Simulation of Massive Hydraulic Fracturing for Unconventional Gas Reservoir

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ABSTRACT

Hydraulic Fracturing, the process of initiation and propagation of a crack by pumping fluid at relatively high flow rates and pressure, is one of the several techniques for creating cracks in rock. Fractures in the earth’s crust are desired for a variety of reasons, including enhanced oil and gas recovery, re-injection of drilling or other environmentally sensitive wastes, measurement of in situ stresses, geothermal energy recovery, and enhanced well water production. These fractures can range in size from a few meters to hundreds of meters, and their cost is often a significant portion of total development cost.

There are significant volumes of unconventional gas worldwide. In India, natural gas reserves are located in South basin, Krishna Godavari region, and Tripura, Rajasthan and off-shore area of the Kachchh basin and are estimated to have 647 billion cubic meters of gas reserves. India’s future natural gas demand will be 391 million of standard cubic meters per day. With the increasing demands of hydrocarbons and fast depletion of easy conventional resources, it has become essential to concentrate more on tight formation gas reservoirs. The technology needs to evaluate, develop and produce tight gas reservoir has been under development for more than forty years. In the next forty years, there will be widespread development of tight gas reservoir worldwide. The massive hydraulic fracturing (MHF) in last twenty years has played a significant role in developing low permeability reservoir.

The objective of this paper is to evaluate the applicability of MHF in the Indian tight gas field. For this purpose simulation technique has been used for the prediction of fracture geometry by preparing fracture propagation model in C++ language. The study is capable to predict growth of fracture with respect to time, injection rate, permeability, Young’s modulus. Viscosity, time step, Grid size, Grid ratio etc. on the length, width and pressure profile.

Introduction

The world energy consumption pattern has been changing over the years. Presently, the share of oil in the world energy mix is 40 per cent and that of gas is 23 per cent. The international energy outlook projections indicate that the hydrocarbons will continue to cater to 68 per cent of the total commercial world energy demand over the next two decades. The share of oil may remain the same whereas that of natural gas may go up as the latter is emerging as the preferred feedstock and fuel since it is more environment friendly. Nearly 30% of India's energy comes from oil. Oil reserves are estimated at 4.7 billion barrels. India draws most of its oil from the Bombay High, Upper Assam, Cambay, Krishna-Godavari, and Cauvery basins. About 7 per cent of India's energy comes from natural gas. Power generation, fertilizers, and petrochemicals production are the industries that have been turning to natural gas as an energy feedstock. Natural gas will become a bigger part of the energy picture for India, primarily as a way to reduce dependence on foreign oil. Furthermore, the environmental benefits of its absence of sulphur dioxide and reduced levels of carbon dioxide and nitrogen oxide are appealing to a country increasingly struggling with environmental concerns. Currently, India's natural gas consumption is met entirely with domestic production, however, this scenario is expected to change within a few years. Demand for natural gas likely will outstrip the country's ability to produce it. Natural gas demand is forecast to rise to 1.7 tcf (trillion cubic feet) / year presently to 2.7 tcf/year by 2010. Estimates of India's future natural gas demand are shown in table 1.

Table 1 India's Future Natural Gas demand (in millions of standard cubic metres per day)

<table>
<thead>
<tr>
<th>Year</th>
<th>Forecasted demand</th>
</tr>
</thead>
<tbody>
<tr>
<td>2001-2002</td>
<td>151</td>
</tr>
<tr>
<td>2006-2007</td>
<td>231</td>
</tr>
<tr>
<td>2011-2012</td>
<td>313</td>
</tr>
<tr>
<td>2024-2025</td>
<td>391</td>
</tr>
</tbody>
</table>

Source: Hydrocarbon vision 2025
The area North-West of Mumbai in the Arabian sea is India's natural gas producing region. Bombay High, Heera, Panna, South Bassein, Neelam, Bombay L-II, and Bombay L-III fields are in this area. The region is also rich in crude oil. Off the east coast in the bay of Bengal lies the Krishna - Godavari (Ravva field) and Kaveri basins which together account for less than five percent of India's production of natural gas. An area off the Andaman and Nicobar Islands, also in the bay of Bengal, has shown promise for holding what could be the country's largest reserves of coal bed methane (CBM). Natural gas reserves are located in South Bassein, Krishna Godavari region, Tripura, Rajasthan and offshore areas of the Kachchh basin. These are estimated to have 647 billion cubic metres of gas reserves

\[\text{Table – 2 Distribution of Worldwide Unconventional gas resources.}\]

<table>
<thead>
<tr>
<th>Region</th>
<th>Coalbed Methane (Tcf)</th>
<th>Shale Gas (Tcf)</th>
<th>Tight-Sand Gas (Tcf)</th>
<th>Total (Tcf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. North America</td>
<td>3017</td>
<td>3840</td>
<td>1371</td>
<td>8228</td>
</tr>
<tr>
<td>2. Latin America</td>
<td>39</td>
<td>2116</td>
<td>1293</td>
<td>3448</td>
</tr>
<tr>
<td>3. Western Europe</td>
<td>157</td>
<td>509</td>
<td>353</td>
<td>1019</td>
</tr>
<tr>
<td>4. Central and</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Eastern Europe</td>
<td>118</td>
<td>39</td>
<td>78</td>
<td>235</td>
</tr>
<tr>
<td>5. Former Soviet Union</td>
<td>3957</td>
<td>627</td>
<td>901</td>
<td>5485</td>
</tr>
<tr>
<td>6. Middle East and</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>North Africa</td>
<td>0</td>
<td>2547</td>
<td>823</td>
<td>3370</td>
</tr>
<tr>
<td>7. Sub-saharan Africa</td>
<td>39</td>
<td>274</td>
<td>784</td>
<td>1097</td>
</tr>
<tr>
<td>8. Centrally planned</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Asia and China</td>
<td>1215</td>
<td>3526</td>
<td>353</td>
<td>5094</td>
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<tr>
<td>9. Pacific (Organisation</td>
<td>470</td>
<td>2312</td>
<td>705</td>
<td>3487</td>
</tr>
<tr>
<td>for Economic Cooperation and</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Development)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10. Other Asia Pacific</td>
<td>0</td>
<td>313</td>
<td>549</td>
<td>862</td>
</tr>
<tr>
<td>11. South Asia</td>
<td>39</td>
<td>0</td>
<td>196</td>
<td>235</td>
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<tr>
<td><strong>WORD</strong></td>
<td><strong>9051</strong></td>
<td><strong>16103</strong></td>
<td><strong>7406</strong></td>
<td><strong>32560</strong></td>
</tr>
</tbody>
</table>

(Tcf = Trillion Cubic feet)

As indicated in table 2 there are large volumes of tight gas worldwide Holditch (2006). The technology needed to evaluate, develop and produce tight gas reservoir which has been under development for more than forty years. In the next forty years, there will be widespread development of tight gas reservoirs worldwide. From the available reports of the US gas fields, it is postulated that though at present 5% of the produced natural gas is from such reservoirs, it can be as much as 50% by the year 2020. Development activities and production of gas from tight reservoirs in Canada, Australia, Mexico, Venezuela, Argentia, Indonesia, China, Russia, Egypt and Saudi Arabia has occurred during the past decade. Massive Hydraulic Fracturing (MHF) treatments are used more commonly around the world to stimulate gas flow from low-permeability reservoirs. Such activity will only increase during the coming decades. India, excepting a few known formations like Samdang field in Assam and Razol sand formation in Krishna - Godavari field in Andhra Pradesh, such tight formation gas reservoirs are yet to be discovered. Krishna-Godavari basin has 7 million cubic feet of gas which is almost equivalent to 2.3 billion barrels or 300 million tonnes of crude oil. Till date less than 20% gas of the basin has been explored and rest 80% is yet to be explored. It is only the economics factor that at present is not allowing the development of such un-conventional gas fields. But it is not far when such gas fields will be developed and then the massive hydraulic fracturing treatment will
become most important tool for this purpose. The process of hydraulic fracturing of underground formations is extensively used in tight gas sandstones (low permeability reservoir), high permeability sandstones, very weak sandstones, horizontal wells and many other applications from waste disposal to geothermal reservoir. The application of hydraulic fracturing in the coalbed methane industry is also attracting the attention to the countries like USA, Canada, Australia, Europe, Poland, France and UK. The original perception of coal associated methane as a hazard in mining operations is becoming obsolete. Today a coalbed is considered a reservoir from which large quantities of methane is extracted. This is accomplished currently essentially by hydraulic fracturing. Over the years considerable improvements in this technology have taken place. Many formations which were considered dead and non productive both from the technical and economic point of views have been rejuvenated with this method and in many instances those are now producing more than what they were producing originally. So the hydraulic fracturing method has revolutionised the total production practices adopted in the petroleum industry. Fracturing treatments, depending on the treatment size or the volume, vary from small to medium scale and to the point of massive. The massive hydraulic fracturing (MHF) treatment involves more than 1 million gallon (3.8 x 10³ m³) fracturing fluid and 3 million lbm (1.4 x 10⁶ kg) of propping agent which develops a fracture that extends 1000 to 3000 ft radially from the Wellbore. This definition of MHF is rather arbitrary. In general, MHF simply refers to very large treatments, typically an order of magnitude larger than the conventional fracturing procedures. In Russia, MHF is referred to as having a treatment of more than 150 tons of proppant. The main goal of MHF is to expose larger surface area of the low permeability formation, compared to the conventional procedures, to flow into the Wellbore, thereby significantly increase Well productivity. Though MHF cost accounts for a major portion of the total Well cost, still to-date the only proved economical development method for tight un-conventional gas reservoirs has been MHF treatments. So, keeping in mind, the increasing demand of tight gas in future, the objective of this paper is to evaluate the applicability of hydraulic fracturing in the Indian tight gas fields like sandang field in Assam and Razol sand formation in Krishna-Godavari field. For this purpose simulation technique has been used for the prediction of fracture geometry by preparing fracture propagation model to include both the reservoir flow and fracture mechanism together and improve upon the age old krishitianovitch-zheltov-Geertsma-deklerk (CZDK or CGK) model and Perkins-Kern-Nordgren (PKN) model. Almost 50% of the papers published in the area of Hydraulic Fracturing are related to simulation. The papers by Veatch and Moschovidis (1986), Cleary (1988), and Mendelsohn (1984) present state-of-art reports on the simulation of Hydraulic Fracturing. Most of the hydraulic fracturing simulators that have been developed so far adopt fracture geometry assumptions. The simulator developed by Yamamoto et al (1999), is designed to clarify the mechanics of the entire process of hydraulic fracturing with the fewest assumption and least empirical knowledge in order to better understand the mechanism of hydraulic fracturing. With help of this simulator, they have solved the three dimensional heterogeneous formation of hydraulic induced fracture including bending and twisting of the fracture. A P3DH simulator that computes fracture dimensions in a layered reservoir is presented by Rahim and Holditch (1995). This Pseudo-three-dimensional model (P3DH) has been used extensively to study the effects of reservoir mechanical properties, particularly stress distribution, young's modulus and fracture toughness of the reservoir layers on the height of the fracture. Effects of fluid properties such as apparent viscosity and injected fluid volume on fracture height have also been investigated. The use of this model for different scenarios illustrates the effects of mechanical properties on fracture dimension and proppant transport. The propped fracture geometry has been used in a single phase finite difference reservoir simulator to show the production increase and long-term production performance for different scenarios. In an another paper by the same author in same year, Rahim and Holditch (1995) used a three-dimensional concept in a two dimensional model to predict fracture dimensions. Predicted dimensions were closer to PKN and GDK model. Garcia et al (2005) developed 3D finite difference, fully implicit model that takes into account the non-linear poroelastic deformation of the reservoir rock. This numerical model incorporates a local grid refinement around the perforation depth, the model works with vertical gradient for the initial properties (pressure and mechanical properties). This model allows simulation of fracture propagation during the hydraulic fracture process and monitors changes in the stresses and pressure with time. One of the advantages of this model is the fact that the fracture geometry is arbitrary. Results with and without taking into account the geomechanical effect are presented to illustrate the viability of carrying out fully coupled fluid-flow/geomechanical simulation. Besides, many more research projects are going on towards the improvisation on the earlier works. But the crux of remaining modeling problems is the question: “How does a general-shaped planar pressurized crack propagate in the presence of in-situ stress discontinuities or
gradients and/or interfaces of various types between dissimilar rock types?" Cui et al (2000) in a paper describes a case study of fracturing fluid optimization for MHF in low permeability gas field. They mention that MHF job broke the records in Chinese hydraulic fracturing history and this work sets a start of massive hydraulic fracturing for low permeability gas fields in China. As a result of above success, four MHF treatments were conducted in Bajiaochang gas field located in Sichuan Basin (China) which has been reported in a paper by Jin et al (2002). It is mentioned in the paper that production of gas has been significantly enhanced. Ehrl and Schueler (2000) has discussed the concept of multiple fractured horizontal well that has successfully used for the development of a deep, ultra tight gas reservoirs. Because of extremely low permeabilities (0.01 - 0.02 md) conventionally fractured vertical wells produced at uneconomically low gas rates. The combined methods of horizontal drilling and multiple fracturing proved an economic technique for developing the significant gas resources in the tight gas reservoir. Rushing and Newsham (2001) and Parker et al (2003) discusses some general applications of MHF in tight gas reservoir. Nar Azlan et al (2003) discuss the technical and operational applicability of MHF strategy of enhance production in the Russian oil fields. A comprehensive technical analysis of the Well before after the treatment has been provided. The design and operational aspects of the treatment has been also presented. Al-Hamadah (2005) presents a case history for a tight gas reservoir that has been explored, developed and operated by Saudi Aramco. According to them, this case history will be used to highlight the day to day challenges that are facing simulation engineering, utilizing state-of-art soft/hardware technologies, to come up with feasible and cost effective development scenarios that can be confidently considered in the decision making process. Behr et al (2006) discusses some considerations of a damaged zone in a tight gas reservoir. To represent the fracture geometry and properties, the information about the distribution of the proppant concentration in the fracture width variation is translated into the permeabilities and porosities of the fracture grid blocks. To determine the fracturing fluid saturation in the invaded zone, a new approach was derived to imitate the fracture propagation at a fracturing period under consideration of leak off processes.

**Formulation of computer based numerical modeling and simulation** Fig1 portrays a conceptual version of typical hydraulic process. The formulation of numerical model of a typical block for areal mode is shown in fig 2. It consists of set of mathematical equations which describes the basic features of hydraulic fracture model and a method for solving the equations for reservoir flow, fracture flow, and fracture mechanics simultaneously. The model consider for the present study is based on the theory proposed by Settari (1980) for fracture mechanics, reservoir mass balance, where as the equation for fracture mass balance is based on Carter’s fracture propagation model (1957). Numerical model is implemented by the discretization techniques by finite difference method over space and time. The spatial
discretization of the conceptual reservoir has been done by a point center grid system. This numerical model a conventional five point conservation finite difference scheme implicit in time has been adopted for approximation of reservoir mass balance equation.

\[ P_{foc} = \sigma_{nt} - A_{pc} \left( P_{avg/2} \right) \frac{1}{1 - \left( A_{pv/2} \right)} \]

Fracture propagating pressure \[ P_f = P_{foc} + K_{icr} \frac{1}{\sqrt{\pi L_f}} \]

Fracture Initiation Pressure \[ P_{fi} = P_{foc} + K_{icr} \frac{1}{\sqrt{\pi L_{ji}}} \]

Fracture half width \[ W_f = 2(1 - v^2)L_f \left( P_f - P_{foc} \right) / E \]

Fracture Quarter Volume \[ V_f = \pi(1 - v^2)hL_f^2 \left( P_f - P_{foc} \right) / 2E \]

Fluid flow model \[ \frac{\partial}{\partial x} \left[ \frac{K_x}{\mu B} \left( \frac{\partial P}{\partial x} - \rho C_{\phi} \frac{\partial z}{\partial x} \right) \right] + \frac{\partial}{\partial y} \left[ \frac{K_y}{\mu B} \left( \frac{\partial P}{\partial y} - \rho C_{\phi} \frac{\partial z}{\partial y} \right) \right] = K_c \frac{\partial P}{\partial t} + Q \]

Fracture Mass Balance \[ \frac{d}{dt} \left( \frac{1}{B} \frac{V_f}{B} \right) = i_f - q_{loss} \]

Fluid Loss \[ q_{loss} = \int_0^{L_f} \frac{K_x h \frac{dP}{dy}}{\mu B} \bigg|_{y=0} \]

Implementation of numerical model

Reservoir Mass Balance \[ \Delta x, \Delta y \frac{\partial}{\partial x} \left[ \lambda_x \left( \frac{\partial P}{\partial x} - \gamma \frac{\partial z}{\partial x} \right) \right] \approx \Delta x, \Delta y \left( P - \gamma z \right) \]

Compact Equation \[ \left[ \Delta T \Delta (P - YZ) \right]_{ij} = \frac{V_{ij} B_{ij}}{\Delta t} \Delta_x P_{ij} + Q_{ij} \]

Two Dimensional Areal Implicit Model

\[ TX \left[ i + \frac{1}{2}, j \right] \left( P_{i + 1} - P_i \right)_{ij}^{n + 1} - TX \left[ i - \frac{1}{2}, j \right] \left( P_{i - 1} - P_i \right)_{ij}^{n + 1} \]

\[ + TY \left[ i, j + \frac{1}{2} \right] \left( P_{j + 1} - P_j \right)_{ij}^{n + 1} - TY \left[ i, j - \frac{1}{2} \right] \left( P_{j - 1} - P_j \right)_{ij}^{n + 1} \]

\[ = \frac{V_{ij} B_{ij}}{\Delta t} \left( P_{ij}^{n + 1} - P_{ij}^{n} \right) + q_{ij} V_{ij} \]

Modified Equation

\[ C_{ij} P_{ij}^{n + 1} - P_{ij}^{n - 1} + a_{ij} P_{ij}^{n + 1} + b_{ij} P_{ij}^{n + 1} + g_{ij} P_{ij}^{n + 1} + d_{ij} P_{ij}^{n + 1} + e_{ij} P_{ij}^{n + 1} + f_{ij} P_{ij}^{n + 1} = d_{ij} \]
Boundary Condition (Neumann Type)
\[
\frac{\partial p}{\partial x} = 0 \text{ at } x = 0 \text{ and } x = L \quad (0 < x < L) \quad \text{ and } \quad \frac{\partial p}{\partial y} = 0 \text{ at } y = 0 \text{ and } y = w \quad (0 < y < w)
\]

Unknown Vector
\[
\begin{bmatrix}
P^{n+1}_1 \\
\vdots \\
P^{n+1}_{12}
\end{bmatrix} =
\begin{bmatrix}
P_{11} \\ P_{21} \\ P_{31} \\ P_{41} \\ P_{51} \\ P_{61} \\ P_{71} \\ P_{81} \\ P_{91} \\ P_{101} \\ P_{111} \\ P_{121}
\end{bmatrix}
\]

Resulting Matrix Equation
\[ A P^{n+1} = d \]

Source term equation
\[ q_{\text{loss},i} = (P_f - P_{i,1}^{n+1}) W F_i \]

Discretized Equation
\[ \Delta t \left( i - q_{\text{loss}}^{n+1} \right) = \Delta t \left( M_f \right) = M_f^{n+1} - M_f^n \]

Fracture Propagating Condition
\[ L_f^{n+1} \geq L_f^n \quad \text{ or } \quad P_{f_{\text{loc}}} \leq P_f^{n+1} \leq P_{f_{p}} \]

**Solution strategy**: In devising a solution strategy with the prime intent being to create a flexible and robust tool for investigating fracture propagation by numerical model a flow chart of solution procedure for one time state is given in fig 3

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Fig 3 Flow chart
RESULTS AND DISCUSSIONS

Based on above equation a computer program has been prepared in C++ language. This has been run in PRIMOS 3450 Computer. Various graphs have been plotted by ENER Graphics, a menu driven post processor using a Pentium IV with an HP LaserJet-1000 compatible printer. It is to be noted here that the numerical values of length and width in graphs, are actually those of half-length and half-width respectively which are obtained from computer output.

Effect of Variable Injection Rate: In this case the injection rate (one-fourth of well rate) has been varied from 100 to 700 B/D (i.e. 0.39 to 2.73 cft/min.) and it is observed that number of iterations reduced from 9 to 5 as the rate increased from 0.39 to 2.73 cft/min. Fig. 4 shows the variation of length versus time at different injection rates. At all rates the behaviour or shape of the curve is same as is observed in any other model. First it increases very sharply and then gradually flattens till the fracture closure is indicated. It is observed that up to an average length of 580 ft, all the curves, corresponding to different rates, reach at the same time and then they start separating out. Furthermore, the lower injection rate takes more time to converge and in turn propagates to a larger length whereas, the higher injection rate converges quickly thereby creating a lesser length. This indicates that since the volume of the fracturing fluid remains same in all cases even though the length reduces, therefore, the leak-off must be more in the case of high rate. This argument is validated by the values of Q LOSS (85.239) in the case of lowest injection rate to (563.790) in the case of highest injection rate. The graph of fracture width versus time is shown in Fig. 5. Here also, more or less the same features as in the case of length Vs time is observed. In the initial period, the width becomes maximum and almost same (average 0.0032 ft) for all the rates but within next time step it drops to a lowest value and afterwards with a little increase, tends towards a constant value which are of course different for different injection rates. It is worth noting that in the case of higher injection rates the width becomes small and the fracture closure is quick whereas the reverse is true in the case of lower injection rates. Moreover in all the cases, whatever development takes place in the later period of pumping gets utilised in building up the length of fracture and not the width. Therefore, it is the loss factor, which becomes an important criteria. The graph of fracture pressure versus time has been shown in Fig. 6. In this case, the trend of the curve matches perfectly well with such graph of any other model. With the start of pumping, the fracture pressure reaches its highest value, the initiation pressure and then drops sharply within next time step after which it approaches a value nearing the value of fracture opening/closing pressure. The effect of injection rate in this case is that with higher injection rate the fracture pressure increases and the degree of increment is about 1.35 times for every two fold increases in injection rate. Thus even the fracture opening/closing pressure of any one rate becomes more than the fracture initiation pressure of its previous lower rate. But notably the difference between fracture propagation and fracture opening/closing pressure remains same in the case of every injection rate. Thus the selection of injection rate is very crucial from the point of view of obtaining a predetermined length with minimum loss or leak-off.

Effect of Permeability Variation: This effect has been shown in Fig. 7 to Fig. 9, which depict length Vs time, width Vs time and pressure Vs time graph respectively. The permeability values that are taken for this study vary from .001 md to .01 md. The injection rate in this case is kept constant at 0.78 cft/min. The number of iterations gets restricted to 10 or 11 for converging and one new observation in this case is that here the pressure factor becomes the selective criteria to finally converge whereas in the previous case it was the length factor which determined the final converging. In Fig. 7 it is found that during initiation, an average length of 584 ft is created and then the increases in length or the rate of propagation is quite uniform in all the cases of permeability. Only variation or change being observed is in the terminating length where fracture closure is indicated. This value is more in the case of low permeability region and little less in the case of high permeability region. One more interesting feature in this case is that the value of the "QLOSS' changes very slowly and finally towards termination becomes almost constant which is
one of the reasons for the final converged length to be more or less equal in all the cases of permeability. In Fig. 8, although there is sharp change in the trend of the graph but as such the contribution of ten-fold increase in permeability is very little on the width and the differentiation is difficult not only during initiation but also in the later part of propagation. Similarly the effect of the permeability variation on fracture pressure as shown in Fig. 9 is not at all differentiable. The whole process of fracture pressure coming down from initiation value to propagating value is same in all the five cases of permeability. Thus we observe that in the lower range of permeability (10^{-2} to 10^{-3} md) the effect of its change on lateral propagation of fracture is not so significant.

**Effect of Variation in Young's Modulus**: In this case the value of Young's modulus has been varied from 2x10^5 psi to 5x10^6 psi. The length values do not differ much from one value to another value of Young's modulus. The number of iterations remains restricted to 10 or 11. Thus its effect on length is not much significant. But the effect on width is very much pronounced from the Fig. 10 it is found that by maintaining the same trend as in other cases, the values vary significantly. With the lower values of Young's modulus, width becomes more, whereas for higher values of Young's modulus, width becomes less. Therefore, requirement of more width can be achieved by decreasing the value of Young's modulus. But since the value remains same for a particular type of formation, it is for the purpose of prediction and comparison that a clear idea can be formed about change in width for any change in the values of Young's modulus. The reason for such behaviour is the assumption of an elastic behaviour of the reservoir rock. Interestingly it is the elongation in the transverse direction (i.e. the width), which is more pronounced than the elongation in the longitudinal direction in the same plane. The graph of fracture pressure versus time is shown in Fig. 11. In this case also there is not much change in the propagating pressure with the change in Young's modulus, though the trend of the graph remains the same. Thus Young's modulus has a pronounced effect on fracture width, which is one of the major considerations for increasing fracture volume.

**Effect of Grid Size and Grid Ratio**: Here two cases have been considered - one with the value of ∆x = 100 ft and ∆y varying as 10, 25, 50 and 100 ft. The other case is that the value of ∆x = 50 ft and ∆y varying as 1, 5, 25 and 50 ft. The value of injection rate is kept fixed at 0.78 cft/min. The number of iterations is found to be 10 or 11 in the cases of coarse grids (i.e. ∆y / ∆x = 1, ½, ¼, 1/10) but it becomes restricted to 7 or 9 in the cases of refined grids (i.e. ∆y / ∆x = 1/50, 5/50). Their effects on length versus time graph is shown in Fig. 12. In this figure it is found that decreasing ∆y with fixed ∆x decreases the propagation rate; except where an abnormal behaviour is found like in the case of very refined grid (∆x = 50 ft and ∆y = 1 ft). In this grid ratio instead of decreasing propagation rate, it increases abruptly. This abnormality can be attributed to large truncation error which according to Settari (1980) remains approximately zero upto a grid ratio of about 1:10 but further refinement to this leads to error. This becomes obvious from the graph. In the above reference it is remarked that truncation errors remain small as long as the grid next to the fracture is approximately square (i.e. ∆y / ∆x = 100/100 or ∆y / ∆x = 50/50) and secondly grid ratios close to one are optimal. In this case also same thing is observed which is clear from the Fig. 12. By considering the grid ratios equal to half (i.e. ∆y / ∆x = 25/50 and 50/100), it is found that the values of fracture length are different although grid ratio is same whereas in the case of ∆y / ∆x = 25/50 and 25/100, the values of fracture length are very much closer although grid ratios are different. Thus it clearly indicates that it is not only the grid ratio but also the grid size that is equally important. Therefore for an optimum value, a relatively coarse and square grid will be the right choice. The effect of grid size and ratio on fracture width has been shown in Fig. 13. Here similarity in the shape and values of fracture width with those of previous cases (i.e. 6.1 to 6.3) are observed. The only exception found is in the case of ∆y / ∆x = 1/50, which do not follow the decreasing trend, rather in this case the width values become more than that of ∆y / ∆x = 50/50. Reason may be same as discussed above. Effects of grid ratio and size on the fracture pressure is shown in Fig. 14. Here upto a grid ratio of 1:10 a uniform decreasing trend with decrease in ∆y is found in all the three types of pressures, i.e. fracture initiation, propagation and opening/closing pressures. But unlikely in the case of grid ratio 1:50, instead of behaving opposite, it allows the same decreasing trend excepting that the rate of decrease is faster here. Hence it is observed that moving from coarser to finer grids makes a significant
change in the prediction of fracture propagations and therefore to obtain an optimal value, a very
careful selection of grid size and grid ratio is essential.

**Effect of Variation of Time Step:** Time step selection is one of the very complicated tasks in this
simulation run. With the given set of data, to obtain convergence, proper selection of time step is
crucial to the successful running of this program. The time step in this program, has been
expressed as fraction of total pumping time and it has been varied from 0.030 to 0.055 keeping
injection rate constant at 0.78 cft/min. Its effects on length is shown in Fig. 15. From the graphs it is
clear that with very fine time step the convergence is achieved with more number of iterations
whereas with increase in time step the number of iterations decrease and simultaneously the
projected length also decreases. But with careful observation it becomes clear that the difference
or change in the fracture length over time steps ($\Delta t \cdot L_f$) becomes less and less until it converges.
This change is finally small (5 ft) in the case of $t = .03$ whereas it is more (13 ft) in the case of
$t = 0.055$, although number of iterations is less in the case of $\Delta t = 0.055$. Besides, it is established
that to obtain smooth solutions, $\Delta t \cdot L_f$ must be limited to a fraction of a block size (i.e. $\Delta t \cdot L_f \leq (0.1
to 0.25) \Delta x$. Hence for all purposes the value of time step ($\Delta t$) considered is equal to 0.03. In the
case of fracture width versus time relationship, as shown in Fig.16 it is found that with increasing
time step the width decreases and at any time the difference in their values for different time
steps is uniform. So, it has same effect as it has on length. The graph of pressure versus time is
shown in Fig.17. Here instead of decreasing trend, the pressure values increases with increasing
time step. It is observed that the difference between fracture propagation pressure and fracture
opening/closing pressure ($p_{fp} - p_{foc}$) is smaller (4.7 psi) in the case of $\Delta t = 0.03$ whereas this
difference is more (6.8 psi) in the case of $\Delta t = 0.055$. Though these differences do not have any
practical significance in actual field operations, but for theoretical purposes to choose a proper
time step, no doubt, this difference (i.e. $p_{fp} - p_{foc}$) is also one of the criteria. Thus the effect of time
step has to be considered for a better simulator run.

**Effect of Viscosity Variation:** In this case the viscosity of the fluid is changed from 1 cp to 10 cp
and at every 1 cp variation the simulator run is being made. The injection rate is kept constant at
0.78 cft/min. The graph of length versus time is shown in Fig.18. With the trend of the curve
remaining same, it is found that within a viscosity range of 1 to 5 cp the propagating length is
differentiable and it increases with increases of viscosity. But beyond 5 cp viscosity, no increase
or change in noticeable. Hence, for propagation purposes less viscosity is more preferable.
Another observation in this case is that there is not much change in the terminating length, that
means, the fracture closure criteria remain unaffected by the change in viscosity. The effect of
viscosity variation on width has been shown in Fig.19. Here the variation is too narrow to be
differentiated. It is mainly the loss factor which brings about changes in length, width etc, but
since this factor ‘QLOSS’ is changing very slowly towards closure, therefore whatever change is
observed is only on length. No significant change is on width. Similar is the case with pressure
also, which is shown in Fig.20. In this case the values surprisingly become same beyond viscosity
value of 2 cp. Only in the case of 1 and 2 cp the values are changing little. Hence if only the
propagation aspect of the fracturing is to be considered, it is the low viscosity that effects better
than the higher values.
Fig 20
Conclusions: Developed numerical model is different from other conventional models like CGK or PKN models in that, here it depicts truly the rate of propagation of fracture within the reservoir. From this model it is possible to know the exact position of the tip of the fracture within the reservoir grid blocks at any time after the start of pumping. This is not possible to be obtained by other models mentioned above. Hence, it will serve as an important tool in the petroleum industry for properly planning a fracturing job specially when the volume of fluid to be handled is massive. Study of comparing the effects of various injection rates will lead to select an optimum value of injection rate. This study will be helpful in finding out the suitability of applying a fracturing job in any horizon. It is necessary to have 2-D simulator to correctly model some of the problem regularly encountered in the field during hydraulic fracturing such as the near wellbore fractures of a well. An additional advantage of the software is that it is easily adapted to other problem of fracture in geomechanics such as pressure grouting of cracks in dams cohesive crack propagation, and compression induced fracture in brittle material.

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