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Establishing well operability limits for frac pack sandface well completions using a screen erosion model and well completion score card

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ESTABLISHING WELL OPERABILITY LIMITS

FOR FRAC PACK SANDFACE WELL COMPLETIONS

USING A SCREEN EROSION MODEL AND WELL COMPLETION SCORE CARD

by

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ABSTRACT

Completion quality has a direct impact upon the maximum production rate at which a frac pack well should be operated. Best practices for frac pack well completions ensure the highest possible quality for the well completion. A novel frac pack well completion score card was developed based on best practices for frac pack well completions identified through consultation with industry experts. The score card systematically combines and assesses completions data readily available standard completion reports. The outcome of the score card process is a numerical completion quality rating, which combines all well design and frac pack operations information.

The completion quality rating is integrated with a proprietary screen erosion tool that determines fluid velocity exiting the perforations at the inside of the surface of the casing (Vc), and calculates an associated fluid velocity at the sand screen (Vs) based on results of a computational fluid dynamics model. A C-factor based on fluid velocity at the casing perforations is used to determine the safe drawdown operating limit for the frac pack well.

The frac pack completion score card provides a substantial improvement to previous methods of determining frac pack well operational limits, by combining all known factors contributing to well completion quality and identifying how those factors ultimately affect the well's maximum allowable drawdown. The frac pack score card also raises awareness of the best practices identified in the research and therefore promotes the use of those best practices during frac pack installation. The score card and associated screen erosion model have been tested and verified by industry, and have been accepted for industry use.

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NOMENCLATURE

Symbol	Description
ΔPperf	Differential Pressure at the Perforations
ΔP skin-mechanical	Differential Pressure Due to Mechanical Skin
σ_v	Vertical Stress
σ_{Hmax}	Maximum Horizontal Stress
σ_{hmin}	Minimum Horizontal Stress
μ	Viscosity, cp
v	Poison's Ratio
ρ	Fluid density, lb/ft^3
A	Area Open To Flow
A	Cross-sectional Area of a Rock Core
A_{1p}	Cross-sectional Area of One Perforation Tunnel
B	Non-Darcy Turbulent Coefficient, 1/ft
BHA	Bottomhole Assembly
BOP	Blowout Preventer
cp	Centipoise
CFD	Computational Fluid Dynamics
d40	Diameter at which 40% of the Sample by Weight is Retained
d90	Diameter at which 90% of the Sample by Weight is Retained
d_p	Diameter of the Perforation Tunnel
DPSV	Dynamically Positioned Stimulation Vessel
D_q	Phase Change and Rate Dependent Damage Effects
E	Young's Modulus
EMW	Equivalent Mud Weight
F	Force
FLCD	Fluid Loss Control Device
FLP	Fluid Loss Pill
FLPAP	Fluid Loss Pills After Perforating
FP	Frac Pack

FVF	Formation volume factor, rb/stb
G	Shear Modulus
Gap	Screen OD Minus Casing ID
GP	Gravel Pack
H	Net Pay, ft TVD
h_{perf}	Perforated Interval Thickness, ft
HEC	Hydroxyethyl Cellulose
HPF	High Permeability Fracturing
HRWP	High Rate Water Pack
ID	Inside Diameter
JIP	Joint Industry Project
K	Average Horizontal Permeability, md
K_ρ	Proppant Permeability, md
KGD	Khristianovich, Geertsma, de-Klerk
L_p	Perforation Length, in
L/D	Lay Down
LPSA	Laser Particle Size Analysis
md	Milli-Darcy
MD	Measured Depth
MDT	Modular Formation Dynamics Tester
N_{pof}	Number of Perforations Open to Flow
NTU	Nephelometric Turbidity Units
OB	Overbalanced
OD	Outside Diameter
P	Pressure
$p_{density}$	Perforation density in shots per foot
P_{eff}	Perforation efficiency
$P_{hydrostatic}$	Hydrostatic Pressure
P_{wf}	Bottomhole Pressure
P_r	Reservoir Pressure
PKN	Perkins, Kern, Nordgren

POOH	Pull Out Of Hole
PPG	Pounds Per Gallon
PPS	Pre-Packed Screen
PTA	Pressure Transient Analysis
P/U	Pick up
PVT	Pressure-Volume-Temperature
RB	Reservoir Barrels
RFT	Repeat Formation Tester
STB	Stock Tank Barrels
Q	Fluid Rate, stb/day
S	Skin
SC	Score Card
Sd	Skin Due to Reservoir Damage
Sp	Skin Due to Perforating
SAS	Stand Alone Screen
SEM	Screen Erosion Model
SwRI	Southwest Research Institute (SwRI)
SSSV	Subsurface Safety Valve
TSO	Tip Screenout
TCP	Tubing Conveyed Perforating
TVD	True Vertical Depth
UC	Uniformity Coefficient (d40/d90)
UCS	Unconfined Compressive Strength
UB	Underbalanced
VBA	Visual Basic
Vs	Velocity at the Screen
Vc	Velocity at the Perforation Tunnel (Casing)
WAG	Wild Guess
WWS	Wire Wrapped Screens

1. INTRODUCTION

Sand production refers to the appearance of sand grains in produced reservoir fluids. Sand production is a complex phenomenon that depends on the stresses near a wellbore and the properties of reservoir rock and fluids. Many factors, such as geology, rock, mechanical factors, drilling, and production modes must be considered to obtain an understanding of how and why sand production occurs.

Rahmati et al (2013) provides a recent, comprehensive review of sand production prediction models. These models combine near wellbore principal stresses (σ_v, σ_{Hmax}, σ_{hmin}) with rock mechanical properties (E,G,v), rock strength and friction to determine the likelihood of sanding.

Rock strength is probably the single most widely used parameter in predicting the likelihood of sand production and the need for a well completion with sand control. Rock strength is commonly determined with a compressive strength (UCS) test on core, which measures the shear strength of the rock under no confining pressure. When core is not available, UCS may be derived from offset well logs, to create a synthetic geomechanical profile for the well to be drilled. Chevron uses a powerful proprietary mathematical algorithm (RMA) for calculating rock mechanical properties, reservoir stress states, and to perform the sanding production prediction analysis. Many companies have developed similar proprietary sand production prediction methods, which vary depending on the way in which UCS is determined, or the sanding mechanism theory.

Well operations and the manner in which a well is produced significantly affect the likelihood or extent of sand production. Reservoir sand typically enters the wellbore if the rock strength is exceeded by the pressure differential across the sandface, which is referred to as drawdown. Thus, excessive drawdown pressures exacerbate sand production. A very rough rule of thumb based on a drawdown of 1.7 times the unconfined compressive strength is used to predict the likelihood of sand production, and therefore require some form of sand control. However this rule of thumb is only a rough estimate, and cannot be used in place of rigorous engineering sand control design.

Industry has long recognized the benefit of limiting well flowrate, i.e. drawdown, as a means of controlling sand production. This technique is still employed today, although flux across the sandface is now a limiting criterion, as described in this thesis. The onset of water production later in the life of a well may also lead to sand production, because water adsorbs at the clay surfaces and can reduce the magnitude of formation internal friction. Water production may also weaken the cementation material of the formation (HES, 1995).

Sand production in an oil or gas well can cause a host of problems. Cavity formation around the wellbore can cause buckling of the casing as shown in Figure 1.1. Erosion of downhole or surface equipment, plugging of the wellbore, and fill up of the surface separator with sand may also cause production to cease or the well to fail. An example of damage to downhole equipment due to sand production is shown in Figure 1.2. Issues of disposing of the produced sand, lost production, and equipment replacement costs though not specifically well failure are certainly at a minimum economic problems that are undesirable. Considering the high cost of installing deepwater wells (10’s of millions US dollars for each well), it is necessary to address sand production for wells completed in weak rock reservoirs (Dickerson, 2006).

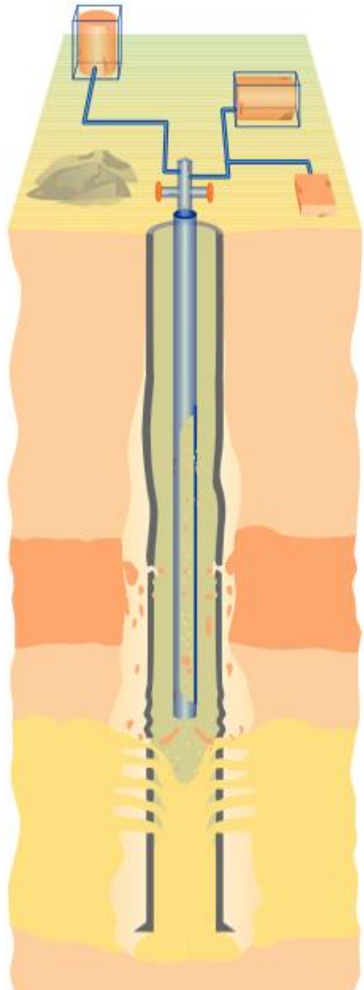

Figure 1.1 Wellbore sand production problems including voids behind casing, formation subsidence, casing collapse, and sand fill (Carlson et. al, 1992)

Figure 1.2. Erosion of downhole equipment due to sand production (Statoil, 2013)

If sand production is predicted and the amount of sand cannot be tolerated through the completion and production equipment, then some form of sand control must be included in the well completion design. Figure 1.3 summarizes the many types of sand control completions.

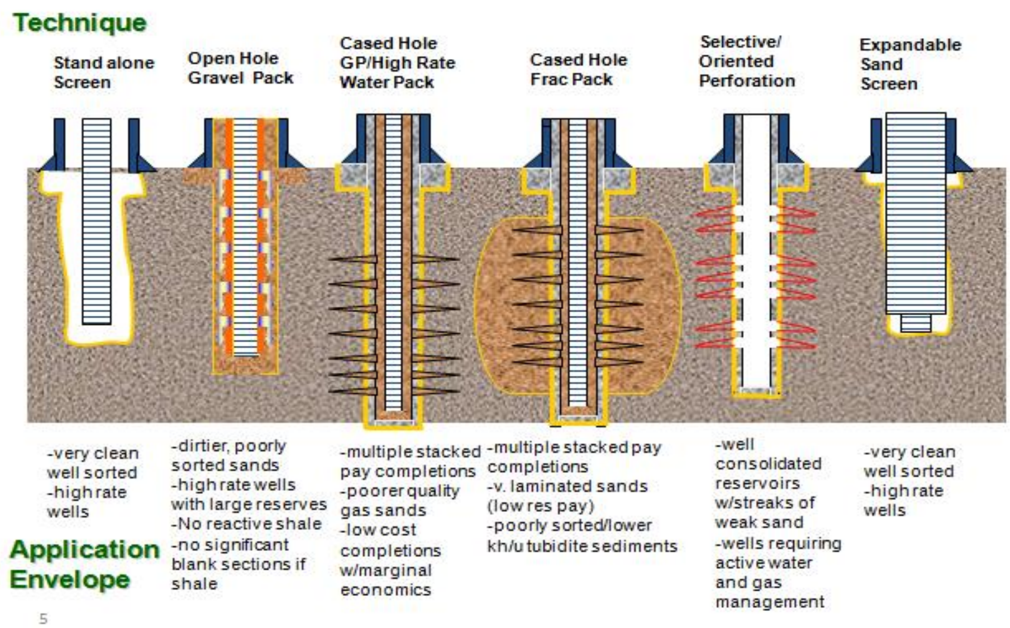

Figure 1.3. Examples of the most common types of sand control and their typical applications (Norman, 2008)

Most of the sand control methods shown in Figure 1.3 are sand consolidation or exclusion techniques. These methods include stand-alone screens, openhole and cased hole gravel packs, high rate water pack, and expandable screens. Oriented perforating is a special method of sand control.

Orienting or restricting perforation placement may reduce or eliminate sand production without the need for specialized equipment shown in Figure 1.3. Oriented perforating places the perforation in the direction of σ_{Hmax}, thereby limiting forces on the side of the perforations to σ_{hmin}. The primary challenge of this approach is correctly modeling the principal stresses orientations, and then shooting the perforations in the correct direction. Selective perforating can also be used to perforate only the higher strength rock interval and limit forces applied to the weaker rock intervals. Unfortunately, there tends to be a significant negative correlation between reservoir strength and permeability, thus the most prolific productive zones in a well tend to be composed of the weaker formation material. Clearly, there is a big incentive to perforate and produce from the most productive zones in any well.

Screens have been used prevalently to exclude sand from oil and gas wells. There are many types of screens available including wire-wrapped screens (WWS), pre-packed screens (PPS) and premium screens (sometimes called mesh or woven screens). Where only a screen is run in the completion, it is referred to as a standalone screen (SAS). Standalone screens are used widely, particularly in horizontal wells, but have demonstrated poor performance due to plugging or collapse. Figure 1.4 shows a sand control screen.

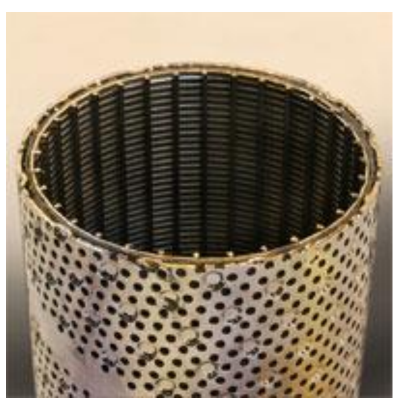

Figure 1.4. PetroGuard Mesh Screen (Courtesy Halliburton)

Gravel packing is a widely applied sand exclusion method whereby a specifically sized sand (referred to as gravel) is pumped downhole with special equipment and placed behind a screen in an openhole well, or between the screen and casing, and inside the perforations in a cased hole well. Gravel packing does not exceed the breakdown pressure of the formation to place the sand. High rate water packs (HRWP) are similar to gravel packs except that low viscosity water, pumped at high rates, is used to transport and place the gravel.

An expandable sand screen is a standalone screen that can be mechanically expanded to increase in diameter as necessary (Ott and Woods, 2003). The screen will expand against the formation and provide strength and support. Belarby (2009) provides a useful overview of expandable screens. Expandable screens have nearly replaced openhole and cased hole gravel packs in some operating areas of the world.

It is important to note that the sand control exclusion methods (screens, gravel packs, HRWP) are completions that act as ‘filters’ for the formation sand, and thus introduce large positive skin effects. Even wells with low initial skin values (<10) typically experience the progressive evolution of a large skin value as fines plug the filtering mechanism (Economides, M.J.; Watters L.T.; and Dunn-Norman, S., 1998). Hence, it should be understood that these sand control methods all reduce well production.

Frac pack completions are different than the other sand control methods, as they include high permeability fracturing (HPF) techniques. High permeability fracturing

(HPF) is a specific fracturing technique designed for high permeability reservoir environments, utilizing a short yet wide fracture geometry. As in all hydraulic fracturing, HPF provides a low skin factor, which enables reservoir flow. HPF was also found to be a useful means of stabilizing sand production, when combined with casing and a screen. Today, more than 65% of the wells in the US Gulf of Mexico, and many other wells worldwide, utilize frac packs for sand control, due to their inherent advantages in well productivity.

1.1. FRAC PACK COMPLETIONS

Frac pack well completions are a relatively advanced sand control technique that attained widespread use starting in the early 1990's. Frac packs are primarily a cased hole sand control technique using standard or premium screens, but may also be applied in openhole completions using expandable screens (Camps, Chando, and Ellis, 2010).

Figure 1.5 depicts an aerial view of a frac pack in a cased hole completion, utilizing a screen. There are two principal fractures, which are relatively short. Many of the other perforations have taken some of the gravel, and may also receive fluid from the fractures, through the high permeability formation adjacent to the wellbore. If the formation permeability is low compared to the fractures, then the other packed perforations flow contribution will be small compared to the induced fracture (Bellarby, 2009).

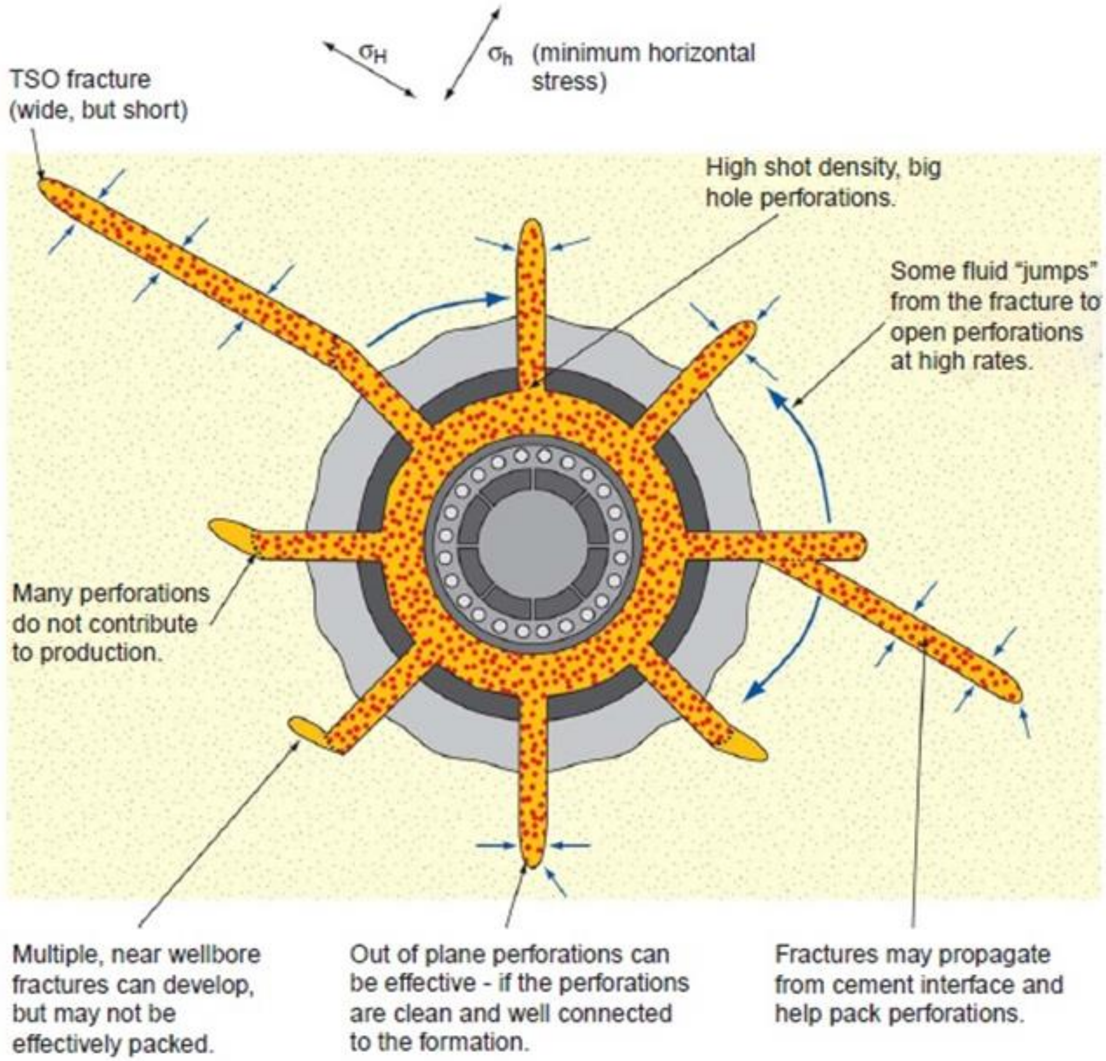

Figure 1.5. Frac Pack Geometry and Production Behavior (Bellarby, 2009)

Properly designed and placed frac pack completions provide a greater flow capability than similar gravel pack completions. Their enhanced conductivity can result in larger rates through the perforations. However, turbulence and inertial flow effects become more important with frac packs due to the reduced flow area through the smaller perforation and the higher flow rates. These non-Darcy effects (i.e. rate-dependent skin effects) are dependent on the permeability of the gravel (Bellarby, 2009).

Establishing fracture width is critical in frac pack completions and relies on an understanding of the formation fluid leakoff, fluid efficiency and closure pressure during the fracturing process. The intent of the fracture treatment is to create a short, yet relatively wide fracture. This is accomplished with tip screenout (TSO) techniques.

A tip screenout refers to when the proppant pumped into the fracture and sand bridges out near the fracture tip, halting the propagation of the fracture length, but the pumping treatment continues for a period of time. The increased mass from continued pumping begins to inflate the width of the fracture, because the fracture can no longer extend in length. The result is a short, relatively wide fracture with high conductivity.

A tip screenout can precede, and is contrasted by, a near wellbore screenout – called a near-wellbore lockup; and also contrasted by screening out in the completion (inside the sand screen) – called screen lockup.

TSO's are an integral part of the frac pack process, because this fracturing technique results in the greatest propped width of the fracture when the pumping equipment reaches its operational limits. A large propped width ensures good packing of the fracture, as well as the greatest opportunity for a low skin and high production rate. A large propped width helps prevent plugging of the filter pack when the well is operated at high production rates due to the movement of fines into the pack from the reservoir rock (Ghalambor et al, 2009).

Net treating pressure is the difference between the downhole treating pressure and σ_{hmin}, which is also approximates closure stress. This net pressure is measured by monitoring the annulus pressure or by using bottomhole gauges.

Nolte-Smith net pressure analysis was introduced in 1981 and has been used to interpret net pressure during a hydraulic fracturing treatment when 2-D models were used for fracture design and most fractures were vertically contained during fracture propagation. Based on PKN fracture geometry (Perkins and Kern, 1961; Nordren, 1972), KGD (Khristianovich, 1955; Geertsma and de-Klerk, 1969) and radial models, Nolte and Smith analyzed the fracture pressure response, and then predicted fracture morphology based on the pressure response. The interpretation of the fracture growth during pumping is explained as modes or slopes of the log of net treating pressure plotting against the log of treating time, as shown Figure 1.6. The low constant slope of Mode 1 represents stable length growth, while the horizontal Mode 2 (zero slope) represents stable height growth. Mode 3a is usually associated with restricted growth in length but an associated addition width growth such as during TSO, and the steeper slope of 3b represents the near-wellbore screenout with an accompanying rapid increase in wellbore pressure. The negative slope shown by mode 4 is associated with rapid height growth that may be reflective of radial fracture geometry.

During a frac pack treatment the tip screenout event is confirmed if the slope of the Nolte-Smith plot is greater than or equal to one during the pumping of the fracture treatment (Nolte and Smith, 1981).

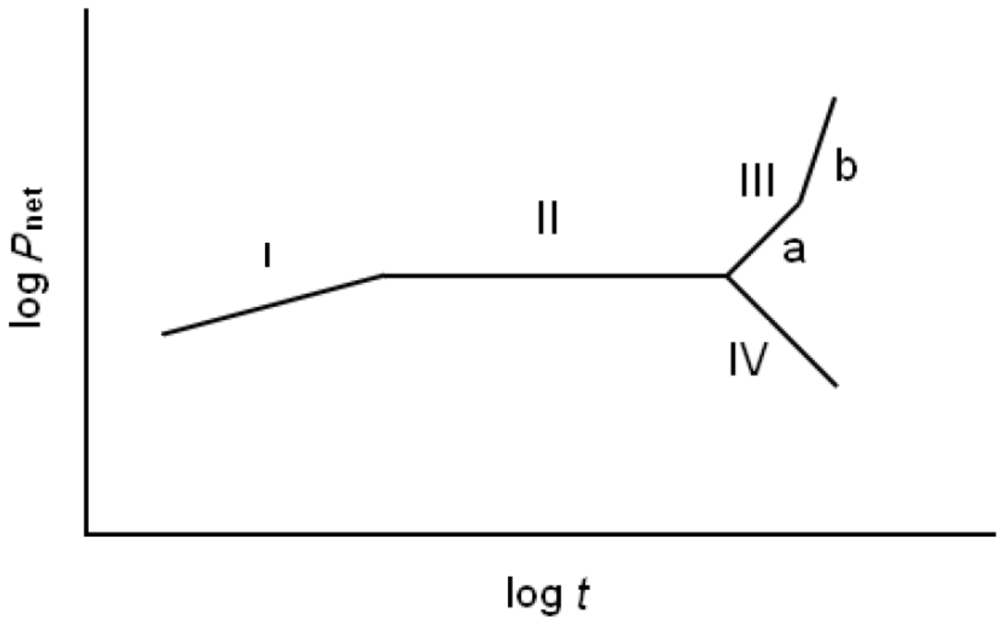

Figure 1.6. Nolte-Smith Analysis Pressure Interpretation Plot (Nolte and Smith, 1981)

1.1.1. Frac Pack Field Installation Procedures. Fundamental aspects of frac pack completion installation are provided here to assist the reader in understanding materials (especially fluids), and processes that affect the overall quality of the frac pack completion.

Following drilling of the wellbore, casing is cemented into the interval to be completed, and the casing is perforated using shaped explosive charges. After removal of the perforating guns, a packer is run, and the frac pack completion assembly including the sand screen is placed in the well. Figure 1.7 depicts a typical lower completion assembly used for a frac pack installation.

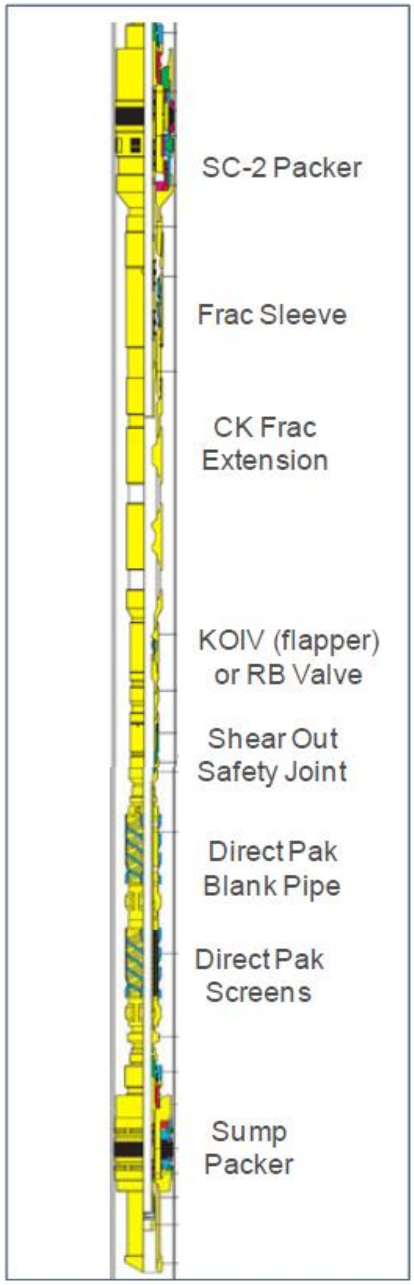

Figure 1.7. Typical Lower Completion Equipment (Prada et al, 2012)

A slurry of frac fluid and proppant ("gravel") is pumped down the wellbore using specialized equipment to place the filter pack into the annulus formed between the sand screen outside diameter (OD) and casing inside diameter (ID). High pressure surface pumping equipment causes the frac fluid to overcome the minimum horizontal stress of the reservoir, and a fracture is opened in the formation. The fractures typically result in two wings approximately 180 degrees apart and oriented vertically. Fractures tend to form vertically due to the depth of the petroleum bearing zones, as overburden (vertical stress) is larger than the minimum horizontal stress.

Proppant fills the perforation tunnels and rock fractures, and as the fluid leaks off into the reservoir, a permanent “gravel pack” is placed into the “fracture” (hence the name “frac pack”). The pack also includes the annulus between the OD of the downhole screen and the ID of the casing, and this part of the pack is called the annular pack. This annular pack is a very important part of the completion because it helps to exclude the formation sand and prevent it from reaching the sand screen. A typical frac pack sand screen in shown in Figure 1.8.

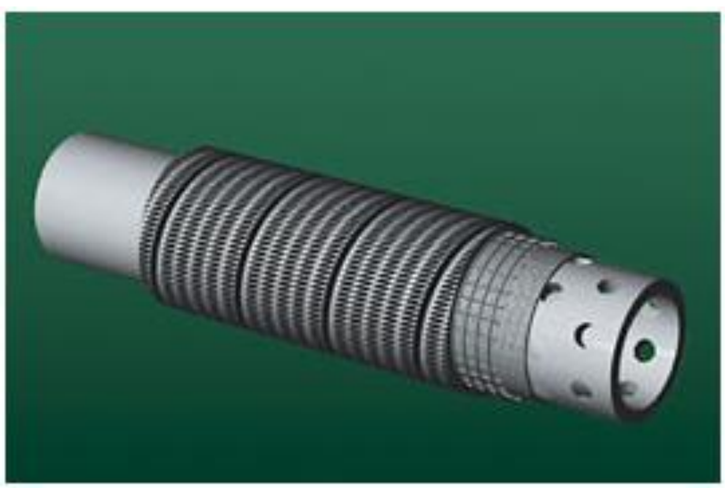

Figure 1.8. Typical design for a wire-wrapped sand screen overlaying perforated base pipe used for frac pack well completion applications (Alloy Machine Works, 2013)

The bridging effect of the sand grains in the formation at the perforation tunnels also helps prevent movement of formation sand into the wellbore and works in concert with the annular pack as shown in Figure 1.9.

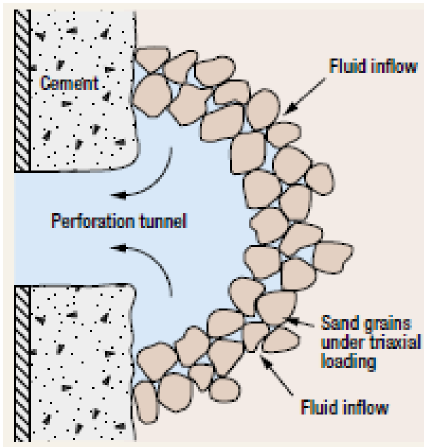

Figure 1.9. A stable arch of formation sand grains on the formation side of a perforation tunnel (Ott and Woods, 2003).

The annular pack also disperses the fluid flux during petroleum production thus prevents direct impingement of the produced fluids onto the surface of the sand screen. The quality of the annular pack is the primary contribution to overall well completion quality. The presence of voids in the pack is the primary indicator of the pack quality.

Gradivar (2004) indicates that approximately 65% of sand control well completions in the Gulf of Mexico are frac packs. Most frack pack completions are required for wells located offshore rather than on land. A frac pack is typically pumped from a Dynamically Positioned Stimulation Vessel (DPSV). A DPSV is a ship that houses the required pressure pumping equipment, piping, proppant, and frac fluid to complete the large frac packs required for deepwater wells. Examples DPSVs are shown in Figures 1.10 and 1.11.

Figure 1.10. Dynamically positioned stimulation vessel (DPSV) (Pennet, 2013)

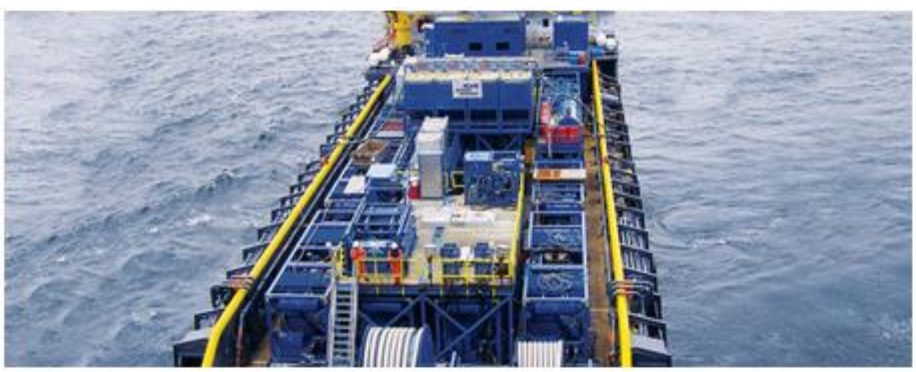

Figure 1.11. A view of the deck of a dynamically positioned stimulation vessel (DPSV) (Baker Hughes, 2013)

The following discussion provides a more detailed description of the steps and materials involved in a cased hole frac pack completion. The manner in which these operations are conducted, and their successful outcome, will do much to determine the final quality of the frac pack placed downhole.

1.1.1.1. Sump packer operations. The sump packer (Figure 1.6) operations begin with rigging up the wireline unit and running the gauge ring / junk basket to capture and remove any junk from the hole, then logging the pass-through zone. This assembly is then pulled out of the hole, and the sump packer is picked up and run to the setting depth and set to separate the zone to be treated from the bottom of the well or the zone below if a frac pack has already been installed below. The running tool is then pulled out of the hole, and the wireline unit is rigged down.

1.1.1.2. Tubing conveyed perforating (TCP). The purpose of perforating the well is to connect the wellbore and the formation. The perforations will be the conduit for the pumping of the frac pack treatment, and after the well is online, it will be the conduit for the petroleum to enter the wellbore for production. Following a safety meeting, the TCP assembly is picked up and tripped (ran) into the hole. After tagging (touching) the sump packer, the assembly is picked up and spaced out. The packer is set and the flow head is rigged down, then a pressure test is conducted. A second safety meeting is held, then the circulating valve is opened, and the perforating charges are detonated, and the wellbore pressure is monitored. The circulating valve is closed, and the tubing pressures are bled down. Two tubing volumes are reverse circulated to clean out the tubing.

1.1.1.3. Monitor fluid losses. Fluid losses are monitored for well control purposes. Excessive fluid loss rate is a concern because the wellbore must always be kept full of fluid to provide sufficient hydrostatic pressure to prevent a kick or blowout. If necessary, a fluid loss control pill is spotted. A fluid loss control pill is substance that is mixed with completion fluid that when placed into the well in the zone with fluid losses, the losses are slowed or stopped. Examples of fluid loss pills include K-max (a proprietary cross-linked polymer), HEC (hydroxyethyl cellulose – a gel made of cellulose), and carbonates (Halliburton 2013). The flow head is rigged down and the packer unseated, then the packer is pulled out of the hole along with the perforating guns. The TCP assembly is laid down at the surface.

1.1.1.4. Sand control tool assembly. The sand control screens, blank pipe, and washpipe are assembled. Blank pipe is used to separate the zones that require sand screens, and washpipe is tubing used to convey fluids from the surface to the zone of interest. The sand control assembly is tripped into the hole and the tally is checked. Pup joints are used to space out at the surface as needed to place the assembly at the correct depth. A pup joint is a length of pipe that is shorter than a standard length of pipe and used for the purpose of setting an assembly at the correct depth. For example, if the normal length of a tubular is 20 feet, then pup joints may be available in 10 feet or 5 feet lengths.

1.1.1.5. Set and test packer. The packer setting tools (service tools) are rigged up then the ball is dropped and allowed time to reach the seat. After pressuring up to set the packer, the pressure is bled down and the casing is filled with completion fluid. The blowout preventer is closed and the annulus is pressured up to release the service tool.

1.1.1.6. Boat frac job. The boat frac job consists of rigging up the lines on the rig floor to the frac head and testing the ability to pump fluids. The lines are pressure tested then bled down. The ability to pump is tested by pumping at the circulating rate and pressure, then the frac assembly is shifted to the “weight down – circulate” position. Pumping is then tested at the injection rate and pressure.

1.1.1.7. Pickle workstring. Pickling the workstring means that the workstring is cleaned with an acid solution. The pickle lines are rigged up, and the pickle is pumped down the workstring. It is then reversed out to bring the fluids back to the surface.

1.1.1.8. Acid treatment. An acid treatment is pumped to improve the hydraulic pathways in the formation in preparation for pumping the frac pack. The suction lines for the acid are lined up and then the acid is pumped to the packer. The frac tool is shifted from "reverse circulate" to "weight-down circulate". The frac tool is a ratcheting downhole tool that controls the flowpath of fluids pumped into the well. The position of the ratcheting tool is changed in much the same way that positions are changed on a ballpoint pen from "retracted" to "write". The calibration fluid is then spotted, and the acid injected into the formation. The pressure decline is monitored.

1.1.1.9. Calibration testing and redesign the frac treatment. Calibration testing is performed to collect the pumping rate and pressure data necessary for redesigning the fracture treatment. The fracture treatment is initially designed with theoretical or assumed rate and pressure parameters, but the final design should be based on parameters for the actual well zone to be treated. The frac fluid lines are lined up and the calibration fluid is spotted. The first calibration test is pumped at the planned treatment rate, and the pressure decline is monitored. A step-rate test is then performed by varying the rate and volume of fluid pumped. Lastly, a second calibration test is pumped. Using the data obtained during the calibration testing, the fracture treatment is redesigned.

1.1.1.10. Frac job. The frac job is started with a safety meeting and rig up of the fluid lines. The frac fluid is spotted and the fracture treatment is pumped. The frac tool is shifted to “reverse”, and the excess fluid (frac gel and proppant) are reversed out of the tubing. The boat lines used to pump the frac job from the boat are then rigged down.

1.1.1.11. Monitor fluid losses. Fluid losses must be monitored for well control. The shift tool and washpipe are pulled out of the packer and the well is monitored again for losses. Based on the volume of fluid lost, and the time to lose that volume of fluid, the fluid loss rate is calculated. If necessary, a fluid loss pill is mixed and spotted. The result of the fluid loss pill is monitored, and the loss rate should have reduced substantially.

1.1.1.12. Pull out of the hole with service tool. The service tool (the downhole equipment used to allow pumping of the frac pack) is pulled out of the hole. The service tool is then laid down at the surface. If the well will be completed with two or three zones, the above procedures are repeated at necessary for installation of the additional frac packs.

1.1.1.13. P/U seal unit. The hanger assembly seal unit is picked up and the volume of hydraulic fluid required to pressure up the control lines is confirmed using a hand pump. The production tubing is picked up and the seal unit is tripped into the hole, and the control tubing connected and pressure tested.

1.1.1.14. SSSV installed and seals tested. The subsurface safety valve (SSSV) is installed and the production tubing is picked up and control lines attached. The tubing string is landed and the packer is tagged. The seals are tested and charted, and the assembly is spaced out.

1.1.1.15. Install tubing hanger and tree. The hanger assembly is made up and completion fluid is circulated. The stack is drained and the hanger is landed and the seals engaged. A pull test is conducted to ensure the tubing hanger is seated properly, and the hanger assembly control line connection is pressure tested and charted. The BOPs are rigged down and the backpressure safety valve is set. The tree is landed and control line are installed (Norman 2008, Long et.al. 2008).

Following a frac pack installation the service company will prepare a brief report describing the treatment and pumping execution. This pumping report provides important data regarding the project such as the slurry rate, net pressure and pressure analysis during treating, and proppant density placed in the fracture.

1.2. PROBLEM OF SETTING FRAC PACK RATE LIMITS

The rate at which a frac pack can be produced is affected by completion quality, because the quality of the frac pack ultimately affects screen velocity (Vs). Historically there has been little systematic evaluation of frac pack quality. Some operators have inferred the quality from the one-page simple list of questions on a feedback form that is filled out for the service company pumping the frac pack. However, this feedback form is very limited and focused primarily on the quality of service and whether the client was satisfied with the pumping operation. This type of evaluation is generally not helpful in setting production rate limits.

Similarly, while the service company's post-frac pumping report does provide important data regarding the project such as the pump rate, materials placed and pressure response during the treatment, this report itself is not sufficient in determining frac pack completion quality or in setting production rate limits.

An initial effort was made by industry to determine general well completion quality through a quality questionnaire, designed for use in all openhole and cased hole sand control completions (Keck, 2010). This project was not specific to frac packs. Due to the general nature of the questionnaire, it was believed that this questionnaire was not sufficiently rigorously to determine completion quality for frac pack wells and therefore to provide accurate input into a screen erosion model to set production rate limits (Chevron and BP, 2007).

Screen erosion is the primary frac pack failure mode and is attributed to excessive fluid velocity at the screen (Vs). Figure 1.12 illustrates the consequences of failure to consider screen erosion failure criteria in setting rate limits in frac pack wells. This failure mechanism is direct impingement of fluid at the surface of the sand screen.

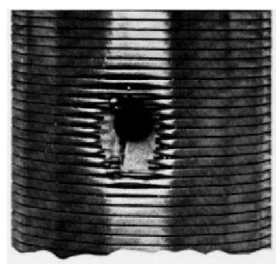

Figure 1.12. Screen hole due to erosion (Hendrix, 2010)

Screen erosion has been shown to be a function of the fluid velocity at the screen (Vs), as discussed in Section 2 of this thesis. However, historical approaches have significant limitations in the calculation of screen velocity. In particular, historical screen erosion models failed to include completion quality factors and use a rigorous model that adequately accounted for permeability heterogeneity in the reservoir. Previous models also have limitations in the manner of calculating Vs as discussed in this thesis.

Finally, it should also be noted that historically rate limits were set based on drawdown. This approach is also incorrect, although many companies persist in this approach today.

1.3. RESEARCH OBJECTIVES

The purpose of this project was to develop a comprehensive model that combined completion quality with a rigorous screen erosion model, to determine the maximum rate for producing a frac pack well. The overarching concept was that a completion with "poor" quality would not sustain the same production rate as one that had "fair" or "good" completion quality. By integrating frac pack quality indicators with a rigorous screen erosion model, frac pack production rates would maximize production while eliminating rate based failures.

The method developed for assessing completion quality was, therefore, expected to collect all relevant frac pack completion data and to express those data in a numerical manner, which could be used to influence the limit for C-factor at the perforation tunnel. This work also required development of a new screen erosion model, that addressed limitations found in historical methods.

All of the work performed in this project was conducted within an industrial setting, rather than within academia. A team of Chevron researchers and a subcontractor were responsible for development of the screen erosions model. The author's contribution to the project was development of the completion quality measure, the successful integration of that measure with the screen erosion model, and ultimate testing of the final model.

This work significantly advances previous methods of setting rate limits for frac pack completions.

2. LITERATURE REVIEW

There is a large body of literature related to sand control in general and various aspects of frac pack completions. This review focuses on historical literature and sources related to screen erosion, fluid velocity at the screen and perforations, and factors affecting frac pack performance.

2.1 SAND SCREEN FAILURE MECHANISMS AND RATE LIMITS

Below is a discussion of the sand screen erosion failure mechanisms and frac pack well rate limits.

2.1.1. Physical Measurements by the Southwest Research Institute. The Southwest Research Institute (SwRI) Sand Screen Erosion Joint Industry Project (JIP) in 1998 investigated the factors affecting the rate of sand screen erosion, mechanisms of sand screen erosion failure, as well as the limits that should be placed on sand screens. The results of this research were not published. These investigations were based on physical modeling. Small-scale laboratory mock-ups were constructed to physically model a wellbore which provided initial data. Later, a large-scale flow loop was used to realistically model wellbore geometry.

2.1.1.1. Erosion rate. The erosion rate for various screen types was measured on a mass-removal basis. Although there was an obvious drawback using mass-removal as a metric (namely that the larger the mass of the screen, the smaller the resulting specific erosion), baseline data regarding the relative erosion resistance of different types of sand screens was obtained.

Physical experiments of the JIP determined that a number of parameters affect the rate of sand screen erosion. These parameters include: Fluid type, density, and viscosity; fluid velocity, solids concentration, solids particle diameters, particle hardness, screen material / hardness, impingement or strike angle, and wellbore geometry. The results of the testing are shown in Figure 2.1 indicating the variation of specific erosion (erosion on a per unit mass basis) with volumetric flux (fluid flowrate per unit area of screen). As expected, the larger the volumetric flux, the larger the erosion rate.

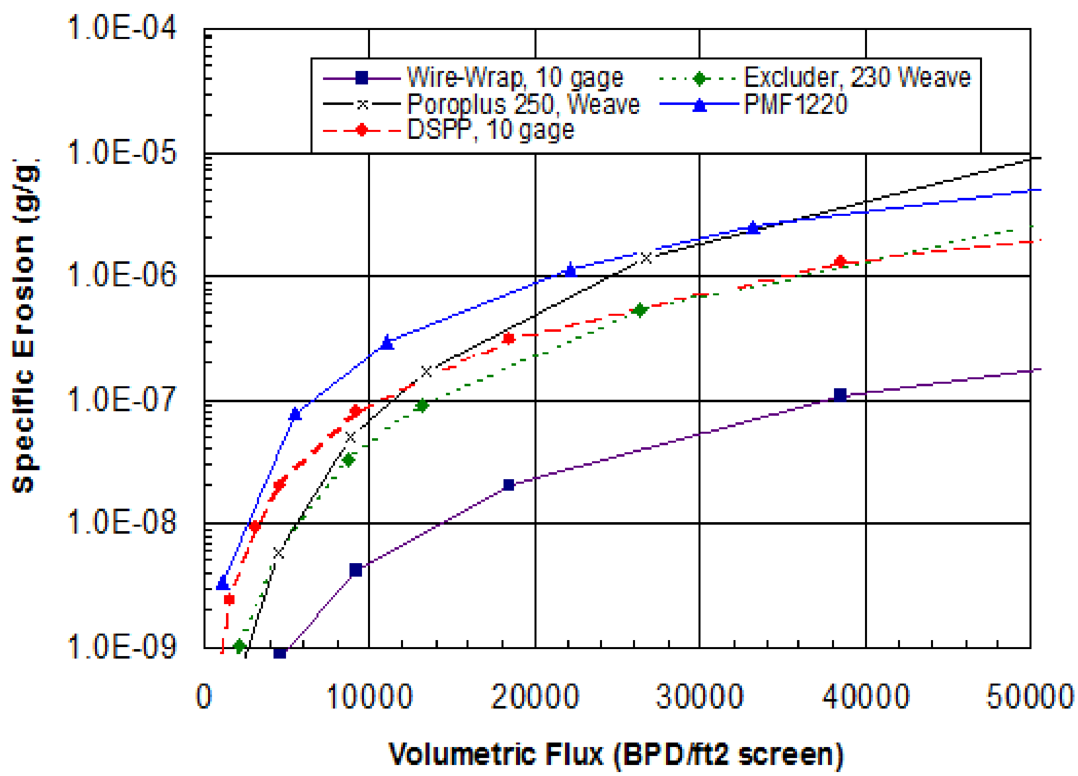

Figure 2.1. Specific erosion rate versus volumetric flux for some common types of sand control screens (Southwest Research Institute, 1998).

2.1.1.2. Determination of screen velocity limit Vs. The second primary outcome of the screen erosion JIP was determination of the screen velocity (Vs) limit which will cause screen failure. This was accomplished using physical modeling of a wellbore with sand screen. Water with an abrasive flowed through the sand screen at various rates, and the specific erosion rate was measured. Specific erosion is the mass removed by erosion as a function of original mass. It was determined through this physical modeling by the JIP that the limit of velocity at the screen surface (Vs) was approximately 1 foot/second. Vs is the velocity of the fluid impinging upon the surface of the screen. The casing velocity limit (Vc) could not be readily measured because the perforations in a frac pack well completion are packed with proppant and the gravel pack in the screen / casing annulus prevents direct measurement. Vc is the velocity at the perforation tunnel at the casing. Vs and Vc are important because they are measures of two important parameters that contribute to sand screen failure. Wells operated with Vs > 1 ft/sec and Vc > 10 ft/sec are at risk for sand screen erosion failure.

2.1.1.3. Mechanisms of screen failure. The mechanisms of screen failure are discussed below.

2.1.1.3.1. <u>Direct impingement at the screen surface.</u> The third primary finding from the screen erosion JIP was the determination of the mechanisms for screen failure. One mechanism discussed above is direct impingement of the fluid on the surface of the screen. In direct impingement, when the fluid reaches a critical velocity, a tipping point is reached whereby the rate of mass removal of the screen is significant enough to cause accelerated screen failure. The result is a hole in the screen. When a hole is present, the proppant is no longer held in place, and the screen is no longer performing its function, and the well fails due to sand production. Large amounts of sand can plug the wellbore, or cause erosion of other downhole or surface equipment, or cause disposal problems.

2.1.1.3.2. Eddy current in a loosely packed or partially filled pack. The other screen failure mechanism is the formation of eddy currents in the voids of a gravel pack or at the top of an insufficiently filled gravel pack causing destabilization of the pack. The destabilized pack of loose proppant swirls with the fluid in the eddy current, and a sandblasting action causes accelerated erosion of the sand screen (Southwest Research Institute (SwRI) Sand Screen Erosion Joint Industry Project, 1998).

It has also been observed that properly packed gravel packs can fluidize due to pressure instability and therefore fail (Stadalman, 1985). Therefore, it is important to bring a new sand control well on through a steady and controlled pressure ramp-up that will minimize pressure surges. Additional erosion-related issues can be observed during pumping of the sand or proppant for the gravel pack, and subsequent flowback. Placing the proppant can erode perforation tunnels, and flowback can erode downhole equipment as well as surface equipment. Erosion can be up to 95% more severe when the gravel pack is composed of angular sand compared to low-density spherical ceramic proppant (Vincent, 2004).

2.1.2. Investigation of Fluid Velocity Limits by Wong. Wong(2003) details the well operating limits (Vs and Vc) based on an analytical model and field data. The graphical presentations of Wong's results are shown in Figures 2.2 and 2.3 below with plots of drawdown due to mechanical skin versus fluid velocity. The well control failures that lie to the left of the vertical line indicating the velocity limit (Vs $\leq$ 1 ft/sec and Vc $\leq$

10 ft/sec) are explained by failure mechanisms unrelated to production. These other failures are infant (installation) failures, compaction, and annular pack design.

The maximum fluid velocity criterion for the destabilization of the annular pack in the vicinity of the perforations was determined to be 10 feet / second (Vc ≤ 10 ft/sec). Maximum flow velocity criterion for direct impingement on the screen was determined to be 1 foot / second (Vs ≤ 1 ft/sec). The field data suggested that pressure drawdown did not sufficiently predict sand screen erosion failure. A main assumption was that Vs is a function of annular gap, casing ID, and perforation pattern. Another main assumption was that ΔPperf = ΔP skin-mechanical. Although this simplifying assumption was necessary for the construction of this first rudimentary model, it is understood that the differential pressure across the perforations in a well are dependent upon much more than the mechanical skin only. Total skin is composed of mechanical skin, partial penetration and slant skin, wellbore damage, and rate effects (Wong, 2003 and 2010).

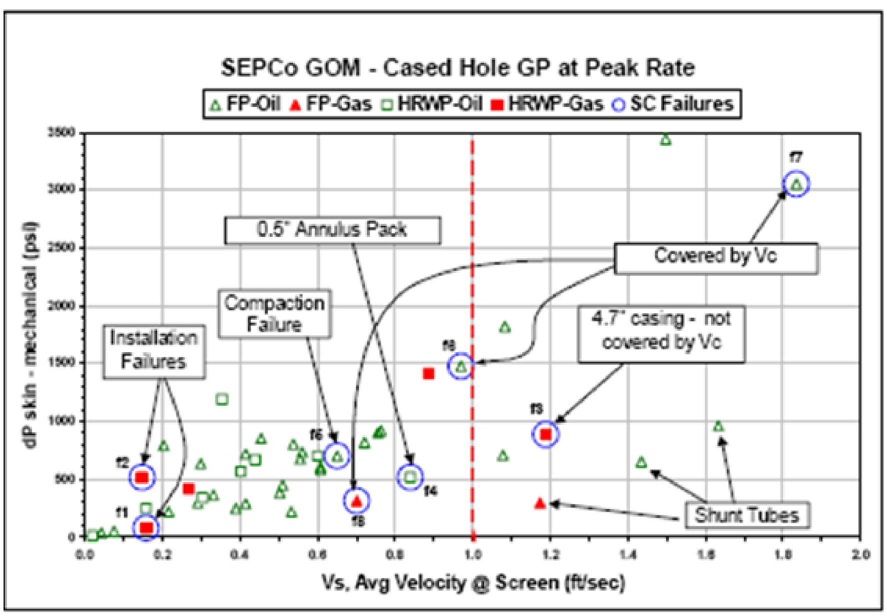

Figure 2.2: Pressure drawdown due to mechanical skin versus fluid velocity at the sand screen surface for Shell's wells (Wong, 2003). The failures below 1 ft/sec are not velocity related.

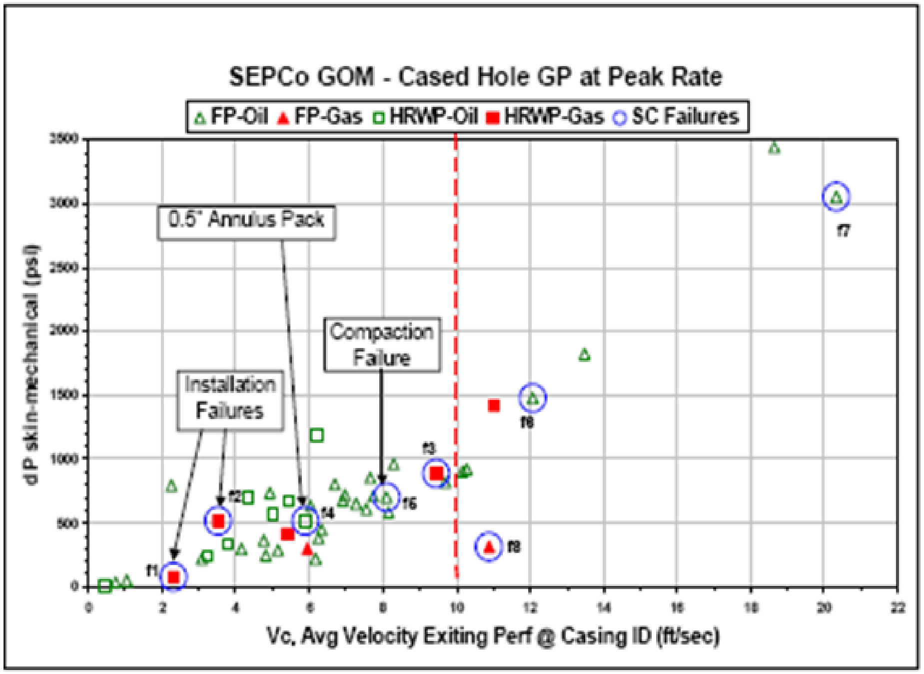

Figure 2.3: Pressure drawdown due to mechanical skin versus fluid velocity at the perforation tunnel for Shell's wells (Wong 2003). The failures below 10 ft/sec are not velocity related.

2.1.3. Velocity Limits from Tiffin Based on Field Data. Although C-factor had previously been applied to the erosion of downhole equipment other than sand screens as noted in Zhang (2007 and 2008), Tiffin (2003) and Keck (2005) were the first to publish well operating limits for sand screens based on C-factor. They defined a new standard measurement for screen erosion based on an analytical model and field data. Their work defined a flux based limit of C-factor at the perforations, which is fluid velocity times the square root of density. An additional important finding of the research was no correlation between pressure drawdown and sand control completion failure. As shown in Figure 2.4, the wells operated at the highest drawdown did not show sand control failure. Also, some wells operated at low drawdowns did have failure. The BP data also indicated that screen erosion failure was the most common failure mechanism of frac pack well completions excluding infant failures. High failure rates began at Vc ⩾ 20 ft/sec for gas wells and Vc ⩾ 10 ft/sec for oil wells. Their work also suggested limiting high quality completions to a C-factor of 60, and average quality completions to a C-factor of 30 (Tiffin 2003, Keck 2005 & 2010). These results are shown in Figures 2.5 and 2.6.

Pressure drawdown has historically been used with a rule of practice being between 500 psi to 650 psi, and even as high as 1,000 psi, however these practices have not been based on data but rather historical safe performance at these pressure drawdowns (Laursen, 1999).

More than half of the industry continues to use pressure drawdown as the primary criterion for limiting the risk of failure of the frac pack sand face well completions, the most common method of sand control for production wells in use today. This is due to a lack of understanding of the failure mechanisms of frac pack well completions, and a lack of sophisticated and accurate methods of applying the principles of screen erosion modeling (Hendrix, 2008).

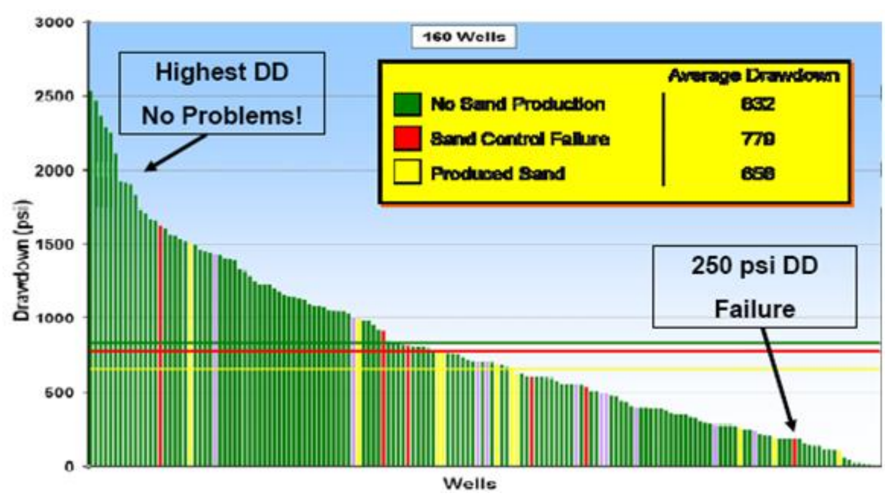

Figure 2.4. No correlation between drawdown pressure and sand control failure for 160 frac pack wells in BP's study (Tiffin, 2003).

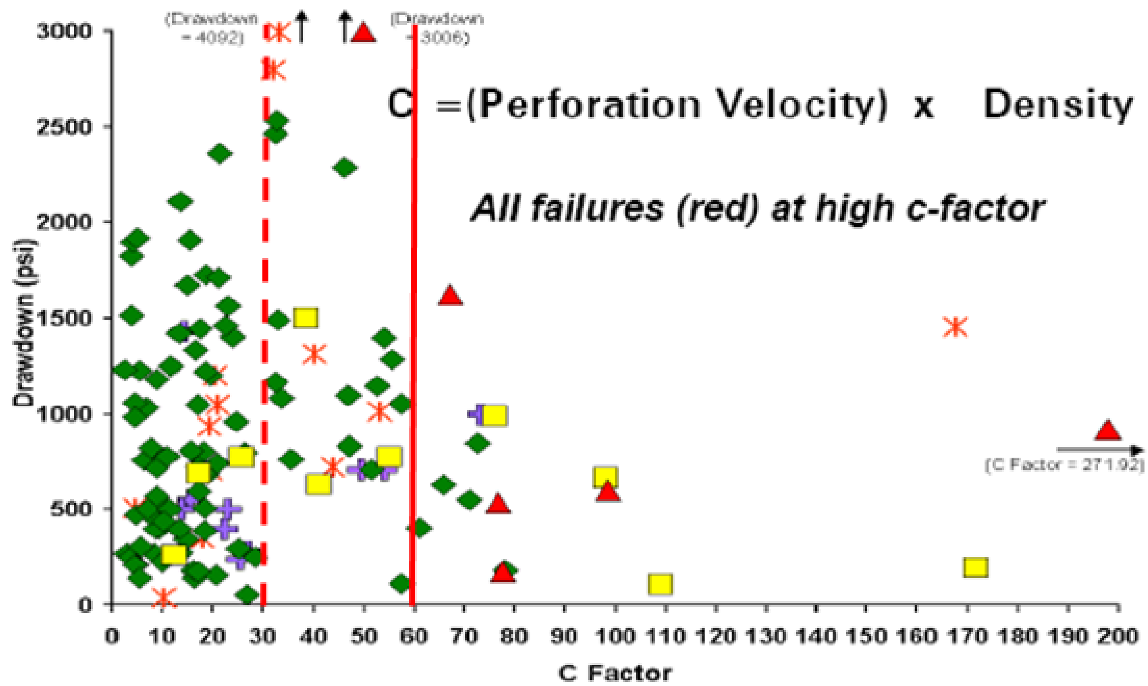

Figure 2.5. Drawdown pressure versus C-factor for BP wells (Tiffin, 2003). Sand control failures (shown in red) occur at high C-factors unless completion quality is low.

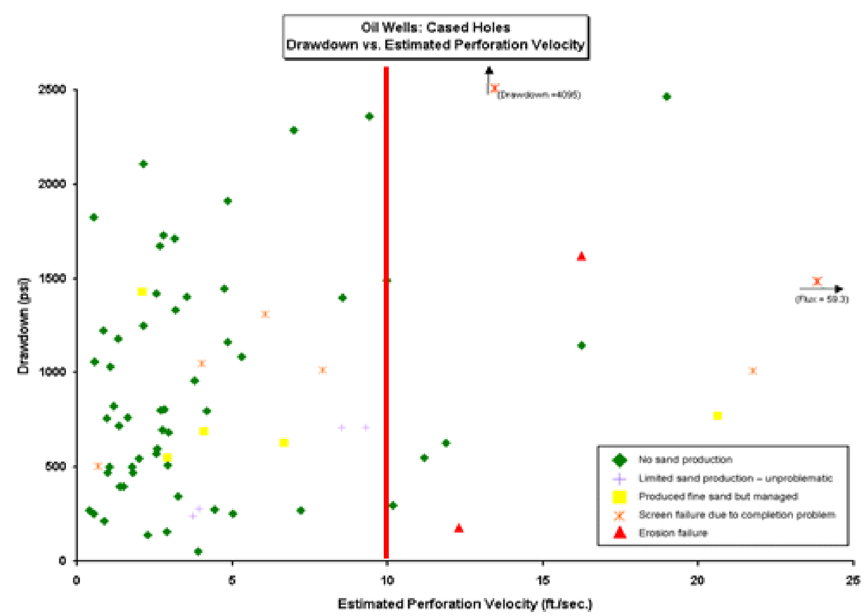

Figure 2.6. Pressure drawdown versus estimated perforation velocity (Tiffin, 2003). No well failures for BP's frac pack wells when perforation velocity (Vc) is below 10 ft/sec.

2.2. LIMITATIONS OF THE PREVIOUS METHODS

Previous attempts have been made to reduce the risk of failure of frac pack well completions by identifying screen erosion as the primary failure mechanism. By defining flux at the perforations as a significant measure of the screen failure potential, and by demonstrating that drawdown alone is not an adequate means of preventing frac pack failure.

However, there are significant limitations to the historical work to address rate limits in frac pack wells in particular, not using a rigorous screen erosion model to perform the rate calculations, and failure to systematically integrate well completion quality.

The limitations of the previous screen erosion models are demonstrated by the lack of accounting for permeability heterogeneity along the wellbore in the fracture zone, and not correlating Vs (fluid velocity at the sand screen) with Vc (fluid velocity exiting the perforation at the inside surface of the casing) to arrive at a reasonable estimate of actual fluid velocity at the sand screen.

Well completion quality has not adequately been used in setting rate limits for frac pack well completions. In the cases where methods for estimating completion quality are being used, the methods are not rigorous and not frac-pack specific (Keck, 2010). Well completion quality that does not consider the specifics of frac pack design and installation are not beneficial in setting rate limits for frac pack wells. Based on literature review and the author's experience, there are no known rigorous methods of well completion quality measurement. This thesis presents the first rigorous method of integrating well completion quality in setting frac pack operational limits.

3. THREE DIMENSIONAL CFD MODELING

This section summarizes the computational fluid dynamics (CFD) modeling efforts to determine an accurate measurement of Vs by Brekke as part of this project. It is included to provide the reader with a basic understanding of the model, since the author's quality measures are integrated with the results of this work.

3.1. DIFFICULTY IN MEASURING Vs

Both the velocity of the fluid flow at the wellbore casing in the vicinity of the perforation tunnels (Vc) and the velocity of the fluid flow impinging upon the sand screen (Vs) are important criteria for sand screen failure. Vc is relatively easy to calculate from production rate, perforation diameter, perforation density, and length of perforated interval. A detailed discussion of the mathematics behind these calculations is presented in section 4.2. However, Vs cannot be easily measured because the fluid is dispersed through the gravel pack between the perforations and the sand screen. Therefore, there must be a reliable method of estimating Vs from Vc.

3.2. CFD MODELING PERFORMED

Brekke (2007) performed a three dimensional Computational Fluid Dynamics (CFD) modeling study to investigate the effect of wellbore geometry, completion design variables, and production rate upon screen velocity Vs. Screen diameter, perforation diameter, casing diameter, perforation density (shots per foot), gravel permeability, and production rate were varied to determine which of these variables affected screen velocity.

Assumptions made in the development of the CFD model include constant pressure boundary in the reservoir at a radius of 12”, reservoir is homogeneous and isotropic, radial symmetry in the geometry of the sand face well completion (screen and gravel pack perfectly centered inside the casing), the perforations are properly packed with proppant and therefore have the same permeability as the properly packed annulus between the screen OD and casing ID. These simplifying assumptions were necessary to be able to complete the project within the budget and scope of the project.

It was determined that the relationship between Vs and Vc is controlled by two aspects of wellbore geometry: screen OD / Casing ID gap and perforation diameter. This was a major finding and served as the foundation for the development of the subsequent screen erosion model. The sensitivity analysis determined the mathematical relationship between Vs and Vc so that Vs could be calculated from Vc. Screen OD / casing ID gaps of 0.55”, 1.12” and 1.88” and perforation diameters of 0.7” and 1.0”, were investigated for both laminar and turbulent flow regimes.

A vertical and horizontal cross-section of the wellbore geometry of a typical frac pack well is shown in Figure 3.1. This figure shows the arrangement of the wellbore, cement, casing, frac pack annulus, the screen, and the locations of Vc and Vs. Figure 3.1 also shows how perforation fluids impinge on the frac pack screens. Figure 3.2 depicts the cross-section of the wellbore as simulated in the computational fluid dynamics software showing the formation (tan), casing and cement (no color), gravel packed annulus(green), sand screen(red), and open volume inside the screen(blue)(Brekke,2007).

Perforation diameter, perforation length, wellbore diameter, screen diameter, and gap (one half the quantity of casing ID minus screen OD) were varied in the CFD model. Figure 3.3 is an example figure from the CFD model showing the flow velocity vectors. In the cross section the cement and casing have no color, and the proppant pack and screen are the inner blue color. The formation is the larger blue area. Areas of higher flow velocity show up as pink, which occurs in the perforation through the casing and cement. This figure clearly shows how fluid flow is accelerated through the narrow perforation. Figure 3.4 is a similar view, which better illustrates fluid impingement on the screen after exiting the perforation.

The results of this study were compared with the work of Wong (2003), and that comparison is summarized in Figure 3.5. As shown, the results developed by Chevron differ significantly from the prediction of Vc/Vs prediction offered by Wong (2003). Chevron's model is more accurate because it is based on CFD modeling which links perforation velocity to the screen velocity.

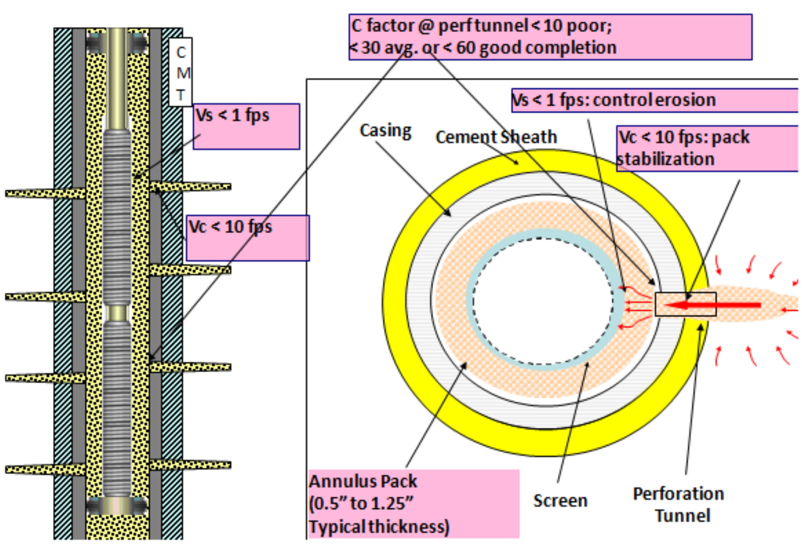

Figure 3.1. Vertical and horizontal cross-section of a typical frac pack well (Wong, 2003)

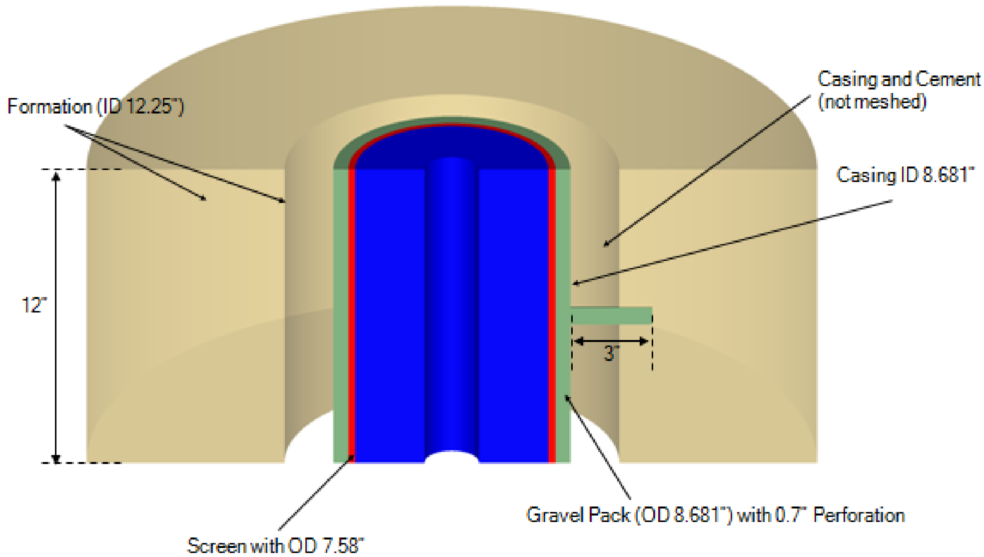

Figure 3.2. Cross-section of wellbore simulated in computational fluid dynamics software (Brekke, 2007). It shows the formation (tan), casing & cement (no color), gravel packed annulus (green), sand screen (red), and open volume inside the screen (blue).

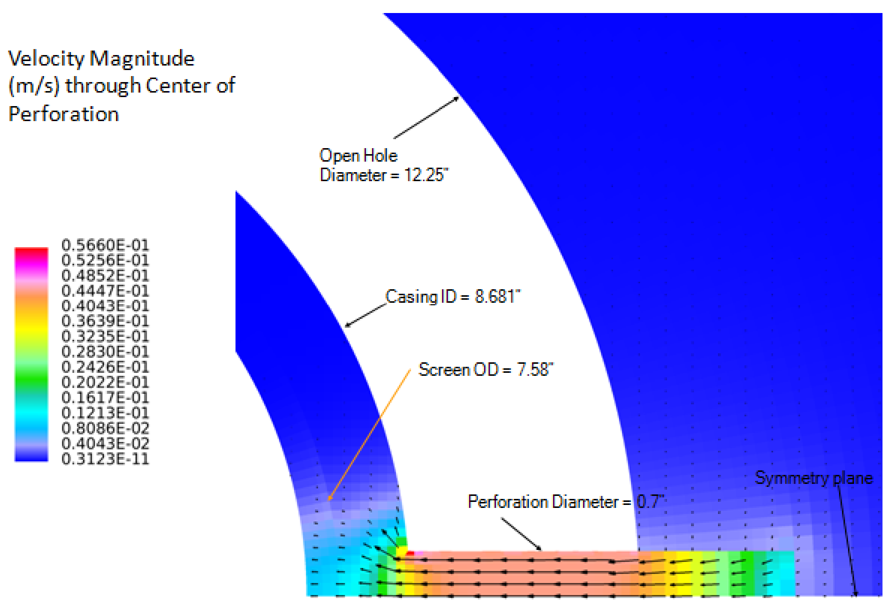

Figure 3.3. Horizontal cross-section of the simulated wellbore at a perforation (Brekke,2007). It shows formation (large blue area), cement and casing (no color), proppant pack & sand screen (smaller blue area), and the fluid flow in the perforation (multi-colored).

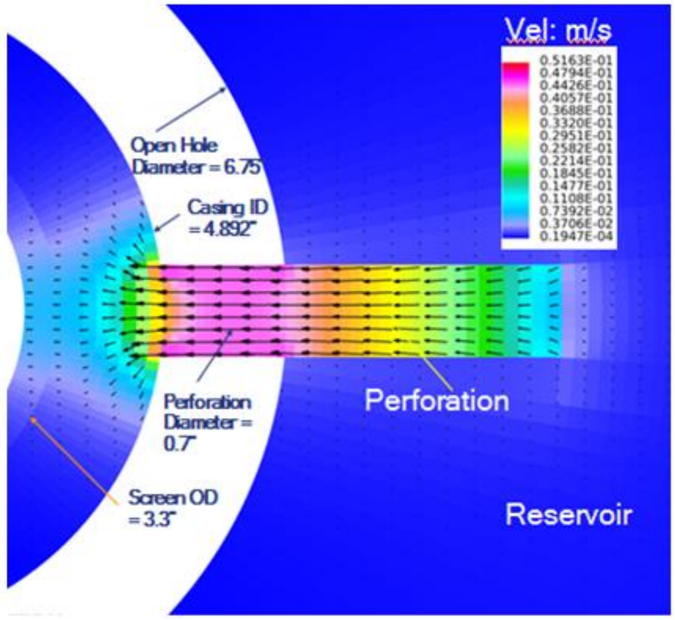

Figure 3.4: A typical result from the computational fluid dynamics model in this study (Brekke, 2007). It shows the fluid velocity vectors in a horizontal cross-section of the simulated wellbore at a perforation. Note that the highest velocity is in the casing and cement. The filter pack reduces the fluid velocity before it reaches the sand screen.

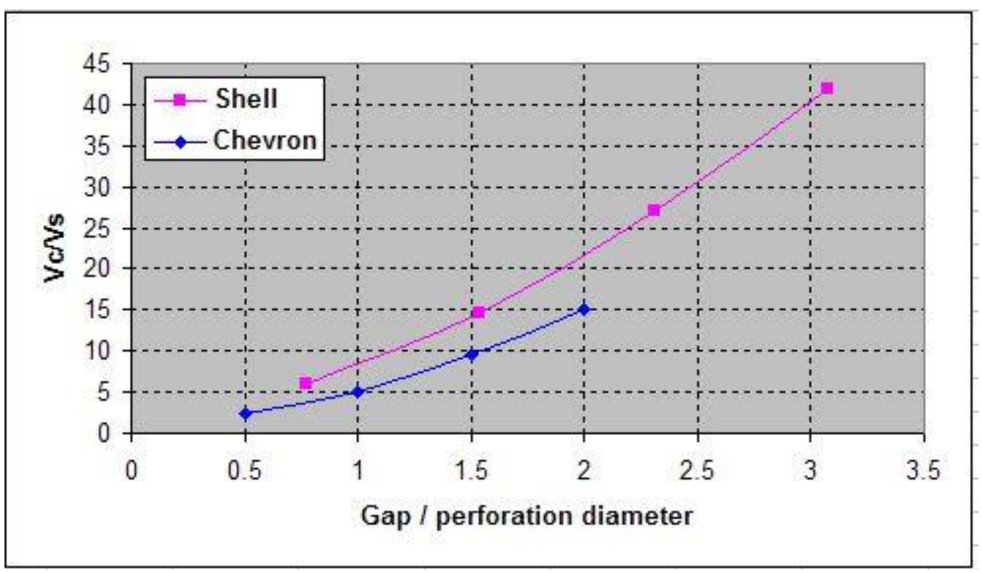

Figure 3.5: A comparison of the final results of the Chevron correlation between Vc and Vs compared to the Shell correlation (2003). The results indicate a significant improvement of the accuracy of the correlation based on the Chevron computational fluid dynamics modeling.

4. SCREEN EROSION MODEL

4.1. INTRODUCTION TO THE SCREEN EROSION MODEL

The purpose of the screen erosion model is to provide easy and reliable method for the analysis of screen velocity, casing velocity, and C-factor as a function of frac pack well completion parameters. This analysis is used to optimize well productivity and minimize completion failure risk based on the limits of velocity and C-factor parameters. Wells that have a higher completion quality (less impaired) can be flowed at a higher production rate than wells with lower completion quality (more impaired). The model also allows engineers to consider the effect of operating a well at a high rate through a short completion interval during the design phase to prevent potentially poor completion designs from causing well failures, as well as hot spots (areas of high fluid flowrate) due to poor annular packing and due to known high permeability zones. The high permeability zones can be discovered through fabrication of synthetic well logs from offset wells prior to well design, and confirmed from logging during wellbore construction. The screen erosion model can also be used to consider the PVT effects on downhole erosion conditions. Due to the cost and operational challenges of deepwater wells, these wells demand high well deliverability and longevity.

4.2. MATHEMATICAL BASIS OF THE SCREEN EROSION MODEL

The Chevron screen erosion model was first programmed in Visual Basic (VBA) by Brekke (2007) and designed to be used to investigate the well operating conditions for cased hole frac pack wells that produce oil, gas, or water. The tool was based on the theory described in Wong (2003). An updated version of the screen erosion model was programmed in C by Mengjiao Yu.

The operating limits that are considered in this model are Vs (velocity at the screen), Vc (velocity at the perforation tunnel), and C-factor (C-factor at the perforation tunnel). Pressure drawdown is also calculated since in the past it has been considered an important metric for setting production rate limits, however it should not be used as a metric since there is no correlation between pressure drawdown and well failure.

The minimum well performance data needed to begin a calculation is skin factor and production rate for the well in question. If the calculation is for a well that has not yet been drilled, then an estimate of skin and rate can be made from offset wells, otherwise it is best to have the skin and production rate data from pressure transient analysis so that the most accurate analysis can be performed. With skin and rate, along with the assumption that all of the skin is mechanical skin and results only from the pressure drop across the perforations, the Darcy equation can be rearranged for the calculation of pressure drop for an oil well. The assumption regarding the skin only occurring in the perforations is a simplifying assumption that is necessary because all of the components of skin are not additive. Deconvolution of skin into individual components is beyond the scope of this simplified tool.

$$\Delta Pskin = 141.2 \, \frac{q \, FVF \, \mu}{Kh} * skin \tag{1}$$

Q = Fluid rate, stb/day

FVF = Formation volume factor, rb/stb

μ = Viscosity, cp

K = Average horizontal permeability, md

H = Net pay, ft TVD

And for gas wells…

$$\left(P_{wf_s}\right)^2 - \left(P_{wf}\right)^2 = d_1 q^2 + d_2\, q \tag{2}$$

$$\Psi(P_r) - \Psi\left(P_{wf}\right) = e_1 q^2 + e_2\, q \tag{3}$$

d_1, d_2, e_1, e_2 are constants given by Brown (1984). Equation 2 is valid for gas wells with pressure less than 2,000 psi and equation 3 is valid for gas wells at any pressure. After the differential pressure across the perforations is determined from the calculation shown above, the fluid velocity at the surface of the casing (Vc) is calculated using rate divided by inflow area from inflow performance and the following equations (4), (5), and (6) from Brown (1984):

$$\Delta P_{skin=} a V_c + b V_c^2 \tag{4}$$

$$a = 0.00001799\, \rho \beta L_p \tag{5}$$

$$b = 113800\, \frac{\mu L_p}{K_p} \tag{6}$$

ρ = Fluid density, lb/ft^3
K_ρ = Proppant permeability, md
B = Non-Darcy turbulent coefficient, 1/ft
L_p = Perforation length, in

Then using the mathematical relationship that was determined from the CFD modeling, V_s is determined from V_c. The constants were determined by curve fitting.

$$\frac{V_c}{V_s} = c_1 \left(\frac{gap}{d_p}\right)^2 + c_2 \left(\frac{gap}{d_p}\right) + c_3 \tag{7}$$

The C-factor at the perforation tunnel is determined from Equation 8:

$$Cfactor = V_c \sqrt{\rho} \tag{8}$$

Next the number of perforations open to flow is calculated using Equations 9 and 10. A_{1p} is the area open to flow for one perforation:

$$N_{pof} = 0.0119154 \left(\frac{qFVF}{V_c A_{1p}}\right) \tag{9}$$

$$A_{1p} = 5.4542 \; x \; 10^{-3} \left(d_p\right)^2 \tag{10}$$

The perforation efficiency is defined as the number of perforations actually open to flow divided by the theoretical number of perforations open to flow along the perforated interval. Perforation density is the number of perforations per foot of measured depth of perforated interval:

$$P_{eff} = \frac{N_{pof}}{P_{density} h_{perf}} \tag{11}$$

h_{perf} = perforated interval, ft

Using equations 12, 13, and 14 the well operating conditions are determined. The primary metrics of Vc, Vs, and C-factor must be modified to account for hot spots (zones of high fluid flux) instead of being based simply on the *average* over the entire interval. It is not the average velocity or average C-factor that presents the highest risk to the integrity of the well completion. A high permeability streak will concentrate flow (velocity), and therefore increase the risk of sand screen failure at this hot spot. This is accounted for by using a heterogeneity factor, which is the ratio of maximum permeability to average permeability.

$$V_{c,max} = V_c \left(\frac{K_{max}}{K_{av}}\right) \tag{12}$$

$$V_{s,max} = V_s \left(\frac{K_{max}}{K_{av}}\right) \tag{13}$$

$$Cfactor_{max} = Cfactor \left(\frac{K_{max}}{K_{av}}\right) \tag{14}$$

The previous mathematical discussion described how the screen erosion model tool is used in the "diagnostic" mode. The diagnostic mode determines the well operating conditions for a well using current well operating characteristics. In other words, it determines Vs, Vc, and C-factor for the well as the well is being operated – not the maximum allowable limit for Vs, Vc and C-factor. However, if it is desired to know the maximum allowable operating limits, the results of the diagnostic run are used and input into the model in the "prediction" mode. In the prediction mode, the perforation efficiency determined from the diagnostic mode is held constant. The production rate is manually raised until the output parameter desired (Vs, Vc or C-factor) is equal to the upper limit based on recommended limits or tolerance for risk. The recommended upper limits are Vs $\leq$ 1.0 ft/sec and Vc $\leq$ 10 ft/sec for velocity. C-factor is limited to $\leq$ 10, 30, or 60 for poor, fair, or good quality well completions respectively as determined by the score card. For Vc, equations 12, 10, and 9 are used; for Vs, equations 13, 7, 10, and 9 are used; and for C-factor, equations 8, 14, 10, and 9 are used (Brekke, 2007). The graphical workflow for the screen erosion model implementation of the mathematics described above is shown in Figure 4.1 below.

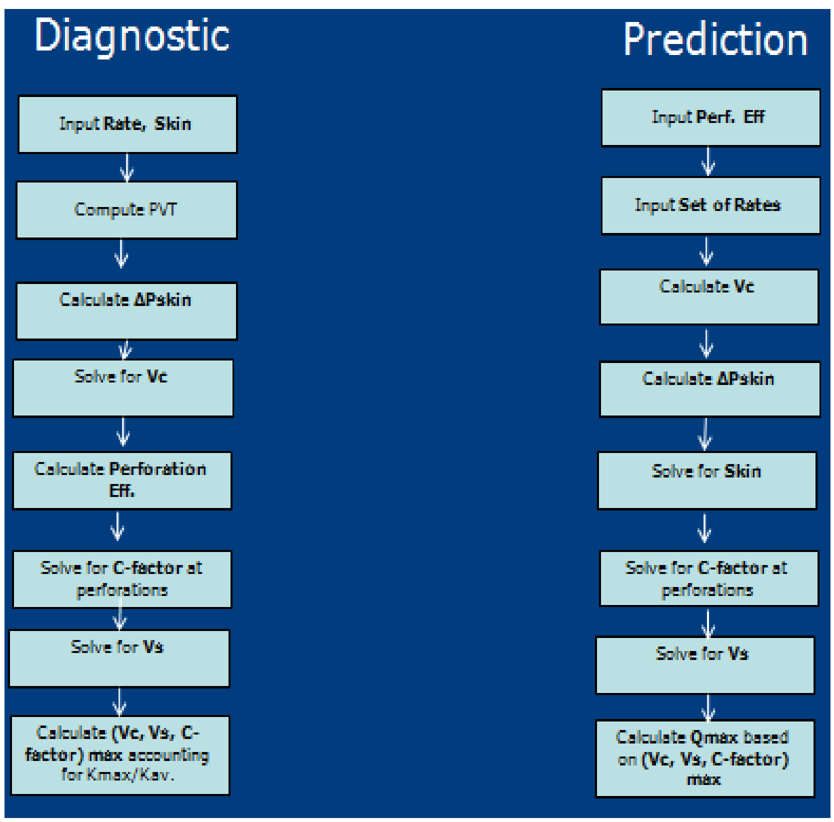

Figure 4.1. Graphical workflow for the screen erosion model (Hendrix, 2010).

5. WELL COMPLETION QUALITY SCORE CARD CALUCULATOR

This section describes development and application of a scorecard method for systematically assessing frac pack completion quality.

5.1. WELL COMPLETION QUALITY SCORE CARD DESCRIPTION

Below is a description of the well completion quality score card. This discussion includes the major categories and how the score card is used.

5.1.1. Overview of the Well Completion Quality Score Card Calculator. The completion score card is a method of grading the quality of the well completion installation, and is in Excel spreadsheet format. Raw data are captured on site during the installation of the well completion in the form of Job Notes, Post Job Report, and Daily Completion & Workover Reports. These sources are used to populate the score card. During the data collection phase, an input matrix can be used to quickly document the data for later entry into the score card spreadsheet. The individual questions are scored from 0 to 5 with 0 being the worst score and 5 being the best. Each item is weighted in accordance with its relative importance in establishing completion quality. All the scores are summed and then normalized to 100 basis for ease of interpretation, therefore the final score will fall between “0” and “100” and determines whether the completion was “poor” (0 – 33), “fair” (34 – 66), or “good” (67 – 100). This score sets a C-factor limit of 10, 30 and 60 for "poor", "fair" or "good" frac pack completions, correspondingly. This completion quality C-factor limit is then compared to the calculated C-factor from the screen erosion model. If the well is operating with a velocity determined C-factor above the C-factor limit as determined by completion quality, then the well is considered at risk for screen failure.

This score card was developed from the experience of the author and by soliciting input from an experienced team of completion engineers from operations throughout the world with extensive experience in this specialty field. The score card was also pilot tested in approximately half a dozen projects, then extensively peer reviewed. Based on feedback from the peer review, the well completion score card was modified to provide a dual score. The line items on the score card were coded with either a red color or blue color. The items coded in red are aspects of completion quality that directly affect screen erosion, and thus count toward calculation of the C-factor limit. The items coded in blue are used to grade general completion quality and do not count toward the C-factor limit calculation. The broad-based general completion quality score is used to help drive continuous improvement in frac pack best practices.

The workflow for populating the well completion score card is shown in Figure 5.1. Figures 5.2 through 5.7 show the input matrix for each section of the score card. Figure 5.8 shows the output of the well completion score card in the form of a spider plot.

5.1.2. Why the Completion Score Card is Needed. The purpose of the score card is to provide a quality rating for the well completion. The quality rating is divided into the general categories of “poor”, “fair”, or “good”. The well completion quality rating is used to establish the recommended allowable limit for the C-factor. The C-factor is a measure of the flux flowing through the perforations into the wellbore. The C-factor limit is used to evaluate the well’s recommended maximum safe production rate sing the screen erosion model. High quality well completions get a high C-factor limit, and can thus be operated at a higher safe production rate.

The general well completion quality is used to provide a lookback to determine where there are opportunities for improvement in completion practices, and to drive the completion operations to best practices.

5.1.3. Well Completion Quality Score Card Categories. The score card contains information about the following criteria related to well completion:

- Reservoir characteristics / geology
  - (uniformity coefficient, unconfined compressive strength, vertical heterogeneity)
- Well cleanup / preparation
  - (cleanup of the wellbore with brushing & scraping, NTU's (nephelometric turbidity units) of completion fluid before perforating)
- Perforating
  - (over-balanced / underbalanced perforating, perforation cleanup, use of fluid loss pills)
- Mechanical equipment
  - (running screen, screen OD/casing ID gap, fluid loss control device failure, fluid loss pills, reversing out, inspection of bottom hole assembly)
- Post job analysis / diagnostics
  - (tracer logs, fluid loss after fracking, skin, TSO prediction, % proppant below crossover, frac in zone, hard TSO, reducing pump rate to induce screenout, net pressure build after screenout, slope of Nolte-Smith curve)

- Startup procedures
    - (monitoring for proppant / sand during startup, continuous monitoring or daily samples)

5.1.4. How the Completion Quality Rating is Used. The completion quality rating (poor, fair, good) determines the upper recommended limit of the C-factor (related to the fluid flux flowing through the perforations into the wellbore). Poor completion quality limits C-factor to a maximum of 10. A fair completion gives a C-factor limit of 30. A good completion allows operation at a C-factor of 60. This limit is used in the screen erosion model to aid in setting the safe maximum production rate.

5.1.5. Discussion of C-factor. C-factor is the product of the fluid velocity and the square root of the fluid density flowing through the wellbore perforations. It is a measure of how fast the fluid is hitting the sand-screen, and takes into account the density of the fluid. It allows us to determine the recommended maximum allowable production rate that does not damage the sand screen. Calculations are preformed using the screen erosion model.

5.1.6. How the C-factor is Used by the Screen Erosion Model. The velocity of the fluid entering the wellbore is determined by dividing the production rate (Q) by the area of perforations open to flow (A). Recall that C-factor is the product of the velocity of the fluid flowing through the perforation and the square root of the fluid density. C-factor is maximized up to the C-factor limit of 10, 30, of 60 as determined by the score card to allow for maximum production rate from the well that will not damage the sand screen. These calculations are performed using the Chevron screen erosion model.

5.2. DISCUSSION OF THE LINE ITEMS IN THE SCORE CARD

Note that the line items coded **RED** are scored for completion quality as it is related to sand screen erosion. This score is used as input into the screen erosion model. This list was compiled by the peer review team as representing only the most important categories.

The line items coded **BLUE** are scored for general completion quality. Both the blue and red scores together provide a general overall indication of well completion quality, and can provide a basis for understanding what is being done well, and what where there is room for improvement in the well completion process. Note that in order to prevent confusion in the use of the following instructions for using the well completion score card, the codes **RED** and **BLUE** have been used since the actual well completion score card is color coded for ease of use.

5.2.1. Reservoir Characteristics / Geology Category (Figure 5.2). Below is a discussion of the reservoir characteristics and geology category.

5.2.1.1. Uniformity coefficient of reservoir pay sand (BLUE). The uniformity coefficient is a calculation performed using data obtained from a particle size distribution laboratory test, either by sieve analysis or laser particle size analysis (LPSA). If d40 is defined as the diameter of the particles at which 40% of the sample by weight is retained on the screen during sieve analysis, and if d90 is defined as the diameter of the particles at which 90% of the sample by weight is retained, then UC = d40/d90, and will be a number greater than 1.

A large uniformity coefficient of the formation sand indicates that the sample has a large variation in particle size (the sample is not considered very uniform). The closer the uniformity coefficient is to 1, the more uniform the sample is, and the closer the sand grain diameters are to being the same size. A sample with a uniformity coefficient greater than 5 is considered a poorly sorted sample based on Chevron internal practices.

Uniformity coefficient is important in well completion due to the requirements for the engineering design of the sand control gravel pack (filter). The larger the uniformity coefficient of the formation sand, the more difficult it is to design a gravel pack that will prevent formation sand from entering the wellbore.

A large uniformity coefficient is given a low score on the score card. A small uniformity coefficient is given a higher score.

5.2.1.2. Unconfined compressive strength (UCS) (BLUE). The unconfined compressive strength (UCS) of a material is defined as the amount of axial pressure that results in failure of a cylindrical test specimen. The pressure required to crush the specimen in this compressive strength test is equal to the force applied divided by the cross-sectional area ($\boldsymbol{P = \frac{F}{A}}$) and is measured in pounds per square inch (psi). In general, the strength of a sandstone rock sample is proportional to the degree and strength of the cementation material between the sand grains. Other factors that can affect the UCS of sandstone are the presence and angle of bedding planes, and the presence of natural fractures.

The importance of unconfined compressive strength to the quality of well completions is that the stronger the formation, the lower the potential for sanding to occur, which in turn reduces the probability of sand control failure. When a formation has a low unconfined compressive strength for example less than 750 psi, it may indicate that the rock is weakly or poorly cemented. Thus the potential for sand grains of the formation being dislodged and transported into the well is greater. Formation failure can also result in damage of the well completion if one part of the formation moves relative to the other in the vicinity of the wellbore.

Completions in wells with formation samples with higher UCS for example greater than 1,500 psi are scored higher because they are less likely to sand up or the formation to fail. Completions in wells with lower UCS' will be scored lower.

5.2.1.3. Fines content of the formation sand (RED). Fines content refers to the percentage of the formation sand particles that are smaller than 44 microns in diameter, which is equivalent to 325 mesh.

Fines content is important in determining completion quality because completions in formations with a large fines content may have problems with the fines migrating through the gravel pack of the well, and into the wellbore. This phenomenon can be mitigated by proper sizing of the gravel pack. Completions in formations with a large fines content, for example greater than 25%, will be scored lower than completions in formations with a small fines content. A low fines content is considered less than 3%.

5.2.1.4. Methodology for sizing of the gravel (BLUE). Laser particle size analysis (LPSA) is generally considered more accurate than traditional sieve analysis. LPSA is determined by passing a laser through a fluid (gas or liquid) in which the particulate sample is suspended and analyzing the halo effect from the diffracted light. This technique is fast and gives more consistent results compared to sieve analysis due to automation and less human error.

5.2.1.5. Pore pressure (BLUE). Pore pressure refers to the pressure in the voids between the individual grains of the rock matrix. It's the same thing as reservoir pressure.

Low bottom hole pressure wells with less than 8 pounds per gallon (ppg) equivalent mud weight (EMW) will require fluid loss pill (FLP) use to prevent excessive fluid loss from the wellbore to the formation because the completion brine cannot be adjusted lower to minimize the differential pressure contributing to the fluid loss. Equivalent mud weight is an expression of pressure that has been converted to the equivalent weight of mud that would cause the hydrostatic pressure in question. Pore pressures in excess of 9 ppg EMW should require minimal pill use because the fluid loss can be managed by adjusting of the brine density lower to minimize the differential pressure.

This category does not directly contribute to the well completion score. Instead, it calibrates the post-perforation pill use. In low pore pressure environments this score category is not reduced for pill use (because there may be no other choice to control fluid loss). In higher pore pressure reservoirs, the score may be reduced for pill use because sometimes the fluid losses can be managed using hydrostatic pressure of the completion brine instead of using a fluid loss pill. The use of fluid loss pills unnecessarily, especially with a high differential pressure between the wellbore and reservoir, will lead to unnecessary formation damage due to the invasion of the fluid loss control pill into the pore throats in the near wellbore invaded zone.

Low equivalent mud weight reservoirs (less than 8 ppg) are scored higher than high equivalent mud weight reservoirs (greater than 9 ppg). This line item does not have a weighting factor. However, the score for this item is used as input for an equation governing the line item “fluid loss pills after perforation”.

To convert pressure to pounds per gallon equivalent mud weight (ppg EMW), take the pressure in psi and divide by the product of 0.0521 psi/ft*ppg * TVD ft. TVD is true vertical depth in feet.

$$\mathrm{EMW} = \frac{\mathrm{P}}{0.0521\ \mathrm{TVD}} \tag{15}$$

The equation is a rearrangement of the formula for hydrostatic pressure. The $0.0521\ \frac{psi}{ft\ x\ ppg}$ is a conversion factor.

$$P_{hydrostatic} = \rho\ \frac{lb}{gal}\ X\ 42\ \frac{gal}{bbl}\ X\ \frac{1\ bbl}{5.615\ ft^3}\ X\ \frac{1\ ft^2}{144\ in^2}\ X\ TVD\ ft \tag{16}$$

$$\mathrm{P}_{\mathrm{hydrostatic}} = \left(\frac{0.0521\ psi}{ft*ppg}\right) * \left(\rho\ \frac{lb}{gal}\right) * (TVD\ ft) \tag{17}$$

Rearranging this equation for density gives equivalent mud weight in pounds per gallon.

5.2.2. Well Cleanup / Preparation Category (Figure 5.3). Below is a discussion of the well cleanup and preparation category.

5.2.2.1. Completion fluid properties before perforation (RED). The completion brine is circulated downhole after running scraper / brush / magnet assembly and prior to perforation. The purpose of circulating the brine is to clean the wellbore of any debris or foreign matter that could plug the formation during and after the perforation activity. The filtered brine is continuously circulated until it is clean. The effluent completion brine is sampled after it has been circulated into the hole. The fluid is tested for NTU content (Nephelometric Turbidity Units) and is a measure of the clarity of a fluid.

It is important for the NTU content to be as low as reasonably achievable due to the high potential of formation damage if solids are allowed to enter the perforations during and after perforation activities. Formation damage during perforation activities is perhaps one of the most important and preventable issues in well completions. Formation damage causes reservoir impairment, increased pressure drop in the vicinity of the wellbore, and results in lost petroleum production. Determination of skin using the data obtained from pressure transient analysis is used to quantify the extent of reservoir damage.

Well completions with high NTU count (greater than 200) are given poor scores; those with low NTU measurements (less than 20) are given good scores. There are no specific limits for NTU's, but based on internal practices, 50 to 100 units would be average.

5.2.2.2. Cleanup of wellbore prior to perforation (RED). Cleanup of the wellbore prior to perforation, as described in "completion fluid properties" above is a critical component of a successful well completion. Each well should be cleaned of debris prior to perforation using a cleanout bottom hole assembly (BHA) using as much time as necessary to reduce the debris content of the wellbore to acceptable levels. The cleanout BHA should contain a bit scraper, brushes, and magnets. All of these items should be properly sized such that they will have maximum effectiveness in cleaning the wellbore. The cleaning and scraping activities must be performed with special attention given to the interval to be perforated. The debris and crud should be circulated out of the wellbore so that it does not end up in the perforations.

Completions that are not cleaned up with a cleanout BHA, or only have minimal cleanup activities performed are scored poorly. Those completions with significant and effective cleanup operation are scored higher. Note that upper completions are not typically cleaned, therefore should not be scored.

5.2.3. Perforating Category (Figure 5.4). Perforating is the term given to the activity of connecting the wellbore and the reservoir following running casing, and cementing the casing into place. Explosive charges punch holes into the casing, cement, and formation. This results in establishing a flowpath, or tunnel, from the formation through the cement and casing, into the wellbore.

Modern wellbore perforating practices are usually conducted using jet perforating techniques with the use of specially designed shaped charges, based on World War II era bazooka rounds. The shaped charges punch through the wellbore casing with a pressure of 3,000,000 psi, and through the natural formation matrix with a pressure of 300,000 psi.

Three kinds of formation damage are created by the perforation process: A low-permeability crushed zone around the perforation tunnels; formation fines can migrate into the perforation tunnels; and debris from the perforating guns can find their way into the perforation tunnels.

Fines and small perforation debris plug pore throats in the near-wellbore formation. The formation damage caused by perforation contributes significantly to skin, increases pressure drop, and limits petroleum production. Placement of proppant for sand control and for hydraulic fracture stimulation is severely impaired by the presence of perforation debris and fines in the perforation tunnels.

The perforation shot density, hole size, orientation, and depth of perforation tunnel invasion all contribute to reduction in fluid velocity and fluid flux impinging upon the sand screen.

Items of importance in the perforating process include: Underbalanced perforating, proper depth control, perforation cleanup, minimizing differential pressure between brine density and pore pressure, and deleterious effects of spotting fluid loss pills after perforating.

5.2.3.1. Perforation OB/UB (RED). The pressure differential between the wellbore pressure and the reservoir pressure determines whether the perforation is performed overbalanced or underbalanced. Overbalanced is the condition when the pressure inside the wellbore is greater than reservoir pressure, and underbalanced is when the reverse is true. In most cases, underbalanced is the preferred pressure condition. This is true because underbalanced perforating removes fines (generated by the pulverizing of individual sand grains due to the very large force on them due to the explosion of the shaped charges) and shaped charge liner debris from the perforation tunnels. These fines and shaped charge liner debris will plug the perforation tunnels and reduce the petroleum production rate. This phenomenon is significantly intensified in sand control wells to be gravel packed or frac packed.

Sometimes due to regulations or well control limitations, it is necessary to perforate overbalanced. If this is the case, then extra effort must be made to surge and clean the wellbore. The hydrostatic pressure of the mud in the well must be determined using the following formula using the mud density and true vertical depth:

$$P_{hydrostatic} = \left(\frac{0.0521\, psi}{ft * ppg}\right) * \left(\rho\ \frac{lb}{gal}\right) * (TVD\ ft) \tag{18}$$

The reservoir pressure is subtracted from the wellbore pressure, and the magnitude and sign are recorded. Overbalanced conditions are present if the difference is positive (reservoir pressure is less than wellbore pressure).

Underbalanced conditions exist if the difference is negative (reservoir pressure is greater than wellbore pressure).

$$\text{OB/UB} = \text{Wellbore pressure} - \text{reservoir pressure} \tag{19}$$

5.2.3.2. Perforation depth control (BLUE). Every effort must be made to perforate at the correct depth. If the perforation is not performed at the correct depth, then loss of production may occur, or a water producing interval may be opened to flow. Perforating at the correct depth results in a good score; perforating at the incorrect depth results in a poor score. Perforation depth control is achieved by tagging the perforation bottom hole assembly on the packer, then spacing out.

5.2.3.3. Perforation cleanup (surging) (BLUE). Perforation surging is the process to create a sudden surge of fluid into the wellbore to remove perforation debris, and remove the damaged zone around the perforation tunnel. It is desirable to circulate this debris out of the well so it doesn't fill and plug the perforation tunnels. Surging can be accomplished using a Cavins bailer, which is a downhole tool designed for this purpose. This tool works on the pressure differential principle using wellbore fluids as the fluid medium.

5.2.3.4 Brine density / pore pressure differential pressure (BLUE). The differential pressure between the wellbore bottom-hole hydrostatic pressure containing completion brine, and the pore pressure (or reservoir pressure) is a primary factor that determines the rate of fluid loss into the reservoir. If the density of the completion brine cannot be sufficiently lowered to minimize the differential pressure because the reservoir pressure is too low (equivalent mud weight less than 8.3), then a fluid loss pill may be necessary. If the reservoir pressure is high enough, then a fluid loss control pill may not be necessary because it is likely that the completion brine density can be lowered enough to mitigate the pressure differential.

Due to the real potential for formation damage due to the fluid loss control pill invasion into the near-wellbore pore spaces in the environment of a high differential pressure, the use of a fluid loss pill is discouraged unless there is no other way the fluid losses can be managed. The higher the differential pressure when a pill is used, the deeper the pill invades the near-wellbore reservoir, and the greater the reservoir damage. The overbalance conditions that are required for drilling mud do not apply to completion brine. A large differential pressure is scored low, and a low differential pressure is scored high. This line item does not have a weighting factor. However, the score for this item is used as input for an equation governing the line item “fluid loss pills after perforation”.

Brine density in pounds per gallon is converted to equivalent hydrostatic pressure using the following formula and is compared to pore pressure (reservoir pressure):

$$P_{\text{hydrostatic}} = \left(\frac{0.0521\, psi}{ft * ppg}\right) * \left(\rho\ \frac{lb}{gal}\right) * (TVD\ ft) \qquad (20)$$

The completion fluid differential is computed by taking the hydrostatic pressure due to the completion brine and subtracting the reservoir pressure from it. The sign and magnitude of the difference is recorded.

5.2.3.5. Fluid loss pills after perforation (RED). Using no fluid loss control pill, and tolerating fluid loss is the preferred method of dealing with fluid loss if the fluid losses are acceptable. If fluid losses are not acceptable and cannot be tolerated, then it will be necessary to use a fluid loss control pill. The type of pill used is an important decision since it will determine the amount of reservoir damage that is likely to result from the fluid loss control pill use. The preferred pill is HEC (hydroxyl-ethyl-cellulose) due to cleanliness. If HEC is not used, then the next preferable pills are K-max or cross-linked polymers. The use of finely ground carbonates as a fluid loss control pill is not a preferred method due to the relatively high potential for reservoir damage because the finely ground carbonates can block formation pore throats.

Scores from two other line items are combined with the score in this line using an equation (internal to the score card). “Pore pressure” and “completion fluid differential pressure between brine density and pore pressure” are combined with “fluid loss pills after perforation” in the equation. This purpose of this calculation is to determine the impact of using pills following perforation. As discussed in the above-referenced related line items, a large differential pressure combined with pill use will damage the reservoir due to pill invasion. If the reservoir pressure is low, pill usage may be unavoidable to control the fluid losses from the well because the brine density cannot be lowered enough to adequately reduce the differential pressure. However, if the reservoir pressure is sufficiently high, then pill usage is not recommended, because the fluid losses can likely be controlled by adjusting the brine density lower to minimize the differential pressure.

If the pore pressure is less than 8 ppg EMW and if the differential pressure is less than or equal to 250 psi and if the pill is HEC, then the fluid loss pills after perforating (FLPAP) score equals 3. If K-max is used under these conditions, then the FLPAP score equals 1, otherwise the score is 0.

If the pore pressure is greater than 9 ppg EMW and if the differential pressure is greater than 250 psi and if the pill is HEC or K-max, then the FLPAP score is zero. However, if the pill score is 4 or 5, then the FLPAP score will be 4 or 5 respectively.

If the pore pressure is greater than 9 ppg EMW and if the differential pressure is less than or equal to 250 psi, then the FLPAP score will be equal to the pill score.

If the pore pressure is between 8 and 9, then the FLPAP score is equal to the pill score.

5.2.4. Mechanical Equipment Category (Figure 5.5). The following is a discussion of the mechanical equipment category.

5.2.4.1. Running the sand control BHA and screen (RED). The sand control bottom hole assembly (BHA) and screen ideally should be assembled and run in hole (RIH) without incident. If so, then it is likely that the BHA will not be damaged, and thus a good score should be given. If minor manipulation of the pipe is necessary to reach total depth (TD), then some minor damage to the BHA can occur, resulting in a lower score. If multiple attempts to reach TD are required, then significantly more damage to the BHA may occur. In this case, the score should be considered poor.

5.2.4.2. Sizing the gap: annulus between casing ID & screen OD (RED). The "gap" is defined as the clearance between the inside diameter of the casing and the outside diameter of the sand control screen. The gap can be computed by subtracting the screen OD from the casing ID, and then dividing the difference by two.

$$\boldsymbol{Gap} = \frac{(\boldsymbol{Casing\ ID - Screen\ OD})}{\mathbf{2}} \tag{21}$$

The gap is important is determining completion quality because it has a direct bearing on the velocity or flux of the petroleum fluid impacting the sand screen. When the gap is relatively large (greater than 0.9 inch), then the gravel in the gap causes the fluid to follow a tortuous pathway to get to the sand screen, therefore the fluid arrives at the sand screen at a lower velocity than if the gap had been smaller. A relatively small gap (less than 0.7 inch) does not provide enough tortuosity and dispersion of the petroleum fluid flow. This causes the velocity or flux to be too high. If the fluid flux is too high, this presents a significant risk of sand screen failure.

5.2.4.3. BHA, sand control equipment QA/QC (BLUE). QA/QC of the bottom hole assembly and sand control equipment means that the service company delivers the equipment as the design specified. The score for this category is docked if the service company makes minor changes in the design specification. If the service company makes major changes in the design specification, then a poor score results.

5.2.4.4. Fluid loss device post fracture (RED). Following hydraulic fracture, fluid losses should be controlled using a mechanical fluid loss control device (FLCD).

An FLCD is any mechanical valve that can be employed to stop fluid losses. When the FLCD is closed, the wellbore is not connected to the reservoir and therefore fluid cannot move from the wellbore to the formation. Examples include a ceramic flapper, ball valve, or ShureShot ball. This category seeks to score whether the mechanical fluid loss control device used following hydraulic fracture works, leaks, or fails. The scoring for this category is self explanatory.

5.2.4.5. Fluid loss pill spotted post FLCD failure (RED). If the mechanical fluid loss control device fails after the hydraulic fracturing event, then it may be necessary to spot a fluid loss control pill to control fluid losses to the formation. The type of pill that is spotted determines the score for this category because different pills cause differing amounts of formation damage.

5.2.4.6. Reverse out issues (RED). The preferred practice is to reverse out until the brine specifications for density and NTU are achieved *at sufficient pipe velocity for debris removal*. The volume of fluid flowing in and out should be equal, and the slurry should be clear. Two full work string volumes should be reversed.

After perforating, the wellbore will still contain metal perforation gun debris, cement and formation particles. These items generally have a relatively high density, and are therefore difficult to remove, especially in highly deviated wells.

The post-perforation debris management process is important in ensuring that debris in the wellbore following perforating is removed such that it does not end up plugging the perforations. Sometimes a sufficient annular velocity is not able to be achieved to remove the debris to the surface, especially for metallic debris from the perforating gun shaped charge liners or metal shavings from tool movements. In these situations it may be necessary to use a down-hole debris filter tool. This tool allows removal of the post-perforation debris without the need to flush it to the surface. The debris not collected by the down-hole filter tool should be collected using a down-hole debris magnetic tool. The down-hole debris magnetic tool is placed near the bottom of the bottom hole assembly, to the bottom of the packer isolation plug.

5.2.4.7. Inspection of BHA after extraction (RED). After the bottom hole assembly (BHA) is removed from the wellbore, it must be inspected. If too many tool movements were necessary to complete the job, there may be an indication of shiny tools and washpipe. The washpipe may have been stuck during the job. If any of these conditions are present, it is likely that the completion hardware may have been damaged to some extent.

If there is an indication of possible damage to the completion hardware, then the score for this category is downgraded.

5.2.5. Post Job Analysis / Diagnostics Category (Figure 5.6). The following is a discussion of the post job analysis and diagnostics category.

5.2.5.1. Screen / blank annulus fill (tracer logs) (RED). The proppant (gravel) used to pack the annulus between the ID of the casing and the OD of the screen must fully cover the screen, and also cover the blank. There must be no voids present in the gravel. This complete gravel coverage with no voids is critical to ensure that the sand screen does not experience premature failure. The gravel protects the sand screen by lowering the velocity / flux of the petroleum fluid entering the well. The fluid is dispersed by following a tortuous path through the intergranular spaces. If a void is present, the fluid flow can impinge directly on the sand screen, resulting in sand screen failure. The screen / blank annulus fill is perhaps the most important criterion in determining the quality of the well completion, due to the relatively high potential for failure.

The coverage of the screen and blank is determined using a radioactive tracer log. A radioactive tracer is added to the gravel before it is placed. Following placement, the tracer log is run, with the results provided to the completion engineer.

A well that has complete coverage of the screen and blank with no voids gets a good score. If only the screen is covered, with no voids present, a fair score is given. If the screen is not fully covered, or if voids are present, this results in a poor score.

5.2.5.2. Proppant reserve / length of blank (RED). Having a sufficient length of blank above the screened interval and having sufficient proppant reserve in that blank section is considered critical to the ultimate success of a frac pack well completion. As settling occurs in the pack, a sufficient reserve will ensure continued coverage of the sand screen.

5.2.5.3. Did the job pump as planned? (BLUE). There is a nearly infinite list of things that can go wrong during the pumping of a frac pack job. Many of these items affect the planned pressure to pump the job at, or the planned volume of proppant to be placed. Most of the time the pressure and volume will have a direct impact on the quality of the frac pack, and thus an impact on quality of the fracture bypassing the invaded zone in the near wellbore area linking the reservoir to the well.

If there are some differences in the planned and executed pressure and volume, then a fair score is given. If significant differences exist, then a poor score is given.

5.2.5.4. FLI after frac pack, before activating FLCD (BLUE). The intent of this category is to be a substitute for skin if no skin data is available. The calculation for FLI is based on the steady state well performance equation given in Economides, et.al. (1994). FLCD is the abbreviation for fluid loss control device.

Steady state well performance equation:

$$Q = \frac{kh(P_h - P_r)}{141.2 \; x \; 24 \; \mu(8 + skin)} \tag{22}$$

Q = production rate, bph

k = permeability, md

h = reservoir thickness, ft

P_h = hydrostatic pressure, psi

P_r = reservoir pressure, psi

μ = viscosity, cp

If pressure transient analysis data is not available, then this may be the only way of determining a substitute for skin. It is based on the fluid losses after the frac pack before activating the fluid loss control device. The steady state well performance equation was rearranged, and several different values for skin were substituted for the unknown skin variable. The viscosity of the fluid is assumed to be 1 cp, and the natural log of drainage radius divided by wellbore radius was assumed to be 8. Finally, the number is multiplied by 1,000,000 for ease of comparison. The resulting spread of values (corresponding to the assumed skin values) were assigned a score of 1 to 5 depending on the quality of the fluid loss indicator.

The fluid losses that are indicated after pumping a frac pack but before the fluid loss control device is activated give a rough indication of the success or failure of the frac pack. If the frac pack results in the development of a fracture with good fracture conductivity, then the near wellbore damage is bypassed and a good hydraulic connection is made between the wellbore and reservoir. This results in "high" fluid losses before activating the fluid loss control device.

If the fluid losses are low, then this is an indication of poor hydraulic connection between the reservoir and wellbore, representing a poor frac pack.

For the purpose of scoring this item, the raw fluid loss is only one of several parameters considered. Other than the raw fluid loss, other items of consideration are the permeability of the formation, the height of the formation, and the pressure differential between the wellbore and the reservoir. The purpose for the treatment of fluid loss in this manner is that if the other parameters were not taken into consideration, reservoirs with a high permeability would always score well, and reservoirs with a low permeability would always score poorly. Considering the fluid losses compared to the flow potential of the reservoir is a more accurate way of determining "fluid losses" for the purpose of the completion score card. Warning: The following equation is not dimensionally correct, and should therefore not be used for any other purpose than for scoring the completion.

$$\boldsymbol{FLI = 1\,x\,10^{6}} * \frac{\boldsymbol{Q}(\boldsymbol{bph})}{\{\boldsymbol{K}(\boldsymbol{md})*\boldsymbol{h}(\boldsymbol{ft})*[\boldsymbol{P_{hyd}}(\boldsymbol{psi}) - \boldsymbol{P_{res}}(\boldsymbol{psi})]\}} \tag{23}$$

The fluid loss indicator (FLI) determined from this equation is compared to the fluid loss categories in the score card to determine the score.

5.2.5.5. Skin (RED). Skin is the name given to the effect of near wellbore reservoir damage that results in larger than expected pressure drop between the reservoir and wellbore. This additional pressure drop causes a resulting decrease in production rate. Positive skin is caused by partial completion / wellbore slant effects (when the well is not completed for the full height of the reservoir or is completed at an angle with respect to vertical) denoted by $S_{c+\theta}$, too few perforations – the perforation skin effect denoted by S_p, phase change and production rate-dependent (non-Darcy) effects denoted by Dq, and damage to the reservoir permeability denoted by S_d. Frac packing normally results in lowering the skin (it may even become negative) because the near wellbore reservoir permeability damage is bypassed by the fracture. Other than sand control, this is an additional purpose of frac packing – to reduce the skin.

Skin is important in determining the quality of the completion because skin has a direct impact on the production rate of the well. A good frac pack should significantly reduce the skin, and significantly increase production rate. Therefore, a low skin is given a high score, and a high skin is given a poor score.

5.2.5.6. How was skin determined? (BLUE). Skin is preferably determined using pressure transient analysis (PTA) by means of a pressure buildup test or pressure drawdown test. PTA is the most reliable method of determining skin. Nodal analysis, fluid losses, or a wild guess (WAG) based on other wells in the same or similar reservoir are other methods of determining skin. If the skin was not determined using PTA, then there may be considerable doubt concerning the accuracy of the skin estimate. If the screen erosion model is to be used, then it will be necessary to have a production rate that corresponds to the skin estimate.

5.2.5.7. Time to tip screenout predictable (BLUE). If the time to tip screenout actually measured on the rig does not match the expected time to tip screenout from the frac pack design, then there may be a problem with the execution of the frac pack.

The greater the difference between the expected and actual time to tip screenout, the lower the score for this category will be.

5.2.5.8. Percent proppant below crossover - actual / design (RED). The percentage of proppant placed below the crossover is computed by dividing the number of pounds of proppant that was actually placed below the crossover by the number of pounds of proppant that was designed to be placed below the crossover.

When this percentage is close to 100%, it indicates that the design for the frac pack, as well as the execution of the frac pack, was appropriate based on actual reservoir conditions. If significantly more or less than the designed weight of proppant was placed in the reservoir, then this is an indication that either the design or the execution were not performed properly.

If the percentage of the proppant placed below the crossover is close to 100% then a good score is given. The farther that this score deviates from 100%, the poorer the score.

5.2.5.9. Coverage for the perforated interval (RED). In general, a frac pack is designed such that the resulting hydraulic fracture will stay within the geologic unit that is considered the pay zone. The purpose of this is to help prevent potential influx of water from non-petroleum producing zones. However, in some cases the decision is made to fracture across small shale zones to connect all of the pay zones. This may be done to even out the production rate with respect to the vertical, thus reducing the potential of localized high flux zones that may contribute to screen damage.

If the hydraulic fracture stays in the pay zone or zones as designed, then the potential for water influx is reduced. This results in a good score. If the hydraulic fracture grows outside of the pay zone (unless it was designed to do so) then the potential for water influx is greater. This results in a poor score.

5.2.5.10. Was a hard tip screenout (TSO) achieved? (RED). The tip screenout information is obtained from the Post Frac Job Summary Report. A tip screenout is indicated when the slope of the Nolte-Smith curve is close to 1. A slope of greater than 1 indicates early (premature) screenout. A slope of less than 1 indicates that the fluid efficiency is higher than expected (fluid losses less than expected). There is no screenout and fracture width has not been created.

5.2.5.11. Reducing pump rate to induce a screenout (BLUE). If the pump rate is reduced at the end of the job to induce a tip screenout, then this indicates a problem with the design of the frac pack, and could mean uncontrolled growth of the fracture. The pumping schedule should be designed such that the screenout occurs naturally.

5.2.5.12. Back-side (annulus) opened at the end of the job? (RED). If the annulus is opened to induce a tip screenout, then it may indicate the same kind of problems as described above.

5.2.5.13. Net pressure build after TSO event (RED). Net pressure build information can be obtained from the Post Frac Job Summary Report. A large net pressure gain after screenout is necessary to build width in the fracture. A large width in the fracture is necessary to provide the best hydraulic connection between the reservoir and the wellbore.

5.2.5.14. Slope of the Nolte-Smith log-log plot after TSO event (BLUE). The slope of the Nolte-Smith log-log plot after the TSO event is reported in the Post Frac Job Summary Report. A slope of near 1 for the Nolte-Smith plot indicates a hard tip screenout. A slope of greater than 1 indicates early (premature) screenout. A slope of less than 1 indicates that the fluid efficiency is higher than expected (fluid losses less than expected). There is no screenout and fracture width has not been created.

5.2.6. Startup (Figure 5.7). The following is a discussion of the startup category. Startup must be monitored for production of sand.

5.2.6.1. Did the well produce non-transient sand or proppant? (RED) Production of proppant or sand following startup may be in indication of sand screen failure.

5.2.6.2. Continuous monitoring & daily samples (BLUE). If continuous monitoring equipment (such as acoustic monitors) is installed, then it will aid in early detection of sand control failure. If continuous monitoring is not installed, daily samples can be analyzed for sand or proppant content.

5.3. SPIDER PLOT FOR SCORE CARD

Figure 5.8 shows an example of a spider plot for the expression of the results for a score card. A spider plot is a graphical representation of data, and derives its name due to the resemblance to a spider’s web. Each thread of the spider web is an axis where the value for the variable represented by the thread is plotted, and the length of the thread is proportional to the value of the variable. The endpoint of each thread is connected by a line. This type of representation allows a large amount of data to be quickly summarized in one picture without having to assimilate a large matrix of numbers.

In the referenced example provided in Figure 5.8, each of the axes represents a major category of the score card (reservoir characteristics / geology, well cleanup / preparation, perforating, mechanical equipment, post job analysis / diagnostics, and startup). The score for each of these categories is plotted on the spider plot for each of the two zones of the well completion. A different color is used for each zone and a legend shown on the plot with the name of the zone.

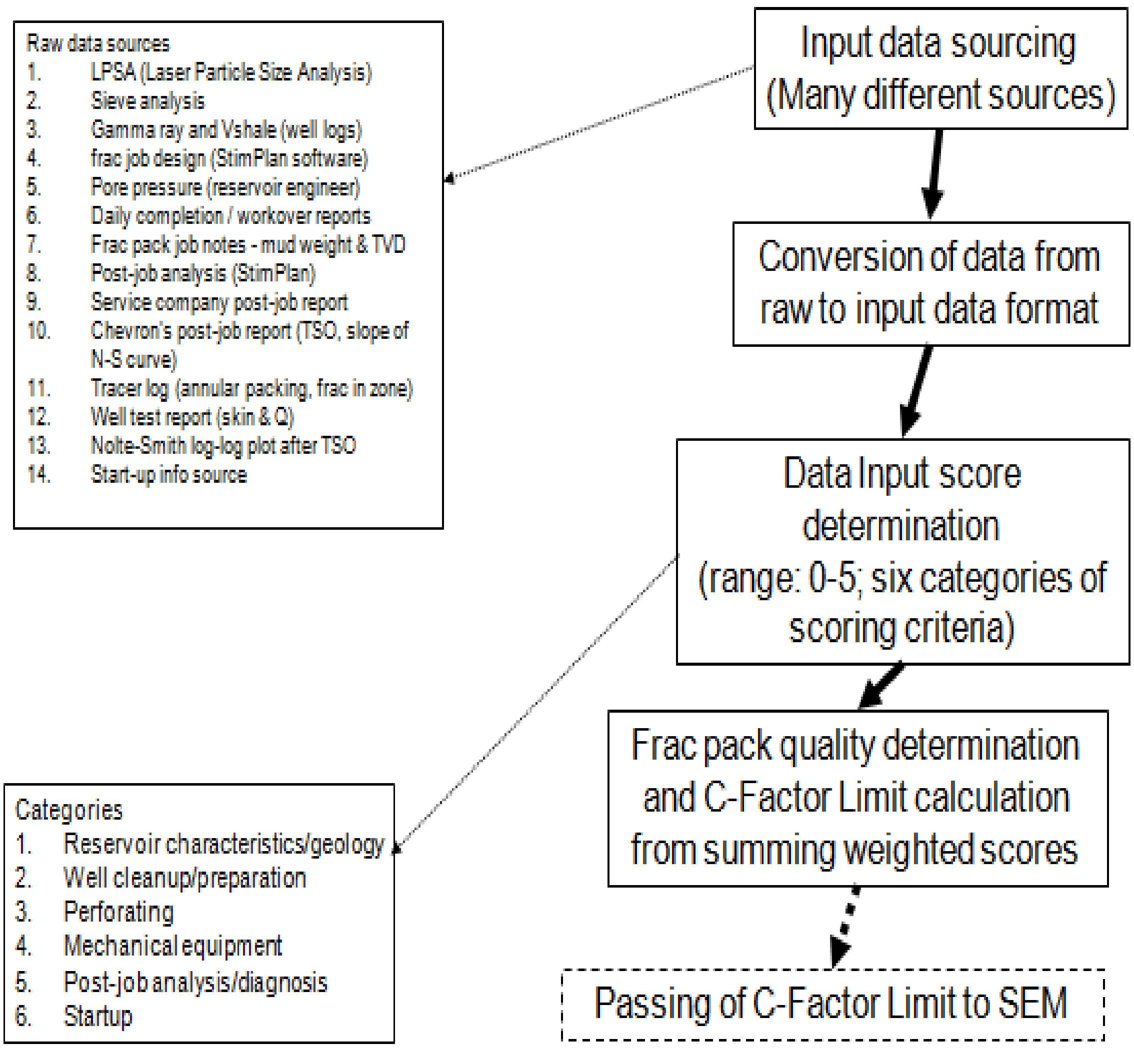

Figure 5.1: Workflow for populating the frac pack well completion score card to determine well completion quality and set the C-factor limit for use in the SEM.

Project Name and Well Name	Well X / Zone 1
RESERVOIR CHARACTERISTICS / GEOLOGY	
Uniformity coefficient (UC) of reservoir pay sand	
d40	
d90	
UC = d40/d90	
Unconfined Compressive Strength (UCS)	
Vertical heterogeneity	
Fines content (<44 microns or 325 mesh)	
Methodology for sizing of the gravel	see comments
Pore pressure (convert Pres to EMW at top of perfs)	
Reservoir pressure from job notes Pres (psi)	
TVD to top of perforations	
Pres in EMW ppg = P psi / (0.0521 psi/ft*ppg)(TVD ft)	

Figure 5.2 Input matrix for score card – Reservoir Characteristics / Geology section.

WELL CLEANUP / PREPARATION	
Completion fluid properties: Solids content of the effluent completion fluid measured in NTU's before perforation	
Cleanup of wellbore: Cleanout BHA, including bit scraper, brushes, magnets, trip across perforated interval, tools properly sized.	

Figure 5.3 Input matrix for score card – Well Cleanup / Preparation section.

PERFORATING	
Perforation OB/UB	OB
Perforation depth control	
Perforation cleanup (surging)	
Completion fluid differential pressure between brine density and pore pressure	
P_{brine} psi = (0.0521 psi/ft*ppg)*(ρ lb/gal)*(TVD ft)	
Brine density ρ (lb/gal)	
TVD to top of perforations	
$P_{reservoir}$ from the geology category above	
$\Delta P = P_{brine} - P_{reservoir}$	
Fluid loss pills after perforation	

Figure 5.4 Input matrix for score card – Perforating section

MECHANICAL EQUIPMENT	
Running the BHA and screen - note any problems	
Sizing of the gap: annulus between casing ID & screen OD	
Casing ID - *state the specification of the casing in notes*	
Screen OD - *state the specification of the screen base pipe*	
Gap = (Casing ID – Screen OD) / 2	
BHA, sand control equipment QA/QC	
Fluid loss device post fracture (ceramic flapper, shure shot ball)	
Fluid loss pill spotted post FLCD failure	
Reverse out issues	
Inspection of BHA after extraction: Many tool movements, shiny washpipe recovered, washpipe sticking, unexplainable mysteries. Get from Daily Completion / WO report. See notes.	

Figure 5.5 Input matrix for score card – Mechanical Equipment section.

POST JOB ANALYSIS / DIAGNOSTICS	
Screen /blank annulus fill (tracer logs)	
Did the job pump as planned?	
Fluid losses indicator after job, before activating fluid loss control device (FLCD) = 1E+6*Q(bph)/{K(md)*h(ft)*[Phydrostatic(psi) - Preservoir(psi)]}	
Fluid losses after frac packing before activating FLCD, Q (bph)	
Average permeability of the perforated interval K (md)	
Thickness of the perforated interval h (ft)	
Hydrostatic pressure of brine at tops of perfs Phydro (psi)	
Reservoir pressure from job notes Pres (psi) (SEE GEOLOGY)	
Skin	
How was skin determined?	
Time to tip screenout predictable	
% proppant placed below crossover (actual / design) (N/A if TSO is NOT achieved)	
Frac stays within zone (only from tracer log data) unless frac designed to connect separated zones	
Did you achieve a hard TSO (not an induced screenout)? Choose yes or no under raw score.	
How much did you reduce rate at the end of the job to induce a screenout?	
Did you open the back-side (annulus) at the end of the job?	
Net pressure build after TSO event	
Slope of Nolte-Smith log-log plot after TSO event	

Figure 5.6 Input matrix for score card – Post Job Analysis / Diagnostics section.

STARTUP	
Did the well produce reservoir sand or proppant during cleanup?	
Continuous monitoring & daily samples	

Figure 5.7 Input matrix for score card – Startup section

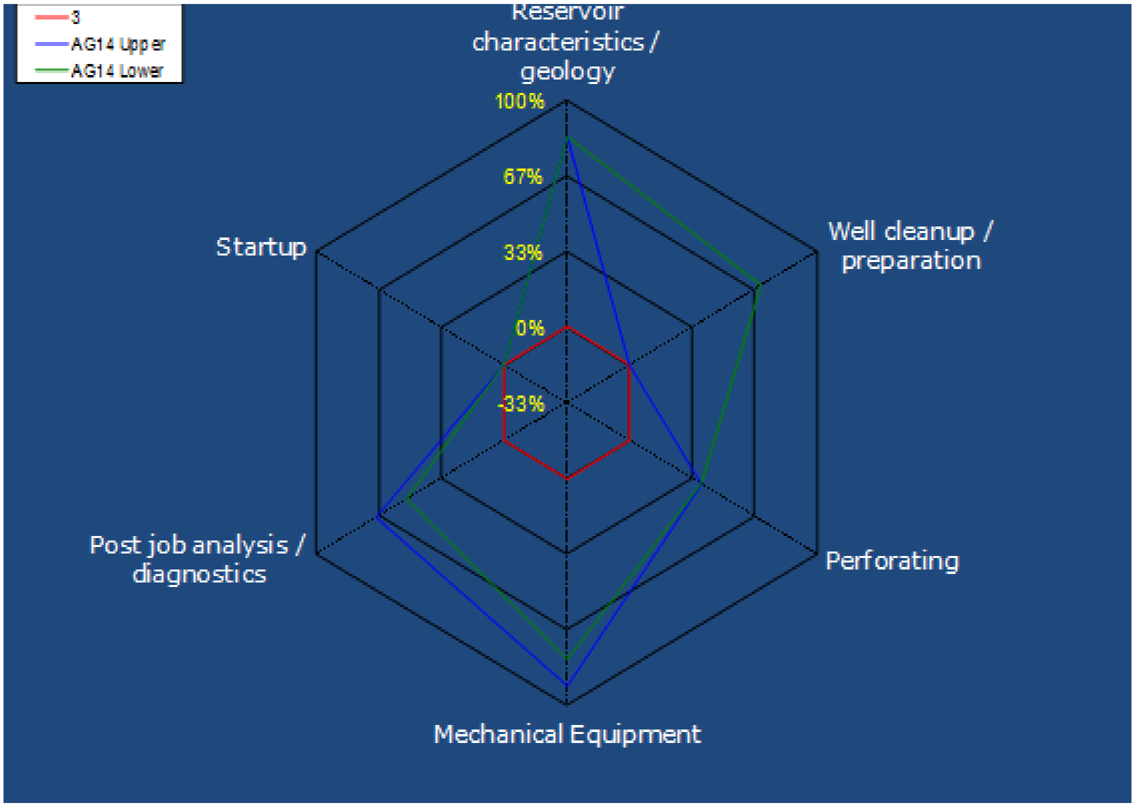

Figure 5.8: Example of the graphical output of the frac pack well completion score card in spider diagram format for a two-zone frac pack well

6. PILOT TESTING OF SCREEN EROSION MODEL AND SCORE CARD

The following section describes the results of pilot testing the screen erosion model and well completion score card for frac pack well completions.

6.1. PROJECT RESULTS FROM PILOT TESTING

Pilot testing of the screen erosion model and well completion score card tools was conducted using actual Chevron project data from three regions – Nigeria, Angola, and Gulf of Mexico, as shown in Figure 6.1. A summary of the results of the screen erosion pilot testing is shown in Table 1 below, and a summary of the detailed results for two of the well completion score card pilot tests is shown in Table 2. Field and well names have been removed due to confidentiality restrictions.

Table 1 shows the number of wells in each of the pilot tests, as well as the number of zones. Single zone frac packs have only one zone, whereas multi-zone frac packs typically have either two or three zones. Due to the non-linear increase in complexity, cost, and risk for failure, it is uncommon to perform frac packs with more than three zones. The range of skins from pressure transient analysis and range of production rates is shown for each set of wells. The calculated perforation efficiencies are shown for each zone of the sets of wells. The calculated velocity at the perforation tunnel (Vc), velocity at the screen surface (Vs), and C-factor are shown.

The skin and production rate that the well was tested were entered into the screen erosion model on a zone by zone basis for the stacked frac pack well completions. Additional data requirements are documented in the input matrix as shown in Figures 5.2 through 5.7. The input matrix is a convenient spreadsheet summary that lists all the data requirements required for both the scorecard and screen erosion model. The input matrix saves time during data mining for the large amount of data required for the tools. With skin and rate from well test conditions, the perforation efficiency for each zone was calculated (the screen erosion model was operated in diagnostic mode). Perforation efficiency was then held constant, then the actual rate that each zone was producing at was entered (screen erosion model was run in forecast mode) to obtain the velocity of the fluid exiting the perforations at the casing (Vc), velocity of the fluid impinging upon the sand screen (Vs), and the C-factor.

The well completion score card was populated with the data required as shown in the input matrix (Figures 5.2, 5.3, 5.4, 5.5, 5.6, and 5.7). After entering the data into the well completion score card, the C-factor limit for each completed zone was established (10, 30, 60 for poor, fair, good completion quality). Table 2 shows the final weighted average of the well completion quality for each zone, and the corresponding C-factor limit based upon the well completion quality score. The Vc, Vs and C-factor output from the screen erosion model was then compared to the operability limits (Vc < 10 ft/sec; Vs < 1 ft/sec; C-factor < 10, 30, or 60 as determined by well completion quality using the score card). The wells that were being operated outside of the suggested limits were understood to be at risk for early failure. Wells operating below these limits were considered to be operating at safe production rates. Detailed reports were prepared for each project and submitted to the completion engineers and / or production engineers responsible for producing their respective wells. The reports described the data used, the methodology, the results of screen erosion modeling / determination of well completion quality, and recommendations regarding the suggested production rates. In general, the pilot testing received good feedback from the completion engineers that performed the well completions. The well completion quality generally agreed with the perception of the completion quality for the majority of the wells. However, there were enough exceptions to this trend to highlight the need for quantitative determination of well completion quality and to promote best practices (Hendrix, 2008).

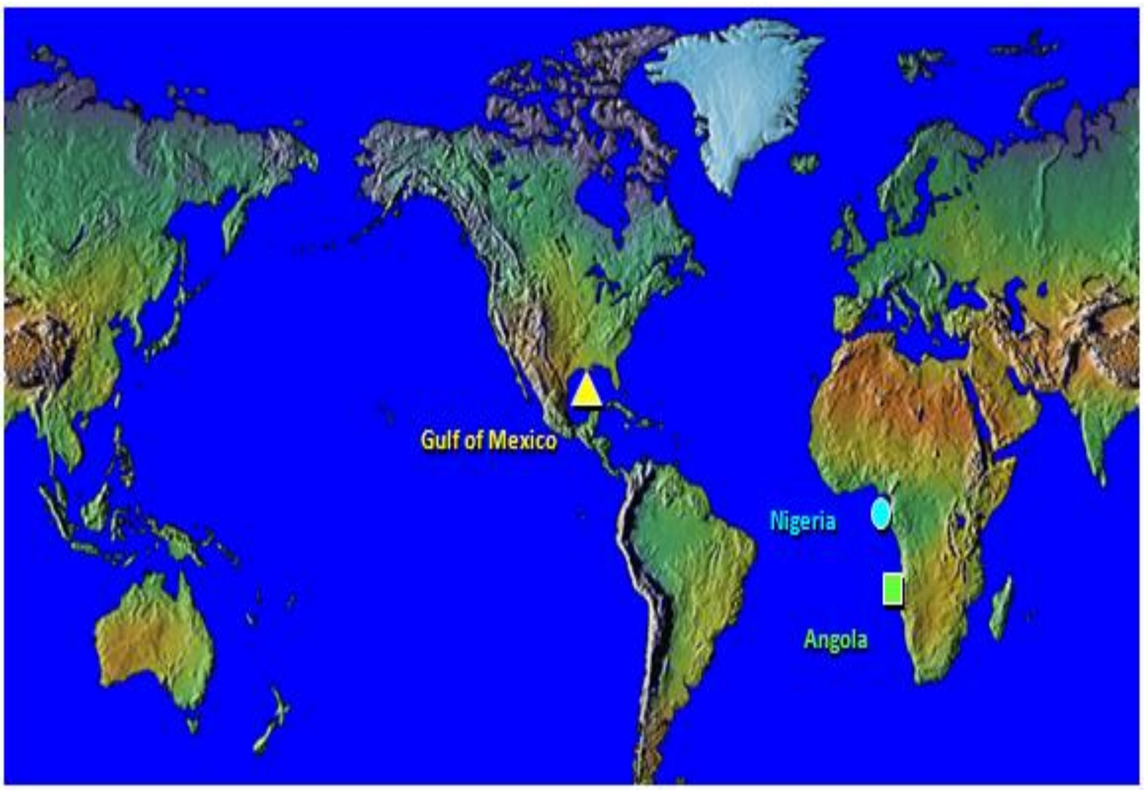

Figure 6.1 Project locations for testing the screen erosion model and well completion quality score card (Hendrix, 2008). The screen erosion model and well completion quality score card were pilot tested using data frommultiple deepwater projects in the regions of the Gulf of Mexico, Nigeria, and Angola.

Table 6.1. Results of the pilot testing of the screen erosion model and well completion score card (Hendrix, 2008)

Field	Field A	Field B	Field C	Field D	Field E
Wells	10*	3	3	2	5
Zones	21*	4	4	4	5
Skin	½ to 41 (from Peff)	2 to 30	1 to 4	4 to 9	4 to 21
Rates (bpd)	2,200 to 42,800	4,200 to 23,000	7,800 to 14,000	12,000 to 23,000	2,500 to 28,700
Perf eff (%)	2 to 10	1.7 to 19.2	5.1 to 7.9	31 to 58	3 to 34
Vc (ft/sec)	4.2 to 4.8	8.2 to 26	2.8 to 4.0	6.6 to 7.5	1.7 to 16.2
Vs (ft/sec)	0.7 to 0.8	0.5 to 1.5	0.3 to 0.5	0.6 to 0.7	0.5 to 1.4
C-factor	30 to 60	54 to 167	19.1 to 17.6	47 to 54	11 to 109

Table 6.2. Detailed results of the pilot testing of the score card for two projects (Hendrix, 2008)

Well	Score	C-factor limit
A	46.7	30
BL	55.6	30
BM	56.6	30
BU	58	30
CL	75.9	60
CM	68.4	60
CU	56.4	30
DL	50.4	30
DM	33.4	30
DU	66.7	60
EL	55.8	30
EU	57.7	30
FL	66	30

FU	65.8	30
GL	59.3	30
GU	67.7	60
HL	51.5	30
HU	56.3	30
IL	53.9	30
IU	57.8	30
JL	75.9	60
JM	68.4	60
JU	56.4	30
1	82.3	60
2L	87	60
2U	79.2	60
3	81.3	60

7. PEER REVIEW - SCREEN EROSION MODEL AND SCORE CARD

The following section describes the peer review of the screen erosion model and score card by subject matter experts from Chevron.

7.1. PEER REVIEW BY THE CHEVRON SANDING SOLUTIONS TEAM

The screen erosion model and well completions score card have taken several years to develop. During this development process the tool has been improved based on extensive feedback from the subject matter experts in the Sanding Solutions Team of the Drilling & Completions Department, Chevron Energy Technology Company, which constituted the first round of peer review.

7.2. PEER REVIEW USING THE LEAN SIGMA PROCESS

Extensive feedback was received from a wider peer review team composed of subject matter experts from a representative group of completion engineers and production engineers from Chevron Business Units that are routinely responsible for recommending production rate limits from their frac pack well completions – this was the second round of peer review. During this round of peer review the Lean Sigma process was used, and a blackbelt level certified Lean Sigma facilitator was used. Of the 37 score card line items, each person on the peer review team was allowed to cast 12 votes for the most important score card line items. The voting was based on each subject matter expert's opinion regarding the relative importance of the line item in calculating well completion quality as it applies to screen erosion. The results of the voting was captured on a Lean Sigma spreadsheet for analysis of the data. This allowed the well completion score card to be updated to reflect improved weighting factors based on a tested and proven method (Lean Sigma) of grading the relative importance of each line item.

7.3. PEER REVIEW FROM PROJECT ENGINEERS - PILOT TESTING

Additional feedback on the two tools (SEM and SC) was solicited based on pilot testing of the tool using data from several different independent and geographically / geologically diverse deepwater Chevron fields (third round of peer review). Each time the tools were pilot tested using real project data from specific producing wells, feedback was solicited from the completion engineers and / or production engineers involved in the projects.

7.4. PEER REVIEW USING PROJECT READINESS INDEX

A final fourth round of peer review was obtained from a peer assist team composed of subject matter experts from Chevron representing deepwater fields from around the world. The project readiness assessment tool uses readiness categories and a "traffic light” scale, with definitions that depend on the type of review that is being conducted. The comments from the peer review team were captured using the project readiness spreadsheet to calculate the project readiness index, which is an assessment of whether or not the project is on track to proceed with deployment to field engineers based on the planning assist team's evaluation of the current state of the tool being evaluated. The assessment was made for each of the three areas (scorecard, screen erosion model, and deployment), as well as an overall project assessment.

During the final peer assist, the well completion score card parameters were mostly confirmed, however minor changes were recommended in the parameters used to measure well completion quality. Two changes that resulted from the final peer assist were minor changes in the weighting factors which determine how important each parameter is, as well as breaking the score card into a dual score card. The revised score card now gives a score for the screen erosion model completion quality, and another for overall completion quality. This change reflects the acknowledgement that primarily a small subset of parameters effect the completion quality as it relates to screen erosion risk, while there is a broader set of parameters that reflect general completion quality. The general completion quality is still an important metric, and is used for documenting opportunities for improvement in the execution of well completions (Hendrix, 2008).

7.5. RELEASE OF THE TOOLS FOR GENERAL USE

The screen erosion model and score card were unveiled at the 2009 Chevron Reservoir Management Forum in The Woodlands, Texas. Both tools were released in 2009 for unrestricted use within Chevron (Hendrix, 2010).

8. CONCLUSIONS AND RECOMMENDATIONS FOR FUTURE WORK

Although the current versions of the screen erosion model and well completion score card for frac pack well completions are novel inventions and represent significant contributions to the field, there are limitations and opportunities for future development.

8.1. COMPONENTS OF SKIN

One of the primary simplifying assumptions in the tool is that all of the skin is due to the pressure drop across the perforations, however this is not entirely true. A more sophisticated model would take into consideration all contributions of skin, and the deconvolution of the skin would allow proper apportionment of only the actual perforation skin to the perforations. As mentioned earlier, the components of skin are not simply additive, but are in some cases functions of one another, therefore the deconvolution of skin into its components is highly complex, and was beyond the scope of this comparatively simple tool.

8.2. PERMEABILITY HETEROGENEITY FACTOR CALCULATION

Based on analysis of field data, it is apparent that the practice of using a factor of Kmax / Kavg to account for the effect of a high permeability zone on the localized erosion in a hot spot on the sand screen results in operating limits that are too conservative. Future work that could address this would be using a finite element model to model the increased fluid flow in a well due to permeability heterogeneities in the vicinity of the perforations in the perforated interval. The results of the finite element study could be used to determine a revised coefficient to account for the increased localized flow. The finite element modeling would be a significant undertaking, and no budget is yet available for this study.

8.3. ADDITIONAL PILOT TESTING

Another opportunity for tool improvement would be using additional field data to “calibrate” the tool. The additional data would need to include a significant number of frac pack wells that have failed. The Vs, Vc and C-factor for the failed wells could be calculated and compared to the same parameters for other frac pack wells that have not failed. This additional data would help confirm the operating limits of 1.0 ft/sec and 10 ft/sec for Vs and Vc; as well as 10, 30, and 60 for C-factor in poor, fair, and good quality well completions. Unfortunately, data for this purpose could not be located by anyone from Chevron since few Chevron frac pack wells have failed to date. No data sets outside of Chevron could be used since no other company collects the same set of data, especially for the score card. Also, data outside of Chevron would likely be considered proprietary, and unlikely to be released.

8.4. PHYSICAL MODELING

In the absence of actual field data, physical modeling of screen erosion could be performed. The experimental apparatus and materials would need to be constructed from actual well and well completion materials with very detailed measurements and quality control procedures for the results to be of beneficial use. A group of subject matter experts would need to agree on the experimental procedures and the metrics to be used to measure success or failure. Recall that the simple calculation of mass removed based on mass of the original screen is not sufficient because the heaviest screen will always be the screen that will show the least erosion as a percentage of initial mass. Another problem is determining screen failure. In previous physical modeling, an erosion rate was determined and the mean time to failure was extrapolated. However, is failure when there is a hole in the screen or when "some" proppant passes the screen? There is no consensus. This process is much more complicated than one would expect. Due to the complexity and high cost of conducting such tests, it is unlikely that this investigation will be performed in the near future.

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From 1999 – 2001 worked as a project engineer for Williams & Company Consulting supervising cleanup of releases of petroleum to the environment. Between 2001 – 2006 worked as a petroleum engineer and drilling supervisor for ECR, Inc. – a petroleum industry service company. 2007 – 2010 worked for Chevron as a petroleum engineer doing research and development in the field of sand control well completions. From 2010 to present worked for Chevron as a drilling supervisor in the Gulf of Thailand.