total of 38 wells were monitored in this portion of the study, and SCP appeared after cementing but prior to stimulation on a total of 7. In total 18.4% of the wells showed short-term SCP development – a drastic decrease from the nearly 50% prior to the cementing procedure change. One difference between original SCP occurrence and that noted after cementing procedure revision is that post-procedure SCP occurrence appears to be clustered on a pad-by-pad basis. This is in stark contrast to Phase 1 results in which SCP occurrence prior to stimulation was random and distributed more evenly among the pads.

The final step in assessing the modified cementing procedure's effectiveness involved gathering information about SCP occurrence that matched information used for the initial statistical analysis. Thus, operations records for 40 wells that were cemented via the modified procedure, stimulated, and placed in production were examined for appearance of SCP after cementing, stimulation, or production. Severity of SCP and variation in intensity after stimulation were also noted.

Due to reduced drilling activity during this data collection period, the data set for modified-procedure wells was smaller than the original (initial statistical analysis included approximately 240 wells). However, the numbers of variables such as cement compositions or service companies were significantly reduced during this second period. Therefore the results of the two analyses can provide insight regarding cementing procedure changes on SCP occurrence. Comparison of these data sets illustrates the overall benefit of the cementing procedure revisions in terms of prevention of gas migration as well as seal durability during subsequent well operations.

Figure 4 shows the SCP occurrence for both pre- and post-cementing procedure change broken down into before and after stimulation, as it was for the initial analysis. It is very clear that the procedure change placing cement top below surface and using a single, more durable cement composition had a major effect on SCP occurrence. This modified procedure decreased SCP around 70% overall. Additionally, significantly fewer wells exhibited SCP resulting from stimulation (5.1% after modification down from 36.1% originally) which indicates the increased durability of the cement composition. However, as with the Phase 1 analysis, the results show that if SCP is occurring before stimulation operations, the stimulation operation affects the SCP magnitude.

In summary, study of SCP occurrence in this shale field resulted in identification of multiple underlying causes of seal failure. Initial review of cementing procedures and outcomes indicated no glaring issues with the cementing process. However, in-depth investigation of SCP appearance over the cementing, stimulation, and early production of the wells revealed SCP occurred over a range of times and events not routinely reviewed during normal well construction and production operations. Two seal failure mechanisms were identified indicating need for several significant modifications to cementing designs and operations. The modified cementing procedure specifically reduced GFP and ensured that likely gas flow zones were sealed with durable cement capable of withstanding stresses resulting from subsequent well completion and production (including hydraulic fracturing). These changes alleviated SCP occurrence.

Conclusions

1. Preliminary study of cementing operations and design uncovered no root-cause for SCP.
2. In-depth analysis successfully identified the timing, rate of occurrence, and that both short-term and long-term well integrity issues existed.
3. This broad analysis identified that SCP incidence was actually more prevalent than originally believed.
4. Seal durability was reduced due to post cementing operational stresses.
5. GFP calculations and the in-depth analysis also showed that short-term gas migration was significantly decreased when top of cement was not brought to surface.
6. Based upon root-cause analysis, cementing operations were altered to allow for TOC to be below surface and improve mechanical properties.
7. Lowering TOC allowed for a more competent cement to be placed and lowered GFP.
8. The mechanical properties of the more competent cement improved long-term seal durability.
9. Overall, SCP occurrence was reduced by 70% because of the operational and cement system alterations.
10. In-depth performance monitoring spanning drilling, completion, and production operations can better identify the nature and extent of the problem as well as indicate potential solutions.

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Nomenclature

API	American Petroleum Institute
BHCT	bottom hole circulating temperature
BHST	bottom hole static temperature
BSEE	Bureau of Safety and Environmental Enforcement
EIA	Energy Information Administration
GFP	gas flow potential
GST	gel strength transition
HVR	hydration volume reduction
LVDT	linear variable differential transducer
RPSEA	Research Partnership to Secure Energy in America
SCP	sustained casing pressure
SPE	Society of Petroleum Engineers
TOC	top of cement
TVD	true vertical depth
UCA	ultrasonic cement analyzer
UCS	unconfined compressive strength

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Tables and Figures

Table 1: Production Lead Cement System Short-term Migration Testing Results

Density (lb/gal)	BHST/BHCT (˚F)	Fluid Loss (cc/30min)	Free water (%)	Static Gel Strength (hr:min)		
				100 ($lb_f/100ft^2$)	500 ($lb_f/100ft^2$)	Transition
10.8	130/122	409	0.0	1:35	2:08	0:33
11.8	130/122	548	0.0	1:29	1:48	0:19
12.8	130/122	976	2.7	1:45	2:05	0:20

Table 2: Temperature Effect on Production Lead System Gel Strength Testing

Density(lb/gal)	Temp. (˚F)	Static Gel Strength (hr:min)		
		100 ($lb_f/100ft^2$)	500 ($lb_f/100ft^2$)	Transition
10.8	80	1:55	3:42	1:47
	92	1:42	2:47	1:05
	130	1:35	2:38	0:33
11.8	80	1:22	2:55	1:33
	92	1:37	2:20	0:43
	130	1:29	1:48	0:19
12.8	80	1:46	3:02	1:16
	92	1:35	2:16	0:41
	130	1:45	2:05	0:20

Table 3: Temperature Effect on Production Lead System Compressive Strength

Density(lb/gal)	Temp (˚F)	Compressive Strength (psi)	
		1 day	7 days
10.8	80	72	264
	92	162	190
	130	423	695
11.8	80	96	1233
	92	122	155
	130	235	849
12.8	80	28	-
	92	81	-
	130	212	1532

Table 4: Production Lead Cement Mechanical Property Testing

Density	BHST (˚F)	7 day Cure Anelastic Strain		7 day Cure Annular Seal
		Slope	% per Cycle	Applied Energy to Failure (Joules)
10.8	130	7.39E-05	6.78E-04	<20
11.8	130	2.93E-05	6.08E-04	22266
12.8	130	5.40E-05	3.40E-03	<20

Table 5: Lowered TOC Production Cement Criteria Recommendations

Lowered TOC Production Cement System	
Density	>14.0 lb/gal
Conditioned YP	>10
Free Fluid	0%
Fluid Loss	<150 ml/30min
UCA at 24 hours and BHCT°F	>1000 psi
Gel Strength Transition Time @ BHCT°F	<1 hr

Table 6: Post Operational Change Cement Short-term Gas Migration Testing

Density (lb/gal)	BHST/BHCT (˚F)	Fluid Loss (cc/30min)	Free water (%)	Static Gel Strength (hr:min)		
				100 ($lb_f/100ft^2$)	500 ($lb_f/100ft^2$)	Transition
14.2	143/143	292	0.0	2:28	2:57	0:29
14.2	120/118	140	0.0	2:48	3:28	0:40

Table 7: Post Operational Change Cement Mechanical Property Testing

Density	BHST (˚F)	Compressive Strength (psi)			7 day Cure Anelastic Strain		7 day Cure Annular Seal
		1 day	7 days	14 days	Slope	% per Cycle	Applied Energy to Failure (Joules)
14.2	130	805	4670	4613	-2.53E-07	2.21E-04	112921

Table 8: Post Operational Change Field Observation of SCP Occurrence

Pad	Number of Wells Observed	Number of Wells Experiencing Short-term SCP
Pad A	3	0
Pad B	1	0
Pad C	3	2
Pad D	1	0
Pad E	2	0
Pad F	4	3
Pad G	2	0
Pad H	2	0
Pad I	2	0
Pad J	1	0
Pad K	1	1
Pad L	1	1
Pad M	3	0
Pad N	1	0
Pad O	2	0
Pad P	2	0
Pad Q	1	0
Pad R	3	0
Pad S	3	0

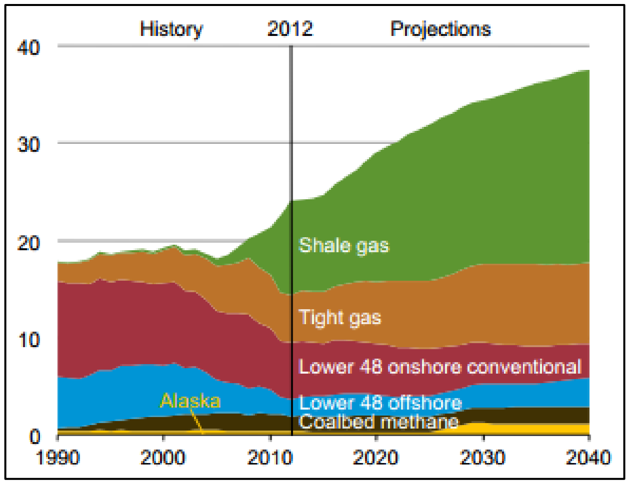

Figure 1: U.S. Natural Gas Production – Reference case (Source: EIA AEO2014)

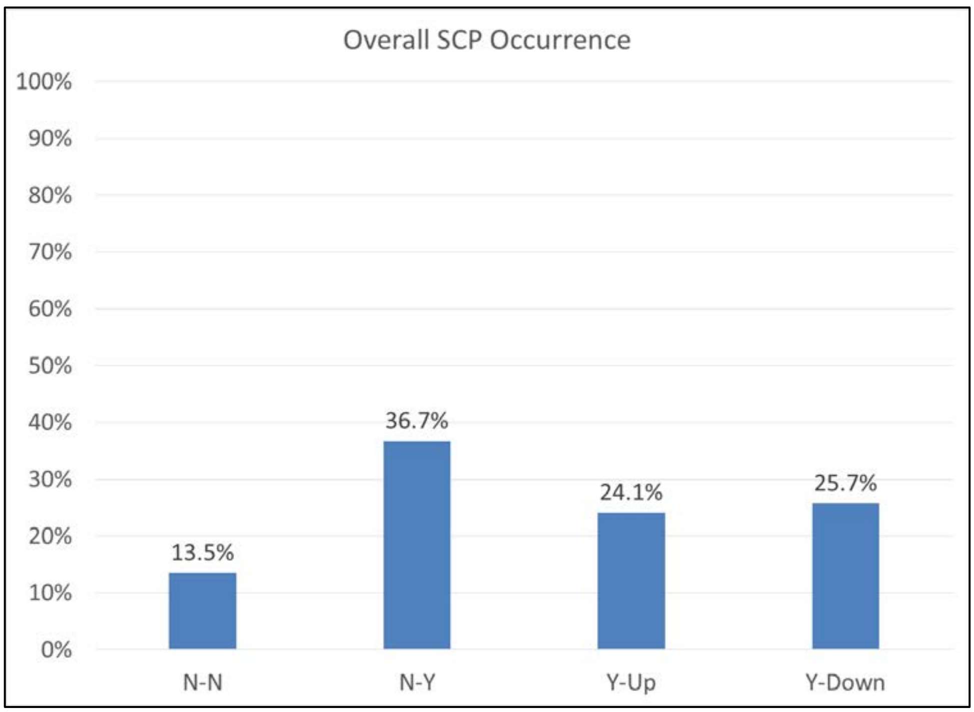

Figure 2: Initial Root-cause Analysis Overall SCP Occurrence

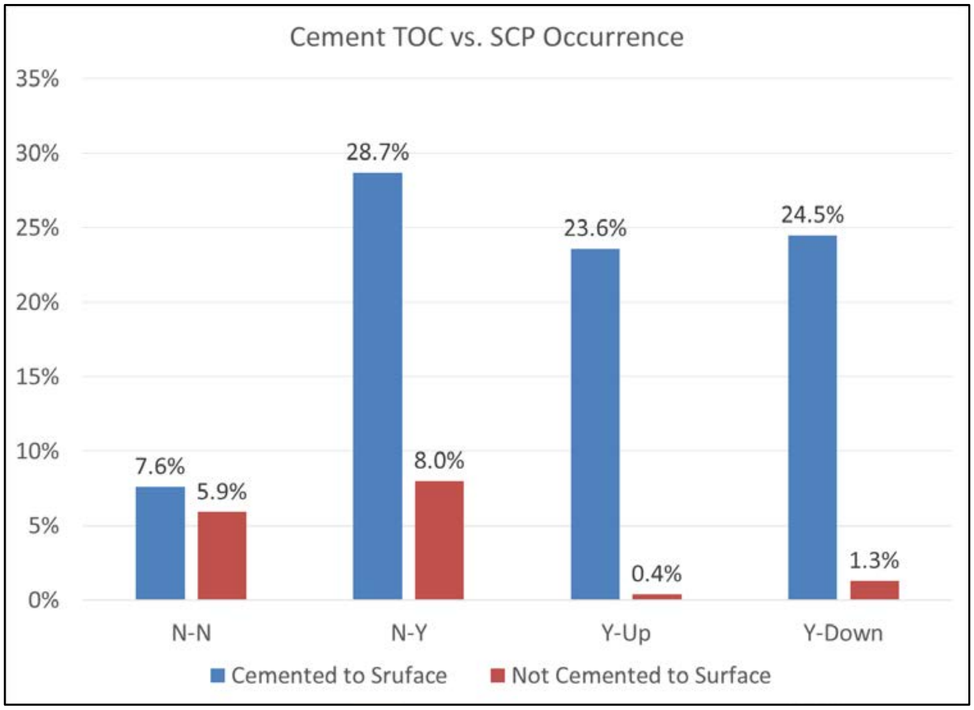

Figure 3: Cement TOC vs. SCP Occurrence

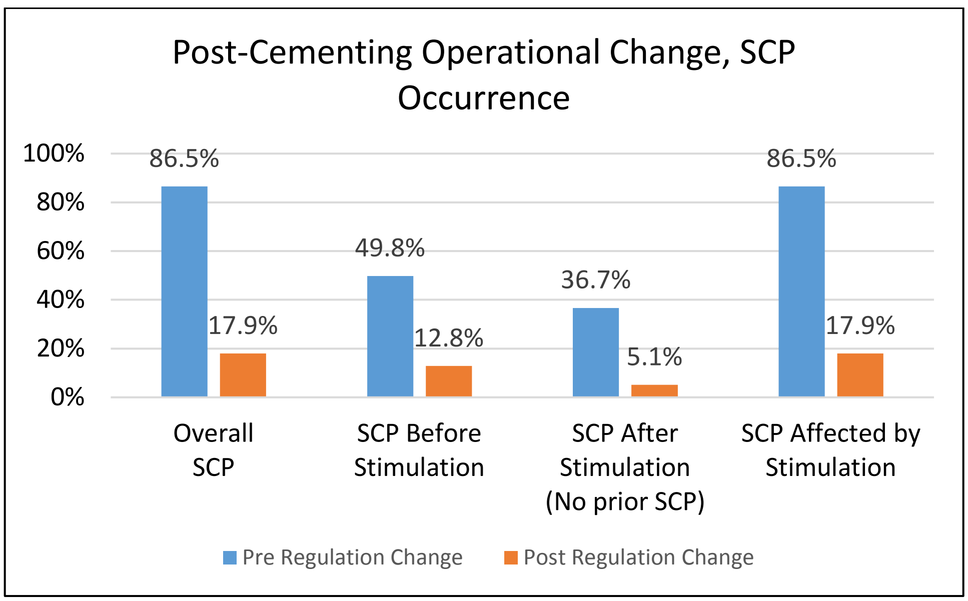

Figure 4: SCP Statistical Occurrence, Pre- and Post-Cementing Operational Change

Appendix A

1400 ft TOC Example of why Lowered TOC is Beneficial

A common and sometimes required practice for production casing cementing operations in shale wells is to cement the production casing to surface. When this is done, concern for lost circulation and fall back limit the density of the cement, which in turn limits the cement's mechanical properties and durability during subsequent well operations. The longer cement column also increases short-term gas flow potential since this entire column experiences hydrostatic decline during the slurry transition period. By leaving the top of cement (TOC) below surface, there are several benefits that can aid in both short and long-term gas migration mitigation. This design change would allow for an increase in the density of the cement used in the critical (vertical) section of the wellbore where the source of annular pressure is usually located. An increase in density would improve well construction through greater control of final TOC with reduction in lost circulation and fall back, decreased short-term gas flow potential (GFP), and improved mechanical durability of cement. To explain this, an example of a well with surface casing set at 1000 ft will be used to compare two different cementing operation scenarios: TOC at 1400 ft and TOC brought to surface. Results, presented in the tables and figures below, compare the hydrostatic pressure of the fluid column after placement in the well and the overall GFP of the two scenarios.

All lead cement density calculations versus depth were based on matching the hydrostatic pressure of the mud/cement column at depth to that of a full column of 11.8 lb/gal cement. This is the middle density of the lead cement systems observed in the initial study done for this project. Figure 5 compares the depth vs hydrostatic pressure of a 14.4 lb/gal cement system with TOC at 1400ft and a 8.8 lb/gal brine fluid column above(Lowered TOC) to an 11.8 lb/gal cement system cemented to surface (Surface TOC). As can be seen, the hydrostatic pressure of the lowered TOC option is less than the surface TOC option down to a depth of 3015 ft. This is significant as it allows for a much higher density cement system to cover the critical section of the well while staying under the risk of loses and formation breakdown associated with the surface TOC option.

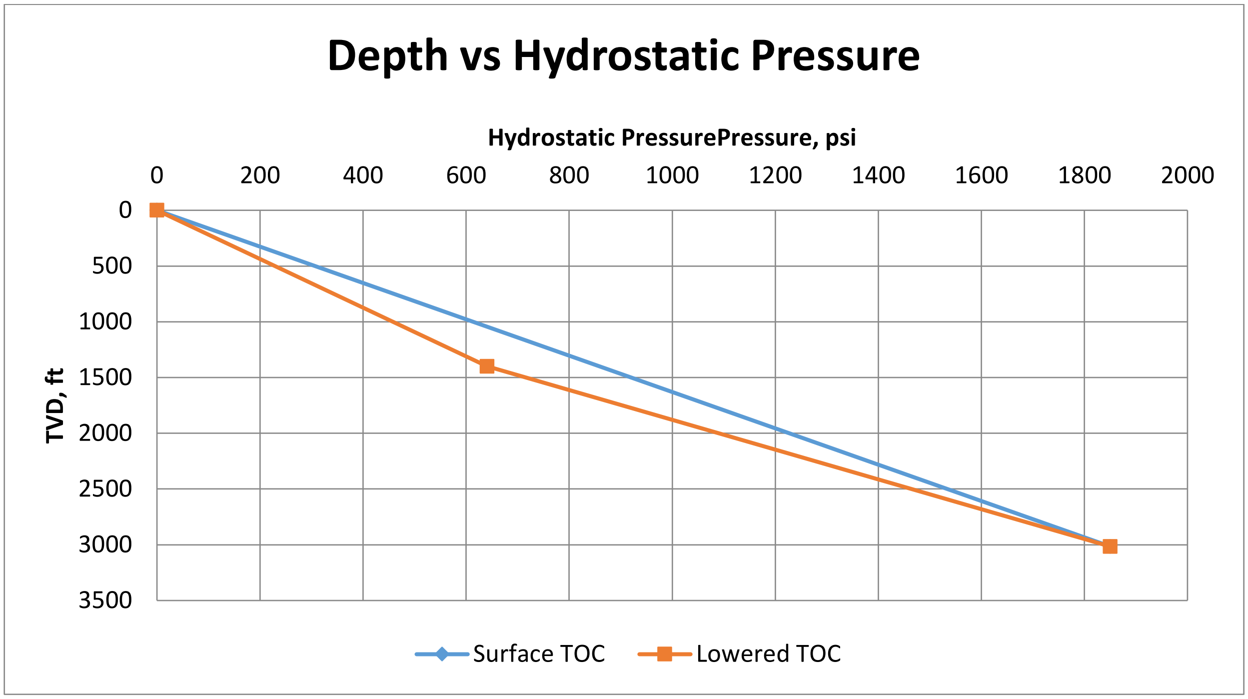

Figure 5: Hydrostatic Pressure Comparison

Lowering the TOC also lowers the GFP, as can be seen in Figure 6. The GFP calculation is highly dependent on initial hydrostatic pressure and reduction in hydrostatic pressure, which is a function of cement column length. It, therefore, makes since that the GFP would be lowered as the lowered TOC scenario has a much shorter cement column than the surface TOC scenario, and much less reduction in hydrostatic pressure will take place. The constant fluid column provided by the 8.8 lb/gal mud in the lowered TOC scenario maintains an unchanging hydrostatic pressure, also aiding in lowering the GFP. GFP is an open-hole calculation, thus the GFP for both scenarios is zero until they reach the bottom of the surface casing at 1000 ft.

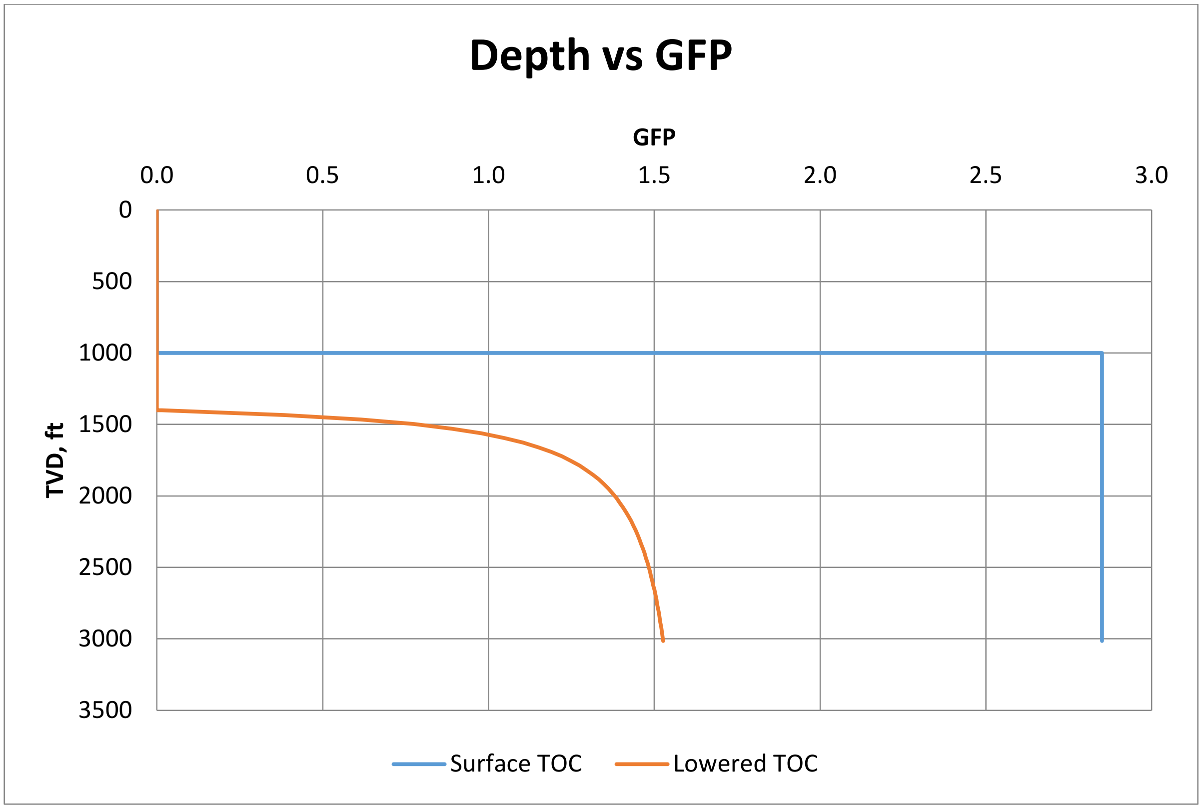

Figure 6: GFP Comparison

As a final example, GFP for various lowered TOC scenario cement densities are summarized in Table 9. The same scenarios described above have been used, with the exception of the cement density of the lowered TOC scenario being varied. The purpose is to show different depths attainable with higher density cement systems left with TOC at 1400 vs cementing to surface with an 11.8 lb/gal system. The chosen general depths of comparison are 2,000 feet and at the hydrostatic pressure intersection depth (HPID). HPID is the point at which the two scenarios hydrostatic pressures intersect, see Figure 5 for reference.

Lowered TOC Production Slurry Density Table				
Density	**14.4**	**14.0**	**13.6**	**13.2**
HPID, ft	3015	3309	3733	4400
GFP @ 2,000 ft	1.38	1.46	1.55	1.66
GFP at HPID	1.53	1.64	1.78	1.94

Table 9: Lowered TOC Cement Density Comparisons