Unit - 2

Proppants Propped Fracture Design, Fracture Propagation Model, Width Equations, Material Balance, Detailed Models. Evaluation of Fracture Design.

Proppants

proppant is a solid material, typically sand, treated sand or man-made ceramic materials, designed to keep an induced hydraulic fracture open, during or following a fracturing treatment. It is added to a *fracking fluid* which may vary in composition depending on the type of fracturing used, and can be gel, foam or slickwater–based. In addition, there may be unconventional fracking fluids. Fluids make tradeoffs in such material properties as viscosity, where more viscous fluids can carry more concentrated proppant; the energy or pressure demands to maintain a certain flux pump rate (flow velocity) that will conduct the proppant appropriately; pH, various rheological factors, among others. In addition, fluids may be used in low-volume well stimulation of high-permeability sandstone wells (20k to 80k gallons per well) to the high-volume operations such as shale gas and tight gas that use millions of gallons of water per well.

Conventional wisdom has often vacillated about the relative superiority of gel, foam and slickwater fluids with respect to each other, which is in turn related to proppant choice. For example, Zuber, Kuskraa and Sawyer (1988) found that gel-based fluids seemed to achieve the best results for coalbed methane operations,[1] but as of 2012, slickwater treatments are more popular.

Other than proppant, slickwater fracturing fluids are mostly water, generally 99% or more by volume, but gel-based fluids can see polymers and surfactants comprising as much as 7 vol% , ignoring other additives. Other common additives include hydrochloric acid(low pH can etch certain rocks, dissolving limestone for instance), friction reducers, guar gum, biocides, emulsion breakers, emulsifiers, 2-butoxyethanol, and radioactive tracer isotopes.

The following factors will influence the proppants

1. Proppant permeability and mesh size
2. Proppant weight and strength[edit]
3. Proppant deposition and post-treatment behaviours
4. Proppant costs

Proppant permeability and mesh size

Proppants used should be permeable or permittive to gas under high pressures; the interstitial space between particles should be sufficiently large, yet have the mechanical strength to withstand closure stresses to hold fractures open after the fracturing pressure is withdrawn. Large mesh proppants have greater permeability than small mesh proppants at low closure stresses, but will mechanically fail (i.e. get crushed) and produce very fine particulates ("fines") at high closure stresses such that smaller-mesh proppants overtake large-mesh proppants in permeability after a certain threshold stress.[2]

Though sand is a common proppant, untreated sand is prone to significant fines generation; fines generation is often measured in wt% of initial feed. A commercial newsletter from Momentive cites untreated sand fines production to be 23.9% compared with 8.2% for lightweight ceramic and 0.5% for their product.[3] One way to maintain an ideal mesh size (i.e. permeability) while having sufficient strength is to choose proppants of sufficient strength; sand might be coated with resin,to form CRCS (Curable Resin Coated Sand) or PRCS (Pre-Cured Resin Coated Sands). In certain situations a different proppant material might be chosen altogether—popular alternatives include ceramics and sintered bauxite.

Proppant weight and strength

Increased strength often comes at a cost of increased density, which in turn demands higher flow rates, viscosities or pressures during fracturing, which translates to increased fracturing costs, both environmentally and economically.[4] Lightweight proppants conversely are designed to be lighter than sand (~2.5 g/cm^3) and thus allow pumping at lower pressures or fluid velocities. Light proppants are less likely to settle. Porous materials can break the strength-density trend, or even afford greater gas permeability. Proppant geometry is also important; certain shapes or forms amplify stress on proppant particles making them especially vulnerable to crushing (a sharp discontinuity can classically allow infinite stresses in linear elastic materials

Proppant deposition and post-treatment behaviours

Proppant mesh size also affects fracture length: proppants can be "bridged out" if the fracture width decreases to less than twice the size of the diameter of the proppant.[2] As proppants are deposited in a fracture, proppants can resist further fluid flow or the flow of other proppants, inhibiting further growth of the fracture. In addition, closure stresses (once external fluid pressure is released) may cause proppants to reorganise or "squeeze out" proppants, even if no fines are generated, resulting in smaller effective width of the fracture and decreased permeability. Some companies try to cause weak bonding at rest between proppant particles in order to prevent such reorganisation. The modelling of fluid dynamics and rheology of fracturing fluid and its carried proppants is a subject of active research by the industry.

Proppant costs

Though good proppant choice positively impacts output rate and overall ultimate recovery of a well, commercial proppants are also constrained by cost. Transport costs from supplier to site form a significant component of the cost of proppants

- During the execution of the fracture treatment, the imposed hydraulic pressure holds the fracture open. However, when the pumping stops, it is up to the injected particulates to hold open or prop the fracture.
- However, two other variables are important in the determination of the proppant pack permeability: the proppant strength and the grain size.
- For a given stress under which the proppant pack will be subjected, the maximum value of fracture permeability can be estimated.
- Bauxite, a high strength proppant, and ISP (Intermediate Strength Proppant, a synthetic material) maintain a large portion of their permeability at high stresses. Sand, however, experiences more than a magnitude permeability reduction when the stress increases from 4000 to 8000 psi. Resin coatings can be applied to sand to increase the crush resistance and therefore the associated permeability.
- Understanding proppant permeability at a given stress is important in the selection of a proppant because, although sands are less costly, they *crush* readily, and therefore higher-strength, but more costly, proppants are more suitable at higher stresses.
- At lower stresses the permeability provided by sand may be sufficient.
- Proppant size is also important. Larger grain sizes result in larger fracture permeability. However, larger sizes are more susceptible to crushing as stresses increases, and the relative reduction in the pack permeability is much larger in the larger-size proppants. Reference [14] contains a number of correlations for size and size distribution effects on proppant pack permeability.
- These permeabilities are maximum values. As mentioned earlier, fracture permeability damage is caused by unbroken polymer residue, which is by far the biggest culprit. Thus, although proppant strength and size selection can be done using formation strength criteria, damage due to fracturing fluid residue must be controlled. Otherwise, additional damage factors, as high as 80% to 90%, can be experienced after the stress-induced permeability impairment is accounted for.
- It is also important to ensure that the proppant remains trapped inside the fracture during clean up and production.
- This can be a major problem in high flow-rate wells and where fluid drag forces dislodge and carry proppant out of the fracture. This can also be exacerbated in wide fractures (6 or more proppant grains) where a stable bridging arch is difficult to maintain regardless of closure stress. In most cases, proppant flowback does not reduce well production, but the proppant that does flowback can have a detrimental wear effect on the production equipment and may require the use of separators in the production line.
- Several techniques have been used to control proppant flowback: forced closure, resin flush, the use of curableresin– coated proppants, and fiber technology. *Forced closure* is a procedure in which fluid flowback begins immediately at the end of pumping. The theorized benefits of forced closure are that a “reverse” screenout takes place at the perforations (i.e., the fracture width closes to below

that required for a stable arch) and that the fracture closes before the proppant has a chance to settle in the fracture.

- The *resin flush technique* involves pumping a curable resin into the fracture at the end of the job. The resin coats the proppant in the fracture near the wellbore and forms a bond that glues the individual proppant grains together while still maintaining most of the permeability.
- A curable resin coating may also be applied to sand or other types of proppants to prevent the flowback of proppants near the wellbore. The curable-resin–coated proppants are mixed and pumped in the later stages of the treatment, and the well is shut in for a period of time to allow the resin to bind the proppant particles together. Under sufficient closure stress, shut-in time, and temperature, the resin-coated proppant cures into a consolidated, but permeable, proppant pack that resists flowback. Fiber technology holds the proppant in the fracture during production without the use of chemical curing reactions. Providing a physical mechanism of random fiber reinforcement prevents proppant flowback while allowing more flexibility in the flowback design.

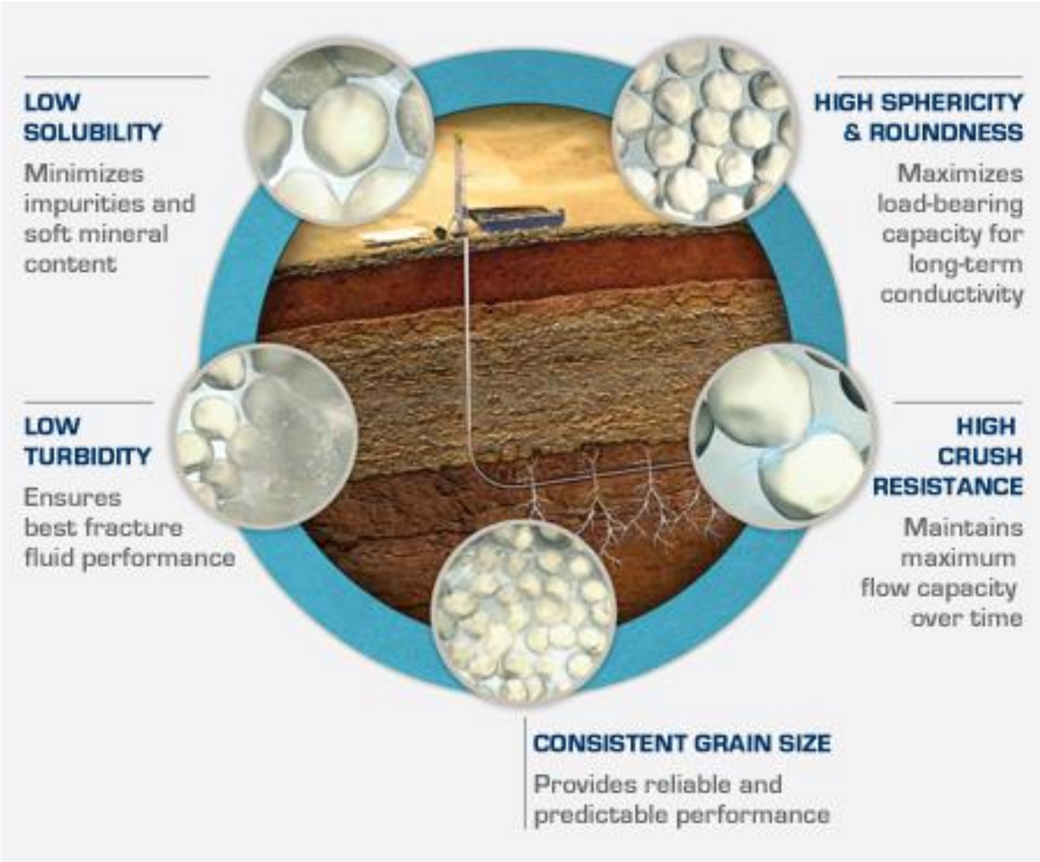


Figure: Factors influencing the design of proppants

Propped Fracture Design:

The most important data for designing a fracture treatment are the in-situ stress profile, formation permeability, fluid-loss characteristics, total fluid volume pumped, propping agent type and amount, pad volume, fracture-fluid viscosity, injection rate, and formation modulus. It is very important to quantify the in-situ stress profile and the permeability profile of the zone to be stimulated, plus the layers of rock above and below the target zone that will influence fracture height growth.

The following factors influence the fractured design

1. **Data requirements**
2. **Design procedures**
3. **Fracturing fluid selection**
4. **Propping-agent selection**

Data requirements

There is a structured method that should be followed to design, optimize, execute, evaluate, and reoptimize the fracture treatments in any reservoir. The first step is always the construction of a complete and accurate data set. Table 1 lists the sources for the data required to run fracture propagation and reservoir models. The design engineer must be capable of analyzing logs, cores, production data, and well-test data and be capable of digging through well files to obtain all the information needed to design and evaluate the well that is to be hydraulically fracture treated.

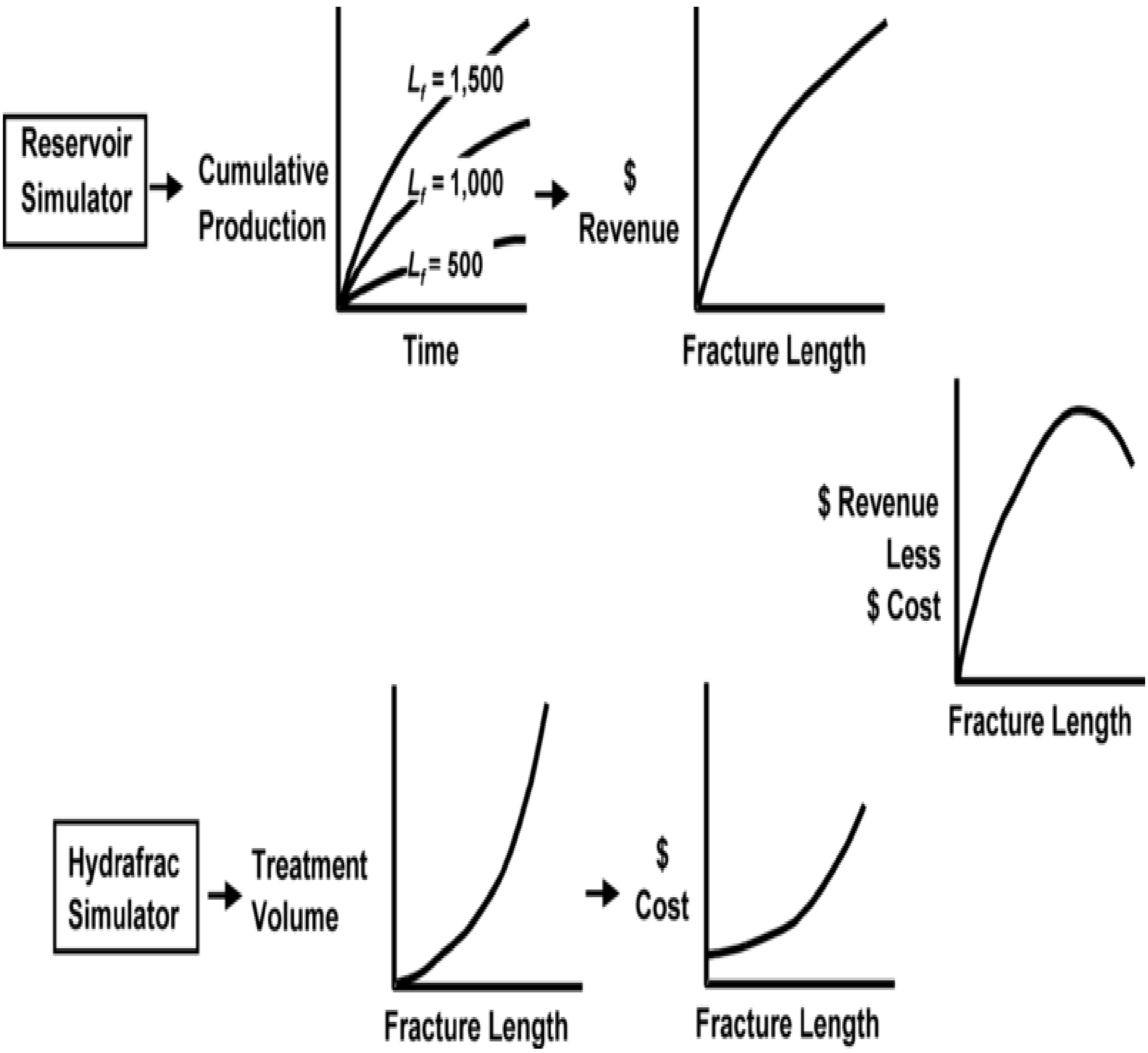
TABLE 8.1—DATA SOURCES

Data Item and Unit	Sources
Formation permeability, md	Cores, well tests, correlations, production data
Formation porosity, %	Cores, logs
Reservoir pressure, psi	Well tests, well files, regional data
Formation modulus, psi	Cores, logs, correlations
Formation compressibility, psi	Cores, logs, correlations
Poisson's ratio	Cores, logs, correlations
Formation depth, ft	Logs, drilling records
In-situ stress, psi	Well tests, logs, correlations
Formation temperature, °F	Logs, well tests, correlations
Fracture toughness, psi - $\sqrt{in.}$	Cores, correlations
Water saturation, %	Logs, cores
Net pay thickness, ft	Logs, cores
Gross pay thickness, ft	Logs, cores, drilling records
Formation lithology	Cores, drilling records, logs, geologic records
Wellbore completion	Well files, completion prognosis
Fracture fluids	Service company information
Fracture proppants	Service company information

Design procedures

Meng and Brown and Balen *et al* presented the concept and applications of the net present value (NPV) as a systematic approach to fracture design. Others have also outlined similar schemes. The complexity of the various design components and their interrelationships invariably require an economic criterion for meaningful comparisons of design options and fracture sizes.

Figure 6.5.10 contains the steps and components for optimizing fracture design. First, a fracture half-length xf is selected. This is done incrementally, with each new fracture half-length longer than the previous (e.g., by 100 ft). At first, let's follow the lower branch on Figure 6.5.10. For a given formation, the lithology, temperature, and reservoir fluids would dictate the choice of the fracturing fluid while the state of stress and the desired fractured performance would point toward the proppant selection. A fracture propagation simulator may then describe the fracture geometry.



A hydraulic fracture propagation model should be run to determine what needs to be mixed and pumped into the well to achieve the optimum values of propped fracture length and fracture conductivity. The base data set should be used to make a base case run. The engineer then determines which variables are the most uncertain. The values of in-situ stress, Young ' s modulus, permeability, and fluid-loss coefficient often are not known with certainty and must be estimated. The design should acknowledge these uncertainties and make sensitivity runs with the fracture-propagation model to determine the effect of these uncertainties on the design process. As databases are developed, the number and magnitude of the uncertainties will diminish. In effect, the design engineer should fracture treat the well many times on his or her computer. Sensitivity runs lead to a better design and educate the design engineer on how certain variables affect the values of both the created and propped fracture dimensions.

Fracturing fluid selection

The selection of the fracture fluid for the treatment is a critical decision. Economides *et al.*[2] developed a flow chart that can be used to select the category of fracture fluid on the basis of factors such as:

- Reservoir temperature
- Reservoir pressure
- The expected value of fracture half-length
- Water sensitivity

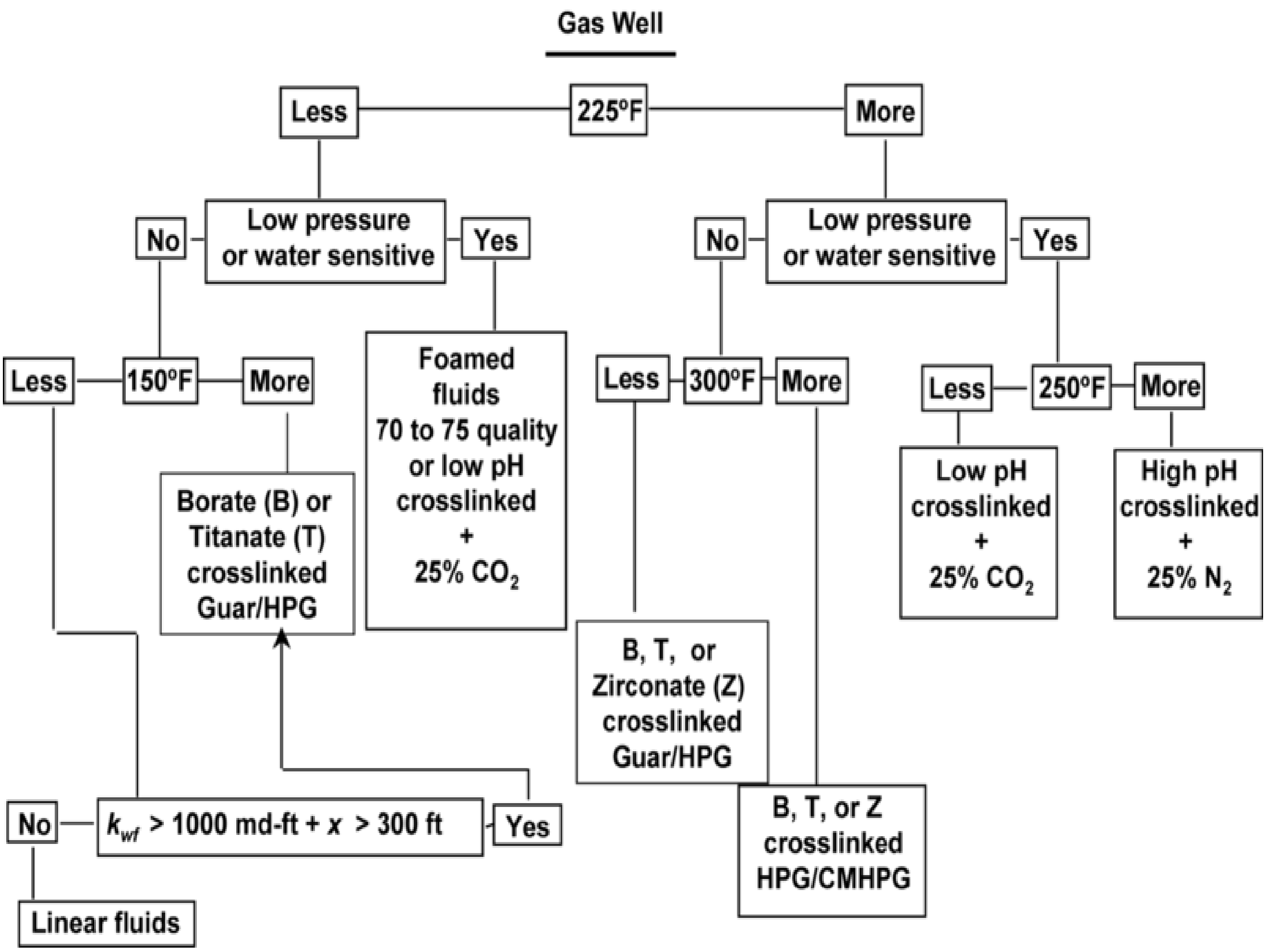
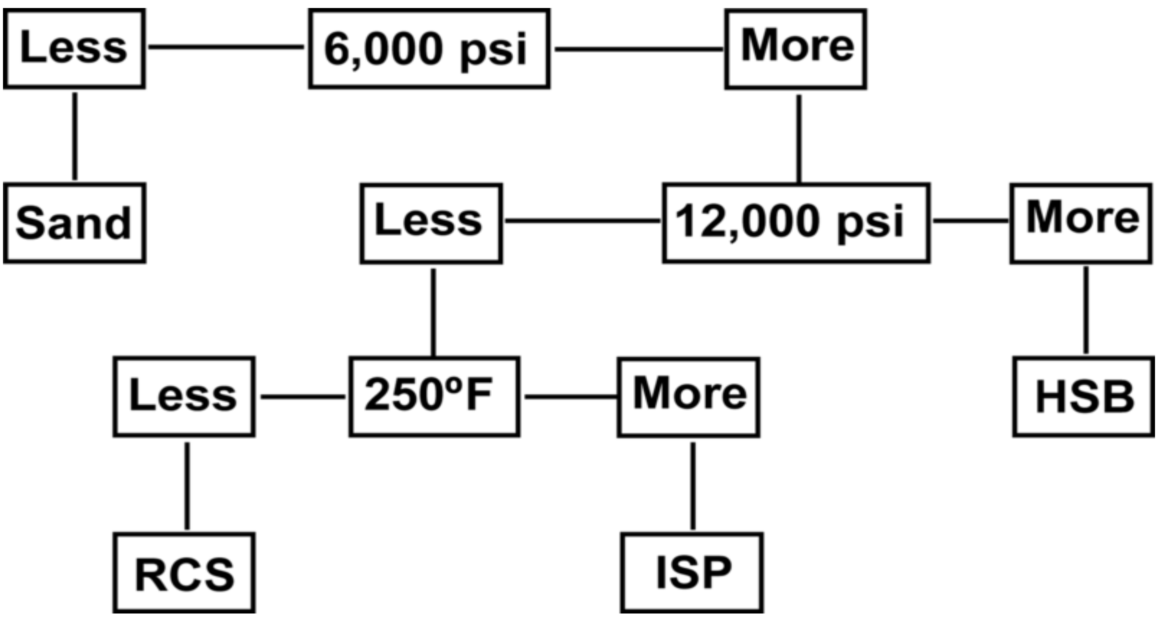


Figure: Process for selecting a fracture fluid

To use **Fig. 2**, one must follow a path that depends on formation temperature, reservoir pressure, and an intangible variable called water sensitivity. For a low-temperature, high-pressure reservoir, the desired fracture conductivity and the desired fracture length must be considered. Economides *et al*. suggest that **Fig. 2** can also be used to select a fluid to fracture treat an oil reservoir that is not water sensitive.

The definition of what comprises a water-sensitive reservoir and what causes the damage is not always clear. Most reservoirs contain water, and most oil reservoirs can be waterflooded successfully. Thus, most fracture treatments should be pumped with suitable water-base fracture fluids. Acid-base fluids can be used in carbonates; however, many deep carbonate reservoirs have been stimulated successfully with water-base fluids containing propping agents. Oil-base fluids should be used only in oil reservoirs when water-base fluids have proved conclusively to not work. Pumping oil-base fluids is more dangerous than pumping water-base fluids, and special care should be taken in the field.

Propping-agent selection
Fig. 3 presents a flow chart created by Economides and Nolte[2] for selecting propping agents. To use **Fig. 3**, the maximum effective stress on the propping agent must be determined. The effective stress is defined in **Fig. 4**. The maximum effective stress depends on the minimum value of flowing bottomhole pressure expected during the life of the well. If the maximum effective stress is less than 6,000 psi, then **Fig. 3** recommends that sand be used as the propping agent. If the maximum effective stress is between 6,000 and 12,000 psi, then either RCS or intermediate-strength proppant should be used, depending on the temperature. For cases in which the maximum effective stress is greater than 12,000 psi, high-strength bauxite should be used as the propping agent.



Fractured Propagation Model

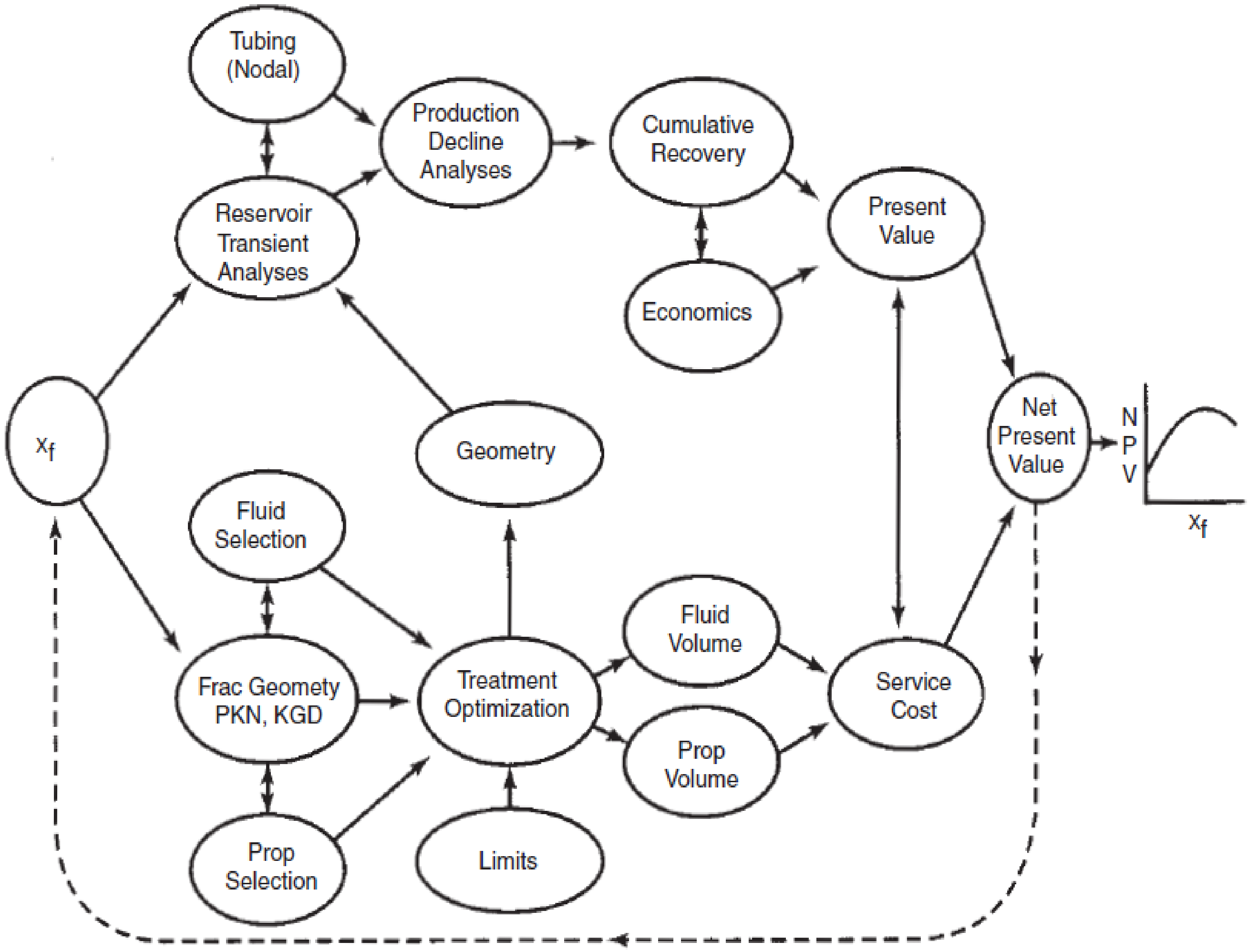


Figure 6.5.10 The components of the fracture net present value (NPV) calculation [15].

There are several types of simulators including fully three dimensional (3D), planar 3D (PL3D), pseudo 3D (P3D) (coupled 3D fracture and two dimension [2D] fluid flow), and the classic analytical 2D models. The latter include the PKN model (Perkins and Kern Nordgren and the KGDmodel (Khristianovich and Zheltov [19]; Geertsma and de Klerk [20]). The higher the complexity of the simulation, the higher the demand fo appropriate data and the longer the simulation time.

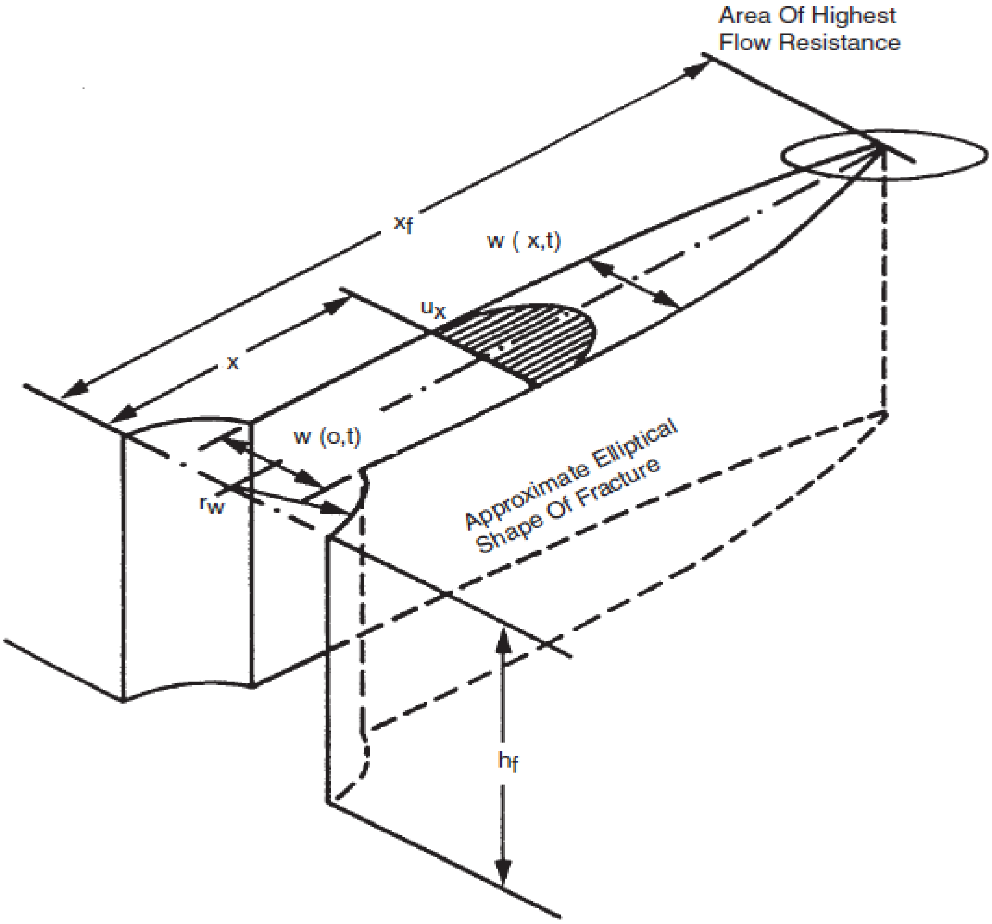


Figure 6.5.12 *The geometry of the Khristianovich and Zheltov [19] and Geertsma and de Klerk [20] model (KGD).*

KL , which is a multiplier to the leakoff coefficient and is applicable during pumping.

$$K_L = \frac{8}{3}\eta + \pi(1-\eta)$$

$$\text{where } \eta = \text{fluid efficiency}$$

The pad volume has been related to the total volume injected, Vi ,

$$\text{Pad volume} = V_i \frac{(1-\eta)}{(1-\eta)}$$

The next item is to calculate the proppant volume and its injection schedule. The latter is given by

$$c_p(t) = c_f \left(\frac{t - t_{pad}}{t_i - t_{pad}} \right)$$

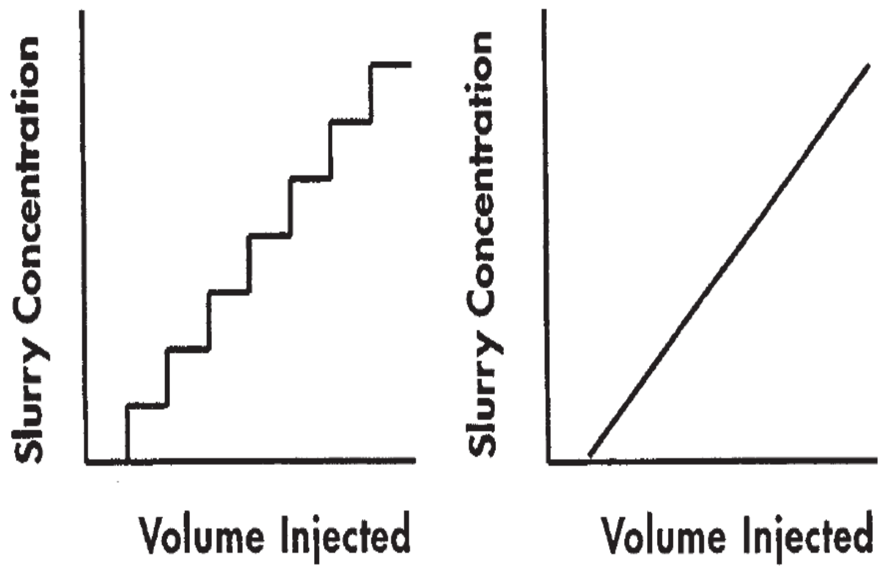


Figure 6.5.13 *Continuous vs. "stairstep" proppant addition. The continuous pressure addition is superior and is described by Equation 6.5.20.*

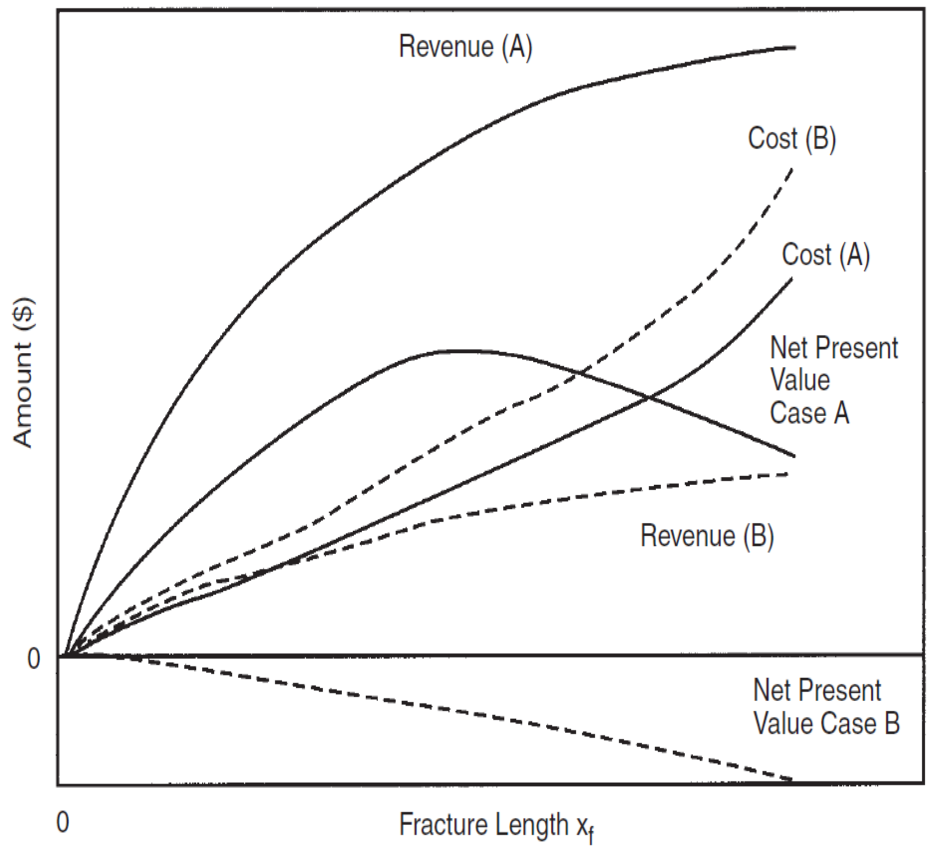


Figure 6.5.14 *Case studies of the NPV design procedure. Case A is positive, Case B is negative.*

A plot of the construction is given in Figure 6.5.14. The fracture half-length is graphed against the NPV. Optimum fracture design corresponds to the maximum NPV. Two case studies are graphed: case A, which provides a positive NPV, and case B, in which the incremental revenue does not recover the stimulation cost. In this case hydraulic fracturing should not be done.

Fractured Propagation Model mainly consists of the following parts

1. **Width Equations**
2. **Material Balance**
3. **Detailed Models.**

1. Width Equations

The theory of linear elasticity provides solutions to idealized problems. One of the them, the pressurized crack problem, deals with a crack (a straight line) of length 2b that is in an infinite plane. The stress s acting far from the crack and normal to its direction is compressive, trying to close it. On the other hand, a pressure p is acting against the stress, trying to open the crack from the inside. If the net pressure,
$\Delta p = p - \sigma$, is positive, the crack will be open and its shape
will be elliptic. The maximum width is given by

$$w_{max} = \frac{(1-\nu)}{G}(2b)\Delta p$$

(The equations, unless otherwise stated, are written in a coherent system of units in this section.) Several models originating from Perkins and Kern [17] figure the hydraulically induced fracture as a constant height channel obeying Equation in every vertical cross-section, with 2b replaced by hf . In such a channel of elliptical shape (with a width significantly less than the height), a Newtonian fluid having constant flowrate q is driven by the pressure drop

$$\frac{dp}{dx} = -\frac{64\mu q}{\pi w^3 h_f}$$

The elasticity relation and the fluid-flow equation are combined to establish a relation between width at the wellbore and fracture length. To obtain a closed form solution, the fluid leakoff is neglected at this stage of the model development. In addition, zero width (zero net pressure) is assumed at the tip. With these assumptions the created width profiles are similar, and hence, a constant multiplier can be used to transform the wellbore width into the average width.

2. Material Balance

Material balance suggests that the injected fluid either generates fracture volume or leaks off. In describing leak off, Carter applied two important assumptions. In his formulation the following was presented:

$$\frac{V_L}{A_L} = 2C_L\sqrt{t} + S_p$$

where V_L = volume of the fluid leaked off
A_L = area available for leakoff
C_L = leakoff coefficient
S_p = spurt loss coefficient

The first term represents decreasing intensity of the fluid leakoff with time elapsed, and the second term is an additional volume that is lost at the very moment of opening (the spurt loss). In addition, Carter assumed that *from the point of view of the material balance*, the fracture geometry can be well approximated by a constant rectangular cross-section, with the only dimension changing with time being the length. He wrote the material balance for a unit time interval in the form

$$q_i = 4\int_0^t \frac{C_L}{\sqrt{t-\tau}} h_f \frac{dx_f}{d\tau} d\tau + 2h_f w \frac{dx_f}{d\tau}$$

where q_i = opening time

If we want to apply the above equation, we have to decide how to estimate the constant width in this relation. It is the sum of the average width and the spurt width,

$$w = \overline{w} + 2S_p$$

Detailed Models

Clearly, the short-cut2Dmodels are based on several approximations, some of those being contradictory. For example, the geometric picture behind the Carter equation (and behind the upper and lower bounds) would require a fracture propagating with a constant width. The PKN or KGD width equations, on the other hand, give width changing in time as well.

Nordgren presented a constant-height model in the orm of a partial differential equation that contains coherent assumptions on the geometry. Kemp showed the correct tip boundary condition for Nordgren's equation. Interestingly, the numerical solution does not differ much from the one of the PKN models. The main reason is that in both the detailed Nordgren model and the PKN versions, the fracture tip propagation rate is controlled by the linear velocity of the fluid at the tip. In other words, in these models there is no mechanism to hamper the opening of the fracture faces once the fluid arrives there.

This latter statement is valid also for the different KGD variations.

Appearance of irregular pressure profiles and posttreatment observation of fracture height growth initiated a departure from the ideal geometry assumptions. This generated higher dimensional models and prompted the introduction of improved calculation procedures. The two most important concepts are the vertical distribution of the (minimum horizontal) stress and the fracture toughness.

Most of the researchers agree that stress distribution is the major factor controlling the height growth of hydraulically induced fractures.Building this concept into a PL3D or P3D model, a more realistic fracture shape can be computed. The fracture is contained in the pay layer if the minimum principal stress is significantly higher in the neighboring layers. On the other hand, if the stress in the neighboring layers is only moderately higher than in the pay layer, then a limited height growth is predicted. The PL3D and P3D models differ in how detailed the computation of the height is and to what degree it is coupled with the fluid flow equation. Although the significance of the vertical distribution of the stress is well understood, the usefulness of this concept is somewhat limited by the fact that the necessary data are often lacking. (In fact, even the value of the minimum horizontal stress in the pay layer might be uncertain within a range of several hundred psi.)

There is less consensus in the usefulness of the concept of fracture toughness. This material property is defined as the critical value of the stress intensity factor necessary to initiate the rupture. The stress intensity factor is a quantity having the dimension pressure (i.e., stress) multiplied by the square root of length. Its value increases with both the net pressure and the size of the fracture. Several investigators have arrived at the conclusion that within the physically realistic range of the fracture toughness, its influence on fracture propagation is not significant.

P3D models are used routinely nowadays for the design of fracturing treatments, in real time during the actual treatment, and for postjob evaluation.

There are two broad categories of P3D models: cell-based and lumped:

● *Lumped* models assume that the fracture consists of two half-ellipses of variable half-heights, joined along a horizontal line in the fracture length direction. At each time step, the fracture length tip and top and bottom tips are calculated as part of the solution.

● *Cell-based* models assume that the fracture is divided into a number ofPKN cells along the fracture length direction. At each time step, the fracture length and height of each cell is computed as part of the solution. Regardless of the numerical scheme employed, P3D models are more powerful than the simpler PKN-type models because they allow limited height growth as part of the solution, thereby expanding the range of treatments that can be designed and monitored.

A major drawback of the P3D models is that these solutions are all based on the concept of averaging reservoir properties over the fracture height, thereby limiting the range of treatments that can be designed. PL3D models remove this restriction because they employ a 2D mesh to describe the fracture footprint, that is, a mesh that allows variations in fluid pressure and fracture width along the fracture length and height directions. PL3D models are much more powerful and can model complicated geometric configurations, including runaway height growth situations, pinch points, concave sections on the fracture perimeter, and indirect vertical fracturing. However, they are computationally very expensive compared with P3D models and are currently only used in a limited number of treatment designs that involve more complex fracturing behavior.

There are two classes of PL3D models available:

● models based on a *moving* mesh (usually constructed with triangular elements)

● models based on a *fixed* mesh (usually constructed with rectangular elements)

The moving-mesh models are desirable because they provide good resolution at both early and late times during the injection and consume a relatively small number of elements, making them computationally fairly efficient. However, remeshing is required as the fracture footprint changes its shape, resulting in accumulative interpolation errors. These errors can become significant, especially in situations involving layered reservoirs. The fixed-mesh models suffer from poor resolution at early times and can become computationally expensive at later times once many elements become activated. However, they do not suffer from errors in mass balance, unless the mesh is coarsened at later times to reduce the number of active elements and improve Computer Processing Unit (CPU) times.

There are also a limited number of noncommercial “truly” 3D models available that allow nonplanar fracture growth (i.e., limited twisting and turning of the fracture). However, these models are currently prohibitively expensive to exercise, even for research purposes, and do not generally address transverse or longitudinal shear failure that will naturally arise as soon as nonplanar fracture growth is allowed.

Many fracturing treatments are performed in reservoirs that exhibit highly nonlinear or plastic-like material behavior, such as in the Gulf of Mexico. The current linear elastic models (whether P3D, PL3D, PKN, KGD, or radial) need to be adapted to cope with these plastic deformations. Fracturing treatments performed in such soft formations are expected to generate more fracture width and different pressure responses compared with fractures injected in competent rock. Possible remedies include the implementation of a fracture growth criterion in current models that are based on continuum damage mechanics theory or the theory of plasticity.

Evaluation of Fracture Design

Successful stimulation is when the optimum design treatment is performed and the posttreatment flowrate coincides with the one forecasted. Figure 6.5.16 shows a posttreatment well performance showing a good agreement with the predicted flowrate from the designed fracture length. If the two deviate and especially if posttreatment performance is far below expectations, then an evaluation procedure should be implemented.

Primarily, two items should be examined:

● Fracture height migration—this can be done via a posttreatment temperature or radioactive log.

● Fracture permeability reduction—this could be the result of proppant pack damage or a choke (over displacement or other reasons that reduce the contact between well and fracture). Assessment of the geometric and conductivity characteristics of the fracture can be done via a post treatment pressure transient test

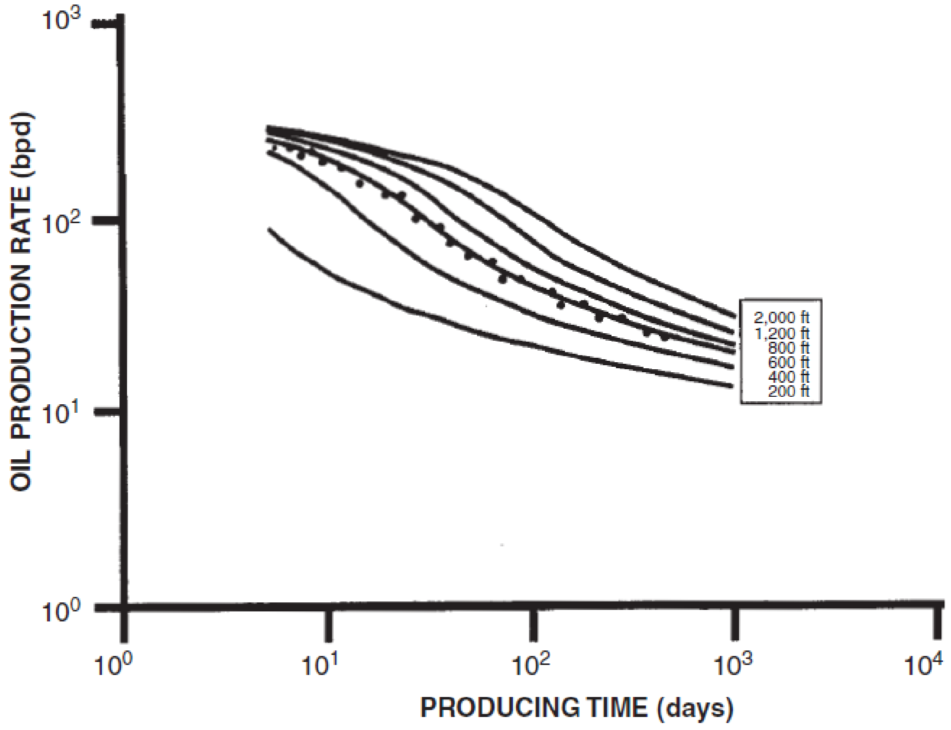


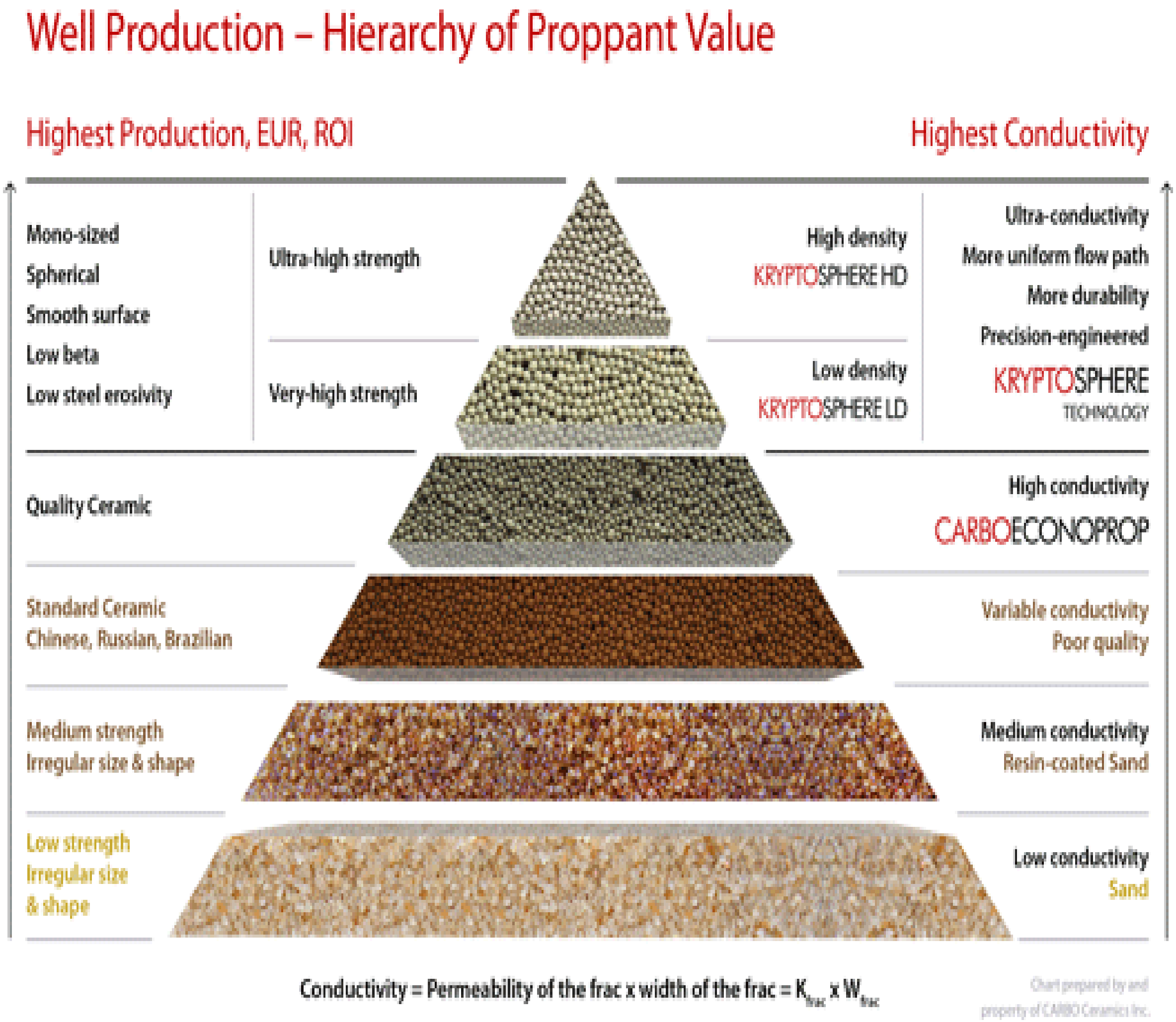
Figure 6.5.16 Posttreatment fractured well performance and comparison with predicted flowrate.

Economic Optimization:

Economic optimization of hydraulic fracture treatments allows production engineers to design a fracture treatment that optimizes the production rate from a well to maximize well profitability. In addition, a good understanding of the key parameters for the fracture treatment can be developed from the optimization study. The fracture conductivity helps in designing and selecting the proppant design as the proppant size and concentration affect the production.

To truly evaluate the realistic production potential and return on investment for any proppant in the fracture, an *Economic Conductivity* analysis should be used.

Economic Conductivity analysis factors in the proppant cost, reservoir contact and downhole conditions to determine the realistic conductivity of a fracture based on proppant quality, strength, shape and consistency. This enables proppant selection to be based on realistic production, EUR and the total costs of hydraulic fracturing activities. We can perform *Economic Conductivity* analysis and help our clients to identify and build the optimal fracture designs for their reservoir that will based meet both their production and economic objectives.



Understanding conductivity in realistic conditions
Evaluating proppant performance in the reservoir requires an understanding of realistic conductivity to ensure that the specified proppant provides the required conductivity in downhole conditions based on your contact strategy.

API RP19-D or ISO 13503-5 test conditions are overly simplistic and yield conductivity results that do not reflect the actual conductivity – or production and recovery – experienced in realistic downhole conditions.

Any laboratory reference conductivity test data must be significantly reduced to account for realistic conditions including:

- Non-Darcy flow
- Multiphase flow
- Reduced proppant concentration
- Gel damage
- Cyclic stress
- Fines migration
- Temperature

Our proppant and fracture technology specialist can help you to understand proppant conductivity in the reservoir to inform the optimal proppant selection and fracture design for your well.

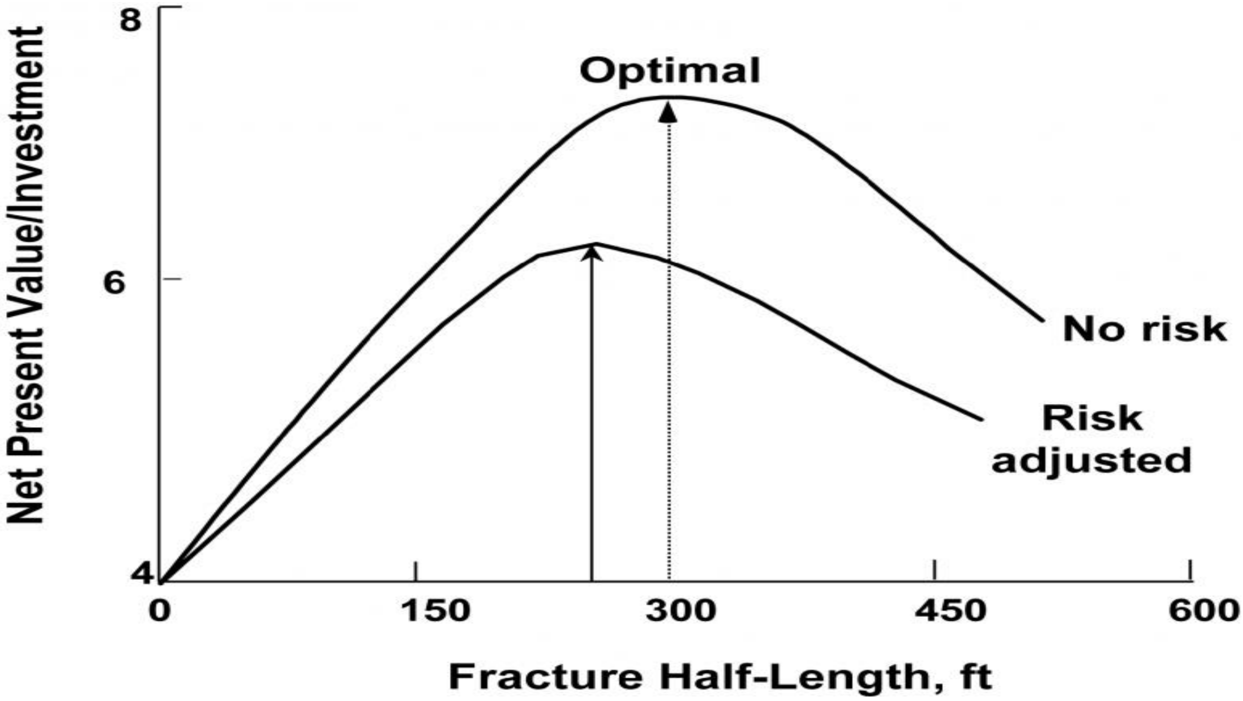
Evaluating risks in the design

The well operator always should evaluate risks such as:

- Mechanical risks
- Product price risks
- Geologic risks

Uncertainties in the data can be evaluated by making sensitivity runs with both reservoir models and fracture propagation models. One of the main risks in hydraulic fracturing is that the entire treatment will be pumped and/or paid for (i.e., the money is spent), but the well does not produce at the desired flow rates nor achieve the expected cumulative recovery. In some cases, mechanical problems with the well or the surface equipment cause the treatment to fail. Other times, the reservoir does not respond as expected.

To evaluate the risk of mechanical or reservoir problems, 100% of the costs and only a fraction of the revenue can be used in the economic analyses. For example, one in every five fracture treatments in a certain formation is not successful; therefore, 80% of the expected revenue and 100% of the expected costs can be used to determine the optimum fracture length. The following **Fig.** illustrates how such an analysis can alter the desired fracture length.



Finally, after the optimum, risk-adjusted fracture treatment has been designed, it is extremely important to be certain the optimum design is pumped correctly into the well. For this to occur, the operator and the service company should work together to provide quality control before, during, and after the treatment is pumped. The best engineers spend sufficient time in the office designing the treatment correctly, and then go to the field to help supervise the field operations or provide on-site advice to the supervisor.