NOVEL EVALUATION METHODS OF UNCONVENTIONAL GAS PRODUCTION FOR OGIP, AND PROXY FORECAST MODELS

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ABSTRACT

Currently, there is an industry assortment of production analysis methods ranging from traditional decline and typecurve matching to rate-pressure normalization techniques and detailed production history matching. Yet conventional decline analysis (despite it's many limitations) is still commonly used in gas (and oil) production analysis due to its minimal data requirements and ease of application - regardless of the development of more sophisticated methods such as those loosely defined by the term advanced decline analysis. As a result, this paper presents an automated computer method for estimating original gas-in-place and other reservoir flow parameter for unconventional (and conventional) gas reservoirs.

Offshore / onshore case studies and experience presented in this paper will demonstrate that a decline and production analysis method will allow for proper identification of flow regimes, reliable evaluation of drainage area and OGIP, and the prediction of future deliverability and depletion. Case studies will also show that up-scaled and aggregate reservoir properties can provide a real measure of gas well deliverability (and therefore a simpler, time-efficient model analysis can be used). Data uncertainty, PVT error, stimulation appraisal, gas storage system (free or absorbed gas) and other factors will be discussed in the context of the case studies, and general reservoir management.

Results will also show that the approach is generally accurate and robust (when used appropriately) and can provide valuable information in circumstances of poor data quality. Finally, the procedure is extremely simple and can be implemented in desktop applications or spreadsheets with minimal computational effort.

INTRODUCTION

Decline curve analysis has been a widely used method (particularly for single phase fluid flow) for forecasting future production from oil and gas fields since Arps[1] formularized the technique during the 1940's. In fact, the procedure can allegedly be applied to production data for any reservoir drive or mechanism: Fetkovich[2] actually established guidelines about how decline curvature can indicate different reservoir systems. However, despite its simplicity (and limitations of constant flowing pressure and stable fluid properties), analysts typically want more information without having to incur more time consuming processes; for example, they are interested in reservoir permeability, formation damage (wellbore skin), and original fluid-in-place (OFIP) in addition to expected ultimate recovery (EUR). Furthermore, there is a desire to use the aforementioned information to generate production forecasts, and evaluate varying operating conditions such as compression.

As result, Fetkovich[2] later proposed a substantial improvement in decline curve analysis by matching production data onto specialized type-curves for reservoir characterization: the procedure (which is a powerful diagnostic tool), used the Arps depletion stems to analyze boundary dominated flow, and the van Everdingen and Hurst[3] constant pressure typecurves for transient production. Al-Hussiany[4] later improved type curve analysis by the introduction of mechanisms for addressing the effects of pressure dependant gas properties viscosity and supercompressibility through the use of pseudo-pressure, while Agarwal[5] presented a pseudo-time function for incorporating pressure dependant properties gas viscosity and compressibility.

Modern methods such as those of Blasingame *et al*[6] and Argawal-Gardner[6] are similar to Fetkovich in that they use type curves for production data analysis (PDA). However, they are independent of production constraints and use flowing pressure data, combined with analytical solutions, to evaluate hydrocarbons-in-place. Another highly popular method is the flowing material balance (FMB): a procedure in which variable rate-pressure data can be normalized for a linear extrapolation to fluids-in-place. Other procedures use tangent methods for evaluating tangents for original gas-in-place (OGIP) based on superposition pseudo-steady-state (PSS) time functions. In general, the modern methods (as indicated by Matter and Anderson[8]) improve upon traditional techniques by normalizing variable rate-pressure data, and handling non-linear fluid properties. These methods have become popular and even compete with traditional well tests which provide many of the reservoir flow parameters including initial pressure[9].

However, despite the power of modern production data analysis methods, they generally deviate from the general work flow process and lose the simplicity that keeps Arps decline popular: economic constraints and timing of projects prevent analysts from performing more advanced analysis. And several factors, including time to reach pseudo-radial flow and the desire to maximize daily production, have made operators tend to decrease the number of well tests performed[9]. Therefore, after acknowledging that the analyst should always use all of the data at their disposal to develop an understanding of the production scenario[10], there is a need for functionality comparable to the aforementioned advanced decline methods, but in a process similar to Arps decline.

Furthermore, given the problems generally associated with production data including poor resolution of rate measurements, or even lack of backpressure measurements, there is not always a need for a more detailed (or more rigorous) analysis method. And as noted by Anderson *et al*[11], production data often does not contain the quality nor the frequency sufficient to produce estimates of reservoir flow parameters such as unique combinations of permeability and skin. For reservoirs with a moderate to high permeability, Anderson *et al*[11] stated that one should not expect to be able to estimate permeability etc. with confidence based on monthly production rates and pressures (although monthly production data may be sufficient for wells in low permeability reservoirs where transient flow exists for months).

Recently, Muhammad Buba[12] (following the work by Knowles[13]) presented a summary of semi-analytic identities and plotting functions which can be used to extrapolate or estimate OGIP using only production data (q_g and G_p) without a prior knowledge of formation and/or fluid compressibility, or even average reservoir pressure. However, the work presented by Muhammad Buba[12] and Knowles[13] required non-standard plotting functions and plots, and fell into the category of advanced production analysis. Yet, an evaluation of the relationship (referred to as the BK model for simplicity) shows that it can be re-arranged for a rapid evaluation of OGIP without deviating significantly from Arps decline method. Specifically, the analyst solely adjusts the initial decline rate (q_{gi}) of the Arps decline, which is used by the BK model to provide OGIP as a function of time.

Moreover, the procedure can be modified to produce either actual (or effective) reservoir parameters for rapid rate forecasting. Furthermore, the procedure can be automated from the results of the Arp's decline with applications to both conventional and unconventional gas.

The integration of an automated reservoir model into the decline process would ideally help remove some of the uncertainty associated with other modern PDA methods, as it is generally accepted that if a good history match is achieved, it can be used as a proxy (or analog) for estimating future performance. In this work, a "tank" model[A] has been coupled to the BK model for history matching as it does not require any complex coding of functions such as pseudo-time[14] etc. (the objective is to balance the *quickness* of the analysis procedure with accuracy).

In short, the procedure will result in an effective permeability for many cases as the rate model assumes a vertical well fully penetrating a producing zone within a circular bounded reservoir. Given the averaging effect of production data analysis, non-unique matches, erratic data sets and data smoothing, it is anticipated that the less rigorous approach used in this paper will be justified. This procedure can be compared to the well recognized and established methods which generate productivity indices as a measure flowing capacity based on production and rate data analysis[15].

PROPOSED METHOD

The BK model (outlined in Appendix A) is simply a quadratic equation relating OGIP to production rate and pressure. This implies that the OGIP can be determined directly from standard flowing data recognizing that 1) cumulative production, flowing pressure, production rate, and finally material balance is not simply a quadratic relationship, and 2) one should not attempt to rely solely on the identity for calculation OGIP one individual data point [12,13]. As a result, to improve the successful use of the model, it is recommended that the analyst evaluates the OGIP trend established from a series of data measurements and that the results be used in conjunction with a simultaneous Arps decline and production model. Basically, as the Arps decline is performed, an OGIP curve is automatically calculated (and drainage radius, and other relevant parameters such as permeability are automatically extracted), while an automated tank model match[B] is performed. In short, the analyst solely adjusts the initial decline rate (q_{gi}) until a linear zero slope of both OGIP and permeability trend is achieved alongside a reasonable production match.

As implied above, the modelling process in this work is capturing an analog reservoir which can be used for forecasting. As a result, deviations in actual versus effective permeability will manifest themselves in errors in transient forecasting, but long-term production forecasting will be reliable. However, it has been shown that a simpler model reservoir model (a single well completed in the centre of a circular reservoir) can be used to represent a far more complex reservoir system and still provide representative reservoir characterization and accurate production forecasting. Jordan, *et al*[16] empirically showed (using synthetically generated data) that radially composite reservoirs, dual porosity reservoirs, and other complex scenarios could be effectively reduced to an equivalent radial homogeneous (ERH) model with accurate reserves, and a gross effective permeability.

Most of the work by Jordan *et al*[16] was based on introducing permeability calculations into the popular a) "rate-cumulative production typecurves" introduced by Argawal and Gardner[7], as well as b) "normalized rate-time plots" introduced by Ibrahim and Wattenbarger *et al* [17,18,19] whose objective was to linearize variable rate-pressure data to the equivalent single rate or constant pressures cases and then evaluate OGIP. With a slight modification to these processes, equivalent permeability can also be extracted as suggested by Toh[20] (who using

[A] An analytical model incorporating early-time transient, transitional, and PSS flow could be implemented, but the authors of this work chose a tank model due to the simplicity in programming.
[B] It is important to note that the automated tank model is based on average OGIP and permeability results as the BK model provides an estimate of reservoir parameters for each measured data point.

numerical simulation showed that random permeability fields and could be represented by an average effective permeability during pseudo-steady state). Ultimately, the examples in this work illustrates the ability to extract an effective productivity index (or permeability, drainage area etc.), as well as OGIP without having to deviate significantly away from traditional Arp's decline.

SIMULATED EXAMPLES

Internal Boundary: Based on the work of Horne and Sageev[21,22], an "internal boundary" model was used to generate a production forecast assuming a constant sandface pressure (100 psia) using pseudo-pressure and pseudo-time[4]. The internal boundary model assumes a 640 Acre reservoir with a 72 Acre hole (i.e. zero permeability and porosity in the hole). Volumetrically, the reservoir has an OGIP of 5.4 Bcf with a reservoir permeability of 20 md. Figure 1 shows a reservoir schematic of the internal boundary system. For analysis, the BK model is tied to both Arps decline, as well as the tank model for gas production modelling.

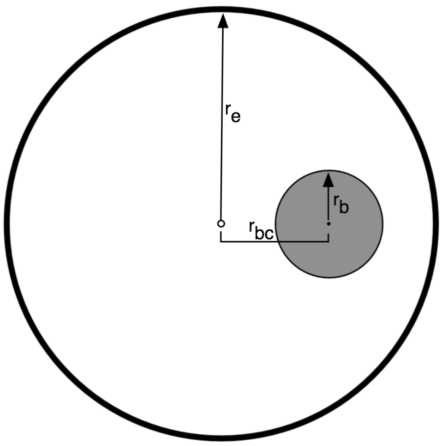

Figure 1: Internal Boundary (NTS)

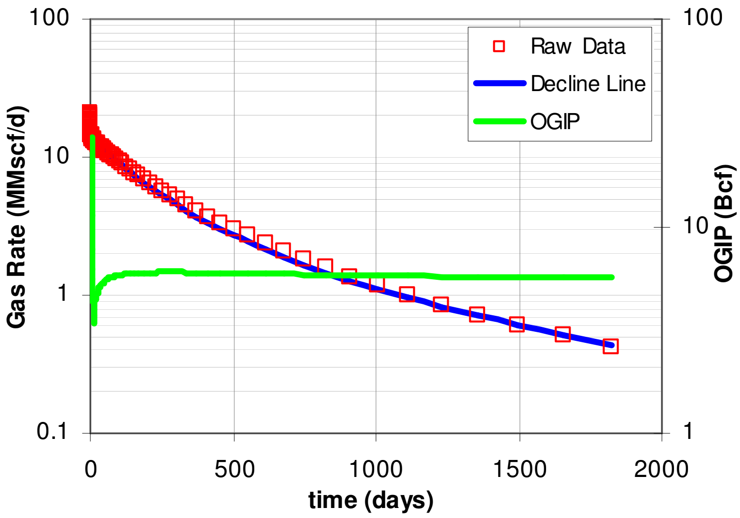

Figure 2: OGIP for Internal Boundary Model

Figures 2, 3, and 4 provide the OGIP, permeability, and the history matching results, respectively. The BK model provided an OGIP of 5.4 Bcf, and an effective permeability estimate of 12 md - which provided a suitable history match despite although the calculated permeability is lower than the true reservoir permeability of 20 md. An initial rate (q_{gi}) of 14.5 MMscf/d was used to achieve the matches.

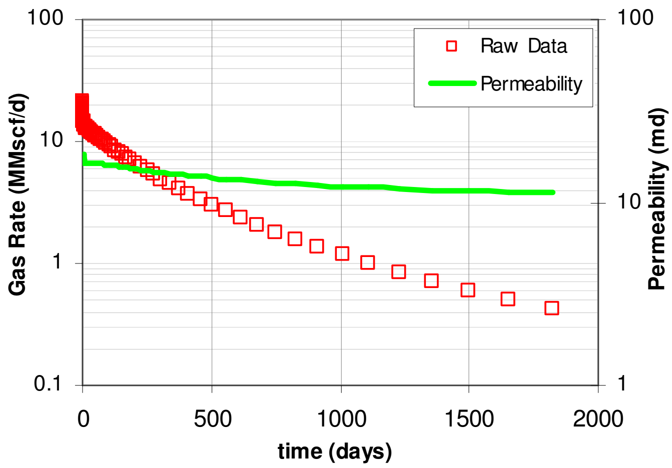

Figure 3: Permeability Results

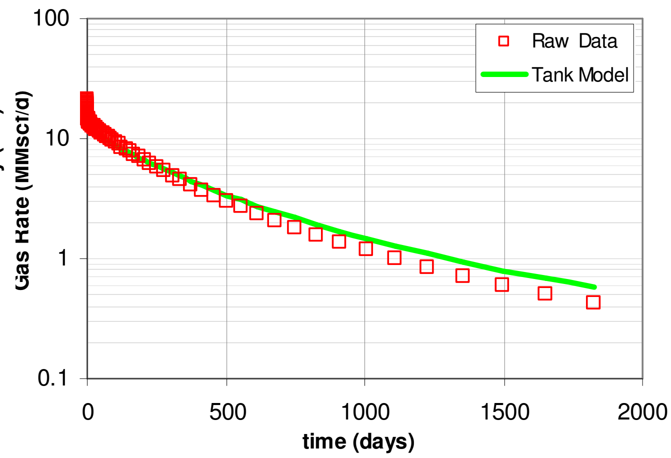

Figure 4: Production History Match

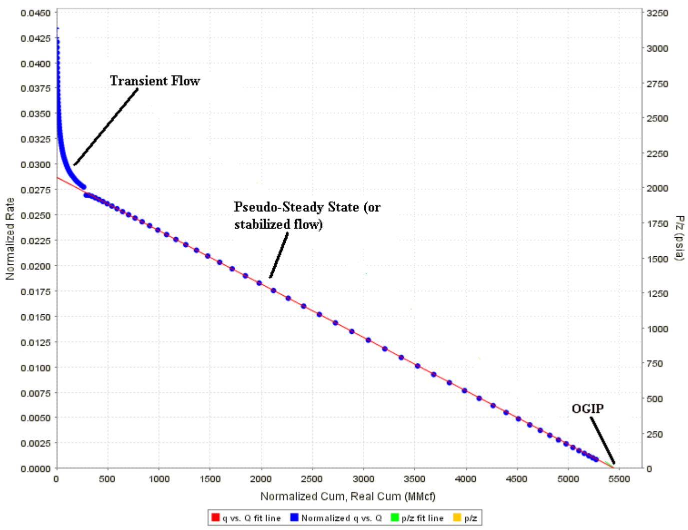

Figure 5: Flowing Material Balance Analysis for Internal Boundary

For comparison, the popular FMB provided a permeability estimate of 16.5 md and an OGIP of 5.4 Bcf as provided in Figure 5. In the next example, the procedure is applied to random rock properties (i.e. permeability and net pay) in a manner similar to that suggested by Toh[20].

Random Heterogeneity: Using an evenly distributed random number generator, values for permeability and net pay were varied from 0.05 to 21 md, and 0.3 and 59 ft (0.1 to 18 m) respectively with average values of about 5.3 md and 10.2 m (refer to Figure 6). The reservoir was set to a square with sides of about 10,000 x 10,000 ft. Initial pressure was set to 5,000 psia, reservoir temp. at 212 °F, and gas gravity at 0.7. Using FMB, the OGIP was estimated to be approximately 85 to 86 Bcf as shown in Figure 7.

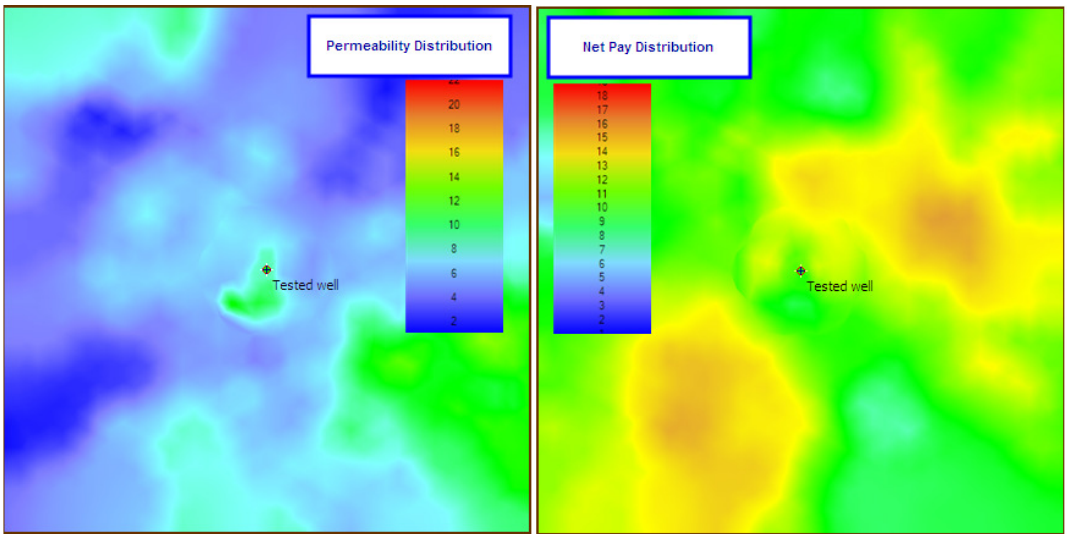

Figure 6: Permeability (md) and Net Pay (m) Distributions

Using the BK model, the OGIP and effective permeability was evaluated as shown in Figures 8 and 9, with the calculated average (effective) values to be 85 Bcf and 8.3 md. Using the effective values, a suitable production history match was achieved as shown in Figure 10. An initial rate (q_{gi}) of 30.1 MMscf/d was used to achieve the matches. The assumed net pay was 9.1 m.

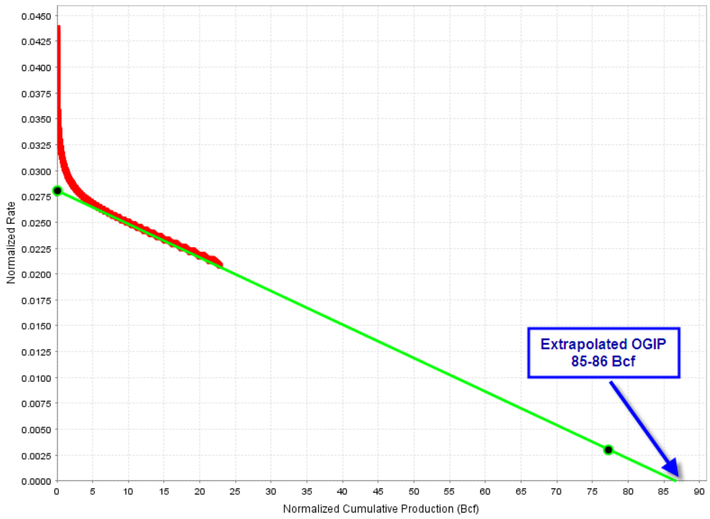

Figure 7: Flowing Material Balance Verification of OGIP

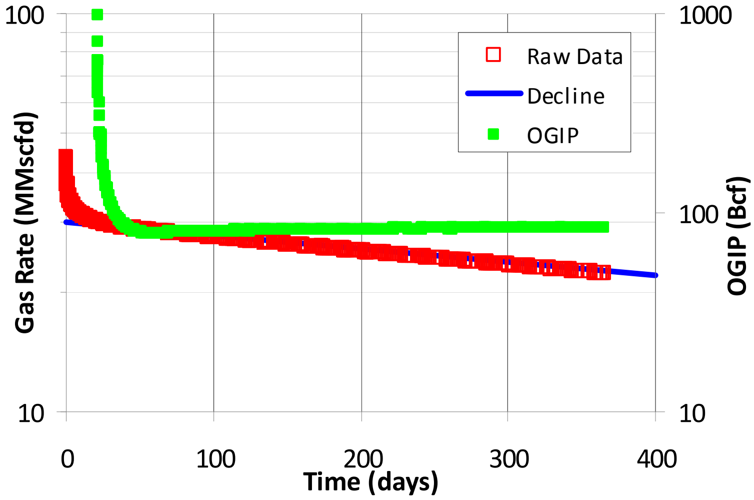

Figure 8: Flowing Material Balance Verification of OGIP

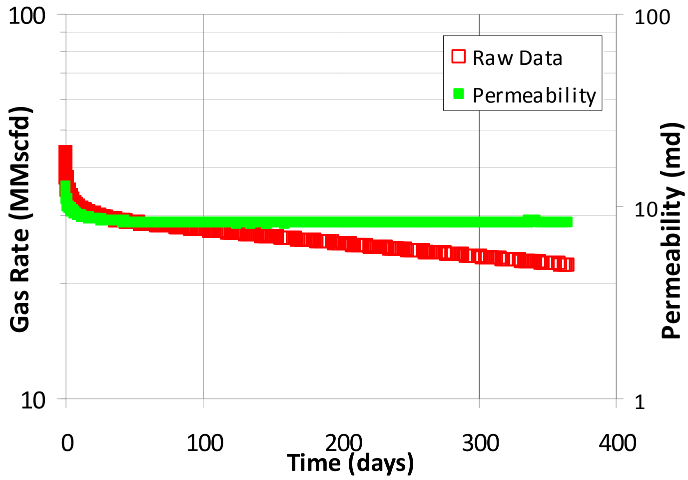

Figure 9: Permeability Results

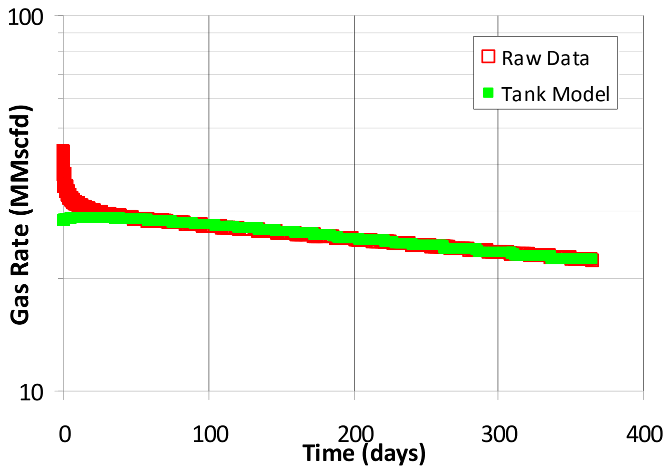

Figure 10: History Match

Incidentally, similar work by Toh[20] who evaluated the depletion performance of heterogeneous reservoirs (based on production analysis of geostatistical models) indicated that an equivalent effective permeability (EEP) could generally be observed, and that it remained generally constant throughout time, and that it was generally equal to the geometric mean permeability. Toh[20] made a general statement that the depletion performance of all reservoirs with randomly distributed heterogeneity (and 88% of reservoirs) with sectional permeability fields can be predicted with an equivalent homogeneous reservoir. And since most production and pressure transient methods "see" the reservoir as a volume average set of properties[10], there is not necessarily a need for more detailed modeling and that a bounded radial homogeneous model may be suitable even if heterogeneity exists in a number of forms. Toh's[20] results also suggested that the EEP does may not always perform appropriately for highly heterogeneous reservoirs with the well completed in a high permeability zone, the work presented by Jordan[16] does suggest the method is suitable to sectionally homogenous reservoirs (i.e. triple zone composite reservoirs). Similarly, work by Yang *et al*[15] that states equivalent or effective values determined from productivity equations in heterogeneous systems can act as a soft input for numerical simulation. Field examples are shown next.

FIELD EXAMPLES

Ballycotton Well: Gas production data was taken from the Ballycotton Field, a major gas accumulation in the Celtic Sea, Ireland[23]. Figure 11 shows a plot of the measured gas and flowing bottom hole pressures. Initial reservoir pressure was set at 1,200 psia, net pay at 76 ft, porosity at 22.3%, form. temp at 120 °F, and gas gravity at 0.554.

Using the BK model and an initial rate (q_{gi}) of 53.2 MMscf/d, average OGIP was determined to be 38 Bcf (Figure 13), and permeability was estimated to be about 109 - 100 md, respectively (not shown). The corresponding history match is shown in Figure 12.

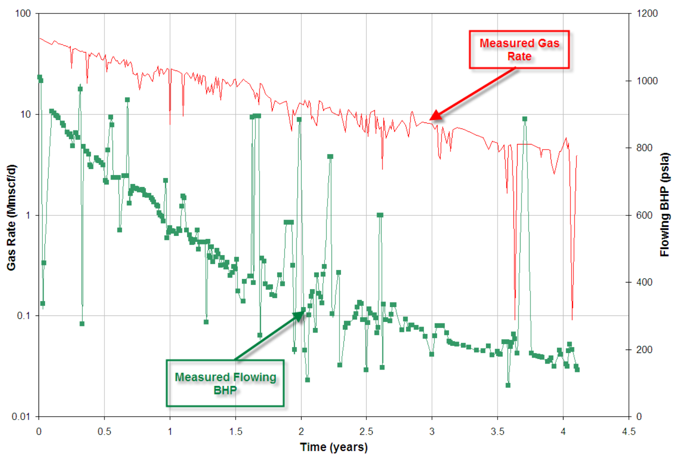

Figure 11: Raw Data

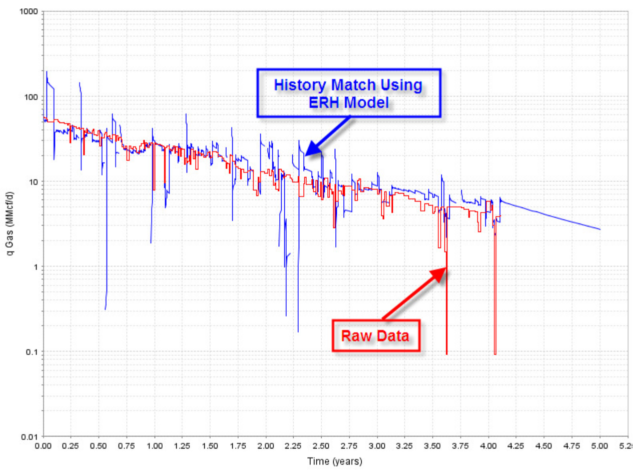

Figure 12: History Match

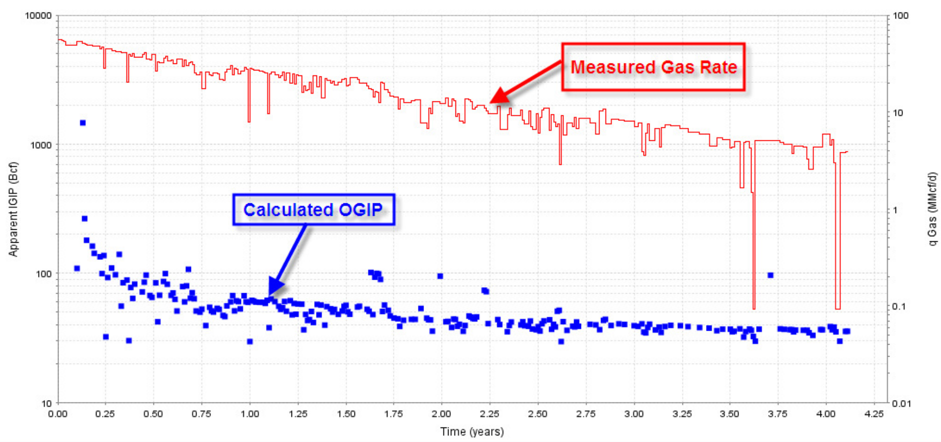

Figure 13: OGIP Analysis

It is interesting to note that despite the fact measured data is not entirely representative of a constant pressure condition the BK model is robust enough to provide reasonable estimates of OGIP and proxy forecasting parameters. In the following examples, unconventional gas examples are addressed.

Tight Gas Well J7: Wattenbarger, El-Banbi, and others presented an analysis of tight gas wells from a field in South Texas, one of which was J7[24]. The well was hydraulically fractured and had been producing for nearly 23 years. Monthly production rates and fluid/rock properties are the only data available. After a number of simulation runs and regressing on model parameters, the two best fits reported by the authors were that of the linear homogeneous closed reservoir and radial transient dual porosity closed reservoir providing an OGIP ranging from 6.9 – 7.1 Bcf[C]. Average net pay, porosity, water saturation, gas gravity, and reservoir temp as 92 ft, 15 %, 47%, 0.65, and 290 °F respectively. Initial pressure was 8,800 psia.

The BK model provided an initial OGIP of approximately 4.1 Bcf (which is slightly lower than the reported results), with an effective permeability of 0.005 – 0.007 md, and an average drainage area of 40 to 48 Acres (the Arp's initial rate used in the analysis was 0.5 MMscf/d). A review of the production history match indicated that the results were generally suitable (Figure 14). It is obvious that the early transient time is not matched as the well is stimulated and the parameter has not been incorporated into the analysis. The production history match was obtained automatically, again by linking the tank model to the Arps decline and the BK model.

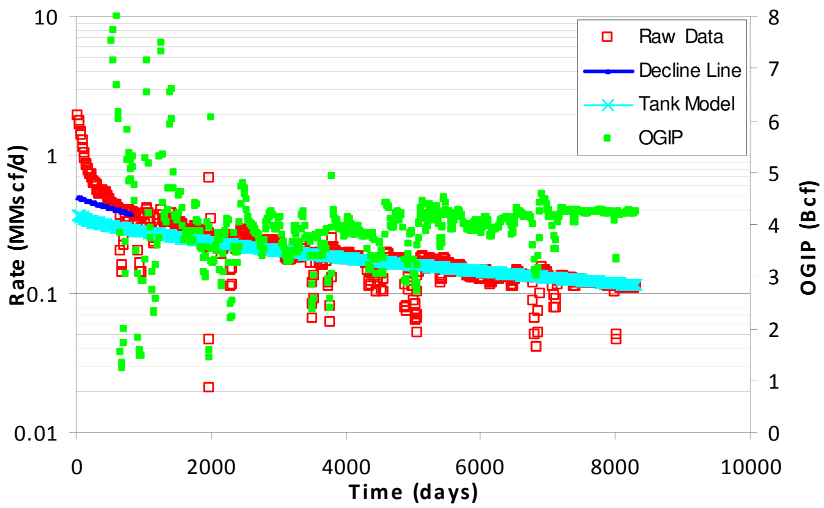

Figure 14: Raw Data, OGIP Analysis, and History Match

Stella Young "Shale Gas: Barnett Well: The Stella Young 4, a Barnett Shale gas well, was drilled and completed in the latter part of 1985[25]. Upon completion, it was hydraulically fractured with approximately 470,000 gal of gel and 875,000 lb and 20/40 mesh sand. Rates were initially high at 2 MMscf/d, but declined to about 0.2 MMscf/d over a period of 5 years Figure 15 shows the measured gas rates and the associated decline line.

Average net pay, porosity, water saturation, gas gravity, and reservoir temp as 184 ft, 3.9 %, 41.2%, 0.747, and 192 °F respectively. Initial reservoir pressure was estimated to be 4,000 psia while the flowing bottomhole pressure has been relatively constant at 200 psia

[C] Two other models (linear PSS dual porosity closed reservoir and linear transient dual porosity closed reservoir) did not provide a suitable match. Incidentally, the operator and others believed that the field had some natural fractures in one direction and that these natural fractures enhanced the permeability in their direction resulting in anisotropic behaviour (for such a reservoir shape, linear flow was anticipated to be observed for majority of the life of the well).

throughout the life of the well. Langmuir isotherm values P_L and V_L were estimated to be 400 psia and 40 scf/ton. Coal density was estimated to be 2.1 g/cm^3. Performing production data analysis using PROMAT^{TM}, the original study estimated permeability to be approximately 0.005 md and OGIP to be 1.1 Bcf with a drainage area of 24.5 acres. The results also indicated fracture half-length to be approximately 130 – 150 ft.

Figure 15 shows the decline match while Figure 16 shows the results from the BK model which provides an average OGIP of approximately 1.1 Bcf, and an extracted permeability of 0.02 md. Although the calculated permeability is high compared to the results from the original analysis, it is an effective permeability for the matrix and wellbore fracture combined and provides a reasonable history match as shown in Figure 17.

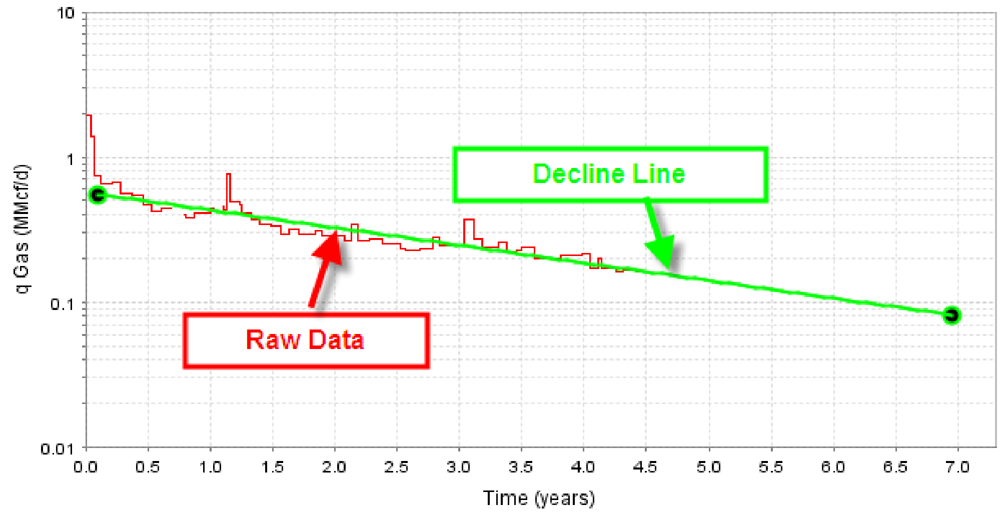

Figure 15: Raw Data and Decline Match

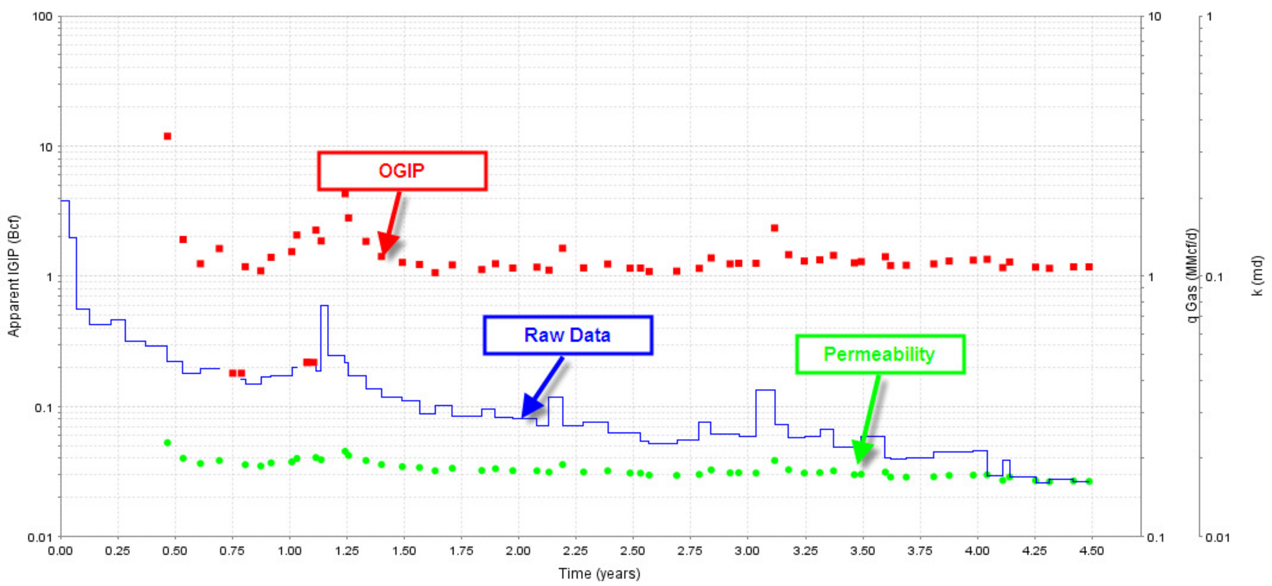

Figure 16: OGIP and Permeability Analysis

Incidentally, given the low amount of absorbed gas (i.e. the low gas content) in the Barnett Shale example, this data set could be treat as purely a tight gas example as opposed to an absorbed gas example.

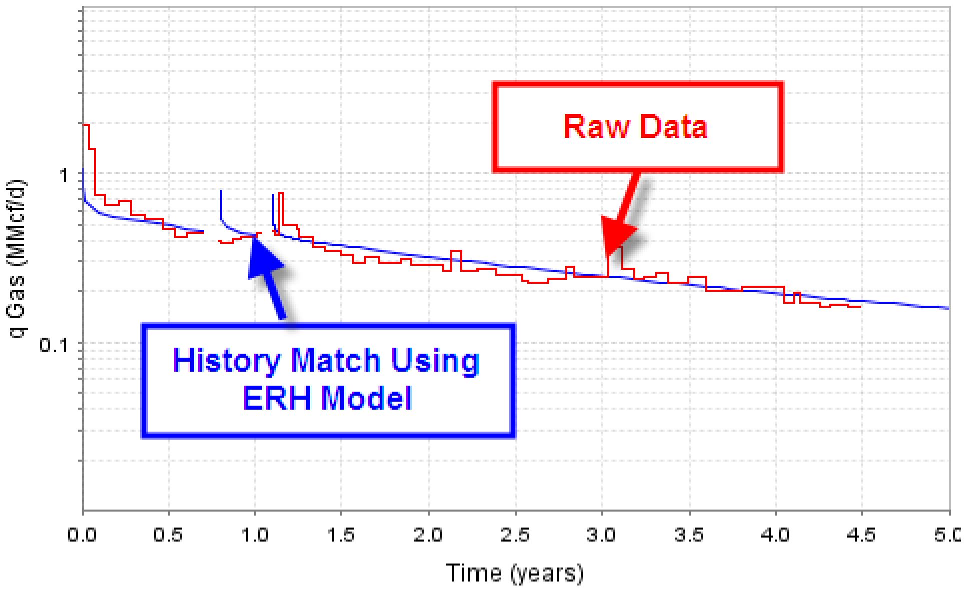

Figure 17: History Match

Horseshoe Canyon Coal Gas. In this example, data is taken from the Horsehoe Canyon coals of the Western Canadian Sedimentary Basin[26]. In this case, individual low rank (sub-bituminous) coal seams were N_2 stimulated, and produced commingled. Average net pay, cleat porosity, gas saturation, gas gravity, and reservoir temp as 49.9 ft, 0.1 %, 100%, 0.55, and 67 ^{o}F respectively. Initial reservoir pressure was low at 86 psia, while flowing pressure was about 20 psia. Coal density was 1.33 g/cm^3. Flowing type curve and buildup pressure analysis, performed by the original analysts, indicated an effective permeability of about 7.3 to 9.2 md, a wellbore skin (-1.4) to (+0.2), and finally an OGIP of 152 MMscfd.

Figure 18 shows the raw data, and the Arps decline match. A review of the BK model in Figure 19 provided an OGIP of 150-170 MMscf, and an average effective permeability of 10-15 md (assuming zero skin). The associated history match is shown in Figure 20.

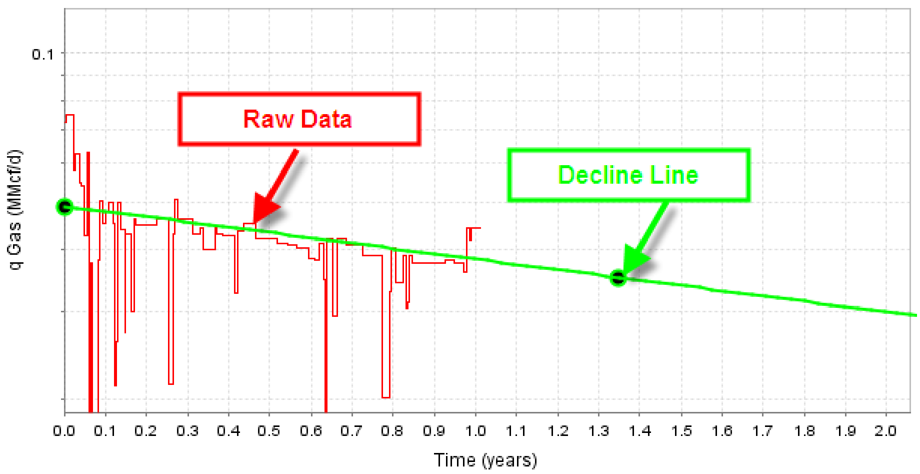

Figure 18: Raw Data And Decline Match

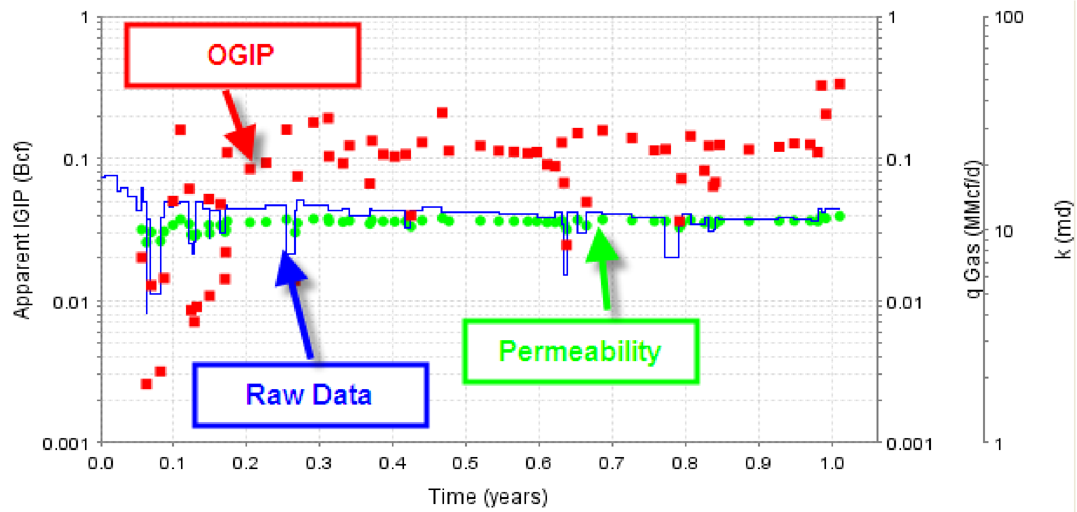

Figure 19: OGIP and Permeability Analysis

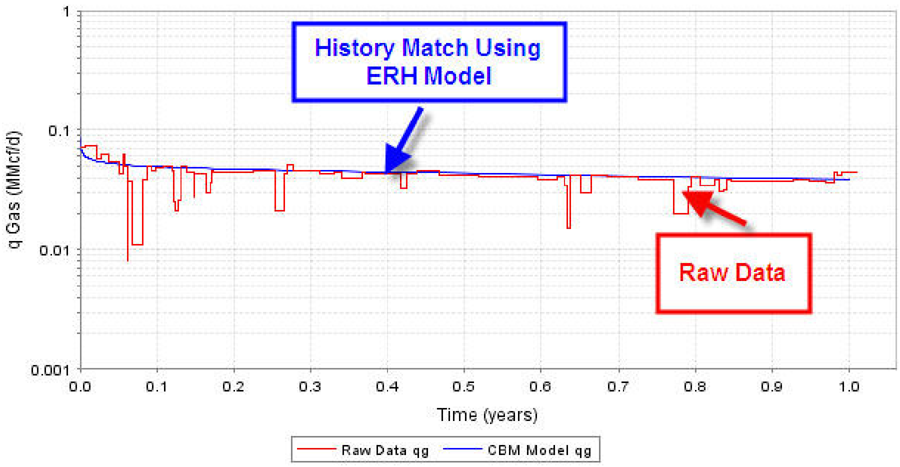

Figure 20: History Match

CONCLUSIONS

The BK model, which linked to production modeling, is fairly robust can provide a reasonable estimate of OGIP and an analog model for effective equivalent permeability (EEP) and/or effective drainage radius. Assuming PSS, the production analog can be based on "tank" type models as heterogeneity and similar anomalies are assimilated through the EEP. The procedure can be applied to both conventional and unconventional gas systems, as well as abnormally pressure systems. Errors in reservoir parameters such as initial pressure and formation temperature appear to have minimal impact on the calculated OGIP. Given the simplicity of the approach, coding and implementation in spreadsheets or other desktop tools is easily accomplished.

It is understood that these linearization methods presented were developed under the assumption that PSS flow exists (permeability, wellbore skin, net pay, etc. are not so interchangeable during transient flow periods). However, long-term deliverability and productivity is generally of more concern than transient or flush production. The process is also assumes that the data does exhibit traditional constant pressure decline (the method is highly comparable to conventional decline with respect to the limitation of constant BHP. However, the method appears to be robust and able to tolerate a small deviation from a non-constant BHP condition.

Of course, similar to all analytical methods, the methodology presented in this paper does make certain simplifying assumptions about production data analysis. For example, it does assume single phase volumetric reservoir behaviour. However, some non-volumetric effects, such as water-drive and interference among multiple wells can be handled effectively using influence functions (e.g. Blasingame type curves have a multi well feature that can accommodate and account for interference effects). The assumption of single-phase production in the reservoir is, in most cases, also considered valid especially for gas wells (as gas compressibility dominates the material balance). The primary impact of multiphase production in gas wells is in the wellbore, where special care must be taken to ensure that the pressure loss from surface to bottomhole conditions is estimated correctly.

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NOMENCLATURE

q_{gi} Arps Initial gas rate,
q_g Gas Rate
G_p Gas producced
OGIP Initial Gas-In-Place
z z-factor
P_i Initial Reservoir Pressure
P_{wf} Flowing BHP
b Arps decline exponent
D_i Arps constant (initial decline rate)

APPENDIX A

Muhammad Buba[12] and Knowes[13], presented the semi-analytic “quadratic rate-cumulative production” relation as shown in (1).

$$q_g = q_{gi} - \frac{2q_{gi}}{\left[1-\left[\frac{p_{wf}/z_{wf}}{p_i/z_i}\right]^2\right]OGIP}G_p + \frac{q_{gi}}{\left[1-\left[\frac{p_{wf}/z_{wf}}{p_i/z_i}\right]^2\right]OGIP^2}G_p^2 \tag{1}$$

A general review of (1) will show that it is a quadratic equation which can be simplified to (2) where a, b, and c are defined by equations (3), (4), and (5) shown below.

$$q_g = c - b(G_p / OGIP) + a(G_p / OGIP)^2 \qquad (2)$$

$$a = \frac{q_{gi} G_p^2}{\left[1 - \left[\frac{p_{wf}/z_{wf}}{p_i/z_i}\right]^2\right]} \qquad (3)$$

$$b = \frac{2 q_{gi} G_p}{\left[1 - \left[\frac{p_{wf}/z_{wf}}{p_i/z_i}\right]^2\right]} \qquad (4)$$

$$c = q_{gi} \qquad (5)$$

Since (2) is a quadratic equation, solving for OGIP can now be easily accomplished as shown in (6), where "η" is defined as shown below in (7), and q_{gi} is one of Arps variables as shown in (8).

$$OGIP = \frac{1}{2} \frac{(2 \cdot \eta \pm 2 \cdot (\eta^2 + \eta \cdot q_g - \eta \cdot q_{gi})^{0.5}) G_p}{\left(q_{gi} - q_g\right)} \qquad (6)$$

$$\eta = \frac{1}{2} \frac{q_{gi}}{\left(1 - \left[\frac{p_{wf}/z_{wf}}{p_i/z_i}\right]^2\right)} \qquad (7)$$

$$q_g = \frac{q_{gi}}{(1 + bD_i t)^{1/b}} \qquad (8)$$

If one performs a traditional decline, an evaluation of OGIP can be automatically evaluated by substituting q_{gi} from (8) into (6) given knowledge of flowing pressure and initial pressure. Assuming that the drainage area of the well is constant during PSS, then a relatively linear plot of OGIP should also be produced as function of tmie. Also, recognizing the PSS relationship in given in (9), an estimate of gas permeability (k_g) can be calculated if reservoir pressure (material balance) calculations are automated using the average OGIP estimated from (6) and the measured field data.

$$q_g = \frac{(\overline{\psi}_R - \psi_{wf}) k_g h}{C_1 T_f \left[\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4} + s\right]} \qquad (9)$$

For adapation to coal-gas, systems where there is absorbed and fee gas, (6) can be used. However, testing has shown the best results are obtained when a contant of 10/12 is included in the solution as shwon in (10).

$$OGIP = \frac{10}{12} \frac{(2 \cdot \eta \pm 2 \cdot (\eta^2 + \eta \cdot q_g - \eta \cdot q_{gi})^{0.5}) G_p}{\left(q_{gi} - q_g\right)} \qquad (10)$$