CSCanada
Advances in Petroleum Exploration and Development
Vol. 5, No. 2, 2013, pp. 1-7
DOI:10.3968/j.aped.1925543820130502.1032

ISSN 1925-542X [Print]
ISSN 1925-5438 [Online]
www.cscanada.net
www.cscanada.org

Enhancing Tight Gas Recovery Through Hydraulic Fracture Treatment Design Optimization

M. M. Rahman[a],*; H. K. Sarma[a]

[a]The Petroleum Institute, Abu Dhabi, UAE.
*Corresponding author.

Received 19 December 2012; accepted 5 May 2013

Abstract

Tight and deep unconventional gas reservoirs are becoming targets for development but the conventional approach to develop them is not feasible. In most cases, they cannot be produced economically without hydraulic fracturing. There have been much progress in the overall hydraulic fracturing procedures to stimulate tight formation, but there is still a lack in treatment-design optimization. Some of the currently available commercial software do not take into consideration several key parameters and associated realistic constraints.

An integrated model to optimize hydraulic fracture treatment has been developed to enhance gas production and net present value with minimum treatment cost. This model couples with the industry experience with hydraulic fracture mechanics. Unlike commercial software, important design parameters are included. The free design variables are randomly varied during optimization. The overall hydraulic fracturing design problem is viewed as a multi-objective and multivariate system design problem, which recognizes complex interactions between a hydraulically coupled fracture geometry model, a hydrocarbon production model and an investment-return cash flow model. The integrated model has been successfully applied to a hypothetical deeper tight gas formation to demonstrate its merits. The optimum treatment design indicates a 300% increment in production over 10 years at a lower cost compared to production from non-fractured tight gas sand. This optimization scheme presents a decision support system, which provides a goal-oriented optimum design in a conflicting environment.

Key words: Stimulation; Enhanced recovery; Fracture optimization; Tight gas; Treatment design

Rahman, M. M., & Sarma, H. K. (2013). Enhancing Tight Gas Recovery Through Hydraulic Fracture Treatment Design Optimization. *Advances in Petroleum Exploration and Development*, *5*(2), 1-7. Available from: URL: http://www.cscanada.net/index.php/aped/article/view/j.aped.1925543820130502.1032
DOI: http://dx.doi.org/10.3968/j.aped.1925543820130502.1032

INTRODUCTION

Although much progress has taken place in hydraulic fracturing, the industry still faces a challenge when trying to determine the optimum design parameters to be executed in the field which will provide the better economics over the life of a well. Based on experience, the authors infer that poor post-frac productivity could be attributed to improper design of treatment parameters in many instances. The design engineer must decide the optimum values of treatment parameters, such as injection rate and time, proppant type and concentration, proppant loading schedule, and fracturing fluid viscosity with power law parameters. A systematic and integrated procedure can aid the designer to perform this design task efficiently and enforce a favourable hydraulic fracture geometry that meets various design objectives. In most hydraulic fracturing design work[1,2], maximization of net present value (NPV) accomplished by parametric sensitivity analysis is used as the main measure of merit. Such a procedure does not guarantee achieving the 'best possible' treatment design. Furthermore, they overlook the possible benefits in considering combined measures of merit (maximizing production/NPV and minimizing treatment cost, C_{TR}).

Aggour[3] conducted a procedural optimization for hydraulic fractures in high permeability reservoirs with NPV as design objective using the generalized gradient method for optimization of nonlinear problem. The work, however, ignored operational factors and fracture growth control requirements. Queipo *et al*.[4] also presented an excellent method of global optimization for hydraulic fracturing treatment design considering Khristianovitch-Geerstsma-DeKlerk (KGD) fracture model. This KGD model is rarely suitable for stimulation of oil and gas reservoirs. Further works[5,6] presented a new way of hydraulic fracturing technology with systematic way of calculation of different parameters and with risk analytical model of fracturing, but without key realistic design constraints. Wang *et al*.[7] showed an expert system of hydraulic fracturing in a systematic way, which finally designs a fracturing model. This covered most aspects of treatment design except the realistic design constraints like the work of Manrique and Poe[8]. Recently, several works[9-12] have been conducted on pinpoint hydraulic fracturing, which produce positive results towards productivity. But the authors found them lacking procedural optimization which could otherwise present much higher productivity with optimum treatment parameters. It has also been noted that there is rarely any investigation to design the optimum fracturing fluid viscosity with power law parameters.

The main deficiency of the foregoing literature cited and the commercial software is the lack of proper optimization scheme which gives the solution of a complex problem coupled with in-situ reservoir properties, hydraulic fracture growth through volume balance of injected fracturing fluid, fluid flow through fractured reservoir and investment-return economics. The solution must satisfy the realistic design constraints so that the final design is executable in the field within the limitations. Though various methods/model are present in the literature to solve the complex problem, the technique of the solution adopted over time is also not unique.

Authors have developed an integrated hydraulic fracture optimization model incorporating the above deficiency and realistic design constraints. The main objective of this paper is to develop the overall design process which is formulated within the framework of the algorithm for optimum solution and to present its benefits.

1. OPTIMIZATION ALGORITHM

For problems with a high degree of non-linearity and noise including discontinuity and non-differentiability in functions, direct search methods, such as Genetic Algorithm (GA)[13] and Polytope Algorithm (PA)[14], are generally slow in convergence but are successful in finding reliable optimum solutions. Optimization algorithm is an intelligent moving object algorithm comprised of direct search method. The model equations involved with hydraulic fracturing optimization are highly non-linear and non-differentiable, and are subjected to a certain number of discontinuities. To handle such problems efficiently, this algorithm is reliable and computationally efficient. The principle of the algorithm is developed based on the combined concepts of PA, GA and Evolutionary Operation[15]. General formulations are also presented in literatures[16,17].

Readers are advised to consult references of Rahman[15] for further details of the algorithm to understand how an optimum solution is found for a constrained problem when formulated within the above framework.

2. HYDRAULIC FRACTURE DESIGN OPTIMIZATION

The model is formulated within the framework of intelligent moving objective algorithm (optimization algorithm). Figure 1 shows essential modules and their interactions among themselves and with the algorithm[18]. Reservoir properties and operational limitations are fed into the model from outside. The optimization process starts with initial values of design variables. The optimization algorithm then interacts with various modules to improve the design objective satisfying all design constraints. The program codes are written in FORTRAN 90.

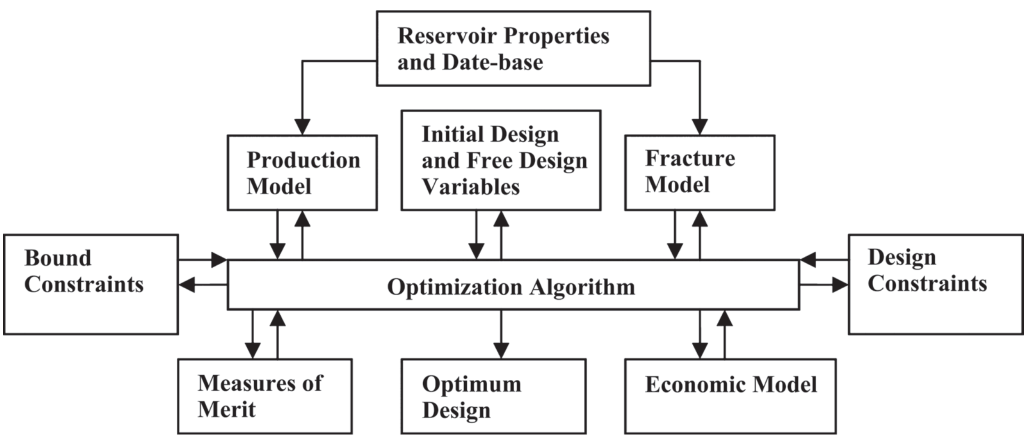

Figure 1
Hydraulic Fracture Design Optimization Model

2.1 Free Design Variables

The free design variables include injection rate, q_i (bbl/min), injection time, t_i (minute), end of the job (EOJ) proppant concentration, P_c (ppg), fracturing fluid viscosity of non-Newtonian fluid, m, (which is related to power law parameters, n and k, of fracturing fluid and average shear rate within the fracture, 1/sec). The shear rate within the fracture is allowed to vary within a range that is suitable for maintaining fracturing fluid viscosity to carry proppant. The fracture model equations are presented briefly in Appendix-A. The design variables are constrained within lower and upper bounds as per industry experience[17].

2.2 Design Constraints

Fracture growth control requirements[19] are:

- The treatment pressure, P_{treat} is kept below the formation critical pressure to prevent any uncontrolled fracture growth.
- To avoid excessive fracture height growth, the net fracture pressure, P_{net} is kept below the difference between the minimum horizontal stresses in the pay zone and the bounding layers.
- The difference between the maximum and the minimum horizontal in-situ stresses in the pay zone must exceed or be equal to ($0.7\times P_{net}$) to prevent the initiation of auxiliary (secondary) fractures.

Operational requirements[20] are:

- The horsepower required should exceed the rated horsepower of the pump to deliver the treatment pressure at the bottomhole within the capacity of the pump.
- The pressure developed inside the tubing is below the burst strength of the tube during injection with a safety factor.
- The pressure developed at the surface does not exceed the pressure capacity of the critical equipment in the injection line.

Geometric and other constraints are:

- The average dynamic fracture width is at least four times the proppant diameter for effective proppant transport.
- The fracturing fluid efficiency is considered greater than 0.5.
- The fracture half-length is always greater than the fracture height.
- The optimum value of dimensionless fracture conductivity is always maintained between 1 and 3 for effective fracture treatment design.
- The proppant fall rate should not exceed 10 ft/hour and is calculated by Stoke's law[5].

2.3 Measures of Merit

Using a formulation technique for multiobjective design optimization[15], the following three objective functions with different measures of merit are formulated in this study:

- Maximize total gas production G_p over 10 years
- Maximize net present value, NPV, over 10 year
- Maximize NPV and minimize treatment cost, C_{TR}

The cumulative production from the hydraulically fractured well is estimated by rate-time integration using analytical methods for transient and the pseudo-steady state flow regimes, presented in Appendix B.

3. APPLICATION TO A TIGHT GAS RESERVOIR

A hypothetical tight gas reservoir (0.1 mD) is used to illustrate the application of the proposed model. The pay zone is bounded above and below by shale formations which are subjected to high stresses. Reservoir, wellbore, proppant and economics data are presented here (due to space limitation), but results are in Table 1. NPV and cumulative production (G_p) have been calculated for ten years. The model was run with three arbitrary designs separately (not presented here) and the optimum design was noted. This is just to check whether the global optimization is really working. It is found that any arbitrary design is improved by up to 50% (not presented here). Some important results are presented in below[18].

Table 1
Optimum Designs for Different Measures of Merit

Parameters symbol	Max-NPV design	Max-Gp design	Max-NPV & Min-C_{TR} design
q_i (bbl/min)	26.60	27.58	14.21
t_i (minute)	118.53	113.60	75.50
P_c (ppg)	15.00	15.00	13.96
m (cp)	213.96	212.40	180.08
x_f (ft)	2500.0	2499.9	1455.0
h_f (ft)	125.0	125.0	100.4
NPV (m$)	15.65653	15.66389	13.75216
Gp (bscf)	25.5110	25.51099	21.89491
C_{TR} (m$)	1.013205	1.013669	0.514185

3.1 Benefit of Combined Measures of Merit

It has been observed that Designs with Measures of Merit (Max-NPV or Max-G_p) are almost the same, whereas with combined Measures of Merit (Max-NPV and Min-C_{TR}) the design is significantly different (Table 1). A significant percentage (49%) of treatment cost saving has been achieved over single measure of merit (Max-NPV). This saving has resulted in 10% NPV reduction over 10 years. This shows the conflict between the measures of merit (NPV and C_{TR}). It is possible to achieve a compromised design by adjusting priority factors in this model.

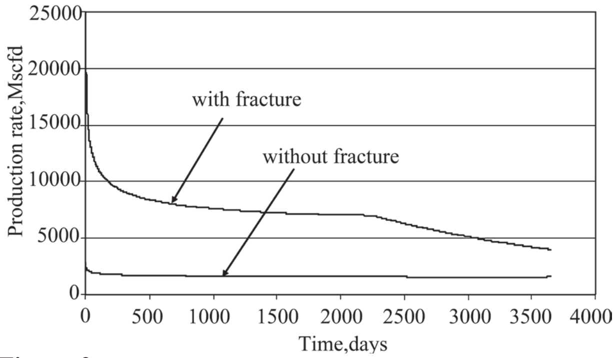

Figure 2
Comparison of Production Profiles: Fractured and Non-Fractured Reservoirs

3.1.1 Effect of Fracture on Production Profiles

Figure 2 shows the comparison of production profiles of fractured and non-fractured gas well.There is a marked difference in production rates after fracturing. The cumulative production after 10 years is 25.5 bscf from fractured well and is 5.9 bscf from non-fractured well. There is 300% increment after fracturing. The slight kinks in the production rate curves show the transition between the transient rate and the pseudo-steady state in production estimation.

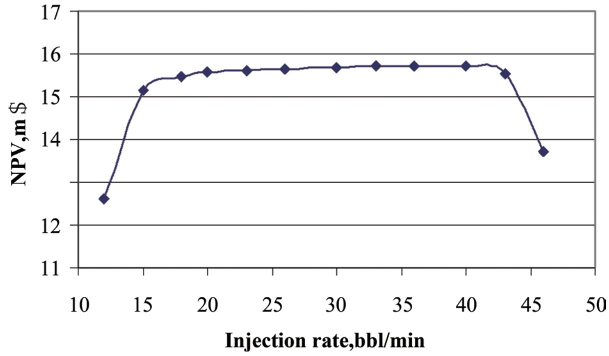

Figure 3
Effect of Injection Rate on NPV

3.1.2 Effect of Injection Rate and Time on NPV

It is interesting to note from Figure 3 that NPV rapidly increases up to 20 bbl/min injection rate beyond which NPV remains almost flat with slight increase up to 40 bbl/min from where it decreases sharply. This justifies the free optimum injection rate of 27.6 bbl/min for maximum NPV design (Table 1) falls on this plateau. The maximum NPV versus injection time exhibited very similar nature to that of NPV versus injection rate (not presented here).

3.1.3 Effect of Fracture Fluid Viscosity on NPV

Figure 4 shows that the maximum NPV increases with increasing viscosity up to its free optimum value, 212 cp, beyond which the NPV decreases. Initially, the increase in viscosity increases fracture width and height, which increases the fracture conductivity. It has been observed that with the increase in viscosity, optimum injection rate decreases slowly, but beyond 212 cp, the optimum injection rate drops significantly. To satisfy the material balance relationships, a shorter fracture half-length is required for viscosity higher than 212 cp. With shorter fracture half-lengths, the fracturing efficiency decreases. This decreases the fracture conductivity and ultimately the production (see the production curve in Figure 5) and NPV.

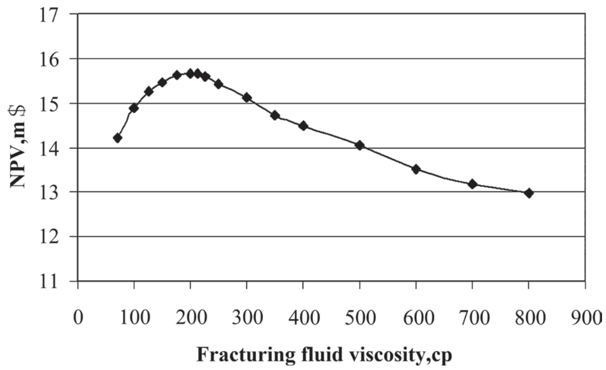

Figure 4
Effect of Fracturing Fluid Viscosity on NPV

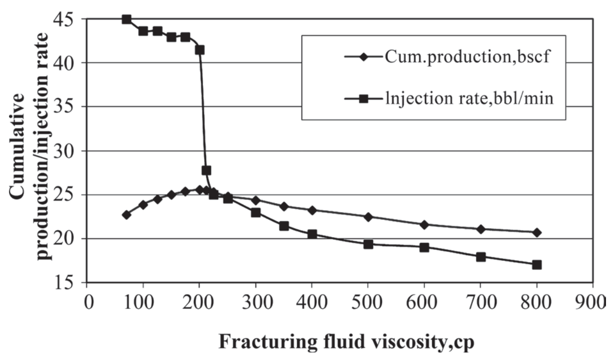

Figure 5
Variation of Cumulative Production and Injection Rate with Change of Fluid Viscosity

3.1.4 Effect of Fracture Half-Length on NPV

Figure 6 shows the variation in the maximum NPV with fracture half-length. For each value of fracture length, the variables are optimized. The free optimum value is 2500 ft (Table 4). The maximum NPV increases as the fracture half-length increases up to this value beyond which the improvement in NPV diminishes. This is because that the non-dimensional fracture conductivity decreases and the treatment cost exceeds the return with increasing fracture length beyond 2500 ft. However, even this 2500 ft half-length represents a massive fracture. The optimum fracture length shortened significantly for high permeability reservoirs. This indicates that a deeply penetrating massive fracture is usually required for very low-permeability reservoirs such as the one studied.

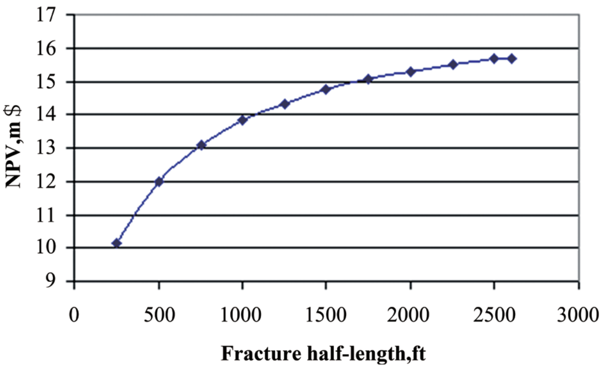

Figure 6
Effect of Fracture Half-Length on NPV

CONCLUSIONS

The following conclusions are drawn with regard to the application of our hydraulic fracture optimization model when applied to tight gas reservoirs:

The proposed model can design the optimum treatment parameters in gas wells, satisfying all realistic design constraints.

The combined measures of merit shows great benefit to those operators who may have financial constraint. It is evident that up to 49% treatment cost can be saved, compromising 10% NPV over 10 years, which is an uncertain period.

Production from a well fractured by maximum-NPV/Gp design causes production at higher rate. It is evident that 300% increment in production over 10 years from a fractured well over a non-fractured well is possible.

Sensitivity analyses show that various treatment parameters have direct effect on productivity/NPV. The design of optimum fracturing fluid viscosity with power law parameters is a critical issue operators are facing, which can be resolved by this model.

REFERENCES

[1] Aggour, T. M., & Economides, M. J. (1998, February). Optimization of the Performance of High-Permeability Fractured Wells. SPE 39474 International Symposium on Formation Damage Control, Lafayette, Louisiana.

[2] Langedijk, R. A., Al-Naabi, S., Al-Lawati, H., Pongratz, R., Elia, M. P., & Abdulrab, T. (2000, October). Optimization of Hydraulic Fracturing in a Deep, Multilayered, Gas-Condensate Reservoir. SPE 63109 Annual Technical Conf. and Exh., Dallas, TX.

[3] Aggour, T. (2001, March). Optimization Strategies for Hydraulic Fractures in High Permeability Reservoirs. SPE 68131 Middle East Oil Show, Bahrain.

[4] Queipo, N. V., Verde, A. J., Canelon, J., & Pintos, S. (2002). Efficient Global Optimization for Hydraulic Fracturing Treatment Design. *J. of Petroleum. Science and Engineering*, *35*, 151-166.

[5] Jiang, T., Wang, X., & Shan, W. (2003, May). A New Comprehensive Hydraulic Fracturing Technology to Minimize Formation Damage in Low Permeability Reservoirs. SPE 82222 European Formation Damage Conf. and Exh., Hague, The Netherlands.

[6] Jiang, T., Wang, Y., Ding, Y., Shan, W., Wang, X., Zhou, X., & Liu, J. (2003, September). The Study of a New Overall Hydraulic Fracturing Mode in Low Permeable and Unconventional Reservoirs. SPE 84820 Eastern Regional/AAPG Eastern Section Joint Meeting, Pittsburg, Pennsylvania.

[7] Wang, Y., Jiang, T., Ding, Y., Luo, N., Feng, X., Wang, X., & Zeng, B. (2004, November). The Study of Hydraulic Fracturing Expert System in Low Permeable and Complex Reservoirs. SPE 89856 *International Petroleum Conference*, Puebla, Mexico.

[8] Manrique, J. F., & Poe, B. D. (2005, October). Comprehensive Performance Design Criteria for Hydraulic Fracturing. SPE 96929 Annual Technical Conf. and Exh., Dallas, TX.

[9] Rodgerson, J. L., Lopez, H., & Snider, P. (2006). Unique Multistage Process Allows Pinpoint Treatment of Hard-to-Reach Pay. *SPE Production and Operations*, *11*, 441-447.

[10] Beatty, K. J., McGowen, J. M., & Gilbert, J. V. (2007, January). Pin-Point Fracturing (PPF) in Challenging Formations. SPE 106052 Hydraulic Fracturing Technology Conf., College Station.

[11] Houser, J., & Hernandez, R. (2009, April). Pinpoint Fracturing Using a Multiple-Cutting Process. SPE 122949 Rocky Mountain Petroleum Technology Conference, Denver, Colorado.

[12] Mohsen, A., Ali, M. A., Samiee, R. A., Ibrahim, E., Taha, I. M., & Hamdy, M. (2010, June). Implementation of Pinpoint Fracturing Technique in the Western Egypt Desert. SPE 133864 Production and Operations Conf. and Exh., Tunis.

[13] Goldberg, D. E. (1989). *Genetic Algorithms in Search, Optimization, and Machine Learning* (pp. 412). New York: Addison-Wesley Publishing Corporation.

[14] Nelder, J. A., & Mead, R. (1965). A Simplex Method for Function Minimization. *Computer Journal*, *7*, 308-313.

[15] Rahman, M. K. (2006). An Intelligent Moving Object Optimization Algorithm for Design Problems with Mixed Variables, Mixed Constraints and Multiple Objectives. *Structural and Multidisciplinary Optimization*, *32*(1), 40-58.

[16] Rahman, M. M., Rahman, M. K., & Rahman, S. S. (2003). Multicriteria Hydraulic Fracture Optimization for Reservoir Stimulation. *Petroleum Science and Technology*, *21*, 1-37.

[17] Rahman, M. M. (2008). Constrained Hydraulic Fracture Optimization Improves Recovery from Low Permeable Oil Reservoirs. *Energy Sources*, *Part A*, *30*, 536-551.

[18] Rahman, M. M., & Sarma, H. K. (2011, October). Maximizing Tight Gas Recovery Through a New Hydraulic Fracture Optimization Model. SPE 148205 Reservoir Characterisation and Simulation Conf. and Exhib., Abu Dhabi.

[19] Smith, M. B. (1997). *Hydraulic Fracturing* (2nd ed.). Tulsa, OK: NSI Technologies.

[20] Nolte, K. G., & Smith, M. B. (1981). Interpretation of Fracturing Pressures. *J. of Petroleum Technology*, *9*, 1767-1775.

[21] Valko, P., & Economides, M. J. (1995). *Hydraulic Fracture Mechanics*. Chichester, England: John Wiley and Sons.

[22] Economides, M. J., Valko, P. P., & Wang, X. (2001). Recent Advances in Production Engineering. *J. of Canadian Petroleum Technology*, *40*, 35-44.

[23] Rahim, Z., & Holditch, S. A. (2003). Effects of Fracture Fluid Degradation on Underground Fracture Dimensions and Production Increase. *J. of Petroleum Science and Engineering*, *37*, 85-99.

[24] Howard, G. C., & Fast, C. R. (1957). Optimum Fluid Characteristics for Fracture Extension. *Drilling and Production Practices*, 261-270.

[25] Economides, M. J., Hill, A. D., & Ehlig-Economides, C. (1994). *Petroleum Production Systems*. Upper Saddle River, NJ: Prentice Hall PTR.

[26] Valko, P., Oligney, R. E., & Economides, M. J. (1997). High Permeability Fracturing of Gas Wells. *Gas TIPS (Fall)*, *3*(3), 31-40.

[27] Cinco-Ley, H., & Samaniego, F. (1981). Transient Pressure Analysis for Fractured Wells. *J. of Petroleum Technology*, *9*, 1749-1766.

APPENDIX A–THE PKN-C FRACTURE MODEL

The well-established fracture model '2D PKN-C', detailed in reference of Valko and Economides[21], is efficient for computation in optimization work. The relationship between fracture width at the wellbore (w_f), fracture half-length (x_f), fracture height (h_f), treatment parameters and rock properties, when a non-Newtonian fracturing fluid is used, is expressed as:

$$w_f = 9.15^{\left(\frac{1}{2n+2}\right)} 3.98^{\left(\frac{n}{2n+2}\right)} \left[\frac{1+2.14n}{n}\right]^{\left(\frac{n}{2n+2}\right)} K^{\left(\frac{1}{2n+2}\right)} \left(\frac{q_i^n h_f^{1-n} x_f}{E'}\right)^{\left(\frac{1}{2n+2}\right)} \quad \text{(A-1)}$$

where $E' = E/\left(1-\nu^2\right)$. K is the consistency index, E is Young's modulus and n is Poisson's ratio.

Based on data provided by the industry[17], the apparent viscosity (μ_a) of fracturing fluid and the average shear rate (SR) inside the fracture are correlated as:

$$\mu_a = (SR)^{-0.5058} \quad \text{(A-2)}$$

The relationship between power law parameters (n and K) and apparent viscosity is given[17,22] as:

$$K = \frac{\mu_a \times (SR)^{1-n}}{47,880} \quad \text{(A-3)}$$

Based on optimum injection rate, the shear rate within the fracture near the wellbore can be calculated[23] by Equation A-4. The shear rate at the fracture tip is considered zero and shear rate within the fracture is then calculated as the average of this calculated shear rate and zero. This average shear rate is satisfied by the optimum shear rate obtained from the optimization tool.

$$SR_w = 40.46 \times \frac{q_i}{2} \frac{1}{w_f^2 h_f} \quad \text{(A-4)}$$

During fracture growth, the general material balance relationship is $V_i = V_f + V_l$. V_i is the total fluid volume injected, $q_i t_i$, V_f is the fracture volume and V_l is the fluid loss volume. Using the Carter II solution[24] for constant injection rate and considering fluid leak-off and spurt loss, the following relationship (Equation A-5) between fracture geometry and fluid injection can be derived:

$$x_f = \frac{\left(w_a + 2S_p\right)q_i}{4C_l^2 \pi h_f}\left[\exp\left(\beta^2\right) erfc\left(\beta\right) + \frac{2\beta}{\sqrt{\pi}} - 1\right] \quad \text{(A-5)}$$

where,

$$\beta = \frac{2C_l\sqrt{\pi t_i}}{w_a + 2S_p} \quad \text{(A-6)}$$

and S_p is spurt loss coefficient and C_l is leak-off coefficient. The fracture half-length, x_f is calculated by solving Equations (A-1 to A-6) using an iterative procedure.

APPENDIX B - PRODUCTION MODEL

The following equation is used to estimate the gas production rate from the hydraulically fractured well in the transient flow regime[25]:

$$q_g = \frac{\left(P_{in}^2 - P_{wf}^2\right)kh}{1637T\bar{Z}_g\bar{\mu}_g}\left(\log t + \log\frac{k}{\phi\bar{\mu}_g\bar{c}_t r_w'^2} - 3.23 + 0.869s'\right)^{-1} \quad \text{(B-1)}$$

where $s' = s + Dq_g$ in which s' is effective/total skin factor, s is near wellbore skin from formation damage/stimulation (dimensionless) and D is non-Darcy flow co-efficient (D/Mscf).

The following equation is used to estimate the gas production rate from a hydraulically fractured well during the pseudo-steady state flow period[26]:

$$q_g = \frac{kh\left(\bar{p}^2 - p_{wf}^2\right)}{1424\,\bar{\mu}_g \bar{Z}_g T} \times \frac{1}{\ln\left(\frac{0.472 r_e}{x_f}\right) + \left(s_f + \ln\frac{x_f}{r_w}\right)} \quad \text{(B-2)}$$

where, r_e is the drainage radius of the reservoir and $\bar{p}$ (psi) is the average reservoir pressure. r_w' is the effective wellbore radius and s_f is equivalent skin. Equivalent-skin is presented by Cinco-Ley and Samaniego[27].