Field Application of Hydraulic Impedance Testing for Fracture Measurement

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Summary

Hydraulic impedance testing (HIT) is a technique for detecting and measuring formation fractures intersecting wellbores. A pressure pulse is introduced into a well, and the resulting pressure trace is interpreted to give fracture dimensions. The first part of this paper describes how HIT can be used to estimate fracture dimensions and presents some results from a laboratory experiment that show that dimensions can be measured accurately with HIT. The remainder of the paper describes field examples of the application of HIT. A demonstration of how HIT traces change as pressure is reduced, which provides a method for determining fracture closure pressure, is included.

Introduction

The presence of fractures that enhance well productivity or injectivity can dramatically improve oilfield profitability. It is therefore important to understand how fractures behave so that fracture designs and production strategies can be optimized.

HIT is a technique for detecting and measuring the size of fractures that communicate with wellbores. It can therefore be an important tool in the drive to improve our understanding of fracturing and to monitor fracture growth.

HIT uses the transient response of the fluid in the wellbore and fracture that results from the introduction of a pressure pulse into the well to provide information about the fracture. The principles behind the technique are not new. In the 1960's, Anderson and Stahl[1] reported changes in the period of fluid oscillation in a wellbore as a fracture formed. In the 1980's, Holzhausen published several papers[2-4] detailing a form of HIT, although the method for analyzing pressure traces differs from that used for the work covered here.

The method reported here provides estimates of both fracture height and fracture length for open fractures that do not contain proppant. This can provide a useful addition to the tools available for fracture measurement, particularly in the design of hydraulic fractures where the engineer often has a good idea of fracture face area and a relatively poor estimate of fracture height.

This paper starts by describing the method developed for estimating fracture dimensions. Results of a laboratory study that show that HIT accurately measures known fracture geometries follow. Field investigations of fracture opening and closing with hydraulic impedance testing are then presented.

HIT Method

Fig. 1 is a schematic of the essential features of HIT. A pressure pulse is introduced into the top of the well. The pulse travels down the well and is reflected, for example at the mouth and tip of any fracture communicating with the well. The reflected pulses travel back to the surface, where they are detected by a pressure transducer. The pressure trace thus obtained can then be interpreted to estimate the size of any fracture connected to the well.

The equipment used to take the measurements consists of a device for introducing a pressure pulse into the well and a high-frequency pressure transducer connected to suitable recording equipment. In its simplest form, the pulse generator may be a ball valve connected to the wellhead and exhausting to atmosphere, which can be rapidly opened and closed manually. Alternatively, mechanically controlled devices that generate shorter, reproducible pulses may be used. The pressure transducer may be attached to the wellhead, avoiding the use of any downhole equipment.

Interpreting HIT Traces. Fig. 2 shows the form of the pressure trace generated by HIT. The trace shows an initial pulse (A), a reflection from the fracture mouth (B), and a reflection from the fracture tip (C). The observation that the fracture response comprises reflections from the fracture mouth and the fracture tip allows a method to be developed for estimating fracture dimensions.

Fracture height can be estimated from the magnitude of the reflection at the fracture mouth; fracture length can be determined from the time that the pulse takes to traverse the fracture. Use of the distinct reflections from the fracture mouth and fracture tip distinguishes the method developed by BP from that adopted by Holzhausen.[2-4]

When a pulse travelling down a pipe encounters a change in hydraulic impedance, it normally produces a reflected pulse and a transmitted pulse. When the hydraulic impedance increases, both the reflected pulse and the transmitted pulse are in the same sense as the incident pulse. When the hydraulic impedance decreases the reflected pulse is inverted. Thus, in Fig. 2, Pulse B was generated when Pulse A encountered a reduction in hydraulic impedance at the fracture mouth. Pulse C was generated by a reflection at the end of the fracture (very high impedance) and is therefore in the same sense as the initial pulse. For flow in pipelines, the impedance change is usuallly the result of changes in pipe diameter. The other factor that changes hydraulic impedance is the wave speed in the conduit. When the pulse hits a fracture mouth, changes in flow area and wave speed are important; the wave speed in the fracture is typically 100 m/s compared with 1500 m/s in the wellbore.[2]

Pulse Transmission in the Wellbore. Pulse transmission in the wellbore may be computed with standard techniques for transient flow in pipes. The capacitance, C_w, inertance, I_w, and resistance, R_w, of the wellbore are given in Chap. 12 of Ref. 5 as

$$I_w = \frac{1}{\pi g r_w^2}, \quad (1)$$

$$C_w = \frac{\pi g r_w^2}{a_w^2}, \quad (2)$$

$$\text{and } R_w = \frac{8\mu_w}{\rho \pi r_w^4}, \quad (3)$$

where the resistance term given is for laminar flow (an alternative expression is used for turbulent flow). The resistance term is small relative to the inertia term at the frequencies of interest, and if resistance is ignored, then

$$Z_w = \sqrt{(I_w/C_w)} \quad (4)$$

Note that while resistance has only a small effect on hydraulic impedance, resistance effects are significant for pulse propagation down wellbores. Resistance effects are discussed in the section on Fracture Height Determination.

The fracture can also be added to the hydraulics system by approximating the fracture as a 1D hydraulic unit. The fracture is then treated as a pipe along which pulses will propagate.

Original SPE manuscript received for review Oct. 3, 1993. Revised manuscript received Sept. 6, 1994. Paper accepted for publication Oct. 10, 1994. Paper (SPE 26525) first presented at the 1993 SPE Annual Technical Conference and Exhibition held in Houston, Oct. 3–6.

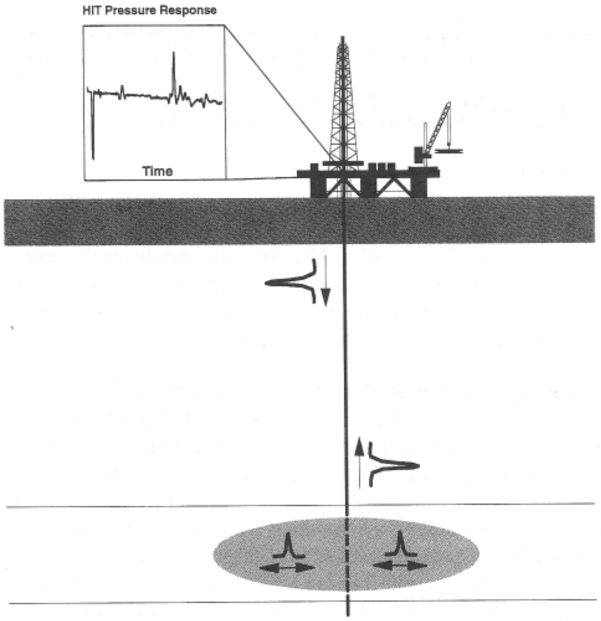

Fig. 1—HIT operation.

1D Approximation of Flow in Fractures. It is assumed that fractures are ellipsoidal and that the fracture width may be related to fracture height and length with the crack model given by Sneddon[6]:

$$b_f = \frac{2p_e h_f(1 - \nu)}{\pi G \alpha_s} \quad \text{. . . . . (5)}$$

where p_e is the excess pressure, which includes poroelasticity effects (i.e., the pressure above fracture opening pressure multiplied by a poroelasticity factor, which takes into account the rise in rock stress associated with changes in fluid pressure) and the fracture shape factor, α_s, is approximately $0.63 + 0.425\ h_f/l_f$. This applies to fractures with lengths greater than heights; h_f and l_f should be interchanged if height exceeds length.

The fracture capacitance, C_f, and inertance, I_f, are computed in a similar manner to that for the wellbore. Fracture height and width are assumed to be constant along the fracture length, with values equal to those at the fracture mouth (use of values of height and width that are averaged over the fracture length are discussed below), and it is assumed that the Sneddon relationship can be applied to localized deformations (i.e., when the pressure changes in only part of the fracture). The capacitance is proportional to the change in volume (assumed to be the result of changing width only) divided by the corresponding change in pressure. Substituting Eq. 5 gives

$$C_f = \frac{\rho g \pi \Delta b_f h_f}{\Delta p_e} = \frac{\rho g 2 h_f^2(1 - \nu)}{G \alpha_s}, \quad \text{. (6)}$$

and inertance, which is inversely proportional to mass, is given by

$$I_f = \frac{1}{\pi g b_f h_f} = \frac{G \alpha_s}{2 g p_e h_f^2(1 - \nu)} \quad \text{. . . . . (7)}$$

If resistance is ignored, the hydraulic impedance of the fracture is given by

$$Z_f = \sqrt{\left(I_f/C_f\right)}. \quad \text{. . . . . (8)}$$

Resistance in the Fracture. The permeability of a fracture can be shown[7] to be $w_f^2/12 = b_f^2/3$. Using values at the fracture mouth and Eq. 5, we can give resistance, R_f, as

$$R_f = \frac{\mu_w}{\rho g k_f^2 b_f h_f} = \frac{3\mu_w}{4\rho g h_f b_f^3} = \frac{3\mu_w}{4\rho g h_f^4}\left[\frac{\pi G \alpha_s}{2p_e(1 - \nu)}\right]^3. \quad \text{. . . . . (9)}$$

At the fracture mouth, the resistance in the fracture is often small relative to the inertia term in the calculation of hydraulic impedance and can be ignored when computing pulse behavior at junctions within the wellbore fracture system. However, resistance in the fracture is significant, and attenuation of pulses that travel along the fracture is likely to be large.

Flow Through the Fracture Faces. Because the fracture faces are permeable, flow to and from the formation can occur. An additional impedance in parallel with capacitance may be included, although its size means that it has a negligible effect on the result.

Wave Speed in the Fracture. In the wellbore, wave speed is largely dependent on fluid compressibility and is therefore relatively high at about 1500 m/s. In the fracture, wave speed is dominated by the compliance of the fracture walls, giving wave speeds of about 100 m/s (Ref. 2). In the fracture, the wave speed is approximately

$$a_f = \sqrt{(A\Delta p)/(\rho \Delta A)}. \quad \text{. . . . . (10)}$$

Using Eq. 5, this gives

$$a_f = \sqrt{(p_e/p)}. \quad \text{. . . . . (11)}$$

Fracture Length Determination. Fracture length can be estimated as $a_f t_f/2$, where t_f is the time for the pulse to traverse the fracture (two-way travel time), as indicated in Fig. 2.

Resistance in the fracture is likely to attenuate the pulse significantly, particularly toward the fracture tip. However, note that the size of the echo from the tip is not of major importance. The reason is that the delay time to traverse the fracture is used in the calculation, so the method is usable if the tip echo is detectable.

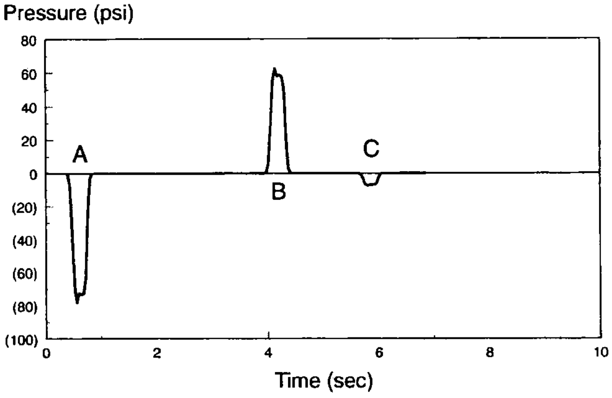

Fig. 2—Idealized HIT pressure record.

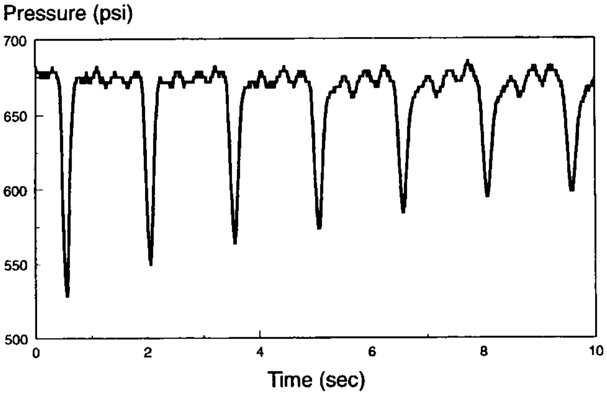

Fig. 3—HIT trace for unperforated well.

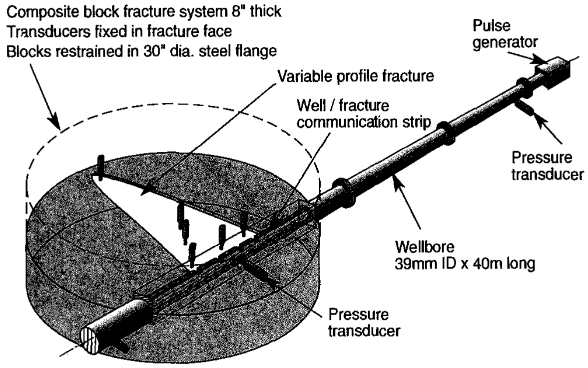

Fig. 4—Equipment used in HIT experiment.

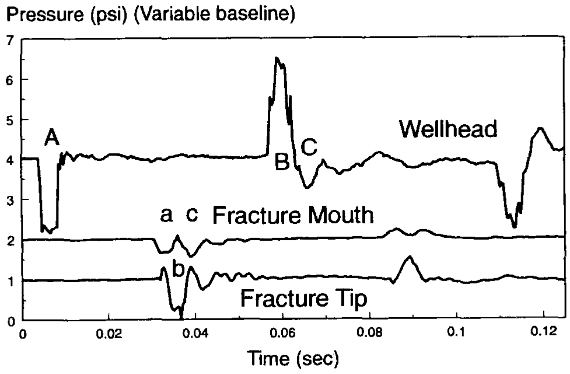

Fig. 5—HIT experiment pressure traces.

Fracture Height Determination. For a simple constant-diameter wellbore connected to a fracture, the reflection coefficient at the fracture mouth, R, is

$$R = \frac{Z_f - Z_w}{Z_f + Z_w}, \quad \text{(12)}$$

where Z_f and Z_w are the hydraulic impedances of the fracture and wellbore, respectively. By obtaining the reflection coefficient from the measured field pressure trace and using known wellbore parameters, we can determine Z_f. Substituting Eqs. 6 and 7 into Eq. 8, rearranging, and entering wellbore and rock parameters allows fracture height to be determined from

$$h_f^4 = \frac{1}{4p_e\rho}\left[\frac{Ga_s}{gZ_f(1-\nu)}\right]^2, \quad \text{(13)}$$

where p_e can be determined from either HIT, as described below in the section on Determining Fracture Closure, or a step-rate test.

While the effect of resistance is likely to be small at the junction between the wellbore and the fracture (if the resistance term for the fracture were large, the large inverted reflections from the fracture mouths would not occur), it will be significant for pulse transmission along the wellbore. **Fig. 3** shows the decay of a pulse in a 1100-m-deep, 14-cm-diameter unperforated well.

Pulse height is reduced by approximately 10% over the 2200 m it travels. This effect needs to be included in estimations of the reflection coefficient at the wellbore fracture junction from pressure traces measured at the wellhead. In its simplest form, this can be effected by adjusting the value of the reflection coefficient by use of an attenuation factor appropriate to the pipe size and the flow conditions.

Using average values of capacitance and inertance for the fracture, rather than the localized values at the fracture mouth, would increase the calculated value of fracture height by approximately 22% without changing the fracture length estimate. In practice, the pulse length determines the region of investigation and hence the reflection coefficient for the fracture mouth, so the height is likely to fall between these two values. However, the pulse length in the fracture is normally less than the fracture length, so the average height of the zone investigated is likely to be closer to that at the wellbore than to the average. While this simplification affects the results, it is likely that wellbore fracture communication has an even bigger impact on fracture height measurement, as discussed in the next section, so further refinement of this part of the model may not improve the results significantly.

There are important uncertainties in the systems being modeled, and the analysis method described has some noteworthy simplifying assumptions. However, it is questionable whether the system being investigated is defined well enough to warrant significant refinement of the analysis method. The next section looks at a laboratory experiment performed to test the validity of the method when the system being investigated was characterized much better than it is in the field.

Laboratory Testing of HIT

A laboratory study was done to ascertain how well fracture size can be determined with HIT. **Fig. 4**[8] is a schematic of the rig. A 40-m-long wellbore of 39-mm diameter is connected to a variable-size fracture. The fracture is contained in the central layer of a three-layer sandwich between two thick perspex blocks. It was necessary to make the fracture walls from a low-Young's-modulus material such as perspex so that the wave speeds in the fracture would be similar to those in the field. High-sensitivity pressure transducers were mounted in the wellbore and fracture walls to monitor pulse propagation.

Fig. 5 shows typical pressure traces obtained during the experiment. Pulse A is the initial pulse; Pulse B is the pulse reflected from the fracture mouth; and Pulse C is the pulse from the fracture tip. The pulse reflected from the fracture tip can clearly be seen in the pressure trace obtained from the fracture mouth as it enters (Point a) and leaves (Point c) the fracture. The pulse can also be seen at the fracture tip (Point b), where it is magnified relative to the pulses at the fracture mouth because the incoming and outgoing signals superimpose.

Table 1 compares the fracture sizes measured with the HIT method described above with the actual geometries for five different fracture sizes.

Wellbore Fracture Communication. A number of runs were made with reduced communication between the wellbore and fracture to try and establish the likely response of a deviated well. For the full fracture height of the first geometry given in Table 1, there were 24 perforations. Runs were made with 8 perforations covering the central third of the fracture height and with 1 perforation at the fracture centre. The run with communication over the central third of the fracture gave height and lengths of 489 and 444 mm respectively whereas the run with one perforation gave 168mm and 480mm. Taking these results with those for geometry 4 of Table 1 indicates

TABLE 1

Shape	Width (mm)	Height (mm)		Length (mm)	
		Actual	HIT	Actual	HIT
	1	500	483	521	518
	1	500	475	166	177
	1	170	157	521	494
	1	360	348	521	479
	2	500	506	521	543

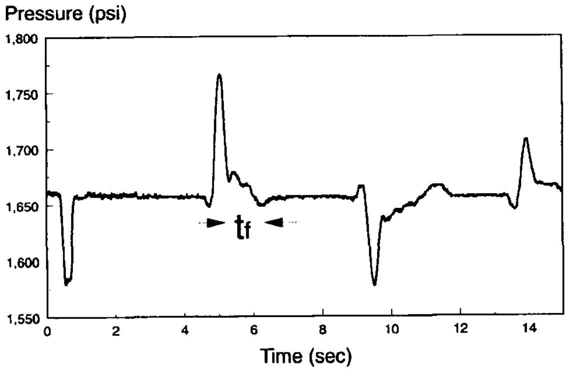

Fig. 6—Magnus C7 HIT trace.

that poor communication is likely to result in under-estimation of fracture height, although the measurement of fracture length is not likely to be affected.

Field Application of HIT

HIT has been used successfully to detect fractures in more than 50 water injection wells. Refs. 9 and 10 report the presence of small fractures in the poorly consolidated rock in the Forties field whilst Reference 8 indicates that larger fractures are present in more consolidated formations. HIT has been performed on several water injection wells in the Magnus field in the North Sea. **Fig. 6** shows one of the HIT pressure traces obtained during a pressure fall-off on well C7, which is near to vertical and has a constant diameter 7" completion. This field case provides a relatively simple example of how the above procedure might be applied.

Determining Fracture Closure Pressure. The fracture closure pressure may be obtained from a step rate test (**Fig. 7**) or from the HIT traces.

If a series of HIT's are made during a pressure fall-off, the changes in the pressure trace will indicate changes in fracture geometry. This provides a method for determining fracture closure pressure and also the excess pressure, required for evaluating fracture dimensions. **Fig. 8** gives reflection coefficients at the fracture mouth for a series of HITs made during a pressure fall-off on Magnus C7. It can be seen that the reflection coefficient increases as pressure is reduced, until the wellhead pressure reaches about 450psi. This is approximately the same pressure as that at which the gradient changes on the step rate test and is taken to be the fracture closure pressure. After a small transition, the HIT traces measured below this pressure do not appear to change further, although the form of the trace indicates that a channel is still open into the formation. The gradient of the step rate plot (Fig. 7) beneath fracture closure pressure also supports the view that channels into the formation remain open. Channels which remain open beneath fracture closure pressure have been detected by HIT in many mature water injectors. This contrasts with HITs measured on new injectors, where fractures close when wells are shut-in, as illustrated in **Fig. 10**.

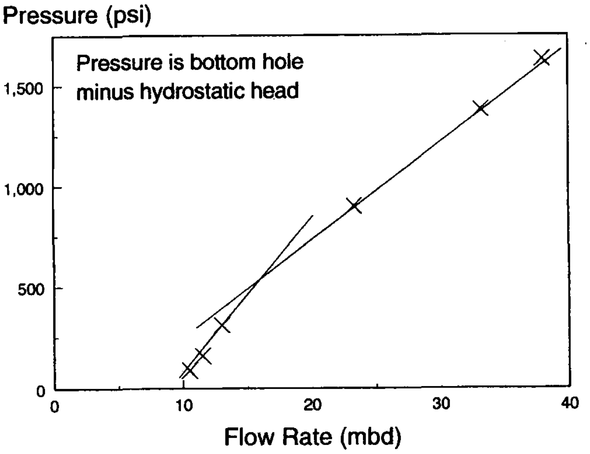

Fig. 7—Step rate test on Magnus C7.

Estimating Fracture Dimensions. The fracture length is obtained from the delay time (t_f = 1.8sec in Fig. 6) and the wavespeed (63 m/s from Eq. 10). In computing excess pressure a factor of 0.5 has been used to take account of poroelastic effects. This gives a fracture length of 56m. This length is within the range of 30–100m predicted by simulation of pressure fall-off tests (performed on Magnus well C2) using a computer program which couples fracture mechanics with a reservoir simulator[11] and by conventional pressure fall-off analysis. Field observation also supports the view that the fractures in Magnus are of moderate length, as high injectivity has been achieved without early water breakthrough to producers, despite the likelihood that fractures are orientated in the direction from injector to producer.

The reflection coefficient for the fracture mouth is obtained from the field trace (Fig. 6) as -0.71. HIT measurements were made on Magnus C5 (a well with a similar completion) prior to perforation

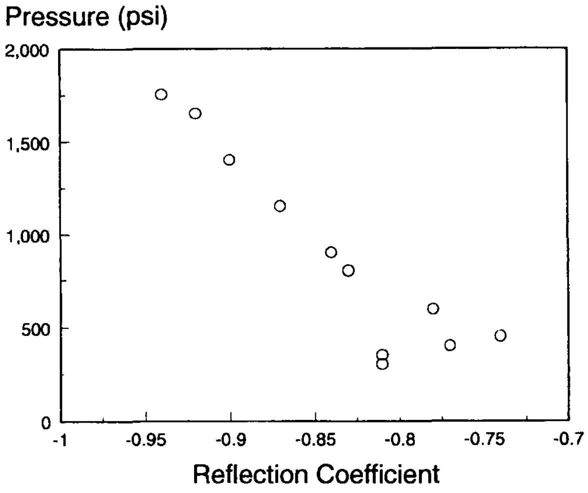

Fig. 8—Fracture mouth reflection coefficient for Magnus C7.

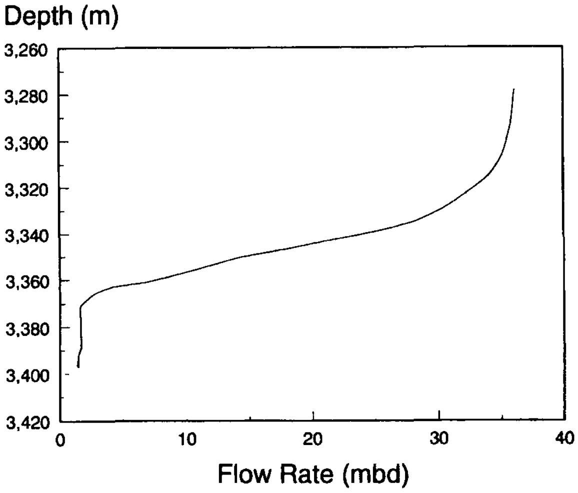

Fig. 9—Spinner trace for Magnus C7.

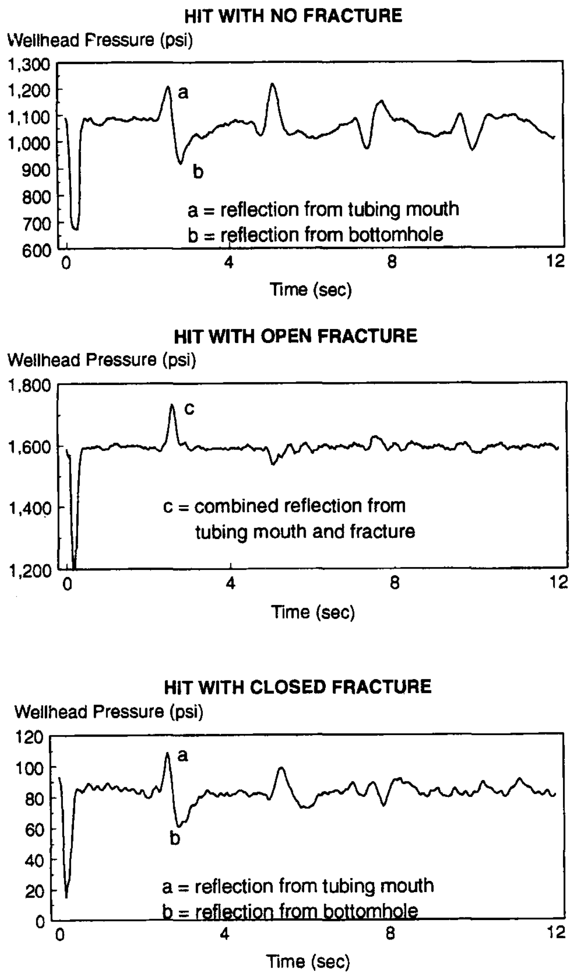

Fig. 10—Wytch Farm HIT traces.

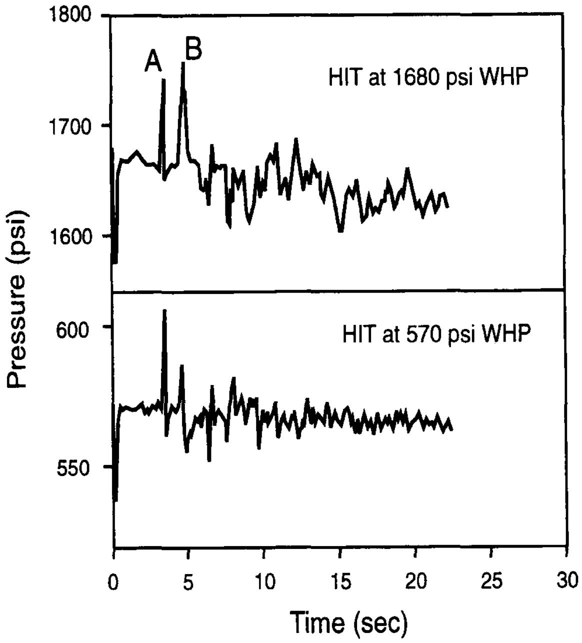

Fig. 11—South Ravenspurn HIT traces.

and these results indicate pulse attenuation in the wellbore of approximately 23% of the initial pulse as the pulse travels to the bottom of the well and back. The reflection coefficient is therefore decreased to -0.92. The hydraulic impedance of the wellbore is found from Eq. 4 as 8200 s/m^2 and the fracture impedance is, from Eq. 12, 342s/m^2. The fracture height is then obtained from Eq. 13 as 8.4m (with G = 8.5E9 = 0.2). The corresponding fracture width, obtained from Eq. 5, is 2.8mm. Calculation of fracture height and width for the HIT traces shown in Fig. 8 indicates that both fracture height and width decrease progressively as wellhead pressure is reduced, reaching about 7.2m and 1mm at a well head pressure of 900psi. A slight increase in height is then found, although this is likely to be the result of parameter uncertainty as fracture closure is approached.

Fig. 9 shows a spinner trace for Magnus C7 indicating that the majority of the flow leaves the wellbore through a 40m interval. The HIT estimate of fracture height is lower. This may be the result of poor wellbore fracture communication. Analysis of a pressure fall-off test on Magnus C7 indicates a skin of approximately -1, which tends to support the view that the well is not well connected to a large fracture. However, it should be noted that HIT estimates of fracture height (most of which have been made on deviated wells) are generally lower than expected, although they are often close to the heights indicated on spinner surveys.[8]

HIT on a Newly Fractured Well. HITs performed, both on wells in the Magnus field and elsewhere, indicate that for wells which have been injecting for several years, fractures do not appear to close fully when the wells are shut in. However, for newly fractured wells, fractures appear to close almost completely when the wells are shut-in. Fig. 10 shows three HITs from a Wytch Farm injector.

The first trace shows the well before start up. The well was then deliberately fractured and the second trace shows the HIT response of the well with the fracture open. The well was then shut-in and the third HIT trace was obtained. This third trace is very similar to the first trace indicating that the fracture has closed. A step rate test, performed concurrently on the well, shows very low injectivity beneath fracture opening and a clear change in the gradient of the plot at the same pressure as HIT indicates fracture opening.

HIT During Hydraulic Fracturing. HIT was performed during the minifrac stage of a propped fracture treatment on South Ravenspurn well A06, which has a near vertical trajectory across the reservoir. **Fig. 11** shows two HIT traces obtained during a pressure fall-off, one above fracture opening pressure and one below. The traces clearly show the effect of fracture closure.

During the treatment a 5.5" diameter fracturing string was present in the well, which contains a 7" liner. The first reflection on the pressure traces (A) therefore comes from the tubing mouth with the later reflections (B) from the fracture mouth.

The fracture mouth response indicates two fracture zones and analysis (by matching the trace obtained from a simulation package with the field record) indicates that the upper zone has a height of just over 2m and the lower has a height of about 5m. The fracture length of the lower zone is estimated at just under 40m. Analysis of the pressure decline following shut-in from a higher injection pressure gives a fracture face area of 27000m^2, which is considerably greater than the HIT estimate. The discrepancy may be because the measurements are made at different excess pressures. It is interesting to note, however, that a spinner log run after the hydraulic fracture treatment shows that approximately 80% of the flow into the well is from two zones suggesting that the HIT result may be showing real features of the flow profile.

Summary. HIT has been shown to be a cheap and reliable method for detecting fractures and identifying fracture closure pressures. HIT appears to give reasonable estimates of fracture lengths, but

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