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Case Study of Hydraulic Fracture Completions in Horizontal Wells, South Arne Field Danish North Sea

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Abstract

This paper provides a case history of hydraulic fracture completions in horizontal wells in the South Arne Field, Danish North Sea (9500 ft TVD, chalk formations).[1] The first three propped fracture treatments attempted in the South Arne Field "screened-out" very early in the design due to excessive fracture complexity and fluid leakoff. A detailed study of the rock mechanical properties, wellbore stress & fracture initiation characteristics, far-field stress regime & fracture orientation, and fluid leakoff behavior was integrated with fracture modeling studies to evaluate this problem.[2] These studies were used to improve the fracture treatment strategy for future wells, resulting in essentially 100% success placing the designed proppant volumes and achieving aggressive tip screen-outs (TSOs) on over 60 fracture treatments.

This paper summarizes the initial fracture treatment problems and provides a detailed discussion of fracture modeling and design issues, mini-frac analysis procedures, and the mitigation and evaluation of fracture complexity.

Introduction

The South Arne field is located in the northern part of the Danish sector of the North Sea. The structure is an elongated Cretaceous inversion ridge situated on the western margin of the Tail-End Graben. The reservoir rock is high porosity/low permeability chalk of Maastrichtian and Danian age, comprising the Tor and Ekofisk formations, respectively. A hard, low porosity interval at the bottom of the Ekofisk formation separates the two formations. Tor formation permeabilities range from 0.2 to 4 mD, whereas the Ekofisk formation permeabilities range from 0 to 0.7 mD. Virgin reservoir pressure is 6350–6450 psig and reservoir temperature is 240 deg F. The reservoir is low to moderately naturally fractured. The combined thickness of the Ekofisk and Tor reservoir varies from 25 to 120m.

The well locations are also shown in **Figure 1**. The horizontal section targets the Tor formation and is typically about 1800 meters in length.[1] The completion method selected for the five wells allows each zone to be mechanically isolated from the rest during both stimulation & production. The wells were completed using propped fracture treatments in each zone.[3,4] The work string is used both for perforating, stimulating and isolating the individual zones.[5] The annulus between the work string and the liner is open during stimulation, providing excellent bottom hole pressure measurements using the static annulus pressure.

Unlike other North Sea Chalk reservoirs where the primary fracture treatment problems are tortuosity and multiple fractures,[6,7,8] the South Arne reservoir also suffers from the apparent activation of natural fractures or fissures, leading to excessive fluid loss that may result in an inability to place proppant. The potential for this behavior was identified during the initial rock mechanical studies (Well A) and verified using both fracture modeling and G-function analyses.

Background

The first fracture treatments in South Arne were conducted in Well A, zones 2 and 3, in May 1998 using 16/30-mesh sand. However, these initial attempts were unsuccessful. A detailed rock mechanics study indicated that fracture initiation procedures and the interaction of the hydraulic fracture with pre-existing natural fractures/fissures resulted in severe fracture complexity and/or excessive leakoff. A second set of "demonstration" fracture treatments were conducted in Well D in December 1998 to evaluate the effectiveness of changes in perforating, fracture initiation, and execution strategies. The first treatment in Well D (zone 1) utilized a high viscosity cross-linked gel to initiate the fracture followed by a 1-ppg 100-mesh sand stage to reduce fracture complexity and to control fluid loss. 20/40-mesh proppant was pumped in zone 1 to reduce the potential of a screen-out due to insufficient fracture width. However, the job screened-out very early in the treatment, with only 100 Klbs of resin coated sand (RCS) being placed (about 20% of the designed proppant volume).

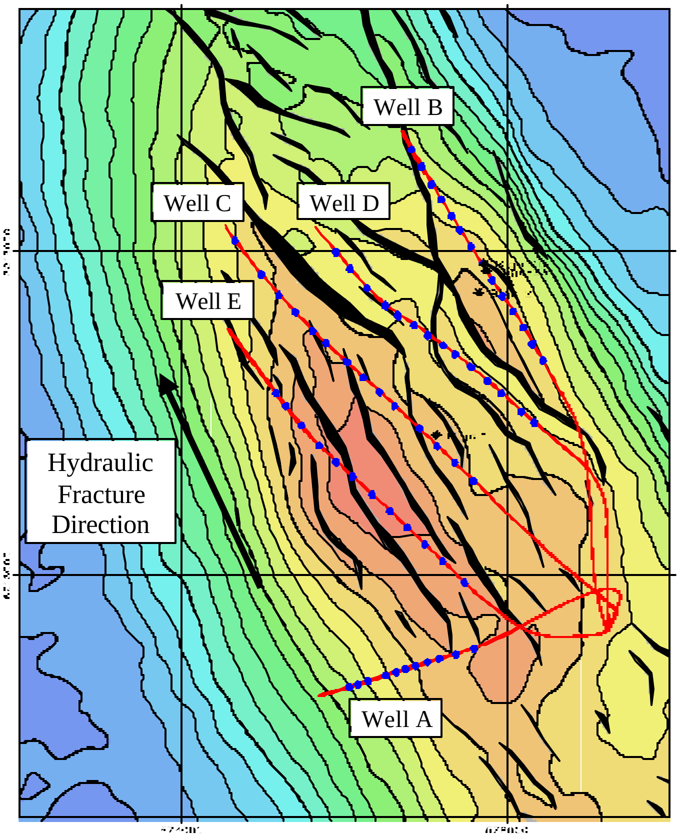

Figure 1 – South Arne Field Map

The post-treatment analysis of the Well D Zone-1 treatment indicated that excessive fluid loss resulted in insufficient fracture width to place the designed proppant volume. It was hypothesized that increasing the concentration of 100-mesh sand could potentially control excessive fluid loss into natural fractures or fissures that may be dilated during the fracturing process. Therefore, the concentration of 100-mesh sand was increased to 4-ppg (ramp 1-4 ppg) during the displacement stage in zones 2 & 3. The Well D zones 2 & 3 *propped* treatments were pumped as designed; placing 450-500 Klbs of 20/40 RCS at concentrations up to 15-ppg while also achieving a TSO net pressure increase of about 500 psi.

The results from the three "demonstration" fracture treatments in Well D provided essential data for future designs. In addition, the Well D treatments showed that modest TSO pressure increases could be achieved with relatively large pad sizes (about 35% pad fraction). The Well D zone 2 & 3 results showed that the appropriate concentration of 100-mesh sand is very important to ***effectively*** control fluid loss and fracture complexity.[2]

The next well that was completed was Well E in March-April 1999. Twelve zones were successfully completed using propped fracture treatments. Well B, Well D, Well A, and Well C were "batch" completed between August-1999 and January-2000. A total of 64 zones were prop fracture stimulated using a total of 50 million pounds of proppant. Although the first three propped-fracture treatments in South Arne were unsuccessful, resulting in very early screen-outs, only three additional screen-outs were encountered during the remaining 61 propped fracture treatments.

General Operational Procedures. All South Arne propped fracture treatments were pumped down a work string with the annulus "live" (no packer) using a rig-based completion system that allows each zone to be fracture stimulated and then isolated for optimum reservoir management flexibility.[4] The "live" annulus provided accurate bottom hole pressure (BHP) measurements, while also allowing stimulation fluids to be circulated to within close proximity of the perforated interval. Each zone was perforated using 6-spf over a 6-ft interval. Typical South Arne fracture treatments included the following stages:

1. Fill surface lines to the wellhead with cross-linked gel.
2. Circulate cross-linked gel to within 3-5 bbls of the bottom of the work string. Add 1-4 ppg 100-mesh sand to the later portions of the circulation stage (typically the portion that will remain in the vertical section of the work string).
3. Close the BOP rams and perform a cross-linked fluid mini-frac injection with a 1-4 ppg proppant slug in the final portion of the injection.
4. Flush the mini-frac with linear gel and shutdown when the proppant slug passes the perforations.
5. Analyze the mini-frac data to determine tortuosity, fracture complexity, and fluid loss behavior. Adjust pad size and proppant schedule.
6. Pump the main treatment cross-linked fluid pad, with the inclusion of a 1-4 ppg 100-mesh slug and 16/30-proppant slugs as/if necessary.
7. Pump the main treatment 16/30 sand stages as designed using cross-linked fluid. Switch to RCP if the tip screen-out (TSO) trend indicates that the designed proppant volume cannot be "reliably" pumped.
8. Pump the main treatment RCP stages as designed using cross-linked fluid if an early switch to RCP was not made in step 7.
9. Flush the treatment with friction-reduced completion brine (typically 1.6 S.G.) or initiate flush early if the TSO trend indicates that all the RCP cannot be pumped.
10. Shutdown and monitor pressure decline.

All SA fracture treatments utilized fresh-water-based 35-50 lbm/Kgal concentrations of guar or HPG gelling agents and borate cross-linkers (typically higher gel loadings in the pad, with reduced gel loadings as the treatment progresses). 2% KCl water was used as the base fluid for all stimulation treatments and surfactant used to prevent emulsions and improve water recovery. Appropriate breaker loadings and types were used to degrade the cross-linked gels.

Fracture Design

There were three major fracture design issues that were addressed during the initial South Arne development:

1. Interval coverage to optimize recovery from the primary Tor and secondary Ekofisk reservoirs.
2. Fracture conductivity and required tip screen-out (TSO) net pressure increase.
3. Fracture length requirements to optimize deliverability.

Interval Coverage. The horizontal well path targeted the upper portion of the Tor formation (primary reservoir). However, capturing hydrocarbon reserves in the overlying Ekofisk formation was also important to SA development. Vertical permeability in SA was estimated at about 10% of the horizontal permeability. Therefore, it was necessary to design the propped fracture treatments to cover the Tor and the *majority* of the Ekofisk interval to ensure adequate drainage. Reservoir simulation and geologic studies suggested that at least 75% of the Ekofisk formation should be contacted by the hydraulic fracture to ensure adequate recovery.

Required Fracture Conductivity. The minimum horizontal stress gradient for SA is about 0.75 psi/ft at 9500 ft or 7125 psi. Flowing bottomhole pressure is projected to be 3000 psi. Thus, closure stress on proppant is slightly over 4000 psi. The major factors that affect fracture conductivity (at a given closure stress) are proppant type & size, proppant pack damage, and the average proppant concentration in the fracture. The average proppant concentration in the fracture is a function of the TSO net pressure increase – larger increases result in higher proppant concentrations in the fracture. The proppant type & size selected for the majority of the SA fracture treatments was high quality 16/30-mesh sand. The required fracture conductivity can be estimated using the following equation.[12]

$$F_{CD} = k_f w_f / k X_f$$

An F_{CD} of 10-30 is considered infinite. Typical propped fracture lengths (X_f) in SA are no longer than 200 ft and permeability (k) is typically 1 mD. Thus the required fracture conductivity ($k_f w_f$) to achieve an F_{CD} of 10 is about 2000 mD-ft. Assuming that the proppant pack retains only 25% of its baseline conductivity due to embedment and fracturing fluid gel residue, then a proppant concentration of 5-6 lb/ft^2 is required to achieve an F_{CD} of 10.[13] Higher proppant concentration are desirable to compensate for non-Darcy and multiphase flow effects that can further reduce fracture conductivity.[14] Thus, 6 lb/ft^2 was considered a lower limit for all fracture designs.

All SA fracture treatments included a 200 Klbs "tail-in" of resin-coated-proppant (RCP) - either 16/30-mesh sand or 16/20-mesh intermediate strength ceramic (ISP) - to control proppant flow back. The RCP is expected to enhance near-wellbore fracture conductivity compared to 16/30-mesh sand. In high porosity (high permeability[1]) zones larger quantities of 16/20 ISP were pumped to further improve fracture conductivity.

Fracture Length Requirements. A reservoir simulation and economic study indicated that longitudinal fractures needed to be near tip-to-tip to maximize net present value (NPV), while optimum fracture length was governed by reservoir permeability for transverse orientation (Well A). However, due to the thickness of the overall target interval in many SA fracture treatments, fracture growth was generally thought to be radial and large treatments (1000 Klbs or more) were required to achieve adequate interval coverage. Thus, in many cases fracture length was controlled by interval coverage requirements and operational limitations. The number of fracture treatment stages and zone spacing was evaluated using reservoir simulation and economic studies of each well and ranged from 11-14 zones and 81-161 meter zone separation. The average spacing between zones for longitudinal fracture orientations was 139 meters (455-ft). Thus, tip-to-tip fracture coverage would require an average fracture half-length (X_f) of 230 ft.

Rock Mechanics & Stress

The orientation of the wellbore with respect to the preferred hydraulic fracture direction can be critical to treatment success in horizontal wells. Well A was drilled perpendicular to the preferred hydraulic fracture direction, resulting in transverse fracture orientation with respect to the wellbore. The remaining wells were drilled "essentially" parallel to the preferred hydraulic fracture direction (Figure 1). It is commonly accepted that longitudinal fracture orientation with respect to the horizontal wellbore will result in fewer complexities due to fracture initiation problems, multiple fractures and near-wellbore tortuosity. However, the fracture treatment data from South Arne did not indicate any "severe" fracture treatment problems when transverse fractures were created (Well A). There were significant problems with the initial fracture treatments in Well A - zones 2 & 3, but fracture treatments on subsequent zones using proper fracture initiation procedures indicated that wellbore orientation (transverse fractures) did not adversely affect treatment success.

Fracture Orientation, Fracture Initiation, & Natural Fractures. The initial problems encountered in Well A resulted in a comprehensive rock mechanical study to evaluate fracture orientation and fracture initiation. The rock mechanics/stress analysis indicated that the near-wellbore fracture geometry is probably complex due to the existence of natural fractures that are oriented in the direction of "starter" fractures from the wellbore. There are some zones with a high density of natural fractures that exhibit a strong tendency towards fracture complexity. **Figure 2** illustrates the orientation of the hydraulic fracture, Well A wellbore, and the dominant natural fractures.

Initiating the fractures with cross-linked gel, using proppant slugs to reduce complexity and "plug" open natural fractures, and avoiding zones with high natural fracture density should mitigate most SA fracture treatment problems. Additional details of the rock mechanics work are provided in a previous paper.[2]

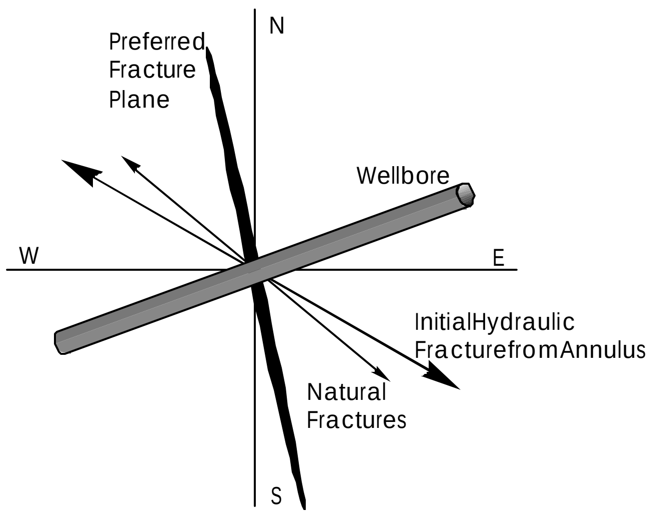

Figure 2 - Orientation of the Well A wellbore with respect to the preferred fracture plane and dominant natural fractures.

Young's Modulus. An important parameter for fracture modeling is Young's modulus. The SA Tor and Ekofisk reservoirs can exhibit significant variations in porosity and therefore Young's modulus can vary from zone-to-zone. These variations were included in the fracture modeling. **Figure 3** shows the basic relationship used to estimate Young's modulus from layer porosity data. Porosity can vary from 25 to 45%, with most zones falling in a range from 30% to 40% porosity. Figure 3 shows that Young's modulus can vary from less than 500,000 psi to over 2,000,000 psi (a factor of 4) and these variations were significant when designing and evaluating SA fracture treatments.

Stress Profile. The stress profile used for the SA fracture modeling was based on a combination of mini-frac closure stress estimates, MDT data, drilling data (ECD and losses), rock type, analogous data from other North Sea reservoirs, and SA fracture treatment data. The SA geologic model was divided into seven layers for the fracture modeling**. Table 1** shows the layer designations and stress profile data used for the SA fracture modeling and evaluations. In some cases, not all layers were present. The range of closures stresses shown in Table 1 represent the values used to match the actual net pressure behavior of the various treatments and are very consistent.

The large variation in closure stress for the Tor interval is primarily due to the low closure stresses measured in Well C (discussed later). In the absence of Well C, the stress profile in each layer typically varied by less than 0.02 psi/ft (less than 200-psi). Much of the variation in closure stress can be attributed to uncertainties in annulus head due to slight variations in brine density (probably about 100-psi) and the reliability of closure stress estimates from mini-frac pressure decline analysis. Some variation in closure stress is expected due to differences in rock properties and structural position.

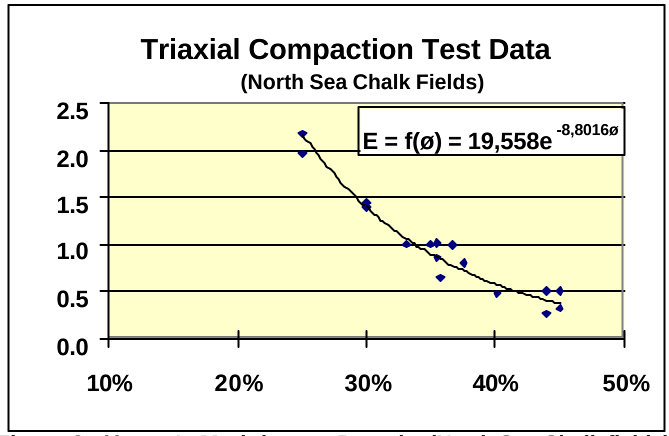

Figure 3 - Young's Modulus vs. Porosity (North Sea Chalk fields)

Table 1 - South Arne Layers & Stress Profile

Layer	Min. (psi/ft)	Max. (psi/ft)	Average (psi/ft)
Above EK	0.83	0.83	0.83
Upper EK	0.75	0.77	0.76
Middle EK	0.75	0.77	0.76
Lower EK	0.75	0.77	0.76
Tight Zone	0.75	0.80	0.78
Tor	0.67	0.77	0.75
Below Tor	0.83	0.83	0.83

In most SA treatments, a mini-frac was performed and the Tor closure stress was directly measured. The bounding zones above the Ekofisk (EK) and below the Tor were assumed to have a stress gradient of 0.83 psi/ft, but no direct measurements of stress were available. The EK stresses were assumed to be similar to the Tor, as the rock-type in the EK is similar to the Tor (both are carbonates). A slightly higher stress was assigned to the EK based on MDT data. The tight zone stress was initially estimated at 0.8 psi/ft, but further review and modeling indicated that a more likely value was 0.78 psi/ft.

In most SA fracture treatments, the thickness of the Tor and EK layers dominated the net pressure behavior and thus there was little sensitivity to the bounding layer stress values. In addition, the tight zone was typically thin and stress values in the tight zone did not significantly affect net pressure behavior.

Fracture Treatment Problems & Solutions

The primary fracture treatment problems in South Arne are fracture complexity and excessive leakoff. The details of the initial problems encountered during the fracture treatments in Well A & Well D have been detailed in previous papers.[1,2] The primary solutions to these problems were:

1. Use high viscosity cross-linked fluids to initiate the fracture treatments. The use of high viscosity fluids to initiate fractures has been shown to reduce fracture complexity.[1,2,8]
2. Use 1-4 ppg 100-mesh sand to reduce fracture complexity and control excessive leakoff.[2]
3. Eliminate the mini-frac or flush the mini-frac with viscous fluid ***in low porosity zones*** to decrease the potential that the shutdown and subsequent fracture re-initiation will increase fracture complexity and leakoff.[2]

The application of proppant slugs (16/20 & 20/40 mesh) reduced near-wellbore tortuosity, but did not effectively reduce overall fracture complexity. It should be emphasized that most fracture treatment problems occurred in zones with porosity less than 30%. The lower porosity, higher modulus zones showed more sensitivity to fracture initiation and treatment procedures. Although this phenomenon is not well understood, it is likely that the higher modulus (harder) zones have a greater tendency to develop natural fractures, planes of weakness, or fissures that are dilated during the fracture treatment – resulting in excessive leakoff and increased fracture complexity. These natural fractures, planes of weakness, or fissures may also be "activated" or "aggravated" by shutdowns (such as mini-frac) that lubricate or pressurize these features during the pressure falloff. In addition, fracture complexity and leakoff can increase after the mini-frac shutdown due to the re-initiation of the fracture with a low viscosity fluid (linear gel) that was used to flush the mini-frac. In most SA treatments, any problems created by the mini-frac shutdown and subsequent fracture re-initiation with linear gel were overcome by using a high viscosity pad fluid with a 1-4 ppg 100-mesh sand slug followed by a 1-4 ppg 16/30-mesh proppant slug in the pad (a spacer was pumped between these two slugs). The 100-mesh sand concentration was found to be critical, with concentrations less than 4-ppg resulting in increased risk of a screen-out in the low porosity zones.

Mini-Frac Analysis

Several closure stress analysis techniques were used to evaluate the mini-frac data gathered during the SA fracture treatments. An accurate estimate of fracture closure pressure (or minimum *in situ* stress) is essential when performing fracture model net pressure history matching. The fracture closure pressure defines fluid efficiency, Tor stress, and fracture complexity. The mini-frac pressure decline data were evaluated using a variety of analysis methods, including:

1. Log-log pressure & log derivative plots,
2. G-function, G-function derivative, and G-function superposition plots,
3. Square-root-of time plots, and
4. Horner plots.

Well D Zone-4 Mini-Frac Analysis. The first step in the mini-frac analysis is to estimate the correct "stabilized" instantaneous shut-in pressure (ISIP). **Figure 4** shows the estimated stabilized ISIP for zone 4, correcting or removing the early time friction-related pressure drop that is seen in most pressure declines. The stabilized ISIP is necessary to correctly calculate the "delta pressure" for the log-log analysis (delta pressure = ISIP – decline pressure). In addition, Figure 4 shows the estimated "final pumping ISIP" which provides an estimate of pressure loss due to "mid-field" tortuosity or other transient pressure losses in the fracture. **Figure 5** shows the plot used to confirm that the stabilized ISIP picked in Figure 4 is correct. The line drawn through the data in Figure 5 should extrapolate to zero at time zero, indicating zero "delta pressure" at the beginning of the pressure decline. After reviewing Figure 5, the stabilized ISIP can be adjusted if necessary.

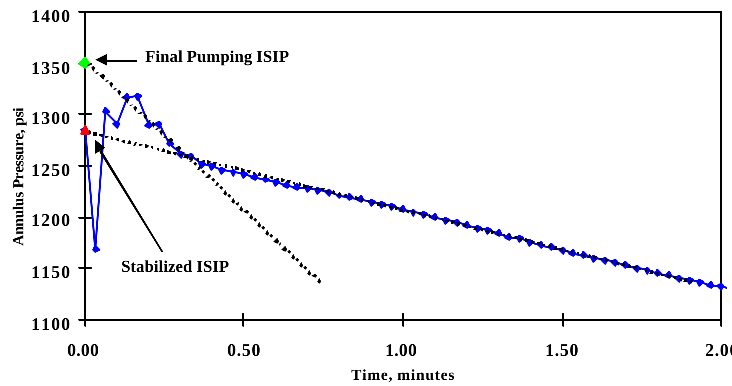

Figure 4 - Stabilized ISIP plot and final pumping ISIP

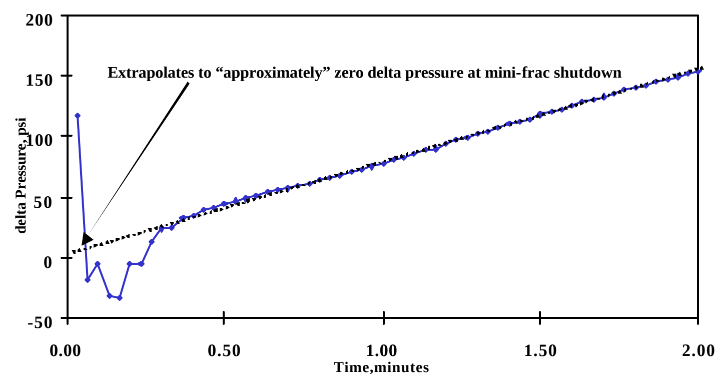

Figure 5 - Extrapolate delta-pressure using "stabilized" ISIP

The ***key*** analysis plots used to identify fracture closure are the G-function and Log-Log plots shown in **Figures 6 and 7**, respectively. These two plots provide significant insight into the flow regime (or pressure regime) exhibited during various portions of the pressure decline. Although identifying fracture closure can be difficult and there are numerous complexities and exceptions, in most cases fracture closure pressure can be identified within reasonable limits using the combination of the G-function and Log-Log plots. In addition, the use of these two plots can many times clearly show when the fracture IS NOT closed and reduce the risk of picking closure pressures that are too high.

There are three curves shown on the G-function plot (Figure 6), the "annulus pressure", the derivative of the G-function-annulus pressure curve (dP/dG), and the superposition of the G-function annulus-pressure curve (GdP/dG). The combination of the G-function derivative and superposition provide a very good tool to identify fracture closure. In general, fracture closure is indicated when the G-function superposition curve deviates from the straight-line behavior shown by line A in Figure 6 (675 psi). In addition, upon fracture closure the G-function derivative should deviate from line B shown in Figure 6 (675 psi).

The G-function plot shown in Figure 6 also provides important insight into leakoff and fracture behavior while the fracture is closing, providing a tool to identify fracture height recession, pressure dependent leakoff, etc.[9] The G-function derivative in Figure 6 exhibits a decreasing trend during this initial portion of the mini-frac pressure decline, indicating that this portion of the pressure decline is affected by complex behavior. However, it is the G-function superposition that provides the most insight into the nature of this early-time complex behavior. There is a clear signature of pressure dependent leakoff in the zone 4 mini-frac pressure decline as evidenced by the G-function superposition's upward deviation from line A in Figure 6. The complex behavior of South Arne fracture treatments and the higher-than-expected leakoff support the presence of natural fractures and/or fissures that "open" during the treatment, resulting in pressure dependent leakoff.

It should be noted that using the G-function superposition to identify pressure dependent leakoff, fracture height recession, etc. might not provide a unique answer, as similar superposition behavior may result from a variety of mechanisms. Therefore, using the g-function superposition to identify complex fracture behavior is not its primary purpose - identifying fracture closure using the g-function superposition is much less problematic.

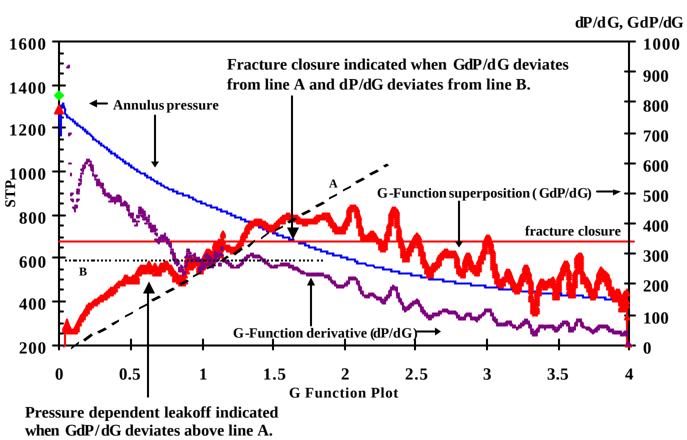

Figure 6 - G-Function Analysis Plot for Well D zone 4

Although the G-function analysis alone is quite useful, a more complete and reliable interpretation is possible by combining alternate analysis techniques. **Figure 7** shows the Log-Log analysis plot for the zone 4 mini-frac pressure decline. The log-log plot used for mini-frac analysis is identical to that used for well test analysis, using the same interpretation techniques and data preparation. There are two curves shown in Figure 7, the delta pressure (dP) curve and the superposition derivative of the delta pressure curve (tdP/dt). Figure 7 provides important insight into the flow/pressure regimes exhibited during the mini-frac pressure decline. The very early portion of mini-frac pressure decline is dominated by wellbore storage behavior (unit slope on the log-log dP and superposition curves). After the wellbore storage period, the data exhibits a ½-slope on the dP and superposition curves, indicating linear flow and an open fracture. It is important that the superposition curve exhibit this ½-slope behavior to confirm linear flow, as linear flow can easily be misinterpreted using the dP curve alone. Fracture closure is indicated when the flow regime deviates from linear-flow (deviates from ½-slope behavior on the log-log plot).

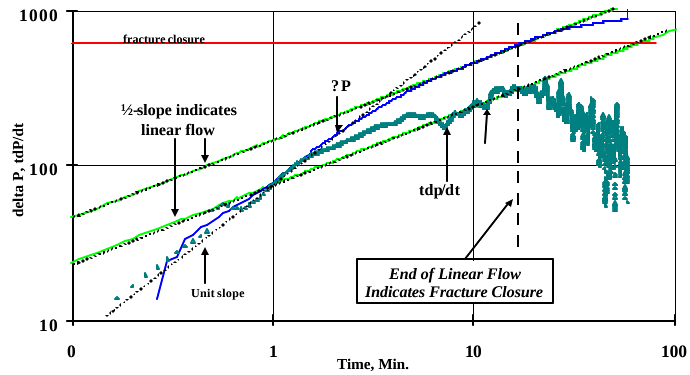

Figure 7 - Log-Log Analysis Plot for Well D zone 4

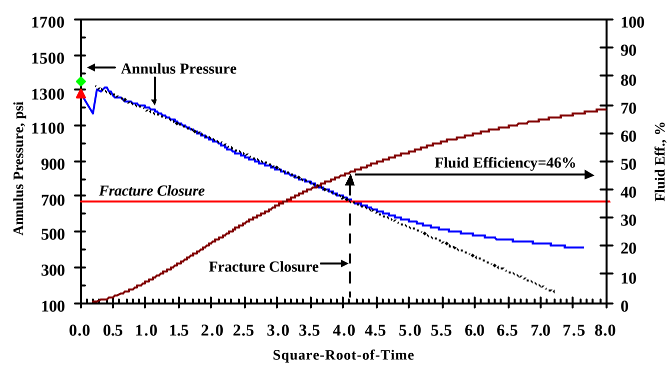

Figure 8 - Square-root-of-time plot: Well D zone 4

The square-root-of-time plot is shown in **Figure 8**. Although this plot is the most common analysis method used to pick fracture closure, it can often be unreliable and lead to multiple interpretations of fracture closure pressure. In an ideal case with constant leakoff during the mini-frac injection, the square-root-of-time plot will exhibit a straight line (indicating linear flow) until the fracture is closed. However, in many field applications (that are not ideal), the square-root-of-time plot does not exhibit a clear straight-line region or a definite change in behavior that *could* indicate fracture closure. The pressure decline for Well D zone 4 (Figure 8) exhibits relatively ideal behavior, resulting in a reasonable fracture closure pressure. The fluid efficiency curve is also shown in Figure 8, providing an easy method to determine fluid efficiency for various closure picks. The fluid efficiency indicated on Figure 8 is 46%. The combination of the G Function, Log-Log, and square-root-of-time analyses results in a consistent and reliable estimate of fracture closure.

Figure 9 shows the Horner plot of the Well D zone 4 mini-frac pressure decline. The *extrapolated* reservoir pressure (surface annulus pressure that corresponds to reservoir pressure) is shown on Figure 9. The extrapolated reservoir pressure from the Horner plot is about 6700 psi (275 psi annulus pressure), which seems too high based on the expected reservoir pressure of about 6450 psi. Therefore, it is likely that the late time data used to estimate reservoir pressure (straight line in Figure 9) is not in radial flow.

The results form the various analysis techniques indicate a Tor closure stress of about 7100-psi or a gradient 0.75 psi/ft. The Well D zone 4 mini-frac is typical for South Arne fracture treatments. However, only about 30% to 50% of the South Arne mini-fracs exhibit this *classical* pressure decline behavior and provide such reliable closure stress measurements (+/-50 psi). The remaining SA mini-fracs exhibit more complex (unusual) behavior and are less reliable, but the analysis usual results in a reasonable estimate of fracture closure pressure (+/-100). However, in some cases the mini-frac data is anomalous and a reliable closure pressure cannot be determined. In these cases the previous zone closure pressure can be used and is normally a reasonable estimate.

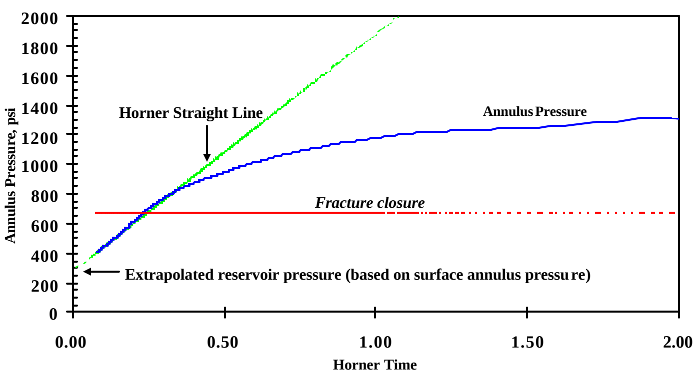

Figure 9 - Horner plot of Well D zone 4 mini-frac

Identifying & Preventing Treatment Problems

Diagnosing fracture treatment problems in South Arne can be divided into three main categories:

1. Identifying fracture complexity through net pressure analysis.
2. Identifying the "potential" for excessive leakoff using G-function superposition analysis to detect pressure dependent leakoff or fissure opening.
3. Identifying tortuosity using the mini-frac injection pressure minus the ISIP or the annular pressure data alone in the absence of a mini-frac shut-in.

The initial two items above are the most critical when executing SA fracture treatments. Fracture complexity is easily identified from mini-frac data when fracture closure pressure is reliable and rock properties are accurately estimated from geological and log data. The level of fracture complexity can be determined from fracture modeling of the mini-frac pressure decline behavior, increasing fracture complexity to match higher-than-expected net pressures. High net pressures, compared to the model-predicted net pressure, are an indication of fracture complexity. In the case of high fracture complexity, achieving the target TSO net pressure increase is normally not an issue. However, preventing an excessive TSO net pressure increase can he an issue. Therefore, if fracture complexity is high (more than 2 multiple fractures), pad size and proppant ramp should be conservative for the propped treatment to prevent excessive TSO pressure increases.

The G-function superposition analysis has been very useful in identifying pressure dependent leakoff or fissure opening during the mini-frac pressure falloff. This can indicate excessive leakoff and increased fracture complexity in the subsequent propped treatment. If pressure dependent leakoff is identified in the mini-frac pressure decline, the concentration and amount of 100-mesh sand pumped in the initial portion of the pad should be carefully designed, making sure a large portion of the 100-mesh sand is pumped at 4-ppg. In cases of high fracture complexity and pressure dependent leakoff, dividing the 100-mesh sand into two stages, 1-2 pp and 1-4 ppg, may be necessary to prevent a screen-out in the pad.

Example of Fracture Complexity: Well A Zone-4. The Well A zone 4 mini-frac is shown in **Figure 10**. The fracture initiation procedures included cross-linked fluid and 1-4 ppg 100-mesh sand followed by a 1-4 ppg 20/40-mesh proppant slug. The mini-frac showed no adverse reaction to 100-mesh sand or 20/40 proppant. A modest 700-psi of tortuosity is evident at the mini-frac shutdown. The Well A zone 4 mini-frac pressure decline analysis is shown in **Figures 11 and 12**. The G-function analysis (Figure 11) indicates a clear closure pressure of 7080 psi (0.75 psi/ft). Figure 11 shows no definite signs of pressure dependent leakoff, however there is a slight indication of pressure dependent leakoff in the GdP/dG curve. The mini-frac fluid efficiency is about 23%. The fracture closure pick is confirmed using the log-log analysis (Figure 12). It should be noted that the porosity in Well A zone 4 is only 25% and much higher fluid efficiency would be expected. For comparison, Well D zone 4 has a porosity of 28% and exhibited a mini-frac fluid efficiency of 46% (example in previous Mini-frac Analysis section). Unusually low mini-frac fluid efficiency in low porosity zones may be a warning sign of secondary leakoff into natural fractures or fissures that could present problems during the propped treatment.

Unfortunately, re-initiation of the fracture after the mini-frac can result in increased fracture complexity and excessive leakoff. **Figure 13** shows an example of a severe reaction to 100-mesh sand during the pad stage of the Well A, zone-4 treatment. There is a 1000-psi increase in annulus pressure when the 1-4 ppg 100-mesh slug passes through the perforations during the main treatment pad stage (260 minutes). However, this severe reaction to 100-mesh sand was not seen during the Zone 4 mini-frac. The Well A zone-4 mini-frac response (Figure 10) shows that the annulus pressure actually decreases by 1000-psi when the 1-4 ppg 100-mesh slug passes through the perforations – a completely opposite reaction than observed during the propped treatment pad.

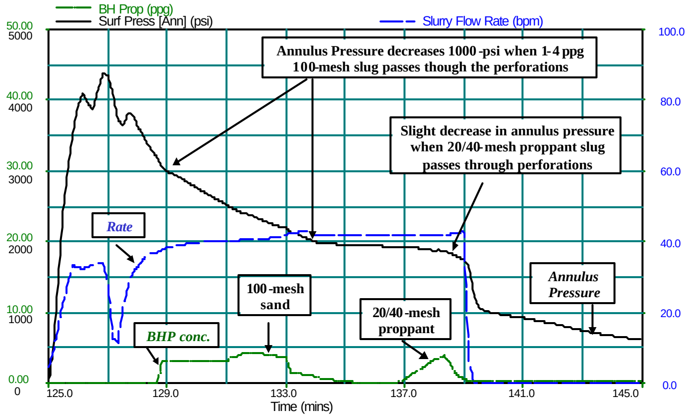

Figure 10 - Well A, zone 4 mini-frac pressure response

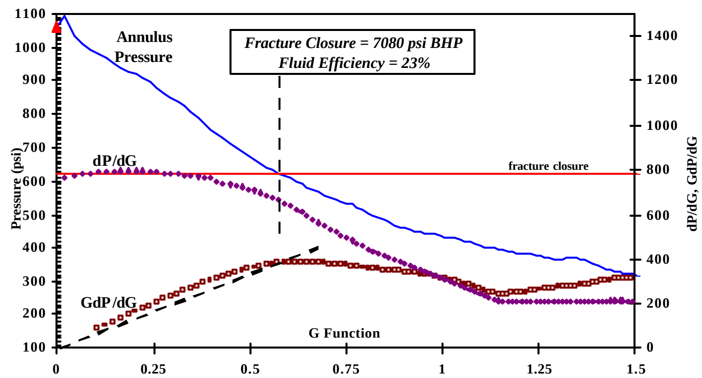

Figure 11 – Well A zone 4 mini-frac: G-function analysis

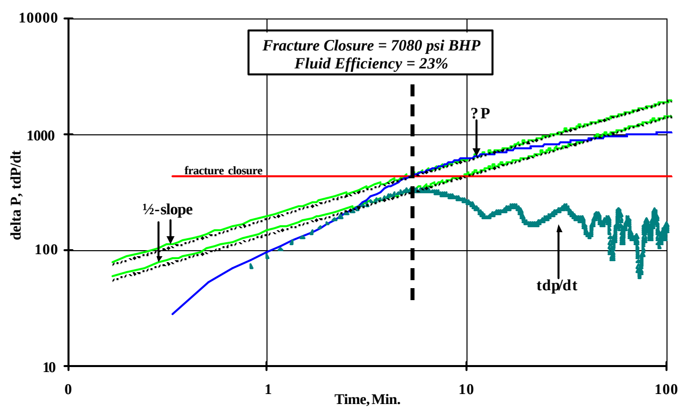

Figure 12 – Well A zone 4 mini-frac: Log-Log analysis

The severe reaction to 100-mesh sand during the propped treatment pad is an indication of a significant increase in fracture complexity and/or fluid loss due to the re-initiation of the fracture with linear gel. Fortunately a screen-out did not occur when the 100-mesh sand passed through the perforations and the 100-mesh sand apparently reduced fracture complexity and/or leakoff to an acceptable level, as the subsequent 20/40-mesh proppant slugs easily passed through the near-wellbore region.

In general, the use of high viscosity fluid to initiate the fracture combined with 1-4 ppg 100-mesh sand followed by a 1-3 ppg proppant slug appears to control fracture complexity and leakoff for both the mini-frac and propped fracture treatment. However, re-initiating the fracture with linear gel after the mini-frac shutdown appears to increase fracture complexity and/or fluid loss. Therefore, eliminating the mini-frac in low porosity zones may reduce propped treatment risk without sacrificing TSO criteria, as achieving an acceptable TSO in low porosity zones should be possible using historical data to design the appropriate pad size.

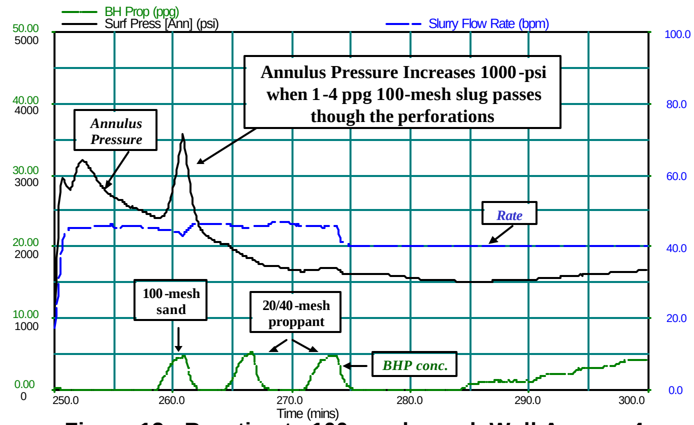

Figure 13 - Reaction to 100-mesh sand, Well A, zone 4

Fracture Modeling

Due to the extremely high stakes, a conservative "bounding" approach to fracture modeling was taken. Two different fracture models were used to bound the range of created fracture dimensions on SA propped fracture treatments:

(1) A *Tip-Dominated* (TD) fracture model where inelastic fracture "tip effects" cause most of the fracture pressure drop to occur near the fracture tip. These tip effects increase the predicted net fracture pressure above that expected from conventional fracture models. This model has a reduced sensitivity of predicted net pressure on fluid viscosity.

(2) A Shear De-Coupled (SDC) fracture model that assumes there is some loss in opening leverage (coupling) across the fracture face. The de-coupling also results in higher predicted net fracture pressures than most conventional models. The SDC model incorporates no "tip effects" and generally predicts greater fracture length (sometimes more height) and less width than most conventional fracture models.

As a precautionary measure both models were employed to provide conservative bounding on fracture design parameters. For example, the shear de-coupled model was used to determine the minimum proppant concentrations and required net pressure increases for all subsequent treatments. In cases where Ekofisk interval coverage was important, the tip-dominated was used to estimate the minimum fracture height and the job/pad size required to cover the Ekofisk formation - increasing treatment and/or pad size as was economically and operationally feasible to achieve the desired Ekofisk coverage. However, all designs targeted a minimum proppant concentration of 6-ppsf using the shear de-coupled model.

This "dual model" design and analysis procedure should result in both adequate proppant concentrations and reasonable Ekofisk coverage. Both models seem to be equally accurate when projecting net pressure behavior for the propped treatment by matching the mini-frac data; thus either model can be used for *real-time* mini-frac analysis and pad optimization. The fracture modeling proved to be a fairly reliable tool for estimating net pressure behavior during tip screen-out (TSO) and for optimizing pad size and treatment designs.

The basic procedure for net pressure history matching the South Arne fracture treatments is described below:

1. Evaluate the mini-frac pressure decline to identify Tor closure stress and fluid efficiency,
2. Adjust the Tor closure stress gradient in the model to match the mini-frac results and then adjust the level of fracture complexity to match the net pressure at the end of the mini-frac (number of multiple fractures),
3. Adjust the leakoff in the model to match the mini-frac pressure decline, closure time, and fluid efficiency,
4. Evaluate various pad sizes by running the calibrated fracture model *forward* to predict the net pressure increase and fracture geometry,
5. Evaluate a range of fracture complexity that reasonably matches the mini-frac data to identify the sensitivity of TSO net pressure increase to fracture complexity, and
6. Compare the various fracture model predictions for net pressure increase to the behavior of previous zones and their treatment schedule and pad size and – integrating all of this information – adjust the pad size to achieve the desired net pressure increase and fracture geometry.

The above procedure may seem time consuming and complicated, but the analysis and modeling can easily be accomplished in 10-20 minutes during the mini-frac pressure decline. The modeling and analysis are performed in real-time, thus the mini-frac history match and pressure decline analysis begins immediately after the mini-frac shutdown, minimizing analysis time. After the treatment has been completed, the model can be "fine tuned" if necessary.

Net Pressure History Match: Well D Zone-4. The following example illustrates the analysis process and results for one fracture treatment stage in Well D. The Well D zone-4 fracture treatment consisted of a 550-bbl mini-frac followed by a 1030 Klbs propped treatment. The Well D Zone-4 mini-frac results were presented already (see Mini-Frac section). This example is representative of the quality of SA net pressure matches and the reliability of the fracture model to predict the propped treatment TSO behavior based on the mini-frac data. A reliable estimate of fracture geometry requires matching the actual net pressure history during the *entire* treatment. The layer data for Well D Zone 4 are shown in **Table 2**.

Shear de-coupled model Results. **Figure 14** shows the net pressure match for the zone-4 fracture treatment using the shear de-coupled model formulation. The predicted fracture geometry for zone 4, using the shear de-coupled model, is shown in **Figure 15**. The stress profile used in the modeling and the permeable layers are shown on the left side of the Figure 15 graph. The figure shows a predicted fracture half-length of about 240 ft and a height at the wellbore of 350-ft. The results show complete coverage of the Tor & Ekofisk (EK) formations. The net pressure match was obtained with a low fracture complexity (1 fracture).

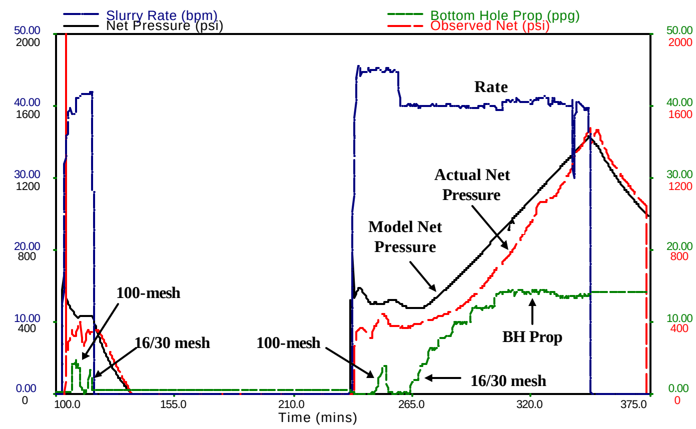

Figure 14 – Well D Zone 4 net pressure match: SDC model

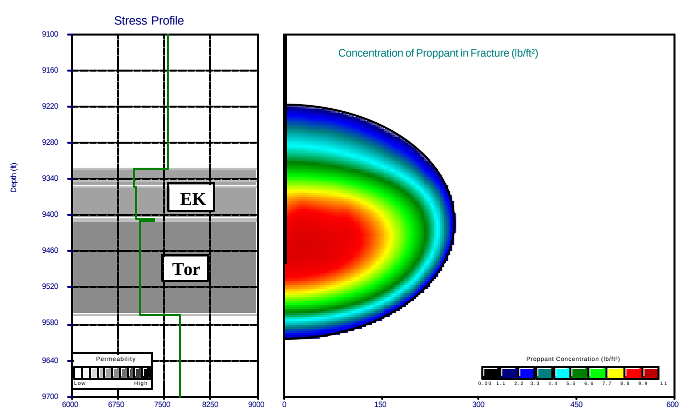

Figure 15 – Well D Zone 5, Zone Fracture Geometry: SDC model

Tip Dominated Model Results. The net pressure behavior for the Well D, zone 4 treatment was also matched using the Tip Dominated (TD) model formulation. The TD model will predict a shorter, wider fracture than the shear de-coupled model. The net pressure history match of the Well D, zone-4 treatment using the TD model is shown in **Figure 16**. Comparing figures 14 & 16, there is very little difference in the quality of the net pressure match between the SDC and TD models. The bounding layer stress gradients are 0.83 psi/ft in the TD model, while they were slightly lower in the SDC model (0.81 psi/ft). All remaining input parameters were the same for the two models (rock properties, stress profile, fracture complexity, etc.) and yet both provide very good net pressure matches of the entire treatment history. This illustrates the uncertainty associated with fracture model selection for the South Arne fracture treatment design and evaluation. Both models can accurately match the SA net pressure data and both models are equally *predictive* when using the mini-frac data to estimate the propped treatment TSO behavior.

Table 2 – Well D, Zone 4 Layer Properties

Depth (ft, TVD)	Top of Zone	Modulus (10^6 psi)
9321	Upper Ekofisk	2.8
9344	Middle Ekofisk	4.0
9354	Lower Ekofisk	1.8
9407	Tight zone	4.0
9410(1)	Tor	1.7
9564	Shale	3.0

Note (1): Zone 1 perfs = 9478-ft TVD

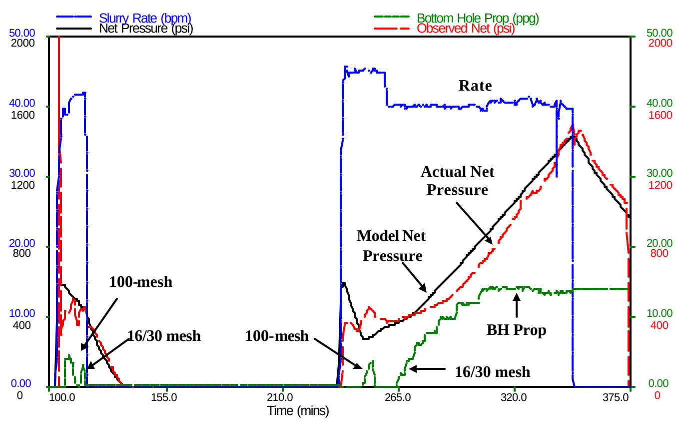

Figure 16 - Well D Zone 4 Net Pressure Match: TD Model

The predicted fracture geometry using the TD model is shown in **Figure 17**. This figure shows an estimated fracture length of 175-ft and a total propped height of 280-ft. The TD model also predicts that the Well D, zone-4 fracture will cover the entire Tor & Ekofisk intervals. Comparing Figures 15 and 17 shows the differences in predicted fracture geometry using the SDC and TD model. The shear de-coupled model predicted a propped length of 240 ft compared to the TD model estimate of 170 ft. The predicted fracture height at the wellbore is 280 ft for the TD model and 350 ft the shear de-coupled model. The fracture height estimates from the two models will typically be more consistent than the length estimates (in SA). Due to the differences in fracture geometry, the predicted average proppant concentration will typically differ by a factor of two between the TD & SDC models.

Effect of Tor Depletion on Fracture Geometry: Well C. During the majority of the SA batch fracturing operations there was little variation in Tor closure stress, with values ranging from 0.74 to 0.76 psi/ft. However, production from wells offsetting Well C resulted in noticeable depletion in the vicinity of Well C. Lower reservoir pressure will result in lower closure stress in the target zone and increased fracture height confinement. Predominantly radial fracture growth was predicted in previous SA fracture treatments, however lower closure stresses in the Tor interval in Well C resulted in more contained fracture height growth and less fracture extension into the Ekofisk interval.

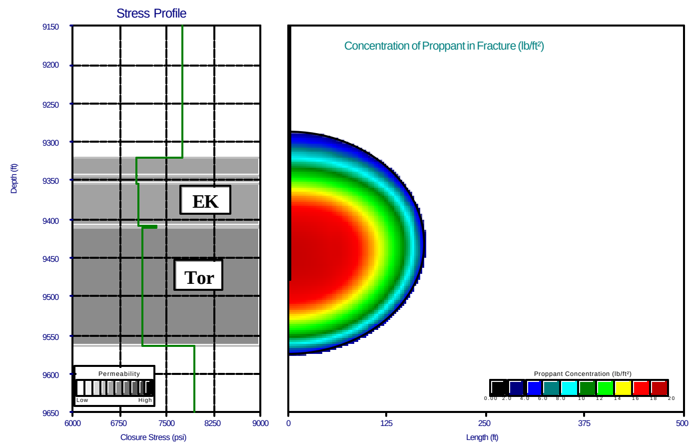

Figure 17 - Well D, Zone 4 Fracture Geometry: TD Model

Well C Zone-6 Mini-Frac Analysis. **Figure 18** shows the G-Function analysis of the Well C, zone-6 mini-frac pressure decline, indicating a fracture closure pressure gradient of 0.688 psi/ft – about 0.06 psi/ft lower than previous SA wells. The fracture closure pressure estimates for most of the Well C zones were similar to zone 6, indicating a decrease in closure stress of about 550-psi. Therefore, a decrease in reservoir pressure of 600 to 700-psi is probable. The zone-6 G-Function analysis (Figure 18) exhibits the signature of height recession as evidenced by the concave upward shape of both the dP/dG and GdP/dG curves.[9] This supports the assumption that the Ekofisk stress is less influenced by reservoir pressure changes.

The mini-frac pressure decline data can provide an estimate of reservoir pressure using classical Horner analysis; assuming radial flow conditions were achieved at the end of the pressure decline period. In most cases, reservoir pressure estimates from mini-frac analysis will indicate the highest possible reservoir pressure due to insufficient shut-in time to reach fully developed radial flow and supercharging effects due to the injected fluid. **Figure 19** shows the Horner plot of the Well C, zone-6 mini-frac pressure decline, indicating a reservoir pressure of 5735-psi. Original reservoir pressure was estimated at about 6450-psi, thus the mini-frac analysis indicates a depletion of about 715-psi. Therefore, about 77% of the change in reservoir pressure (550-psi/715-psi) has been reflected in the reduction in fracture closure pressure. This ratio could be as high as 90% and thus reservoir pressure could be as low as 5630-psi (about 105-psi less). The reservoir pressure from the mini-frac Horner analysis appears to be well within expected limits, supporting the conclusion that offset wells have reduced reservoir pressure in the vicinity of Well C by 600-700 psi.

The combination of lower closure stress (0.688 psi/ft) and the signature of height recession in the G-Function analysis (see Figure 18) seems to indicate that the fracture is extending into the Tight zone and possibly some portions of the Ekofisk, but that the Ekofisk and Tight zone have noticeably higher stress that the Tor zone. The original EK stress was estimated at 0.75-0.77 psi/ft. Thus with the depletion effects in the Tor zone, a stress contrast of 550-750 psi now exists between the Tor and EK intervals. This significant stress contrast has dramatic effects on fracture height growth, potentially confining the fracture to the Tor interval and promoting fracture extension. The effects of depletion on stress profiles and fracture geometry may play an important role in the design and evaluation of future SA fracture treatments.

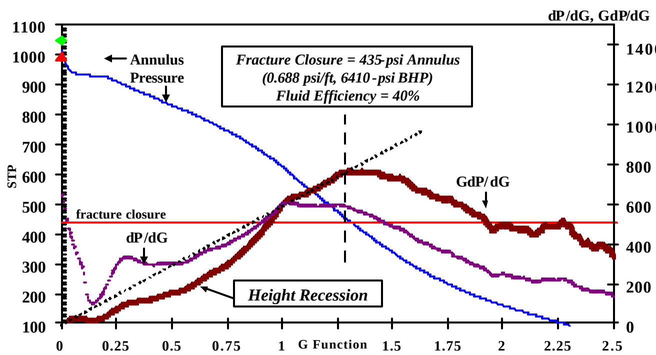

Figure 18 - Well C, zone 6 G-Function analysis

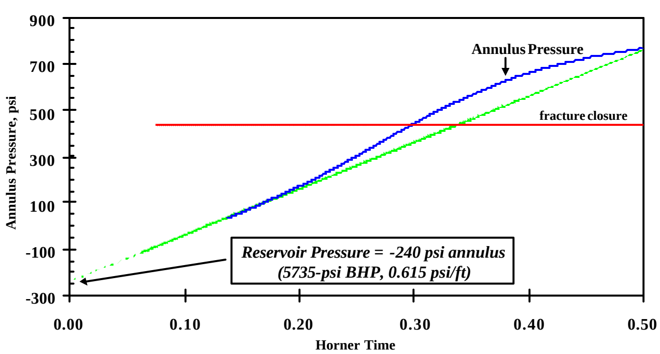

Figure 19 - Well C, zone 6 Horner analysis

Table 3 – Well C, Zone 6 Layer Properties

Depth (ft, TVD)	Top of Zone	Modulus (10^6 psi)
9049	Upper Ekofisk	4.8
9111	Middle Ekofisk	1.7
9151	Lower Ekofisk	3.4
9210	Tight zone	3.4
9243(1)	Tor	1.1
9387	Shale	3.0

Note (1): Zone 1 perfs = 9320-ft TVD

Well C Zone-6 Fracture Modeling. The layer data for Well C zone 6 is provided in Table 3. The net pressure history match and predicted fracture geometry using the shear de-coupled model is shown in **Figures 20 & 21**, respectively. **Figures 22 & 23** show the net pressure match and predicted fracture geometry using the TD model. The Tor closure stress from mini-frac analysis was used in the fracture modeling, while all other reservoir and rock properties remained unchanged from previous SA fracture modeling analyses. It is important to note that the Ekofisk closure and Tight zone stresses were not decreased from previous levels (0.76 & 0.77 psi/ft, respectively).

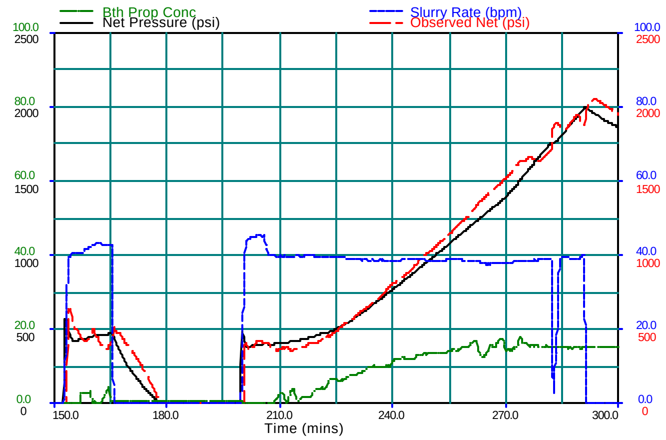

Figure 20 - Well C, zone 6 net pressure match: SDC model

The net pressure matches using both models (Figures 20 and 22) were very good, accurately matching both the mini-frac and the propped treatment TSO. The matches were obtained using a simple fracture geometry (1-fracture). The consistency of the input data and the quality of the net pressure match tend to support the assumption that the stresses in the EK and TZ have not been significantly affected by offset well production.

The predicted fracture geometry using both models shows that the fracture is "essentially" contained to the Tor interval. However, the shear de-coupled model predicts some penetration into the bottom portion of the lower EK, while the TD model predicts that the Tight zone will contain the fracture. Although there is some difference in predicted fracture height between the two models, the difference is not significant. However, the predicted fracture length using the shear de-coupled model is 265-ft compared to 160-ft using the TD-model. This difference in fracture length is similar to previous modeling results.

The implications of lower Tor closure stresses on future fracture treatments may be significant, as much of the field may experience similar or greater levels of depletion during subsequent fracturing operations. If the depletion is primarily in the Tor interval and the closure stress in the EK and TZ remain near initial levels, then fracture penetration into the EK may be severely limited. If fractures are confined to the Tor interval, then smaller fracture treatments may be indicated or larger spacing between zones acceptable since longer fractures will be achieved for the same treatment volume (compared to the more radial fracture growth predicted in un-depleted zones). However, the required TSO net pressure increase may be larger than previous treatments, as the confined fracture height and longer length will require higher net pressures to achieve the desired average proppant concentration.

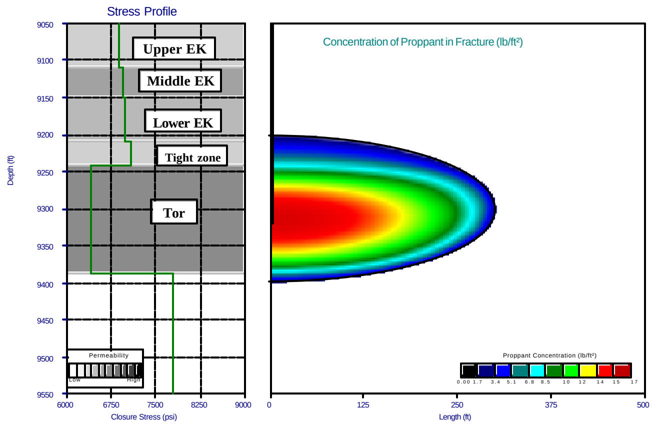

Figure 21 - Well C, zone 6 fracture geometry: shear de-coupled model

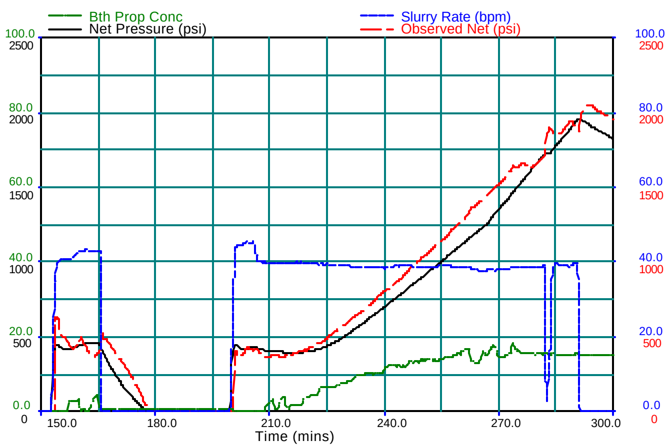

Figure 22 - Well C, zone 6 net pressure match: TD model

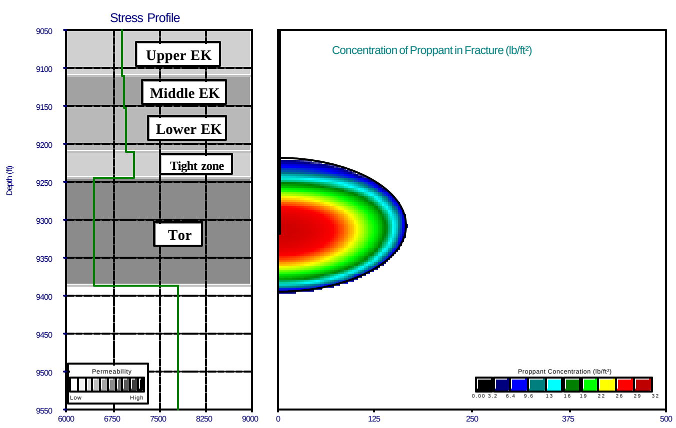

Figure 23 - Well C, zone 6 fracture geometry: TD model

Fracture Treatment Results

The results for three of the SA wells are summarized below. The results are provided to illustrate the ranges of created fracture geometries and interval coverage. The results also illustrate the range in fracture complexity (*equivalent* multiple fractures) used to model the SA treatments.

Well A Results. Well A was the only well drilled perpendicular to the maximum principle stress direction. Thus, it is the only well where the hydraulic fractures are transverse to the wellbore (perpendicular). Zone 1 was acid fractured and the results are not presented in this paper. The fracture treatments in zones 2 & 3 screened out very early in the job, while the remaining treatments were essentially pumped as designed. **Table 4** summarizes the treatment volumes and fracture modeling results for Well A. The screen-outs in zones 2 & 3 resulted in short fractures. The results for both the SDC and TD models are presented in Table 4. The post-treatment evaluation using the SDC model showed that all treatments achieved an average proppant concentration of at least 6 ppsf (except for zone 2). The fracture complexity for the Well A treatments ranged from 1 to 2 "equivalent" fractures.

Table 4 - Summary of Well A Fracture Treatments

			Shear De-Coupled Model				Tip Dominated Model			
	Slurry Volume	Prop	X_f	H_f	Avg. Prop Conc.	Mult-Frac	X_f	H_f	Avg. Prop Conc.	Mult-Frac
Zone	(Kgal)	(Klbs)	(ft)	(ft)	(ppsf)		(ft)	(ft)	(ppsf)	
1										
2	42	9								
3	97	129	59	153	8.2	1.0	47	124	12.7	1.0
4	188	658	150	266	9.8	1.5	106	201	15.4	2.0
5	225	1,131	213	266	9.5	2.0	126	276	17.0	2.0
6	295	1,446	358	318	5.5	1.0	231	322	10.6	1.0
7	267	1,520	236	291	5.5	2.0	151	272	13.5	1.5
8	130	715	203	209	7.1	1.0	127	217	12.8	1.0
9	128	784	166	234	10.4	1.5	119	205	16.0	1.0
10	115	699	180	215	8.0	1.0	126	210	14.5	1.0
11	122	817	216	227	8.6	1.0	128	220	16.0	1.0
Averages	**161**	**791**	**198**	**242**	**8.1**	**1.3**	**129**	**227**	**14**	**1.3**

The Tor and Ekofisk interval coverage predicted by the SDC and TD model is shown in **Figures 24 and 25**, respectively. Both models show very good interval coverage, with about 93% of the target Tor and EK interval covered – on average. The only zones with poor interval coverage are zones 2 & 3 that screened-out.

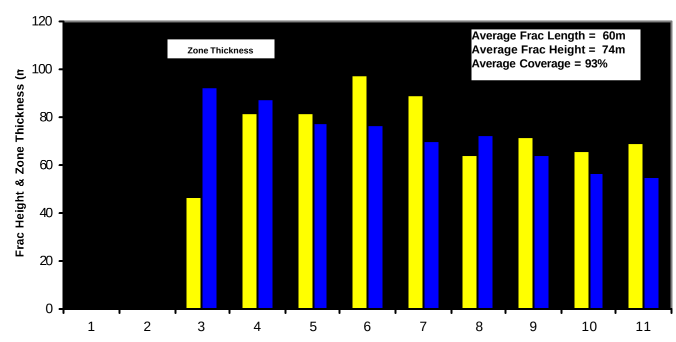

Figure 24 - Well A Interval Coverage: Tor & EK, SDC model

Well D Results. Fracture treatments in Well D averaged 659,000 lbs and resulted in average proppant concentrations of 7 to 14 ppsf using the SDC and TD model, respectively. The Well D results are presented in **Table 5**. The zone-1 treatment screened out very early in the job, resulting in only about 80 ft of fracture length and less than 2 ppsf average proppant concentration. The zone 2 & 3 treatments were very conservative, resulting in 4 to 8 ppsf average proppant concentration and about 130-230 ft of fracture length. The remaining Well D treatments were more aggressive, resulting in higher proppant concentrations. The average fracture length ranged from 122 ft to 190 ft and the average fracture height ranged from 221 ft to 197 ft using the SDC and TD model, respectively. The fracture complexity for Well D treatments was moderate, ranging from 1 to 4 fractures.

The interval coverage for Well D fracture treatments is shown in **Figures 26 & 27**. The figures show a total interval coverage that averages 90% to 95% using the TD and SDC model, respectively.

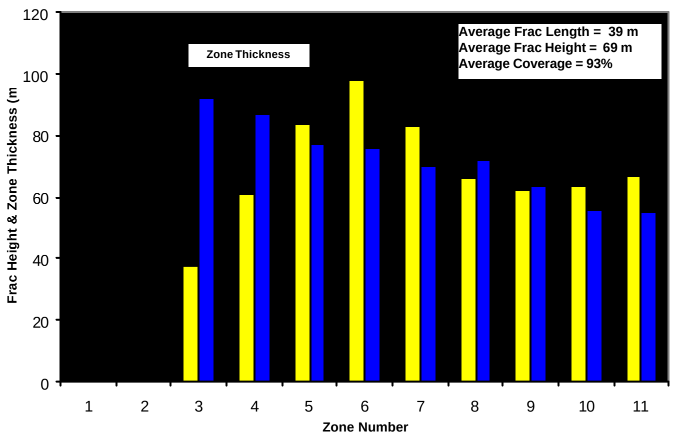

Figure 25 - Well A Interval Coverage: Tor & EK, TD Model

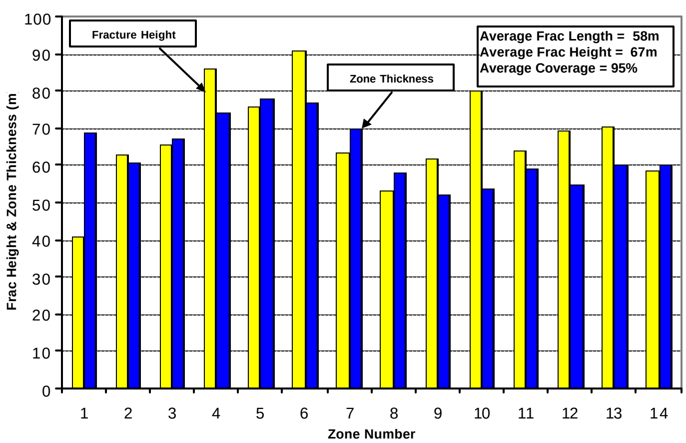

Figure 26 - Well D Interval Coverage, Tor & EK, SDC Model

Well C Results. Well C was the last well completed during the batch fracturing operations and had very poor cement or no cement throughout most of the horizontal section. The ability to place proppant in Well C was uncertain. However, the poor cement quality had little effect on treatment success and fracture complexity was low. It is probable that the orientation of Well C, parallel to the hydraulic fracture direction, mitigated the detrimental effects of poor cement – as the fractures are propagated parallel to the wellbore and complex fracturing is less probable due to uncontrolled fracture initiation. The Well C closure stresses were about 550-psi lower than previous SA wells. The lower closure stresses resulted in much more fracture height confinement in the Tor interval and much less Ekofisk coverage.

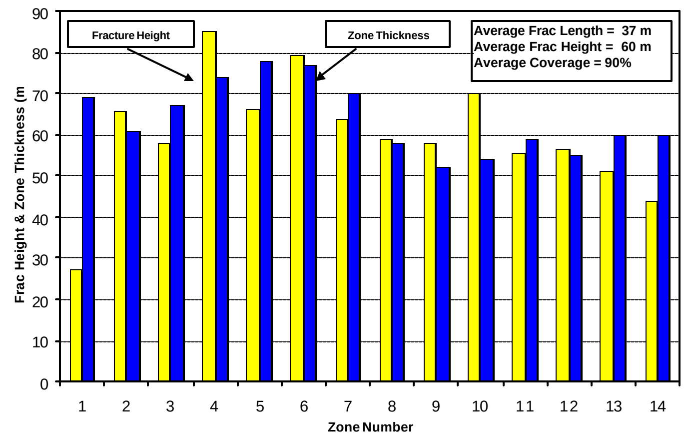

Figure 27 - Well D Interval Coverage, Tor & EK, TD model

Table 5 - Well D Fracture Treatment Summary

			Shear De-Coupled Model				Tip Dominated Model			
	Slurry Volume	Prop	X_f	H_f	Avg. Prop Conc.	Mult-Frac	X_f	H_f	Avg. Prop Conc.	Mult-Frac
Zone	(Kgal)	(Klbs)	(ft)	(ft)	(ppsf)		(ft)	(ft)	(ppsf)	
1	206	105	77	134	0.8	2.0	42	89	1.7	2.0
2	236	440	230	207	3.9	1.0	165	216	7.4	1.0
3	175	495	237	216	4.4	1.0	130	191	7.9	1.0
4	196	1,027	279	282	6.7	1.0	175	280	12.0	1.0
5	189	848	195	248	10.4	2.0	130	218	19.0	2.0
6	205	1,087	187	299	10.6	4.0	135	260	19.0	3.0
7	223	1,117	265	209	6.5	1.0	159	210	14.0	1.0
8	125	667	194	174	8.5	1.0	128	194	15.0	1.0
9	128	804	163	203	12.8	2.0	106	190	23.0	2.0
10	113	699	209	263	6.7	2.0	131	230	12.0	2.0
11	115	681	168	210	10.5	2.0	113	182	20.0	1.5
12	80	499	192	228	5.5	2.0	116	186	13.0	1.5
13	57	405	150	231	6.3	2.0	99	168	13.0	1.5
14	64	357	112	192	9.2	3.0	80	144	18.0	2.5
Averages	**151**	**659**	**190**	**221**	**7**	**1.9**	**122**	**197**	**14**	**1.6**

Table 6 - Summary of Well C Fracture Treatments

			Shear De-Coupled Model				Tip Dominated Model			
	Slurry Volume	Prop	X_f	H_f	Avg. Prop Conc.	Mult-Frac	X_f	H_f	Avg. Prop Conc.	Mult-Frac
Zone	(Kgal)	(Klbs)	(ft)	(ft)	(ppsf)		(ft)	(ft)	(ppsf)	
1	85	63	56	113	4.6	2.0	43	86	8.0	2.0
2	248	1,139	333	237	5.0	1.0	218	249	9.9	1.0
3	191	668	274	185	3.5	1.0	190	213	7.2	1.0
4	279	1,301	427	230	7.3	1.0	276	169	16	1.0
5	127	682	264	213	5.5	1.0	175	190	11	1.0
6	162	949	265	175	10.0	1.0	160	171	20	1.0
7	141	752	235	167	10.0	1.0	132	165	20	1.0
8	268	1,437	315	215	13.2	2.0	172	192	14	2.0
9	178	1,069	278	191	10.5	1.5	159	188	14	1.5
10	169	658	171	178	8.0	4.0	99	165	16	4.0
11	157	1,011	382	133	9.8	1.0	200	137	22	1.5
12	115	479	326	120	5.8	1.0	185	117	14	1.0
13	83	414	290	131	5.3	1.0	163	125	12	1.0
14	88	470	275	128	6.6	1.0	160	130	13	1.0
Averages	**164**	**792**	**278**	**173**	**7.5**	**1.4**	**167**	**164**	**14**	**1.4**

The results for the Well C fracture treatments are presented in **Table 6** The treatments averaged about 800,000 lbs per zone, resulting in an average proppant concentration of 8 to 14 ppsf using the SDC and TD model, respectively. However, the treatment in zone 1 screened-out very early in the job due to excessive fluid loss and fracture complexity, resulting in a short fracture (56 ft) with only 4.6 to 8 ppsf average proppant concentration. In addition, the zone-3 treatment was prematurely terminated due to equipment problems, resulting in an average concentration of only 3.5 to 7.3 ppsf. The average propped fracture length for Well C ranged from 167 ft to 278 ft, much longer than other SA wells due to the confined fracture growth in the Tor interval. The interval coverage is shown in **Figures 28 & 29**. The results show 53% to 58% of the total interval was covered. The results from Well C illustrate the effect of depletion on fracture geometry and may indicate that Ekofisk coverage could be difficult in future SA fracture treatments.

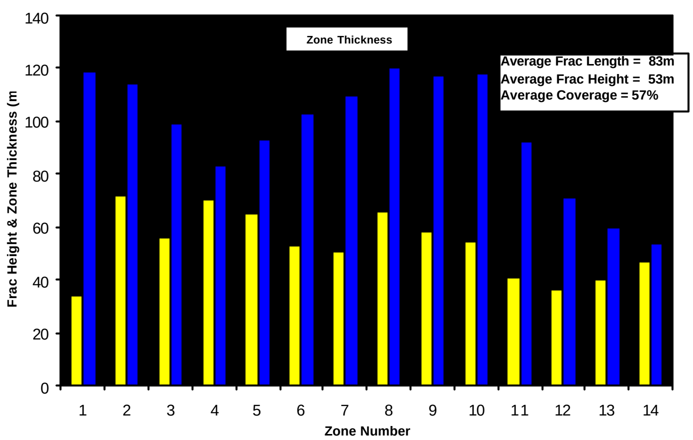

Figure 28 - Well C Interval Coverage: Tor & EK, SDC model

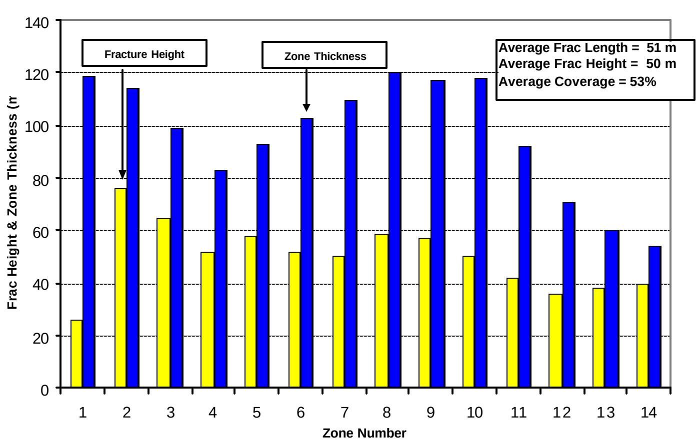

Figure 29 - Well C Interval Coverage: Tor & EK, TD model

Discussion of Propped Treatment Results. The results from the Well A, Well D, and Well C treatments illustrate the expected range in SA propped fracture geometry. The results shown in Table 4, 5, & 6 illustrate that the TD model will predict about 60-65% less fracture length and almost twice the proppant concentration compared to the SDC model. However, the predicted fracture heights are similar and both models show good interval coverage, meeting design criteria. Both models also show similar fracture complexity.

The fracture modeling emphasized the effects of depletion in the Tor interval on total interval coverage, with fractures being confined to the Tor and limiting Ekofisk coverage in Well C. Fortunately, most South Arne propped fracture treatments to-date were performed prior to any significant production (except for the Well C treatments) and therefore interval coverage was excellent throughout the majority of the initial development.

The fracture modeling results also show that the average proppant concentration using the more conservative shear de-coupled model averages 7-8 lb/ft^2, exceeding the minimum design criteria of 6 lb/ft^2. Proppant concentrations could average as high as 14 lb/ft^2 if the actual geometry is closer to the TD model estimates. The key issues for future evaluation are the identification of the ***true*** fracture length and conductivity. When these issues are better understood then the correct fracture model can be selected or appropriate “calibrations” performed to the current models.

Summary

Evaluation of South Arne fracture treatments showed that net pressure behavior could be matched using two different fracture models. Therefore, a dual model design approach was utilized to evaluate adequate proppant concentration and target interval coverage. Both models were equally predictive for use during “real-time” mini-frac analysis and pad optimization.

The ability to control excessive fluid loss and fracture complexity caused by the activation of natural fractures/fissures is very sensitive to the concentration of 100-mesh sand, requiring 3-4 ppg to effectively mitigate problems. Field data from the first 64 fracture treatments indicated that fracture treatment problems were much more likely in lower porosity zones. The lower porosity zones exhibit higher Young’s modulus, which results in less fracture width and much more pronounced pressure dependent leakoff behavior (fissure opening) compared to the higher porosity intervals.

Conclusions

1. Fracture treatment net pressure behavior can be accurately modeled using both SDC and tip-dominated fracture models.

2. Adequate interval coverage (Tor & Ekofisk) and fracture conductivity was obtained from most SA fracture treatments. However, interval coverage was *generally* limited to the Tor interval in Well C.

3. Pressure depletion in the Tor interval can significantly affect fracture geometry, resulting in fractures that are *generally* confined to the Tor interval and much longer than previous SA treatments.

4. The combination of G-function and log-log pressure decline analyses resulted in a much more reliable and consistent interpretation of fracture closure pressure. The application of the G-function superposition and log-log derivatives was key to the mini-frac analysis.

5. The application of G-function superposition analysis of mini-frac data can aid in the identification of pressure dependent leakoff (fissure opening), thus providing a warning sign of potential fracture treatment problems.

6. Excessive fluid loss and increased fracture complexity can result from the activation or dilation of natural fractures/fissures. 100-mesh sand slugs at concentrations of 3-4 ppg can effectively control excessive fluid loss into natural fractures/fissures in the South Arne Field.

7. Re-initiating hydraulic fractures using low viscosity fluid can significantly increase fracture complexity and fluid loss in South Arne. However, the re-application of 4-ppg 100-mesh sand slugs can effectively reduce fracture complexity and leakoff to acceptable levels.

8. Treatment problems **were not** dependent on wellbore orientation (Well A) when proper fracture initiation procedures were employed in South Arne.

9. Treatment problems **were not** increased when cement quality was poor (Well C) for longitudinal fracture orientations.

Nomenclature

EK	= *Ekofisk*
Klbs, Kgal	= *1000 pounds, 1000 gallons*
ppg	= *pounds of proppant added per gallon of fluid*
ppsf	= *pounds of proppant/ square foot of fracture area*
RCS, RCP	= *Resin coated sand, Resin coated proppant*
SA	= *South Arne*
TSO	= *tip screen-out*

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