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State-of-the-Art Fracturing in the North Sea

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Introduction

This paper will focus on recent advances in hydraulic fracturing technology with emphasis on North Sea applications. Five generalized applications that will benefit most from advances in technology have been identified.

Because North Sea oil and gas field development requires the use of platform facilities for wellhead and processing equipment, deviated and horizontal wells are often used to effectively drain the reservoirs. Many of these wells require fracture stimulation. The success rate of such wells has increased significantly in recent years as a result of the following:

- Researchers better understand how fractures initiate and grow.
- Pre-treatment diagnostic techniques have improved substantially.
- Engineers better understand how completion design affects well performance.

With improved understanding of post-frac well performance, engineers can evaluate the feasibility of developing a reservoir through fractured, horizontal wells.

A significant number of the new fields developed in the North Sea will be marginal fields. As a result, the most advanced technologies must be used to ensure economic success, even though the funds available for pre-frac planning will be limited. Advances in diagnostic injection tests,

real-time treatment analysis, and on-site redesign capabilities help ensure that hydraulic fracturing can be successfully applied in such marginal fields.

Several high-pressure, high-temperature (HPHT) fields are currently being developed in the North Sea. Although HPHT fracturing has not yet been attempted in the North Sea, it has been successfully applied in other parts of the world. In addition to a review of the advances in HPHT technology that would apply to North Sea applications, this paper will identify improvements necessary before these techniques are applied in the North Sea.

One of the most significant occurrences in fracture advancement is the expansion of fracturing techniques to reservoirs that traditionally were not considered fracturing candidates. Historically, hydraulic fracturing was considered an engineering tool for improving well productivity from tight, otherwise non-commercial reservoirs. Now, however, hydraulic fracturing is being used more frequently (1) in high-permeability reservoirs to improve the overall profitability of the project, and (2) as an alternative to traditional sand control applications in soft, weakly consolidated reservoirs.

The effect of hydraulic fracturing operations on the North Sea environment must be recognized. The advances in fluid design and post-treatment flowback procedures that minimize these effects are discussed.

References at the end of the paper.

Fracturing Deviated and Horizontal Wells

North Sea oil and gas field development requires the use of platform facilities for wellhead and processing equipment. Deviated and horizontal wells have a natural application in these conditions where wellheads are located close together yet reserves are located in a radial pattern around the installation. Many North Sea reservoirs require stimulation to maximize production rates and economic returns. As a result, propped hydraulic fracture treatments have been successfully used for both oil and gas production in horizontal and highly deviated wells in several sectors of the North Sea. In the Danish sector alone, over 300 propped hydraulic fracture stimulation treatments have been performed to date. The North Sea has led the industry in this technology, and North Sea operators are recognized as the experts in its application worldwide. Propped fracture stimulation of horizontal wells has been improved by such recent advances as an improved understanding of fracture rock mechanics, methods for determining the in-situ stress field, application of pre-frac diagnostic/corrective injection tests, and simulations of fracture-stimulated well production.

Improved Understanding of Fracture Mechanics

Recently, the industry has developed a greater understanding of the fracture mechanics of propped-fracture stimulated horizontal wells. Rock mechanics studies have led to a greater knowledge of tortuosity effects — both during stimulation treatments and on subsequent production. In a highly deviated or horizontal well, tortuosity is the extra pressure drop generated as a propagating fracture realigns to grow in the direction perpendicular to the least principal stress. Tortuosity is caused by the altered stress region in the near-wellbore area and its orientation to the normal stress field (Fig. 1).

Researchers have documented the effect of perforated wellbore length, geometry of the created tortuous path, communication of fractures during growth, and the effects of angle of deviation — all for varying wellbore angles to the existing stress field. [Based on their findings, researchers can recommend the best methods of determining potential geometry growth problems and for parameters that must be determined to predict the magnitude of tortuosity effects.] Laboratory work has been correlated to field data in many publications.¹⁻³

The magnitude and direction of the in-situ stresses must also be determined. The length of the perforated interval and the direction of the wellbore relative to the given stress field control fracture geometry growth and its associated problems. When the length of the perforation interval exceeds

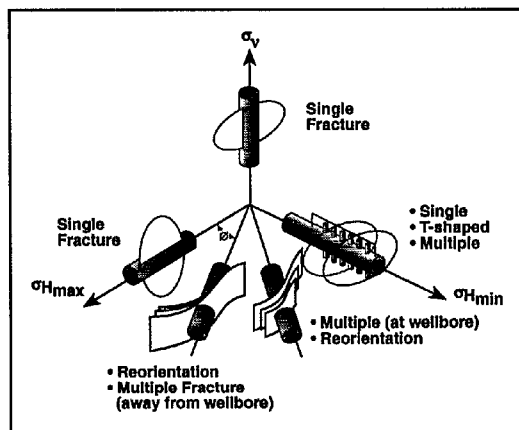


Fig. 1—Fracture geometries vary with changes in principal stress direction in both vertical and deviated wellbores. Characteristic fracture geometries and their representative wellbore orientations are shown.

four wellbore diameters, and the wellbore-to-minimum-horizontal-stress angle is less than 75 degrees, multiple fractures will be created in the near-wellbore area. In wells where the angle of deviation is less than 45 degrees and the two horizontal stresses are unequal, fracture growth is controlled by the difference between minimum horizontal and vertical stresses. If deviations are greater than 45 degrees, the maximum horizontal stress controls the growth of near-wellbore geometry. See Figs. 2 through 4 for graphical representation.

Field and laboratory studies have shown that tortuosity can increase fracture stimulation treating pressure by as much as 2,000 psi. When the rock stresses of the well are known above, below, and throughout the pay interval, 3D geometry models can accurately be used to predict geometry growth of propped fractured horizontal wells. For these 3D geometry simulators to be used, the perforated interval must be short enough to allow a single fracture to propagate.⁴

In-situ Stress Field Determination

Determination of the in-situ stress field is critical to designing a single fracture treatment that will provide the best field development plans. Several vertical well methods have been studied for application in deviated and horizontal wells, and problem areas have been identified. Many of the processes used to determine these critical parameters are performed during the drilling phase.

In-situ stresses must be determined above, below, and through the pay zone. Horizontal well fracture stimulation design also requires the direction of the stresses to be known

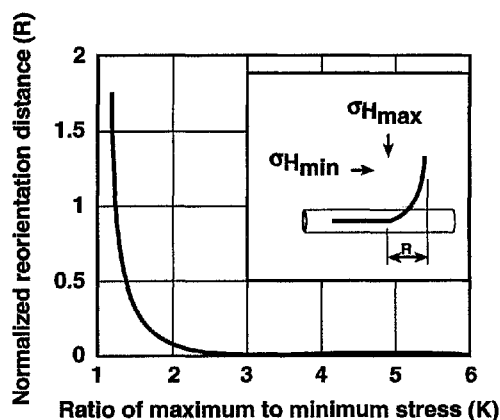


Fig. 2—Reorientation normalized distance vs. stress ratio (K).

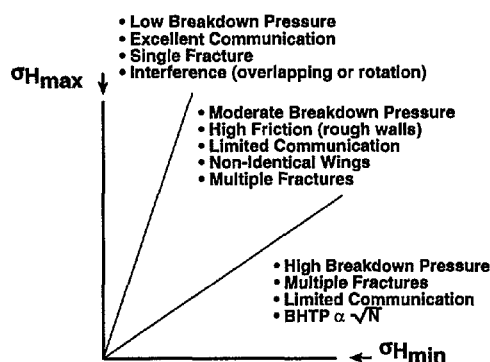


Fig. 4—Principal findings of horizontal well fracturing.

to determine the amount of tortuosity created by realignment of the fracture from the wellbore to the direction of the maximum stress.

Because of the known complications of pressure response when the wellbore is horizontal or highly deviated, a vertical pilot hole should be drilled through the formation of interest to conduct data-gathering tests, which yield results that best characterize the pay zone. Studies have been conducted on microfrac and minifrac tests on horizontal wellbores. Microfrac tests on highly deviated wellbores have been shown to overpredict pressure values.^{5,6} In microfrac tests of horizontal wells, multiple closure pressures have been observed in laboratory studies. Although the second closure

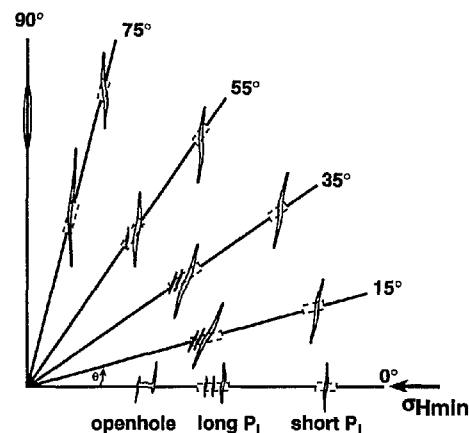


Fig. 3—Top view of fractures induced at various wellbore deviation angles.

is considered to be the minimum horizontal stress, this data is best acquired from a vertical wellbore. As a result, microfrac tests should be conducted in a vertical wellbore before the casing is run. Minifrac tests can be conducted in horizontal wells, but unless adequate volume is pumped, near-wellbore closure on the restricted tortuous growth area can result in an inaccurate calculation of fluid leakoff coefficient. Minifrac data is of value from horizontal wells when previous vertical well data or horizontal well history allows the design engineer to compare a range of realistic C_{eff} values.

Stress data can also be collected from calculations available in long-spaced sonic logs from a vertical pilot hole. The minimum in-situ stress is determined with calculations based on a combination of formation bulk density and an estimate of Poisson's Ratio. Stress data derived from this logging method is most accurate when calibrated with at least one microfrac test, usually in the pay zone.⁷

Knowing the magnitude and direction of in-situ stress is critical for horizontal and highly deviated well planning. Three common methods exist to determine stress orientation: (1) coring after an "off-bottom" microfrac test, (2) anelastic strain relaxation (ASR), and (3) a 12-arm extensometer during a microfrac to detect borehole deformation.

A microfrac can be conducted with the openhole packer just above the well's TD. After the microfrac, an oriented core is recovered. The fracture direction is observed directly on the core. If properly planned, this procedure can often be performed during a drilling program without a significant increase in operating time (Fig. 5).

ASR can be performed in either vertical or deviated wells. During this process, an oriented core is taken and retrieved to

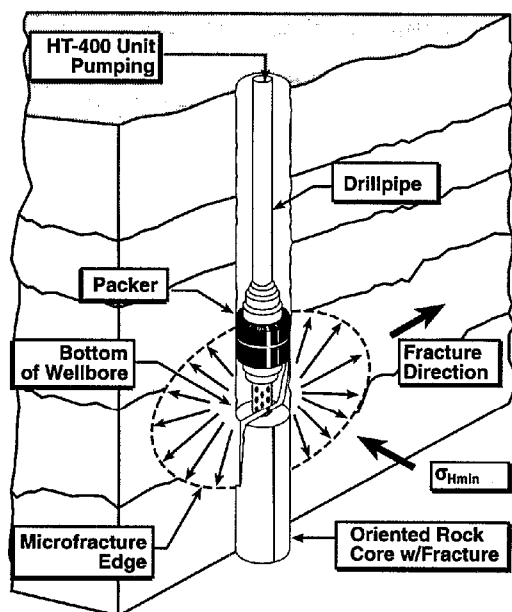


Fig. 5—Openhole microfracture showing closure stress and fracture orientation.

surface. Immediately upon recovery, the expansion of the rock is measured. The rock's direction of maximum expansion indicates the direction of maximum in-situ stress. The process yields the best results with homogeneous, unfractured formation core (Fig. 6).

The 12-arm extensometer allows the following five parameters to be determined:

- in-situ stresses
- in-situ rock modules
- in-situ stress orientation
- fracture width
- fracture closure pressure

This tubing-conveyed extensometer consists of two six-arm calipers and two openhole packers. It is run with a wet wireline connection for surface tie-in of real-time data acquisition, and is used in conjunction with an openhole microfrac. Currently, the system has been used successfully in vertical well applications, and modifications for deviated wellbores are being designed (Fig. 7).^{8,9}

Pre-frac Diagnostic Injection Tests

A major operator in Denmark expanded the conventional treating pressure equation to include the pressure drop associated with tortuosity.¹⁰ From an offshore installation

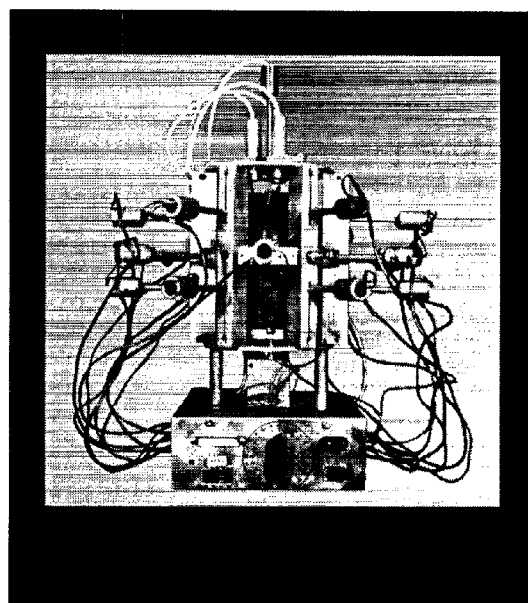


Fig. 6—Test apparatus for vertical well samples.

where wellbores are drilled in a radial pattern, various angles of wellbore direction to maximum principal stress will result, yielding a range of observed tortuosity values. Through the use of bottomhole pressure gauges, the operator was able to separate a combination of perforation friction pressure and tortuosity from other components, making up the conventional treating pressure equation. Further studies of perforation erosion have proven the magnitude of perforation pressure drop to be minimal. The relationship of perforation friction pressure and tortuosity pressure are defined by the following equation:

$$P = CQ^n \quad (1)$$

where

- $n = 2$ for perforation friction
- $n = 0.5$ for tortuosity
- P = pressure drop, psi
- C = constant
- Q = injection rate, bbl/min

A log/log plot of pressure vs. rate can be generated on site to identify the origin of pressure problems. This technique has also been used by other North Sea operators.¹¹

The Denmark operator first used proppant injection tests to

- determine the amount of tortuosity present
- erode the restricted flow path to eliminate tortuosity and allow placement of designed treatments
- create isolation when the primary cement job failed to provide a direct hydraulic connection to the formation from the perforations
- screen out potential multiple fractures that are present for some wellbore to in-situ stress orientation angles

Pre-job proppant injections have allowed stimulation treatments to be placed when other techniques such as acidizing ahead of the fracture stimulation failed.

Simulation of Fractured Horizontal Well Production

Since the late 1980s, service companies have sought to simulate horizontal well production and determine the best number of propped-fracture stimulated wells to drain a reservoir. Models exist for both of these cases, but no case history information is available to confirm the accuracy of the models used.^{12,13} Fig. 8 shows the effects of vertical and horizontal permeability with the number of fractures and cumulative production.

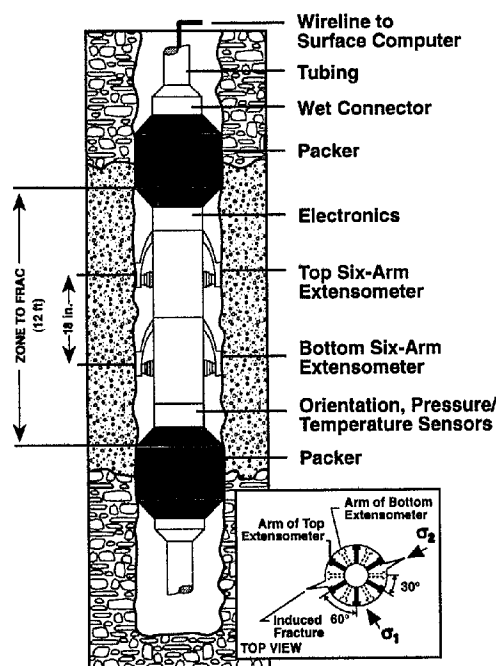


Fig. 7—Twelve-arm extensometer.

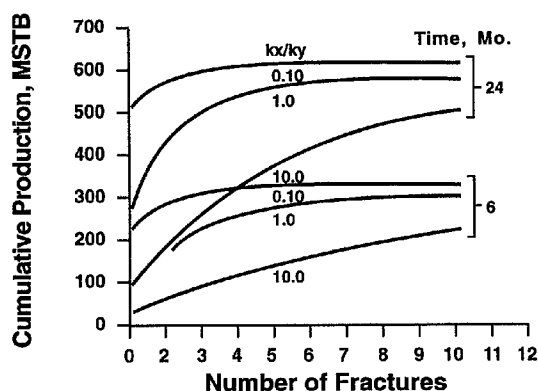


Fig. 8—Cumulative production vs. number of fractures for the effect of directional horizontal permeabilities.

For propped-fracture stimulated horizontal wells, modeling has considered the limited flow area created by the required short perforated interval. The use of high-conductivity tail-in proppants has also been studied. The restricted flow path near the wellbore caused by the previously mentioned tortuosity effects makes the choice of the tail-in proppant critical, especially for fractures that are transverse or perpendicular to the wellbore (Fig. 9).

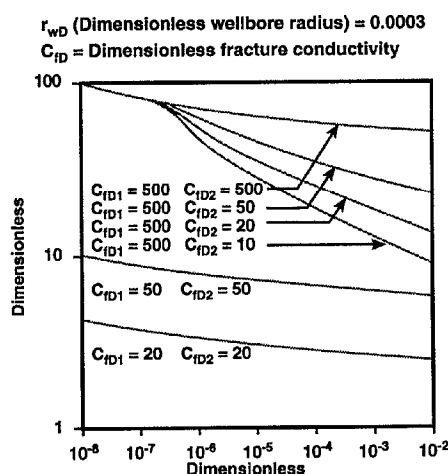


Fig. 9—Well productivity is affected by the conductivity of the tail-in proppant. As conductivity of the fracture increases, the productivity of the well increases.

Simulators also exist that can determine the number of propped fractures per horizontal well and the number of wells required for development of a field (Fig. 10). As with other simulators, the relationship of vertical to horizontal permeability and production rate vs. economics are considered.

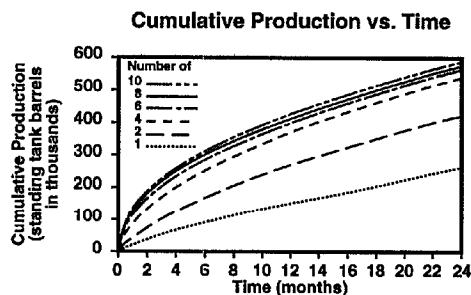


Fig. 10—The production rate of a well is directly related to the number of transverse fractures that are draining it. Production rates vs. the number of transverse fractures can be optimized. In this example, no appreciable gain in production is noticed when the number of fractures is higher than four.

Marginal Fields

As previously mentioned, many of the new developments in the North Sea will be marginal fields. Economics dictate the use of the most advanced technologies to ensure successful development of these fields. One such example is Statoil's Tommeliten Field, which was discovered in January 1977 but not scheduled for development until 1986. Advances in drilling,¹⁴ subsea completion,¹⁵ and stimulation¹⁶ technologies contributed to successful start-up in October 1988, nearly 12 years after discovery.

In some marginal fields, hydraulic fracturing is considered part of the completion program from the onset of the project. In other instances, fracturing will be an option to bypass formation damage, or to improve deliverability if the wells are not producing up to expectations. Whether fracturing is part of the initial development plan or not, it must be recognized that the funds available for pre-frac planning are generally limited. Recent advances in diagnostic injection tests, real-time treatment analysis, and on-site redesign capabilities should provide operators with greater confidence that hydraulic fracturing can be successfully applied in marginal fields.

Treating Pressure Analysis

Bottomhole treating pressure (BHTP) analysis is a good means of learning more about in-situ stresses and formation

response to hydraulic fracturing. Nolte was the first to report that fracture growth could be characterized by examination of treating pressures and flow rates.¹⁷ Fig. 11 contains a simplified Nolte (net pressure) plot. The four regions of the plot are described below:

- Region I indicates unrestricted length extension with little or no fracture height growth.
- Region II indicates controlled height growth or high fluid leakoff.
- Region III is considered a screenout mode.
- Region IV indicates uncontrolled height growth.

Realizing that previous interpretations did not adequately describe all cases, Conway, et al. presented a very useful and concise representation of the various pressure responses that are most commonly observed.¹⁸ Figs. 12 through 16 provide a graphical summary of common well responses. By identifying the well type early in a fracturing-treatment, designers can make on-site changes to the proposed design, resulting in a more effective stimulation. Cleary took hydraulic fracturing treatment analysis one step further by pioneering the use of real-time history matching of observed pressures.¹⁹⁻²¹

State-of-the-art real-time pressure analysis is now routinely used in the North Sea to improve fracturing treatments. Minicomputer-based mobile systems are available that have been designed specifically for advanced stimulation control.²² Using these systems, service and operating company representatives interact to control and redesign the job based upon real-time data and analysis. Refinement of on-the-fly mixing and monitoring procedures for fracturing fluid systems has led to more consistent fluid properties throughout the job.²³⁻²⁵ Advances in friction pressure prediction²⁶⁻³¹ allow more accurate estimates of bottomhole pressures in cases where surface readout of bottomhole pressures not possible.

Minifrac Tests

Pre-frac diagnostic injection tests include minifrac (pump-in/shut-in or pump-in/flowback) and step-rate tests. Step-rate tests are used to determine the fracture extension pressure, which is the pressure required to extend an existing fracture. Step-rate tests are also used to determine the maximum matrix injection rates, or conversely, the minimum injection rate above which fracturing of the formation occurs.

Minifrac techniques allow designers to learn a great deal more about fracturing pressures and formation response than was possible previously. Recent work has shown several benefits that can be obtained by when a set of two or even three pump-in/shut-in tests are run to determine the effectiveness of treating fluids and fluid-loss additives. These procedures have proven to be extremely useful in heterogeneous formations where conditions can vary significantly from one well to the next. Minifrac procedures are particularly

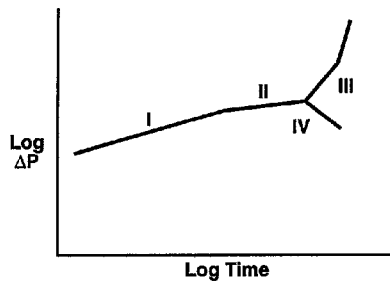


Fig. 11—Net fracturing pressure plot.¹⁷

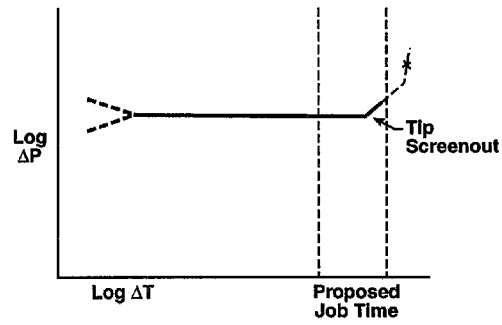


Fig. 12—Type I - Khristianovich response.¹⁸

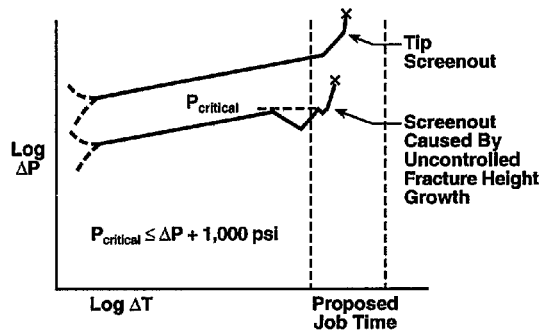


Fig. 13—Type II - Perkins and Kern response.¹⁸

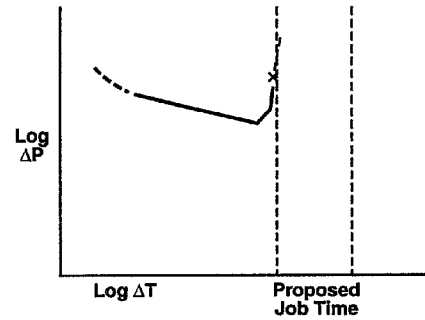


Fig. 14—Type III - Penny response.¹⁸

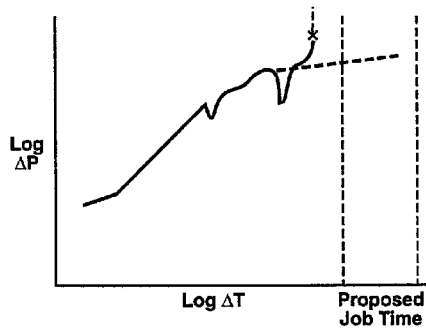


Fig. 15—Type IV - Medlin response.¹⁸

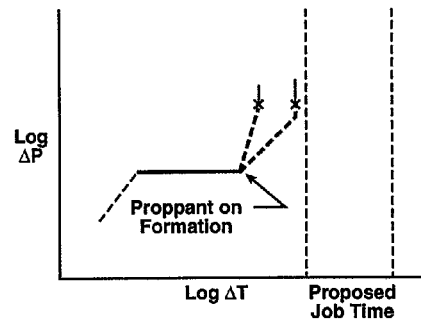


Fig. 16—Type V - Nolte response.¹⁸

attractive in marginal fields where a limited number of wells will be treated and service operators have only one opportunity to do the job correctly.

Historically, all minifrac analysis techniques assumed a simple fracture geometry and a simple fluid-loss function with no spurt loss. The main measure of fluid loss was the wall-building fluid-loss coefficient, or C_w , which is easily determined from laboratory tests. Under low permeability and ideal conditions, this approach was adequate. However, recent laboratory and field results have indicated that spurt loss may be a major factor in the overall fluid loss during fracturing.³²⁻³⁴ Fig. 17 compares the effects of

- assuming zero spurt loss
- estimating C_w then determining spurt loss
- determining spurt loss in the absence of wall-building coefficients³⁵

Dusterhoft recently published a new approach for minifrac analysis that will yield more accurate values for fracture closure pressure, closure time, fluid efficiency, spurt volume and in-situ fluid-loss coefficients.³⁵ This new technique involves the use of a 3D hydraulic fracturing simulator to match the pressure responses observed during the minifrac test. It uses an interactive procedure where either fluid loss, permeability and/or the formation stress contrasts are adjusted to match the observed pressures. Once a match is obtained, the main job design is verified using the parameters obtained from the pressure match. For optimal design, the same fracture simulator should be used in the design process and the minifrac analysis.

High-Pressure/High-Temperature (HPHT)

Several HPHT fields are being planned and developed in the North Sea. HPHT conditions are loosely defined as 15,000 psi and 300°F. Overpressured reservoirs with fracturing gradients as high as 1 psi/ft may require fracture stimulation for production enhancement or sand control reasons. Some of these reservoirs are as deep as 18,000 ft, which could translate to bottomhole treating pressures (BHTP) as high as 18,000 psi.

While numerous HPHT stimulations have been performed in the US and other parts of the world, an HPHT fracturing treatment has not yet been pumped in the North Sea. The three factors that will be critical to the feasibility of these treatments will be the fracturing fluid, available hydraulic horsepower (hhp) of the stimulation vessel, and surface pressure limitations.

HPHT Fracturing Fluids

Of the commonly used frac fluids, the most promising options for high-temperature applications are the HPG/

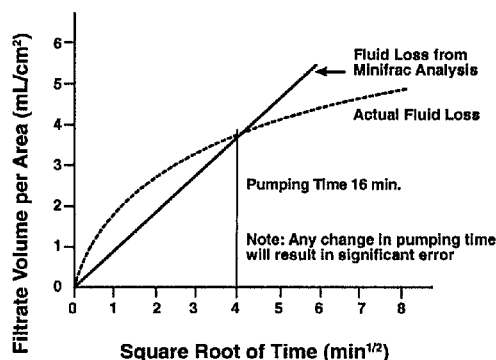


Fig. 17a—Conventional analysis of fluid-loss crosslinked gel in a high-permeability formation (zero spurt assumed).³⁵

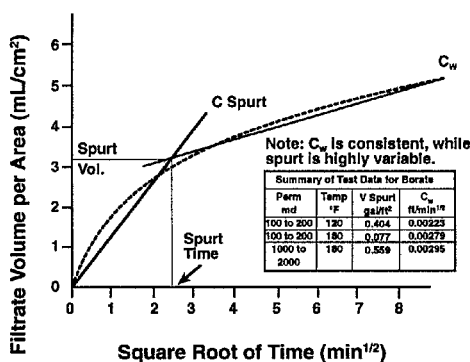


Fig. 17b—Analysis of a fluid-loss crosslinked gel in a high-permeability formation (spurt and C_w considered).³⁵

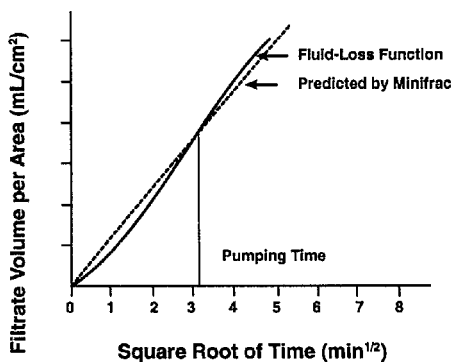


Fig. 17c—Conventional analysis of an HEC nonwall-building fluid.³⁵

Borate, HPG/Titanate, and CMHPG/zirconate systems. Historically, CMHPG/Zr system is the preferred ultra high-temperature frac fluid³⁶ closely followed by the HPG/Ti system. Previously, experience with these systems has almost exclusively been with fresh water (with 2% KCl).

The only seawater-based system having published high-temperature rheology data is the HPG/B system.³⁷ Seawater-based HPG/Ti systems are proven in the North Sea; however, to date, the applied BHTs for this fluid have ranged from of 245 to 265°F. Laboratory studies are in progress to further define the behavior of the HPG/Ti and CMHPG/Zr fluids in sea water at temperatures above 275°F.

Available Pumping Horsepower

The four North Sea-based stimulation vessels report maximum pumping power ranging from 9,800 to 13,760 hhp.³⁸ Assuming an efficiency of 90%, the available power for fracturing ranges from approximately 8,800 to 12,400 hhp. Maximum pumping rates and pressures are inversely proportional and are defined by the following equation:

$$Q = (\text{hhp} \times 40.8) / P \dots\dots\dots (2)$$

where

Q = pumping rate in bbl/min
P = pumping pressure in psi
40.8 = conversion factor

Fig. 18 shows the band of pumping rates and pressures that can be achieved during vessel-based stimulations. Notice that the maximum injection rates decrease as the WHTP increases. At 15,000 psi WHTP, possible injection rates are limited to 25 to 35 bbl/min.

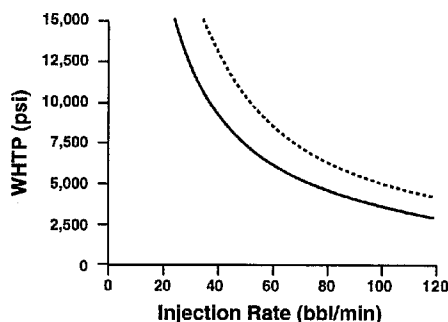


Fig. 18—Possible pumping rates and pressures (North Sea stimulation vessels).

Surface Pressure Limitations

The major mechanical limitation to high-pressure fracturing in the North Sea is the co-flex hoses used to connect the stimulation vessels to the wellhead. Currently, two types of co-flex hoses are in use: 4-in. hoses have a working pressure of 10,000 psi, and the 3-in. hoses have a working pressure of 15,000 psi. A modified 3-in. co-flex hose with a working pressure of 20,000 psi is available.

Based upon the mechanical limitation of the co-flex hoses and available pumping hhp, efficient translation of surface-to-downhole pressures becomes critical to the success of high-pressure fracturing treatments. To determine the wellhead treating pressure (WHTP) required to achieve a given BHPT, the following equation is used:

$$P_{\text{wellhead}} = \text{BHTP} - P_{\text{hydrostatic}} + P_{\text{pipe friction}} + P_{\text{perforation friction}} \quad (3)$$

Depending upon the pump rates, tubing size, and frac fluid system, pipe friction pressures can range from 20 to 150 psi/100 ft. **Table 1**, Page 10, compares the friction pressures for rapid and delayed crosslinked HPG/Ti fluid systems. With this system, it is possible to achieve a 25% reduction in friction pressure by delaying the crosslink. With borate systems, the amount of friction reduction achieved by delaying the crosslink can be extremely significant. **Table 2**, Page 10, summarizes the effects of rate, pH, and crosslinker type on the friction pressures of borate fluids measured in a field experiment.³⁹ Note that the higher friction pressure gradients at the deepest gauge result from the use of smaller tubing in this segment of the well.

Minimizing pipe friction pressure is critical. For example, if we assume a pipe friction loss of 30 psi/100 ft, a hydrostatic fluid gradient of 0.45 psi/ft, and ignore perforation friction, a 16,000-ft well with a frac gradient of 1 psi/ft would be expected to treat at about 13,400 psi. If the pipe friction loss 60 psi/ft, the well would treat at 18,400 psi, which is above the working pressure limitation of the 3-in. co-flex hoses.

Fracturing fluid technology has developed to the point such that crosslink times can be predicted and controlled.^{31,36,39,40} By adjusting the crosslink time to be slightly less than the pipe transit time, significant reductions in friction pressures are achieved. Fracturing-fluid quality control will be imperative to the success of high-pressure stimulations in the North Sea.

HPHT Fracture Acidizing

Fracture acidizing is one area of hydraulic fracturing that is often ignored in HPHT applications. Historically, it was believed that high-temperature carbonates could not be successfully fracture acidized because rapid acid spending

**Table 1: Friction Pressures (psi/100 ft)
50 lb/Mgal HPG, Ti-crosslinker**

Injection Rate (bbl/min)	2 7/8-in. Tubing		4-in. Tubing	
	Rapid Crosslink	Delayed Crosslink	Rapid Crosslink	Delayed Crosslink
30	67.9	50.7	11.6	8.5
40	96.7	71.8	16.5	12.0
50	127.2	93.9	21.7	15.7
60	159.1	117.0	27.2	19.5

Table 2: Field Experiment on Friction Pressure for Borate Fluids (Water Preheated to about 100°F)³⁹

General Data					Gauge at 5,025 ft TVD		Gauge at 6,500 ft TVD		Gauge at 8,360 ft TVD	
Stage No.	Guar Conc. (lb/Mgal)	Crosslinker Type*	pH	Avg. Rate (bbl/min)	Avg. Frict. (psi)	FPG (psi/ft)	Avg. Frict. (psi)	FPG (psi/ft)	Avg. Frict. (psi)	FPG (psi/ft)
1	40	DOB	9.5	41	622	0.1213	931	0.1884	2,433	0.7316
				56	694	0.1354	958	0.161	3,430	1.2041
2	40	DOB	10.5	41	263	0.0513	415	0.0927	1,725	0.6381
				60	500	0.0975	717	0.1323	3,074	1.1481
3	40	DWB	9.5	60	600	0.1171	852	0.1537	3,325	1.2046
4	40	DWB	10.5	41	291	0.0568	448	0.0957	1,638	0.5796
				60	548	0.1069	752	0.1244	2,942	1.0667
5	40	RBS	10.5	40	608	0.1186	798	0.1159	2,310	0.7365
				63	875	0.1707	1,155	0.1707	3,757	1.2674
6	40	None	—	62	455	0.0888	608	0.0933	2,397	0.8714

***Key:**

DOB—Delayed oil-based crosslinker DWB—Delayed water-based crosslinker RBS—Rapid borate salt

rates would limit the effective fracture lengths. A better understanding of reaction kinetics and advances in gelled acid technology has allowed successful stimulation of numerous high-temperature carbonates around the world. Some examples are listed below:

- Arun Limestone in Indonesia, BHT = 350°F⁴¹
- Smackover Dolomite in Mississippi, BHT = 295°F⁴²
- Cotton Valley Lime in south Texas, BHT = 275°F⁴³
- Ekofisk and Tor in the Tommeliten Field, BHT = 265°F.¹⁶

Fracturing in High-Permeability Reservoirs

Controlling sand production in the North Sea as well as other parts of the world is an area of great concern to operators and service companies. This concern includes sandstones and carbonate formations, since controlling fracturing proppant flowback is normally performed using sand control techniques. As the fields become more mature, the need for sand control techniques will continue to increase. The industry is expanding the use of hydraulic fracturing to high-permeability reservoirs to enhance the overall profitability of the project and as an alternative to traditional sand control applications in soft and weakly consolidated reservoirs.

Gravel Packing

Gravel packing is considered the most successful sand control technique and can be used over a wide variety of conditions. Gravel packs have been applied in cased holes, open holes and horizontal wells, as well as through production tubing. Numerous tool and fluid systems are available to enhance the final production from a gravel-packed well.

The efficiency of a gravel pack completion is still not, in many cases, acceptable. Near-wellbore damage as a result of a gravel pack completion has been widely reported. This damage could be attributed to several mechanisms or more likely, is a cumulative result of a variety of mechanisms, including post-treatment plugging of the pack and fluid loss during the completion. Post-treatment plugging could be caused by debris originating from the completion program or by the formation fines invading the pack when the well is put on production.

Fluid loss during gravel packing is a serious problem, especially in North Sea high-permeability zones. Fluid loss can result in a variety of damage mechanisms such as

- scale problems from the mixture of the formation water with fluids lost during the completion phase
- damage caused by the loss of high-viscosity fluids
- damage caused by the inability to completely clean up solid particles such as calcium carbonate or salt used as fluid-loss additives before pumping the gravel into place and locking the solid particulates into place (This condition also creates other problems such as potential voids in the pack at a later date.)

In recent years, advances in fracturing technology for high-permeability formations have given the industry another technique to control sand production. The three fracture completion techniques listed below may be applied depending on the specific well information.

- combination of gravel pack downhole equipment and tip screenout-type fracturing technique
- tip screenout fracturing technique incorporating the use of a resin-coated sand tail-end proppant
- tip screenout fracturing technique alone

Packed Fractures

The combination of fracturing and gravel pack techniques can be traced back a number of years. The "pressure packs" common in the 1950s could be seen as the forerunner of the modern day packed-fracture technology.⁴⁴⁻⁴⁶ As early as 1971, we find references to combining fracturing techniques with gravel pack equipment to stimulate the reservoir and control formation sand production.⁴⁷ The sand-oil-squeeze technology in Venezuela can also be viewed as a forerunner of the modern-day packed-fracture technology.

In the mid-1980s, the use of a tip screenout design was reported,^{48,49} in which a short, wide fracture was used to enhance fracture conductivity rather than using the propped half-length as the source of the productivity enhancement. This design was applied in soft chalk formations.

The use of fracturing followed by gravel packing was reported in the North Sea for the chalk formations on the Valhall Platform in 1988.^{50,51} In this novel approach, the formation below the intended target was perforated and fractured, with the fracture extending up into the zone of interest. The frac job was followed by a gravel pack to control the formation fines.

In 1993, a tip screenout fracture technique combined with a resin-coated sand was used to stimulate and control formation sand on the Gullfaks platform in the North Sea. The technique of fracturing up into the formation of interest was also used.⁵²

In the late 1980s, primarily because of dissatisfaction with the skins being reported on sand control completions, the use of fracturing technology had spread to the high-permeability formations found on the Gulf Coast. The main interest was in finding a way to bypass the damage in the near-wellbore area. Acid treatments using sand/gel diversion techniques followed by prepack treatments had been developed to combat many of the problems related to fluid loss and inadequate attempts at packing the perforations. Acid treatments, however, did not always cure the problem.

A combination of fracturing techniques (tip screenout) and gravel pack downhole equipment (packers/screens) in an effort to bypass the damaged area near the wellbore and control the production for formation fines has resulted in a number of success stories. Numerous reports of substantial increases in the productivity index resulting from packed-fracture stimulations have been published.^{53,53-60} Although much remains to be learned, the technology has merits and should be perceived as one of the methods that should be evaluated when the completion program is determined for high-permeability formations with sanding tendencies.

Discussion of Treatment Designs

When designing a packed-fracture treatment, it is important to first understand the true objective of the stimulation treatment. Typical objectives are listed below.

- bypass near-wellbore damage
- reduce flow velocity in the near-wellbore area
- create a uniform injection profile
- reduce skin factor
- increase productivity index (PI)

For example, if the operator's goal is just to reduce the flow velocity in the near-wellbore area, the service company may be able to simplify the standard packed-fracture procedure by

conductivity. Both of these methods have merit and should not be discounted altogether.

Downhole Equipment. Currently, the industry is still using gravel pack technology for the downhole assembly. This method provides three primary limiting factors:

- erosion of the crossover ports, flow sub ports, and the casing adjacent to the flow sub ports caused by the high flow velocities
- the low pressure ratings of the standard gravel pack packers and service tools
- the movement of the workstring during the treatment

Crossover Ports. The standard two-piece crossover weldment in the service tools has a pressure rating of approximately 5,000 psi. If the differential pressure rating across the packer/service tool is expected to exceed 5,000 psi, a solid-body crossover can be substituted for the standard crossover weldment.

Packers. The standard permanent retrievable packer used in gravel pack applications has a rating of approximately 5,000 psi (depending on the size and weight rating). If the differential pressure rating across the packer is expected to exceed 5,000 psi, a permanent packer can be substituted for the permanent/retrievable packer.

In the smaller casing sizes (5 in. and 5 1/2 in.), a high-rate system has been developed whereby modifications to the service tool and flow sub allow larger than normal flow areas to maximize the acceptable rate through the tools.

Movement of the Service Tools. Movement of the standard multi-position gravel pack service tool is critical to the success of the job. This type of gravel pack service tool changes from a squeeze-to-circulate position to a reverse-circulate position through reciprocation of the workstring. Contraction of the workstring during the treatment may tend to move the service tool out of the expected position. Most packed fractures are pumped with the service tool in the circulating position. If the tool is moved out of position during the fracturing treatment, an anomaly may be seen in the surface treating pressure. By placing the tool in a half-way position, erosion to the crossover port/flow sub may be increased. The use of pull-through collets, such as those used on gravel packs from a floating rig, may be added to help indicate if the service tool is moving out of position.

Weight-Down System. The weight-down system developed for floater work can also be used.⁶⁴ This system allows the tool operator to achieve both squeeze and circulating positions with weight from the workstring stacked onto the packer. By adding weight onto the packer during the treatment, the user can help ensure that the packer remains in the correct position. Squeeze position is determined by closing in the annulus. Circulating position is determined by opening

the annulus. This method has two primary benefits: (1) it simplifies the operation of the tool, and (2) since packed fractures are pumped with the tool in circulating position, annulus pressure can be used to monitor the downhole pressure (minus the friction pressure on the tubing). In some cases, a BHP gauge is run to help gather information for future frac jobs.

Environmental Considerations

Management of stimulation fluids used in the North Sea is both an environmental and an economic issue. The potential impact of the fluid components (as pumped) must be considered along with the handling of the returned fluids. Operators must be able to stimulate wells without impacting the North Sea environment, and service companies need to be proactive in their approach to the environment.

"Greener" Fracturing Fluid Systems

Many different types of fluids and additives are currently available for fracturing operations. It is beyond the scope of this paper to give comprehensive details on all fluids, additives, and their applications. Rather, this section will focus on recent advances in fluid technology that provide more environmentally acceptable systems.

The most commonly used fracturing fluid systems are water-based, because of relatively low cost, high performance, safety aspects, and ease of handling during pumping and disposal. The three major components of a water-based system are water, gelling agent, and crosslinker. Any sizable fracturing operation conducted in the North Sea is vessel-based. The development of liquid gel concentrates (LGCs) has dramatically increased the maximum treatment volumes per vessel loadout by allowing the frac fluids to be mixed on-the-fly with filtered seawater as the base fluid.

LGCs are highly concentrated liquid gelling agents that can be delivered continuously from a supply tank and mixed with water (fresh or sea) to form fracturing gels.^{23,24,65,66} LGC was introduced in the US in 1978 and was first used in the North Sea in 1985. There are two types of LGC: oil and water-based. Oil-based LGC has the advantage of much higher slurry concentration (up to 4 lb of polymer per gallon), however, there are associated disposal problems because of the hydrocarbon phase.

Water-based LGCs (WB-LGC) are limited to lower polymer loading levels; however, these systems are preferred over oil-based systems when the environmental aspects are considered. The first commonly used WB-LGC in the North Sea was a hydroxypropyl guar (HPG) system with a polymer loading level of 0.65 lb/gal.

Recently, a guar/WB-LGC was introduced into the North Sea as an economic alternative to the HPG-based system. This

system has a polymer loading of approximately 1 lb/gal. At the time this paper was prepared, 15 fracturing treatments with the new guar/WB-LCG had been successfully placed for an operator in the Danish Sector.

Another technological advance that has decreased the environmental impact of fracturing fluids on the North Sea environment is related to crosslinker chemistry. A number of metal ions may be used to crosslink water-soluble polymers.⁶⁷ The most common crosslinking agents used in hydraulic fracturing are borate(B), titanium (Ti), zirconium (Zr), and antimony (Sb). Of these metals, the borate ion is the most environmentally friendly and the least expensive.

Since the renewed interest in borate fluids in the mid-1980s, extensive research has been conducted on their behavior.^{27,29,39,68,69} Of notable interest is the expansion of the upper temperature limits for borate systems⁷⁰ and an understanding of their behavior when they are prepared with seawater.^{37,71} Approximately 100 fracturing treatments using borate crosslinked fluids have been pumped in the North Sea in 1993 and to date in 1994.

Handling Well Returns

Historically, there have been three basic methods of handling the well returns following stimulation. In some areas, returned fluids were dumped overboard. This first method is no longer an environmentally acceptable approach and in many cases is illegal as well. In some instances, the operator can collect all fluids in storage containers and return to shore for disposal. This second approach is often cost-prohibitive, since disposal costs can sometimes exceed the actual treatment costs. The third approach is to separate the produced fluids, burn the combustibles, and return the non-combustible portion to shore.

Recent advances in crude oil burner technology have allowed cleaner disposal of produced fluids during reservoir testing. The primary objectives of the "cleaner" burners are to minimize smoke emissions and reduce fallout (oil to sea) from the burner. These burners use internal air-mix atomizers and more stable, reliable pilot and igniter systems to enhance continuous combustion of the well fluids. An expansion of this technology is to use the improved burners when a well is flowed back after stimulation.

Advances in burner design now allow clean disposal of 12,000 to 15,000 BOPD with combustion efficiencies close to 100%.^{72,73} Some of the new burners have been tested with water cuts in the range of 35 to 60%. The presence of water was actually shown to improve the combustion process and reduce visible smoke emissions. Very high water cuts, however, could extinguish the flames. Therefore, careful attention to flowback procedures to avoid slugging (with water) is important. The proper surface equipment and operating procedures must be in place to prevent this.

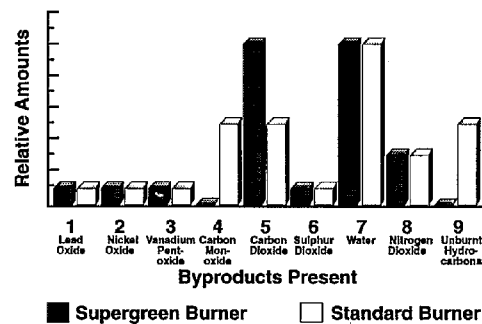


Fig. 19—Comparison of standard combustion products from commercial burners.⁷²

Fig. 19 compares the performance of a standard burner with a cleaner burner.⁷² Note that the relative amounts of standard combustion products are similar, with the exception that the cleaner burner produces significantly less unburned hydrocarbon, less carbon monoxide, and more CO₂. While the reduction in hydrocarbon fallout and carbon monoxide emissions are a significant improvement, the unnecessary burning of produced hydrocarbons is both environmentally undesirable and an economic loss.

As a result of flaring, CO₂ emissions are a potential source of atmospheric pollution. Some North Sea authorities have taken measures to reduce the amount of pollution by levying taxes on CO₂ emissions. The use of an anti-pollution test vessel (APTV) provides a solution to this expensive and wasteful method of handling produced fluids by salvaging the oil that is otherwise lost through burning.⁷⁴

Basically, the APTV takes the produced hydrocarbons (and returned stimulation fluids) on board through flexible hose, processes the fluid stream to separate the oil/gas/aqueous phases, stores the oil, burns the gas, and discharges the now clean water overboard. The process system has been designed to treat all kinds of wellbore effluents, from reservoir fluids with high water content to heavy crudes. It has a capacity of 4000 m³/day of fluids and 300,000 m³/day of gas. The water treatment system is capable of cleaning water to less than 15 ppm, and an in-line analyzer continuously monitors the water discharges to the sea.

Ecotox Testing and Pre-Screening Programs

Current regulations require the elimination of chemical substances that are harmful to humans and the environment. These substances must be evaluated based on ecotoxicological tests. This form of testing has undergone a number of

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evolutionary steps as the scientific criteria for measuring environmental impact are being developed under the guidance and direction of the Paris Commission (PARCOM). To respond proactively, the service industry must dedicate significant resources for researching and developing new chemical substances on the basis of environmental criteria that will apply to the North Sea.

Establishing ecotox prescreen methods to avoid unnecessary research and development costs is the first step in minimizing the financial and personnel investments that will be required to develop "greener" chemicals. PARCOM is developing a system known as the chemical hazard assessment and risk management (CHARM) model, which will allow for a standard rating of the environmental acceptability of a substance. An understanding of the factors considered by the CHARM model (toxicity, biodegradation, bioaccumulation, use, and discharge) will allow a prescreening program to be established.

The pre-screening techniques that show most promise are the measurement of chemical oxygen demand (COD), biological oxygen demand (BOD), and the use of high-performance liquid chromatography (HPLC) to determine logPow.^{75,76} The ratio of BOD and COD values indicates the biodegradability of a substance. LogPow gives an indication of the bioaccumulation tendency of a substance. One North Sea company has used Microtox® equipment to identify acute toxicity in produced water.⁷⁷ Microtox may also have application in a pre-screening program.

The cost of performing ecotox testing at GLP-certified independent laboratories can range from \$7,000 to \$10,000 (US) per chemical. It is significantly less expensive to perform in-house screening. Once prescreen tests are complete, a rational decision can be made as to whether or not a chemical should be submitted for outside testing.

An additional approach is to use molecular modeling to help prescreen and develop "greener" stimulation chemicals. Molecular modeling was first used in the petroleum services industry in 1990 to help design clay stabilizers and corrosion inhibitors.⁷⁸ Using a mathematical calculation technique based upon computational chemistry, it is possible to perform molecular simulations that show how products behave on a molecular scale. The use of computer simulations can significantly reduce the laboratory development time and permit investigation of chemical systems that may be difficult to study experimentally.

Service companies are now using computational chemistry to estimate the logPow values for the various components in a mixture of chemicals. The estimated logPow values are in agreement with the values determined from HPLC. While this technique is still in the development phase, the use of molecular modeling should reduce pre-screening costs, and enable environmentally friendly chemicals to be developed more quickly and economically.

Conclusions

- Improvements in the fundamental understanding of fracture initiation and growth, improved pre-treatment diagnostic techniques, and a better understanding of the effects of completion design have significantly increased the success rate of fracturing deviated and horizontal wells.
- Recent advances in diagnostic injection tests, real-time treatment analysis, and on-site redesign capabilities help ensure that hydraulic fracturing can be successfully applied in marginal fields.
- While HPHT fracturing has been successfully applied in other parts of the world, it has yet to be proven in the North Sea. Seawater fracturing fluid systems need refinement, and surface equipment pressure limitations need to be expanded.
- The North Sea is using (1) high-permeability fracturing to enhance the overall profitability of the project and (2) as an alternative to traditional sand control applications in soft, weakly consolidated reservoirs.
- Advances in fluid design and post-treatment flowback procedures have minimized the effects of hydraulic fracturing on the North Sea environment. While a full range of truly environmentally friendly chemicals is not yet available, service companies are now applying environmental criteria early in the process of chemical development.

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