Evaluation of the Stretched Exponential Production Decline Model and Comparison to Other Decline Models for Shale Reservoirs

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Of the Requirements for the Degree

Master of Science

in Petroleum Engineering

by

Dong Li

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Evaluation of the Stretched Exponential Production Decline Model and Comparison to Other Decline Models for Shale Reservoirs

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Abstract

The discovery and development of shale oil/gas has changed the energy industry. By 2040, shale gas production will account for 50% of the total natural gas production of the U.S. Due to the extremely low permeability of shale reservoirs, shale gas wells exhibit much longer transient flow periods than conventional wells, and this makes it inappropriate to use conventional methods of evaluating estimated ultimate recovery (EUR) of wells in these reservoirs. Therefore, new methods of forecasting shale wells are needed. In this study, I focused on the stretched exponential production decline model (SEPD), and particularly Yu's modification of the model (YM-SEPD). I compared the results with other methods, including Duong's method, and the Arps hyperbolic model. SEPD provided the most reliable EURs for shale gas well when excluding early off-trend data. YM-SEPD gave results comparable to SEPD and is much easier to apply. It is therefore the method we recommend for shale wells.

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Chapter 1 Introduction

The discovery and development of shale oil/gas has changed the energy industry. Since the discovery of shale gas, the production of natural gas in US has been constantly increasing. By the end of 2012, proved reserves of natural gas in US were estimated to be 300 Tcf, following a peak of 317.6 Tcf in 2010. Although there was a decrease from 2010 to 2012, US natural gas proved reserves had been increasing in every year since 1999, with the pace accelerating after the discovery and production of shale gas (EIA 2012). By 2040, shale gas production will account for 50% of the total natural gas production in the US (EIA 2012). Therefore, forecasting production and estimating reserves accurately for these shale plays has become urgent.

Researchers (Duong 2011, Valko and Lee 2010) found that shale wells exhibit much longer transient flow periods than conventional wells, due to the extremely low permeability of shale plays. This makes conventional methods (i.e., Arps' decline model) of forecasting EUR, inappropriate for this application. These unconventional wells have linear and, possibly although infrequently, bilinear flow regimes that were absent in traditional wells; these new flow regimes may dominate a well's productive life (Freeborn and Russell 2012). Therefore, alternative approaches of forecasting shale wells are needed. In the following section, some available forecasting methods will be reviewed.

1.1 Conventional decline curve methods

1.1.1 Arps' decline model

Arps' decline curve models have been broadly used to estimate reserves from depletion drive oil and gas reservoirs since 1945. Even now Arps decline model is used as the major method to estimate EUR. Arps' decline models include three types: exponential (b=0), hyperbolic (0<b<1), and harmonic (b=1). The Arps equations are shown as below:

$$q_t = q_i e^{-D_i} \quad (b = 0) \text{ and} \tag{1}$$

$$q_t = \frac{q_i}{(1+bD_i t)^{(\frac{1}{b})}} \ (b \neq 0), \tag{2}$$

where q_t represents production rate at time t, q_i represents stabilized rate at t=0, D_i is the decline rate at flow rate q_i, and b is Arps' decline constant.

Hyperbolic decline model was introduced because exponential decline gives too conservative estimates in the final stages (Valko and Lee 2010). It is necessary to have the boundary dominated flow (BDF) regime when applying hyperbolic decline method. Recently, iIt has been demonstrated that if wells have long transient flow periods, forecasting using a constant b, obtained from early transient flow, overpredicts well performance (Kurtoglu et al. 2011). The b value obtained by fitting the Arps decline model to transient decline data decreases during a long transient flow period. So Kurtoglu et al. suggested using Arps standard decline hyperbolic decline model until D reaches some specified decline rate, $D_{min,}$ and thereafter use purely the exponential decline model with decline exponent equal to D_{min}. This implies that we must determine the correct terminal decline characteristics of wells in low-permeability reservoirs to use this methodology.

1.2 Newly proposed decline curve methods

1.2.1 Stretched exponential decline (Valko's method)

Stretched exponential production decline (SEPD) model acknowledges the heterogeneity of the reservoir in that the actual production decline is determined by a large number of contributing volumes individually in exponential decay, but with a specific distribution of characteristic time constants for individual contributing volumes (Valko and Lee 2010). Compared to Arps' hyperbolic model, SEPD has asignificant advantages: It is a transient flow model, consistent with actual reservoir behavior, whereas the Arps model is a BDF model. The SEPD model is

$$q = q_i \exp\left[-\left(\frac{t}{\tau}\right)^n\right], \quad (3)$$

where n is an exponent parameter and τ is a characteristic time parameter. q_i represents the stabilized rate at t=0.

The SPED model is believed to have advantages over the Arps family of decline models, at least for unconventional gas applications (Valko and Lee 2010). However, this does not necessarily mean that SEPD will forecast EUR more accurately than the Arps model. In fact, we find in practice that the Arps model and SEPD produce comparable results.

1.2.2 Duong's method

Duong's method was empirically derived based on observed near- linear flow for an extended period in a large number of wells in tight and shale gas reservoirs (Duong 2011). A log-log plot of the ratio of rate to cumulative production vs. time was observed to be fitted well by a straight line in all unconventional reservoir cases presented in Duong's paper. A rate-time or cumulative production-time relationship therefore can be created with the slope and intercept value from the log-log plot. The slope and intercept are related to reservoir rock characteristics, fracture stimulation practice, operational conditions and possibly liquids content. Duong's equations are described as below,

$$q = q_i t^{-m} exp\left[\frac{a}{1-m}\left(t^{1-m} - 1\right)\right] \text{ and} \quad (4)$$

$$\frac{G_p}{q} = \left(\frac{1}{a}\right) t^m. \tag{5}$$

Duong's method appears to be reliable for both vertical and horizontal wells. This method is only suitable for a single early near-tranisent flow regime and cannot be used after the BDF regime appears (Freeborn and Russell 2012). Freeborn and Russell also suggested using Arps' hyperbolic equation in preference to Duong's method, but their recommendation was based on the error in Duong's model when we fail to switch from the model to a BDF model when BDF is observed or expected.

1.2.3 Yu's Modified SEPD

Yu's Modified SEPD (YM-SEPD) was developed using a proposed plot of $ln\left[\frac{q_i}{q(t)}\right]$ vs. t to find the SEPD parameters of n and τ (Yu et al. 2013). Yu assumed that q_i is the highest production rate observed during well production history. The rearranged SEPD equation is

$$ln\left[\frac{q_i}{q(t)}\right] = \tau^{-n} t^n. \tag{6}$$

By plotting $ln\left[\frac{q_i}{q(t)}\right]$ vs. t on a log-log scale, we can find value of n from the slope, and τ from the intercept with the equation below,

$$\tau = exp\left[\frac{-\ln(Int)}{n}\right]. \tag{7}$$

A set of "n" & "τ" values will generate a production decline profile that fits reasonably well the decline behavior of a horizontal well following a multistage fracturing completion. If we eliminate early data off-trend of later production data, YM-SEPD gives more accurate results than if we try to fit the model to all available historical production data.

1.2.4 Switching working equations from SEPD to Arps after well enters BDF

When using the SEPD model, we find in practice that we should switch the decline model from SEPD to Arps after the well enters BDF. When we switch, the working equations to calculate the parameters for the Arps model are summarized below:

$$q = q_i \exp\left[-\left(\frac{t}{\tau}\right)^n\right], \tag{8}$$

$$D = \frac{n}{t}\left(\frac{t}{\tau}\right)^n, \text{ and} \tag{9}$$

$$b = \frac{1-n}{n}\left(\frac{\tau}{t}\right)^n. \tag{10}$$

In the Arps model, D at the time we switch becomes D_i; q becomes q_i; and time t is time elapsed since we switched models. The value of b is switched to 0.4 for gas well after well enters BDF.

In summary, several empirical models have been proposed to forecast EUR of shale gas wells, however, there are no clear conclusions that allow us to select the most reliable decline method. Specifically, the following questions remain unanswered:

1. What is the most reliable model for wells with long transient flow?
2. Will our chosen model be more accurate if we apply different models for different flow regimes in the same well?
3. For a well with relatively short production history, which model is most suitable? How about the well with relatively long production history?

This thesis addresses these questions, with special emphasis of various ways to implement the SEPD model.

Chapter 2 Methodology

2.1 Determining parameters in models

For Arps, SEPD, and Duong models, the value of q/G_p was first calculated to eliminate the initial production rate, q_i. Afterward, the remaining two parameters (D_i and b for Arps, n and τ for SEPD, a and m for Duong) were determined via nonlinear regression using Excel Solver. q_i was then estimated by fitting calculated cumulated production to G_p using Excel Solver. The first six-months of data were excluded from fitting because, usually at early time, wells are not stable and the production data is misleading. However, when applying the SEPD method (and most other methods), many people tend to use all the data available to determine the parameters of the equation. Therefore, in this study, this methodology was considered as an alternative. In figures and and tables that follow, this method is represented by "SEPD-All".

For YM-SEPD, a plot of $ln\left[\frac{q_i}{q(t)}\right]$ vs. t is used to find the parameters of n and τ (Yu et al. 2013) with the following equation,

$$ln\left[\frac{q_i}{q(t)}\right] = \tau^{-n}t^n. \tag{11}$$

A typical YM-SEPD plot is shown in Figure 1. By plotting $ln\left[\frac{q_i}{q(t)}\right]$ vs. t on a log-log scale, we can find the value of n as the slope (0.4598), and τ can be calculated from the intercept, Int with the following equation:

$$\tau = exp\left[\frac{-\ln(Int)}{n}\right], \tag{12}$$

$$Int = 0.0431, \text{ and} \tag{13}$$

$$\tau = exp\left[\frac{-\ln(0.0431)}{0.4598}\right] = 932. \tag{14}$$

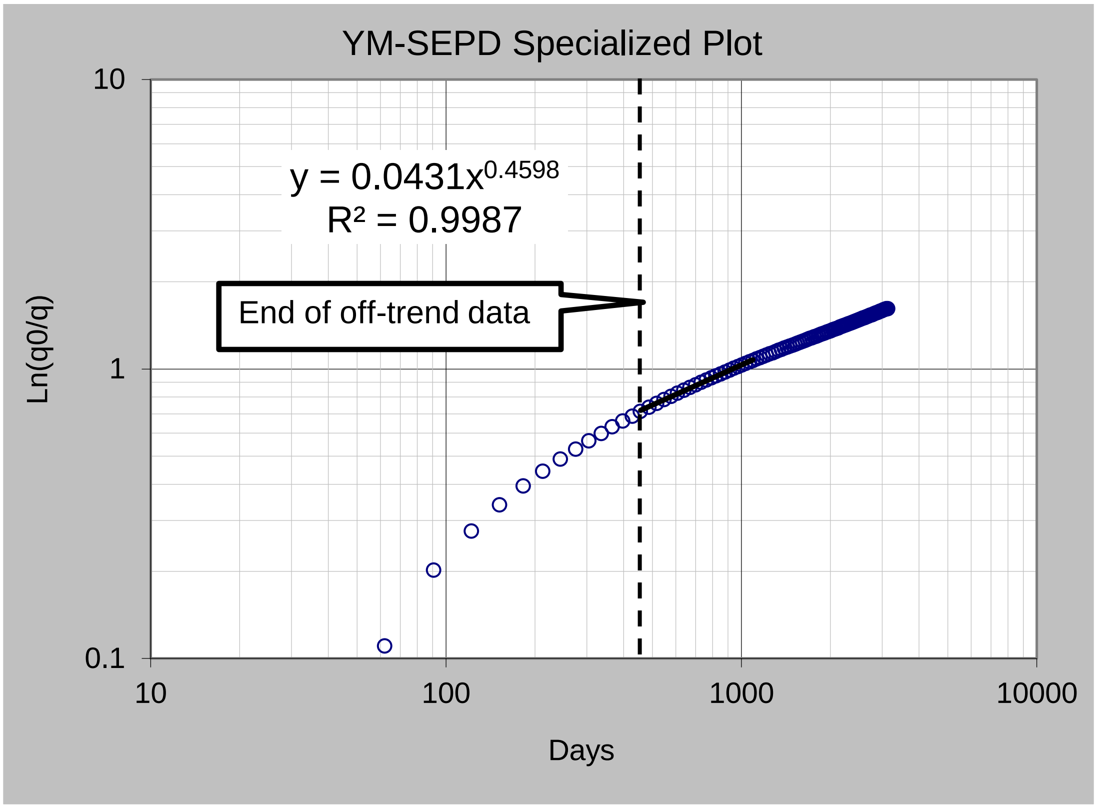

Figure 1. YM-SEPD Plot.

Note that usually there are some off-trend data before a straight line can be observed in the YM-SEPD specialized plot. This is usually because the well is still producing back fracture fluid, because the bottom-hole pressure has not stabilized, and possibly because the SEPD model simply cannot properly fit early data in steep decline. These data will not be used to determine parameters of n and τ.

2.2 Analyzing flow regime using Material Balance Time

The material balance time (MBT) diagnostic plot has been proven to serve as a reliable method to identify flow regimes, "provided that the rate and pressure variation is smooth with time" (Anderson and Mattar 2003). MBT is a time superposition function that retains the character of a plot of transient linear flow vs. time and converts variable rate production into equivalent constant rate production during BDF (Liang et al. 2011).

On a log-log plot of rate vs. MBT, transient linear flow has a characteristic negative half slope and BDF has a characteristic negative unit slope.

2.3 Treating production data from wells

There are two simulated examples and two field examples in section 3.1. The simulated examples are analytical modeling results using Fekete Harmony software. This model accounts for improved localized effective permeability within the stimulated reservoir volume (SRV). In the SRV model, the outer zone permeability is negligible. This model gives conservative values of EURs for shale gas wells. The field examples are from the Barnett Shale Reservoir and the production data were obtained from a public database. The Barnett Shale was the first deep gas shale to be commercially developed. More than 14,000 wells have been drilled in this reservoir.

Shaoyong Yu (ConocoPhilips Canada) provided another four examples discussed in section 3.2 . Three are field examples from the Western Canadian Basin (WCB) and one is simulated.

Chapter 3 Results and Discussion

3.1 Forecasting shale gas wells with Arps, SEPD, and Duong models.

3.1.1 Synthetic dry gas well #1

3.1.1.1 Reservoir, well, fluid properties

This synthetic dry gas well was simulated with an SRV model in Fekete Harmony. Reservoir, fluid and well properties are given in Table 1.

Table 1. Properties of reservoir, fluid and well in the synthetic dry gas well #1.

Reservoir Pressure	5835 psia
Reservoir Temperature	200 °F
Permeability	0.004 md
Porosity	6%
Water Saturation	20%
Net Pay	150 ft
Gas Gravity	0.67
Horizontal Well Length	5000 ft
Number of fractures	20
F_{CD}	71
Fracture Half-length	66 ft

3.1.1.2 Flow regime diagnostic plot and YM-SEPD plot

The MBT diagnostic chart (Figure 2) indicated that the well enters the linear flow regime at 46 MBT months (30 months in real time) and is still in linear flow after 200 MBT month. Because the F_{CD} is relatively small (<300), linear flow started late in the well production history.

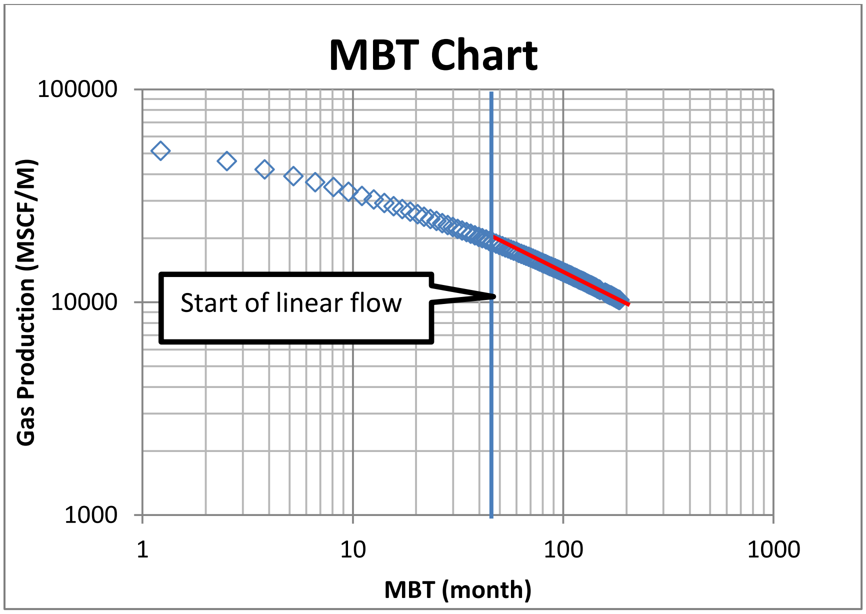

Figure 2. MBT diagnostic plot of synthetic gas well #1. Red line represents the negative half slope line.

The YM-SEPD plot used to determine the parameters n and τ is illustrated below (Figure 3). Only the first three years of data were used to fit a straight line. And any data off the trend were excluded for the fitting. BDF data, if any, were also excluded for using in the plot. The trendline indicates the portion of the data used for fitting.

3.1.1.3 EUR forecast results

Using the first three years data for history matching, all methods fit the data well (Figure 4 and Figure 5). In the tables and figures below, Arps, Duong, and SEPD represent the decline model used, and in each case the off-trend data were excluded from fitting. SEPD-All represents use of the SEPD decline model; all the production data were used for fitting the curve. Arps' model overestimated the well's EUR by 9.68%. Duong and SEPD models both provided reasonably good estimates of the well's EUR. YM-SEPD underestimated the production by 6.25%. When using all the production data, SEPD-All provided the worst prediction compared with SEPD and YM-SEPD.

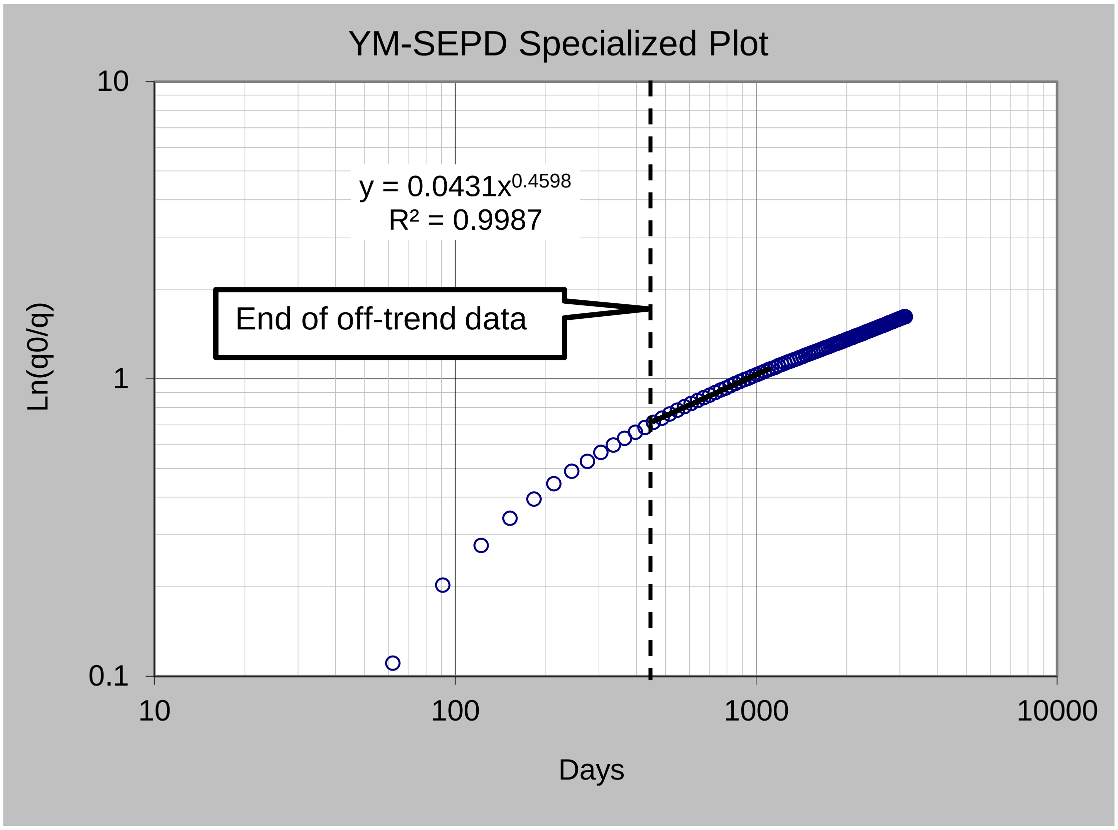

Figure 3. YM-SPED specialized plot for synthetic dry gas well #1. Trendline indicates the portion of the data used for fitting.

Table 2. 30-year EUR of synthetic dry gas well #1 estimated by different models.

Model	**30yr-EUR (MMscf)**	**Error (%)**
Analytical model (SRV)	3710	---
Duong	3790	2.16
Arps	4069	9.68
SEPD	3664	-1.24
SEPD-All	3411	-8.06
YM-SEPD	3478	-6.25

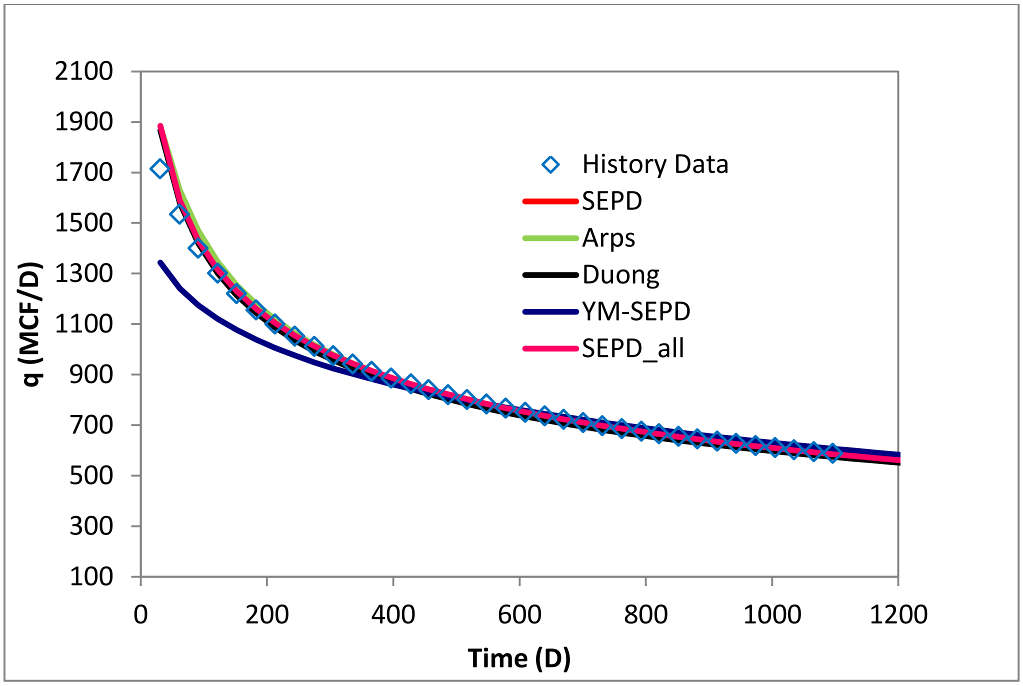

Figure 4. Production rate of the synthetic gas well #1 and the forecast by different methods.

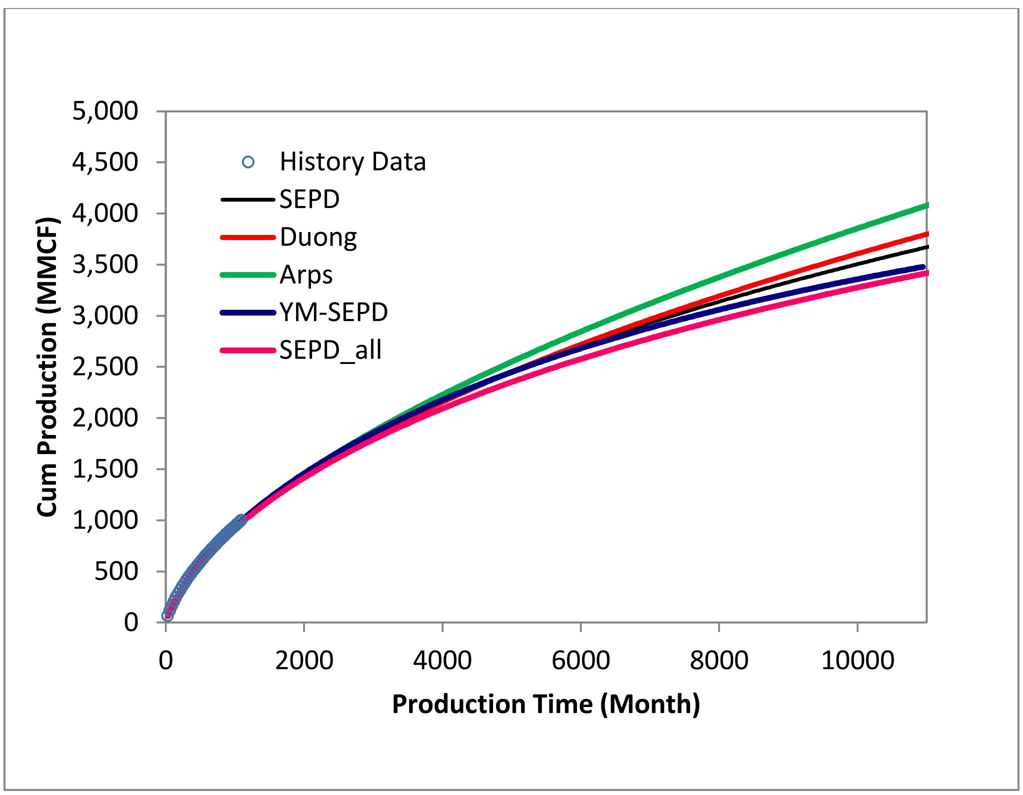

Figure 5. Cumulative production of synthetic gas well #1 and the forecast by different methods.

3.1.2 Synthetic dry gas well #2

3.1.2.1 Reservoir, well, fluid properties

Synthetic dry gas well #2 is simulated by a SRV model in Fekete Harmony. The properties of reservoir, fluid and well are illustrated in Table 3.

Table 3. Properties of reservoir, fluid and well in the synthetic dry gas well #2.

Reservoir Pressure	2558.5 psia
Reservoir Temperature	200 ℉
Permeability	0.0005 md
Porosity	6%
Water Saturation	20%
Net Pay	150 ft
Gas Gravity	0.67
Horizontal Well Length	5000 ft
Number of fractures	20
F_{CD}	68
Fracture Half-length	150 ft

3.1.2.2 Flow regime diagnostic plot

MBT diagnostic chart (Figure 6) indicated that the well is still in transient flow after 200 MBT month. No BDF is observed. YM-SEPD specialized plot used to determine the parameters of n and τ is illustrated below (Figure 7). Only the first three year data were used to fit a straight line. And any data off the trend were excluded for the fitting. BDF data, if any, were also excluded for using in the plot. Trendline indicates the portion of the data used for fitting.

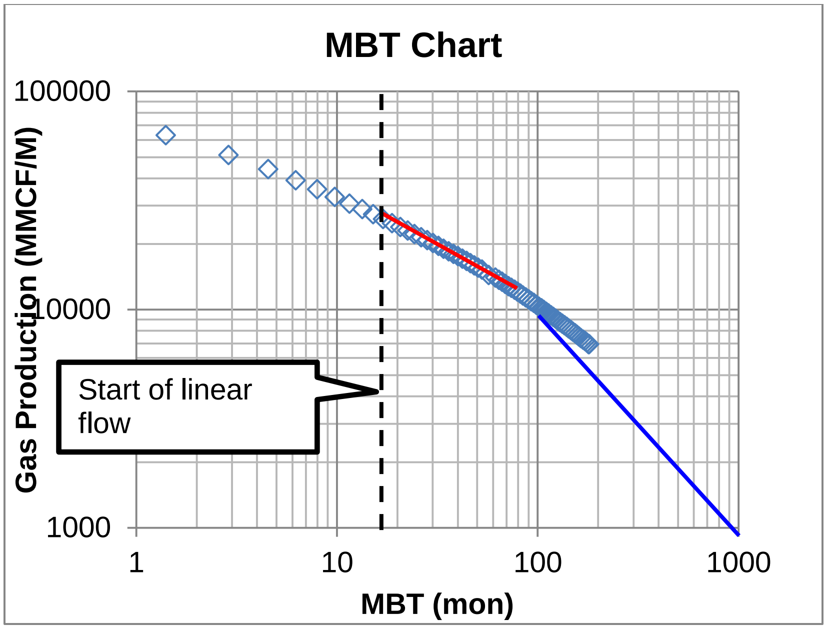

Figure 6. MBT diagnostic plot of synthetic gas well #2. Red line represents the negative half slope line and blue line represents the negative unit slope line.

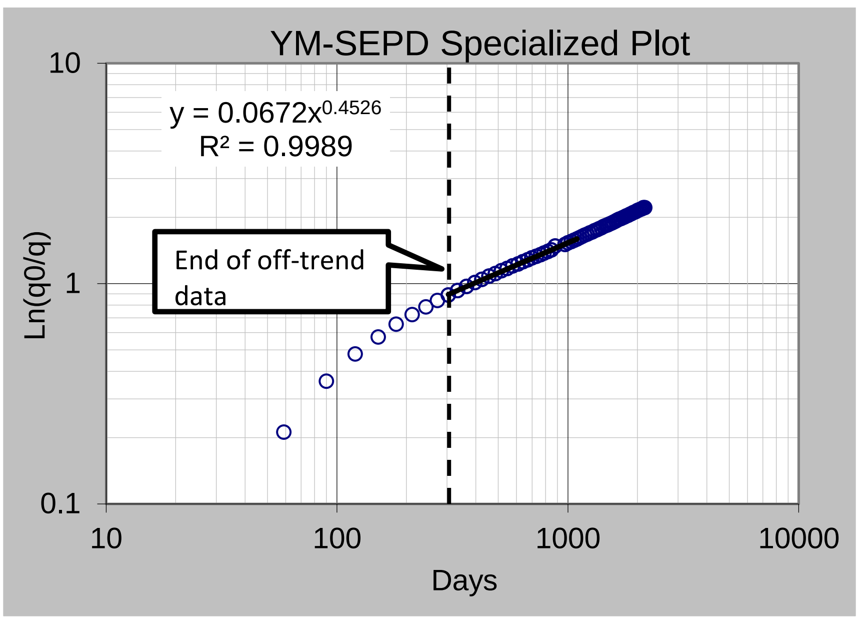

Figure 7. YM-SPED specialized plot for synthetic dry gas well #2.

3.1.2.3 EUR forecast results

Using the first three years data for history matching, the forecast of all methods are illustrated in Figure 8 and Figure 9. Duong model overestimated the well's EUR by

28.89%, giving the worst estimation among all the methods. Arps overestimated the well's EUR with a relatively small error of 4.88%. SEPD, YM-SEPD and SEPD-All all underestimated the production by 2.64%, 5.32%, and 6.25%, respectively.

Table 4. 30-year EUR of synthetic dry gas well #2 estimated by different models.

Model	**30yr-EUR (MMscf)**	**Error (%)**
Analytical model (SRV)	2049	---
Duong	2641	28.89
Arps	2149	4.88
SEPD	1995	-2.64
YM-SEPD	1940	-5.32
SEPD-All	1921	-6.25

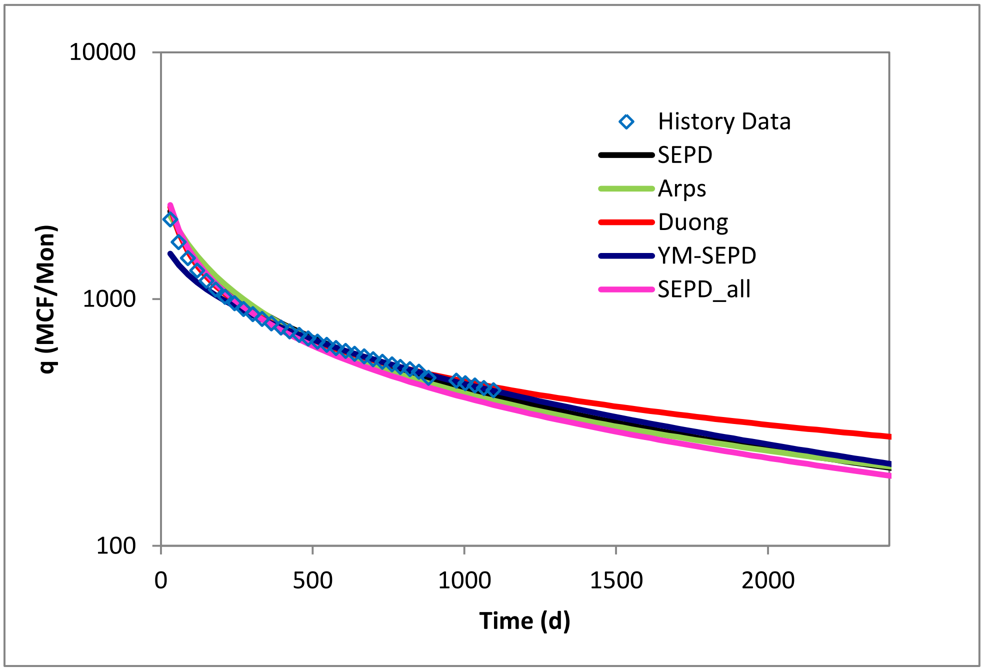

Figure 8. Production rate of the synthetic gas well #2 and the forecast by different methods.

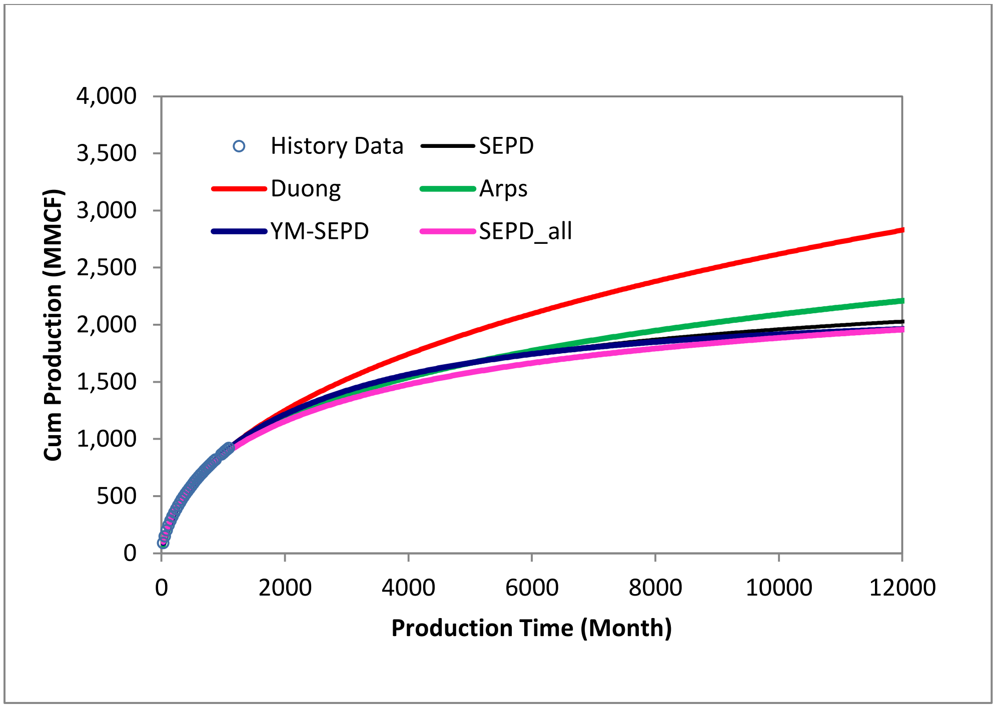

Figure 9. Cumulative production of synthetic gas well #2 and the forecast by different methods.

3.1.3 Field example #1

3.1.3.1 Reservoir, well, fluid properties

A shale gas well in Barnett Shale Reservoir was chosen for analysis. The well is located in Newark County, TX. The well started producing in Feb., 2003 and has a production history of 71 months. The first three-year production is used for history matching and the forecasting results by different models are then compared with the real data.

3.1.3.2 Flow regime diagnostic plot

MBT chart (Figure 10) showed that the well was in linear flow regime until 100 MBT months (61 months in real time). After that, the well entered BDF. YM-SEPD specialized plot used to determine the parameters of n and τ is illustrated below (Figure 11). Only the first three year data were used to fit a straight line. And any data off the trend were excluded for the fitting. BDF data, if any, were also excluded for using in the plot. Trendline indicates the portion of the data used for fitting.

3.1.3.3 EUR forecast results

For the field case, the first three years data were used for history matching to forecast later production. In Figure 12 and Figure 13, history data represents the first three year data and future data represents the later production data that were not used for history matching. All methods overestimated the production of the well. Duong model overestimated the well's EUR by 12.10%. Arps, SEPD and YM-SEPD gave comparable results, with error of 5.97%, 4.72%, and 4.23%, respectively. However, when using all history data to determine the parameters, SEPD-All provided an unsatisfying result with an error of 23.94%.

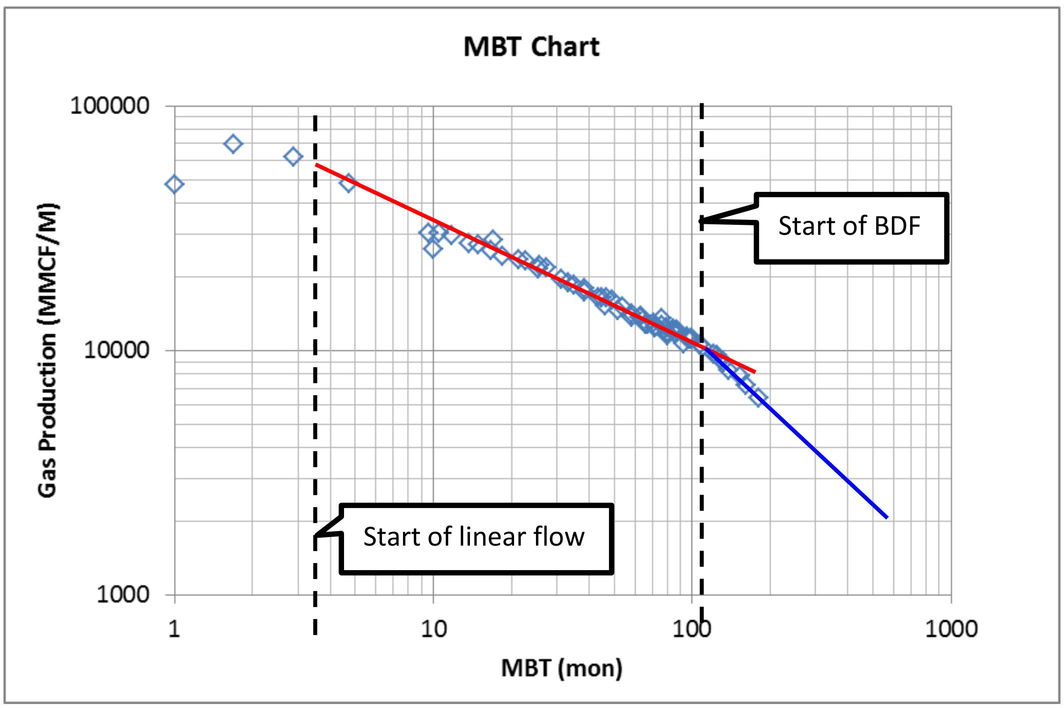

Figure 10. MBT diagnostic plot of shale gas well field example#1. Red line represents the negative half slope line and blue line represents the negative unit slope line.

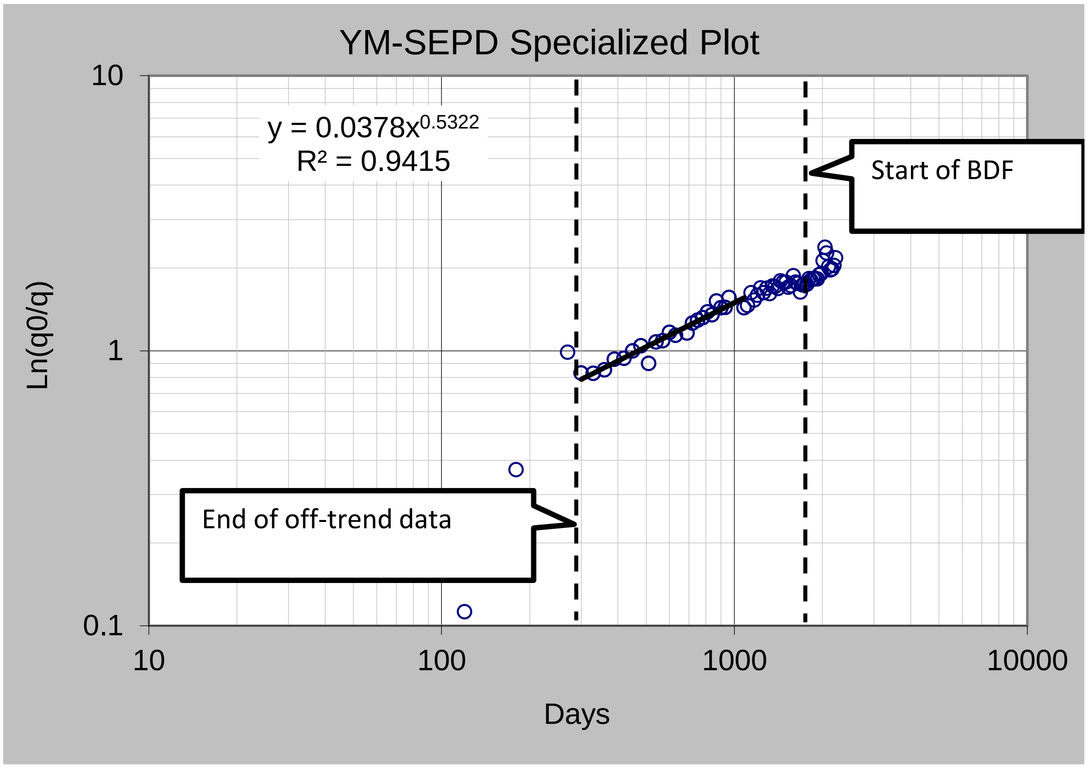

Figure 11. YM-SPED specialized plot for field example #1.

Table 5. Production of shale gas field example #1 estimated by different models.

Model	Production (MMscf)	Error (%)
Real Data	1207	---
Duong	1353	12.10
Arps	1279	5.97
SEPD	1262	4.72
YM-SEPD	1258	4.23
SEPD-All	1496	23.94

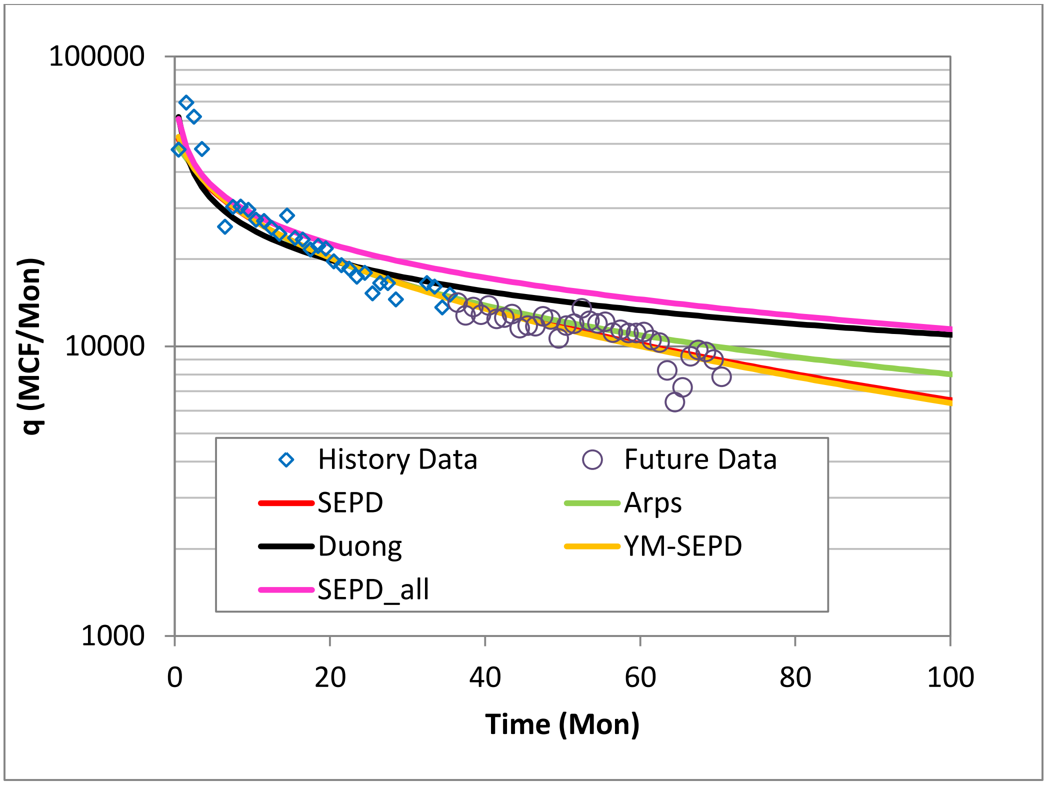

Figure 12. Production rate of the shale gas well field example #1 and the forecast by different methods.

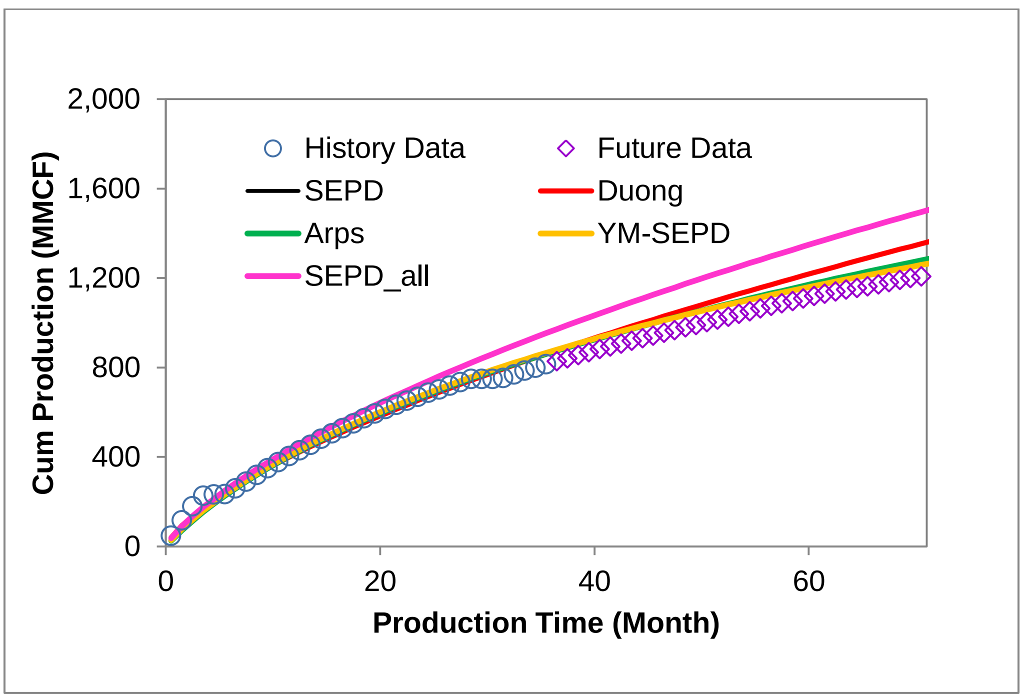

Figure 13. Cumulative production of shale gas well field example #1 and the forecast by different methods.

3.1.4 Field example #2

3.1.4.1 Reservoir, well, fluid properties

This well is also from Barnett Shale Reservoir. The well is located in Newark County, TX. The well has a production history of 109 months. The first three-year production is used for history matching and the forecasting results by different models are then compared with the real data.

3.1.4.2 Flow regime diagnostic plot

MBT chart (Figure 14) showed that the linear flow regime of the well is from 10 MBT months to 65 MBT month (9 months to 34 month in real time) and the well entered BDF regime after 65 MBT months (34 months in real time). For Arps, SEPD and Duong methods, the data before linear flow and after BDF are excluded from fitting. Only data from linear flow regime in the first three year are used to determine the model parameters and forecast production of the well. YM-SEPD specialized plot used to determine the parameters of n and τ is illustrated below (Figure 15). And any data off the trend were excluded for the fitting. BDF data, if any, were also excluded for using in the plot. Trendline indicates the portion of the data used for fitting.

3.1.4.3 EUR forecast results

For the field case, the first three years data were used for history matching to forecast later production. From Figure 16 and Figure 17, both Duong and Arps models overestimated the well's EUR by 9.66% and 15.85%, respectively. SEPD underestimated the well's production with an error of -8.52%. SEPD-All underestimated production with an error of 5.91%. YM-SEPD gave the best estimation of the well's production with an error of 5.41%.

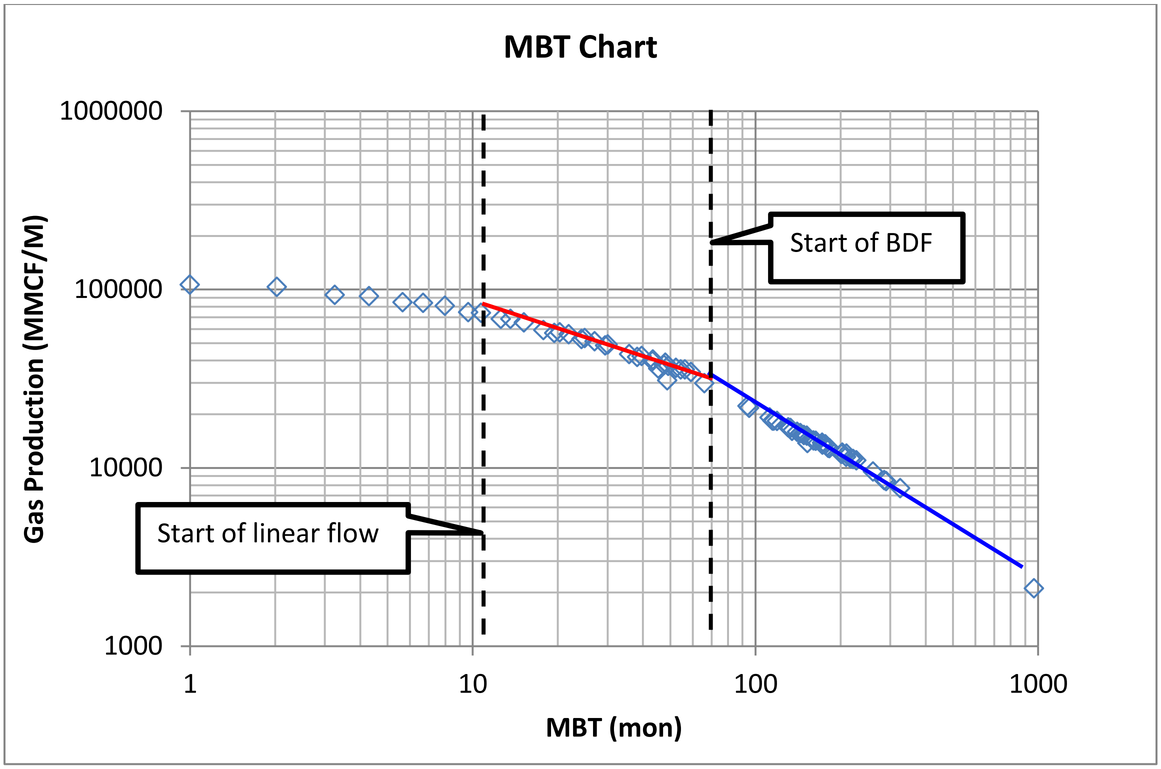

Figure 14. MBT diagnostic plot of shale gas well field example #2. Red line represents the negative half slope line and blue line represents the negative unit slope line.

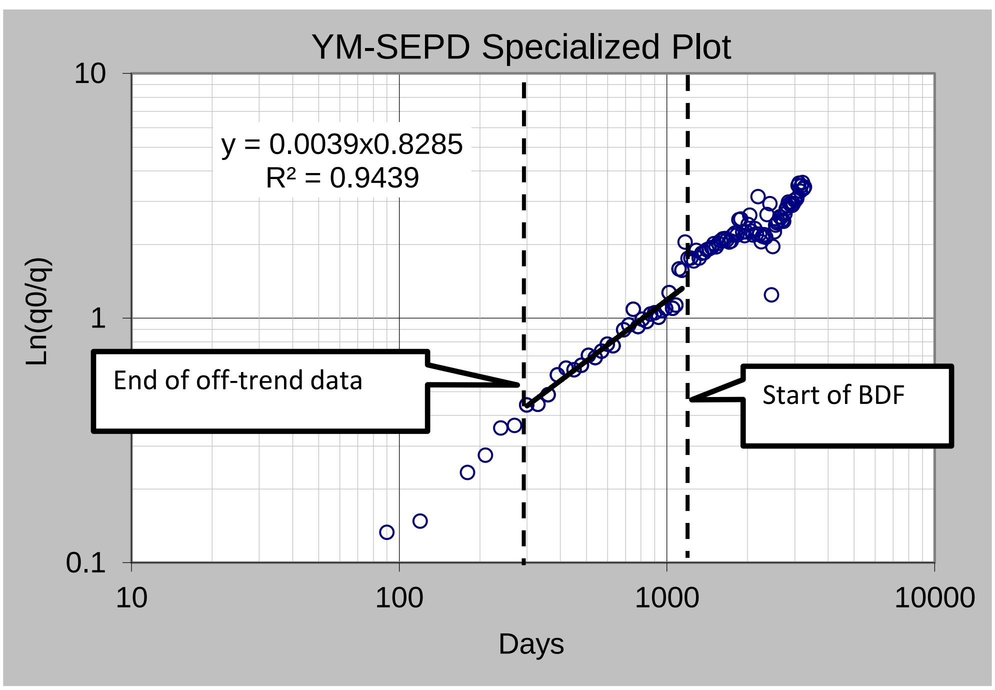

Figure 15. YM-SPED specialized plot for field example #2.

Table 6. Production of shale gas field example estimated by different models.

Model	Production (MMscf)	Error (%)
Real Data	2827	---
Duong	3100	9.66
Arps	3275	15.85
SEPD	2586	-8.52
YM-SEPD	2980	5.41
SEPD-All	2660	-5.91

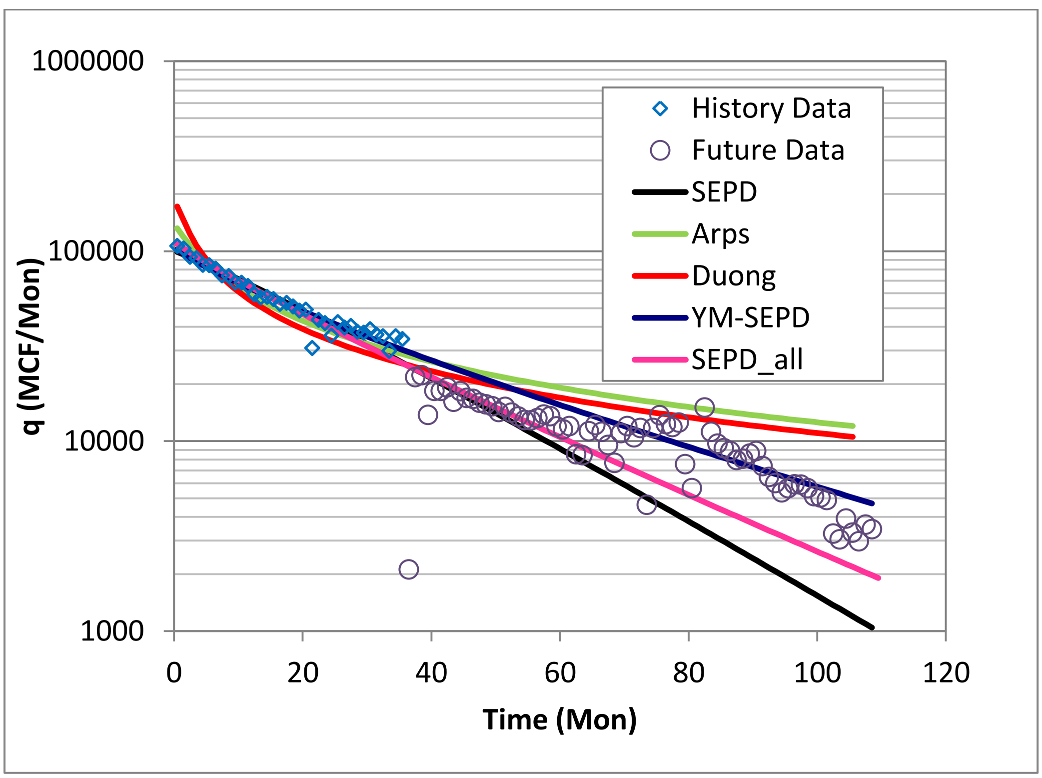

Figure 16. Production rate of the shale gas well field example #2 and the forecast by different methods.

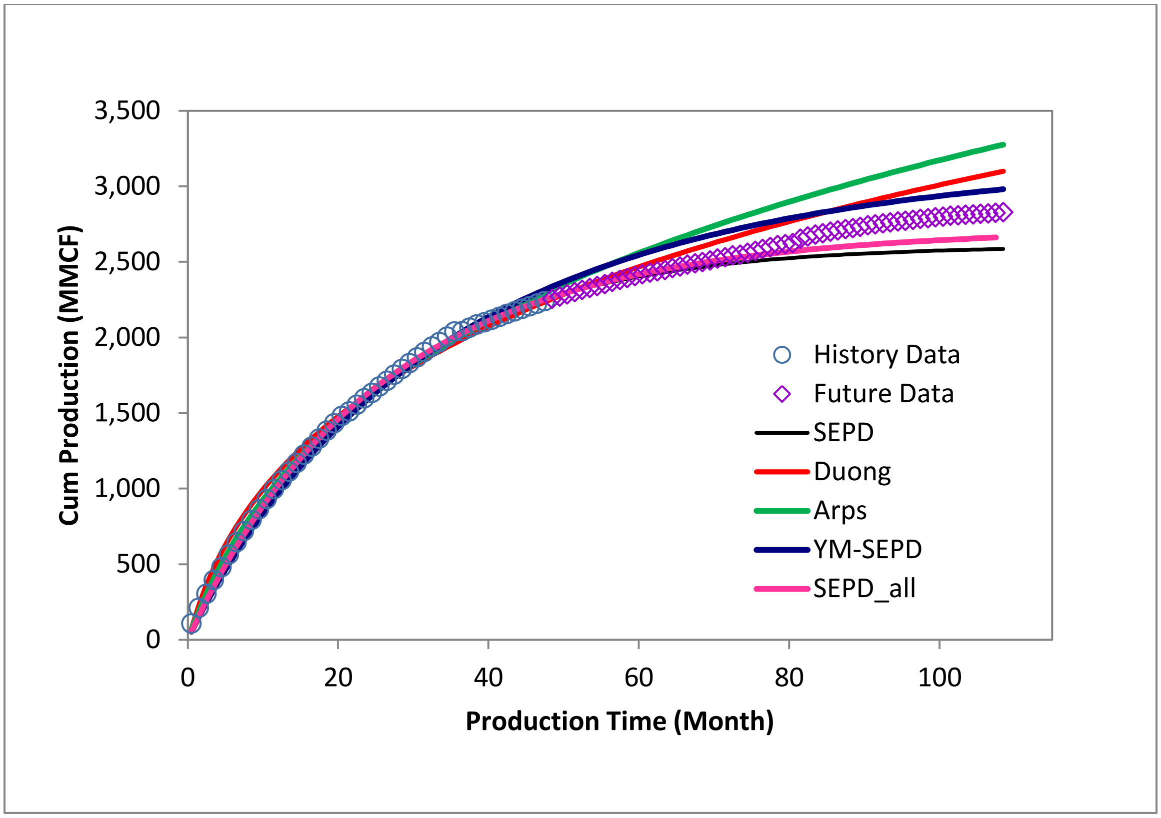

Figure 17. Cumulative production of shale gas well field example #2 and the forecast by different methods.

In summary, from two synthetic cases and two field examples, with off-trend data excluded, SEPD and YM-SEPD model best forecasts the production of shale gas wells compared with Arps and Duong models (i.e., with the smallest error against the model or real data). However, with all data being used for curve fitting, for most of the times, SEPD-All gave poorer estimates than SEPD. This is because at early stage, the well is not stable and the production data may be misleading. Determining the parameters of SEPD model is important to successfully apply this method in practice. The method mentioned in section 2.1 previously has two drawbacks: (1) Microsoft Solver sometimes does not provide a unique or valid result; (2) With q decreasing and Gp increasing along the production period, value of q/Gp becomes smaller and smaller, therefore, it is difficult to validate the fitting of the calculated q/Gp to real data. YM-SEPD avoids these problems with an illustrative specialized plot. Also in this specialized plot, people can easily observe the off-trend data and exclude them for determining the parameters. In the following part of this study, SEPD and YM-SEPD will be compared in four different well types (dry gas, wet gas, synthetic retrograde gas, field retrograde gas). Switching the models after the well enters BDF will also be analyzed.

3.2 Comparison of YM-SEPD with SEPD for different reservoir types

3.2.1 Dry gas well

3.2.1.1 Reservoir, well, fluid properties

The properties of a dry gas well located in Western Canadian Basin (WCB) are displayed in Table 7 below. These production data were obtained from a public database and the properties of the reservoir are obtained from adjacent wells. This well has been producing for 6 years, and the first three-year production data were used for history matching to predict the future 3 year production.

Table 7. Properties of reservoir, fluid and well in the dry gas well.

Reservoir Pressure	2821.5 psia
Reservoir Temperature	181.4 ℉
Permeability	0.05 md
Porosity	6%
Water Saturation	30%
Net Pay	32.8 ft
Gas Gravity	0.621
Horizontal Well Length	2330 ft

3.2.1.2 Flow regime diagnostic plot

MBT diagnostic plot (Figure 18) indicated no obvious BDF happened during the well life even after 6275 MBT days, which is about 2134 days. So there is no need to switch the models to Arps for the forecast. YM-SEPD specialized plot used to determine the parameters of n and τ is illustrated below (Figure 19). Only the first three year data were used to fit a straight line. And any data off the trend were excluded for the fitting. BDF data, if any, were also excluded for using in the plot. Trendline indicates the portion of the data used for fitting. From the plot, it is easy to determine that n is 0.3116, and from τ is calculated as 44.71.

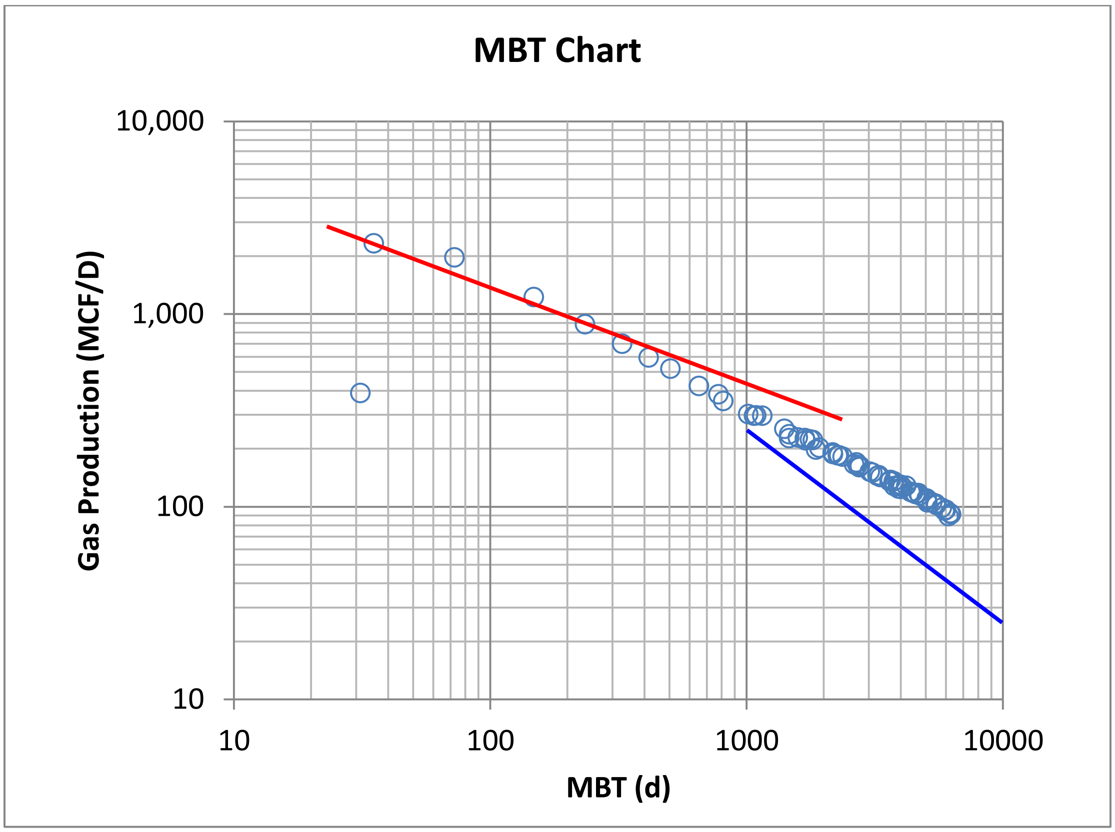

Figure 18. MBT diagnostic plot of wet gas well. Red line represents the negative half slope line and blue line represents the negative unit slope line.

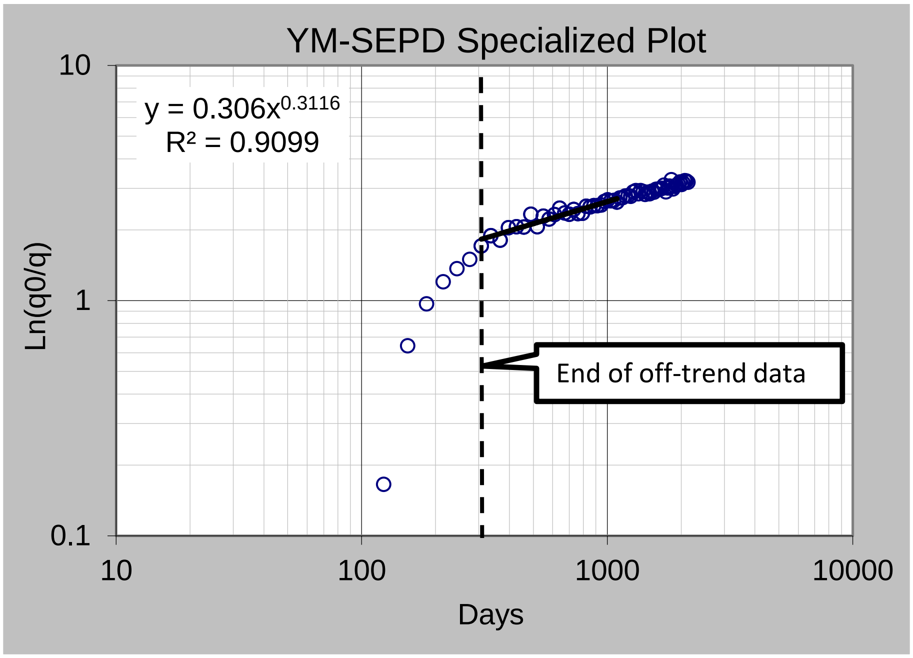

Figure 19. YM-SPED specialized plot for dry gas well example.

3.2.1.3 EUR forecast results

Since there is no BDF observed, there is no need to switch models for estimating the production of the well. Although the two models' parameters are completely different, YM-SEPD and SEPD gave comparable results with very small errors compared to the real data (less than 2%) (Table 8). Figure 20 and Figure 21 also showed that SEPD and YM-SEPD models matched the history data well and provided good forecasts of the production of well. In comparison, SEPD-All generated a bigger error with the estimate.

Table 8. SEPD parameters and estimated EUR for dry gas well.

Method	n	τ	q_i (MSCF/D)	EUR (MMscf)	%error of EUR
YM-SEPD	0.3116	44.71	2319	571	-1.38
SEPD	0.1908	0.3327	16424	569	-1.73
SEPD-All	0.6056	236.13	1631	533	-7.94
Model	---	---	---	579	---

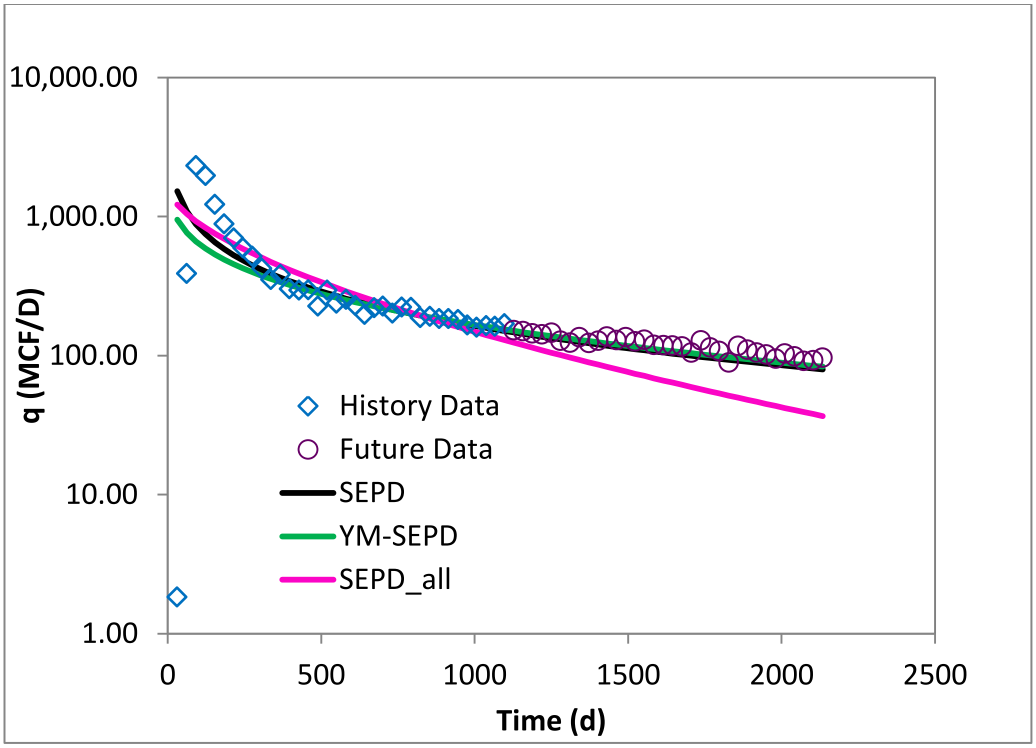

Figure 20. Production rate of the dry gas well and the forecast by different methods.

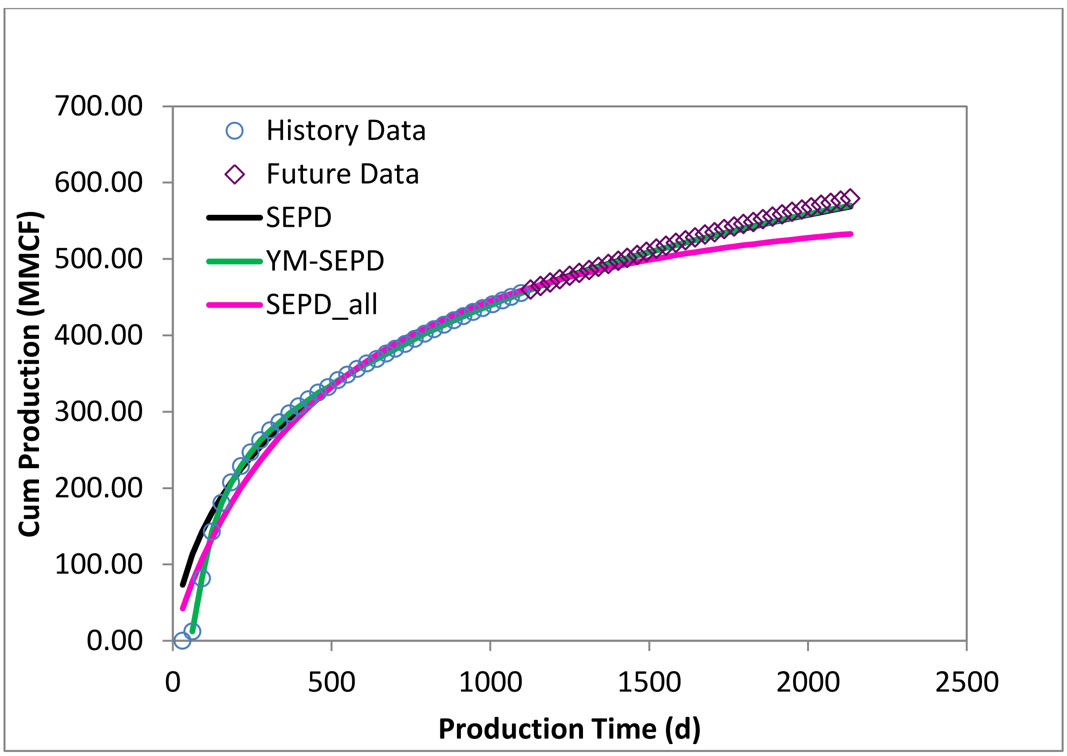

Figure 21. Cumulative production of dry gas well and the forecast by different methods.

3.2.2 Wet gas well

3.2.2.1 Reservoir, well, fluid properties

A wet gas well from WCB was studied. Properties of reservoir, fluid and well are illustrated in Table 9. The condensate yield of this well is about 5 STB/MMSCF. Production data were obtained from public database and reservoir parameters are referenced from a nearby vertical well. The well has been producing for more than 11 years. The first three year production data were used for history match to predict the future production.

Table 9. Properties of reservoir, fluid and well in the wet gas well.

Reservoir Pressure	2625 psia
Reservoir Temperature	176 °F
Permeability	0. 5 md
Porosity	6.5%
Water Saturation	20%
Net Pay	52.5 ft
Gas Gravity	0.716
Horizontal Well Length	3610 ft

3.2.2.2 Flow regime diagnostic plot

From MBT diagnostic plot (Figure 22), we can clearly observe that the well went through linear flow regime with negative half slope and entered BDF regime with negative unit slope at MBT 3000 days (in reality time, it is about 1580 days). For the SEPD+Arps and YM-SEPD+Arps methods, the equation is switched at the time that well enters BDF. YM-SEPD specialized plot used to determine the parameters of n and τ is illustrated below (Figure 23). Only the first three year data were used to fit a straight line.

And any data off the trend were excluded for the fitting. BDF data, if any, were also excluded.

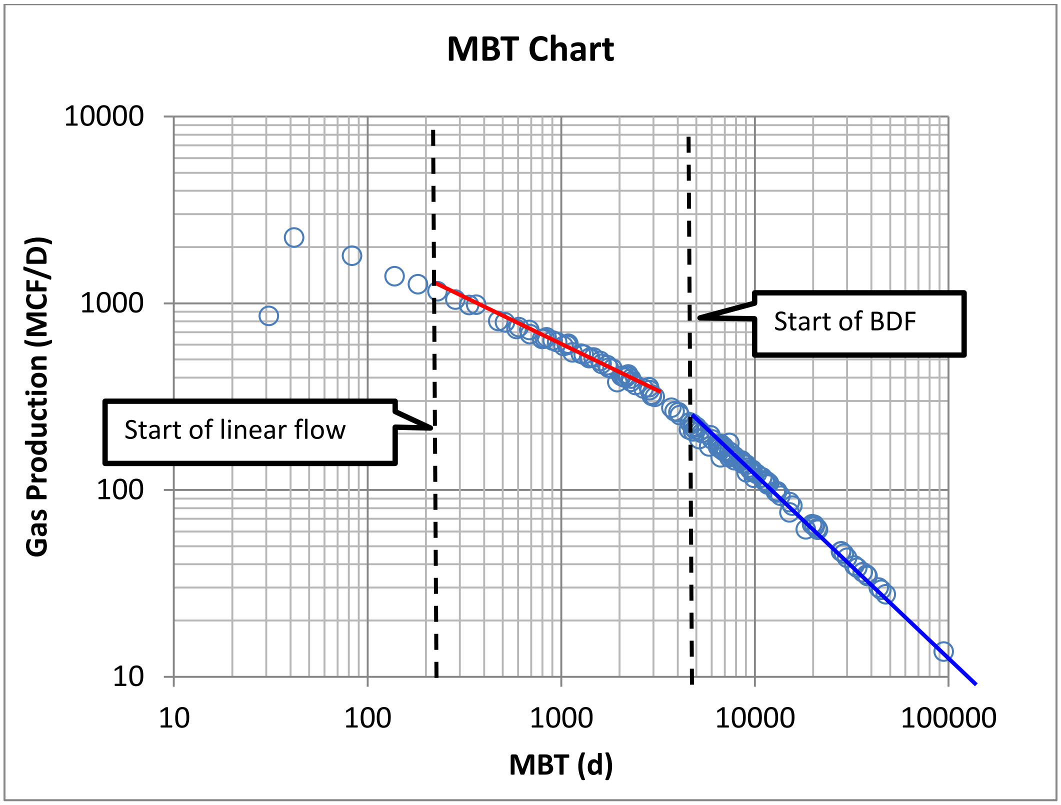

Figure 22. MBT diagnostic plot of wet gas well. Red line represents the negative half slope line and blue line represents the negative unit slope line.

3.2.2.3 EUR forecast results

EUR of the well predicted by different methods are summarized in Table 10 below. SEPD and YM-SEPD gave close results (14.49% higher for YM-SEPD and 11.96% higher for SEPD). With switching to Arps after BDF, SEDP+Arps and YM-SEPD+Arps gave better estimates (7.35% and 7.62% error). History matching and forecast by different methods are also illustrated in Figure 24 and Figure 25. YM-SEPD and SEPD models also have very different parameters (Table 10), i.e., 2242 MSCF/D vs. 4803 MSCF/D for q_i, 0.4263 vs. 0.2421 for n, and 333.725 vs. 30.76 for τ. But the forecast results of these two models do not have as big difference as the parameters.

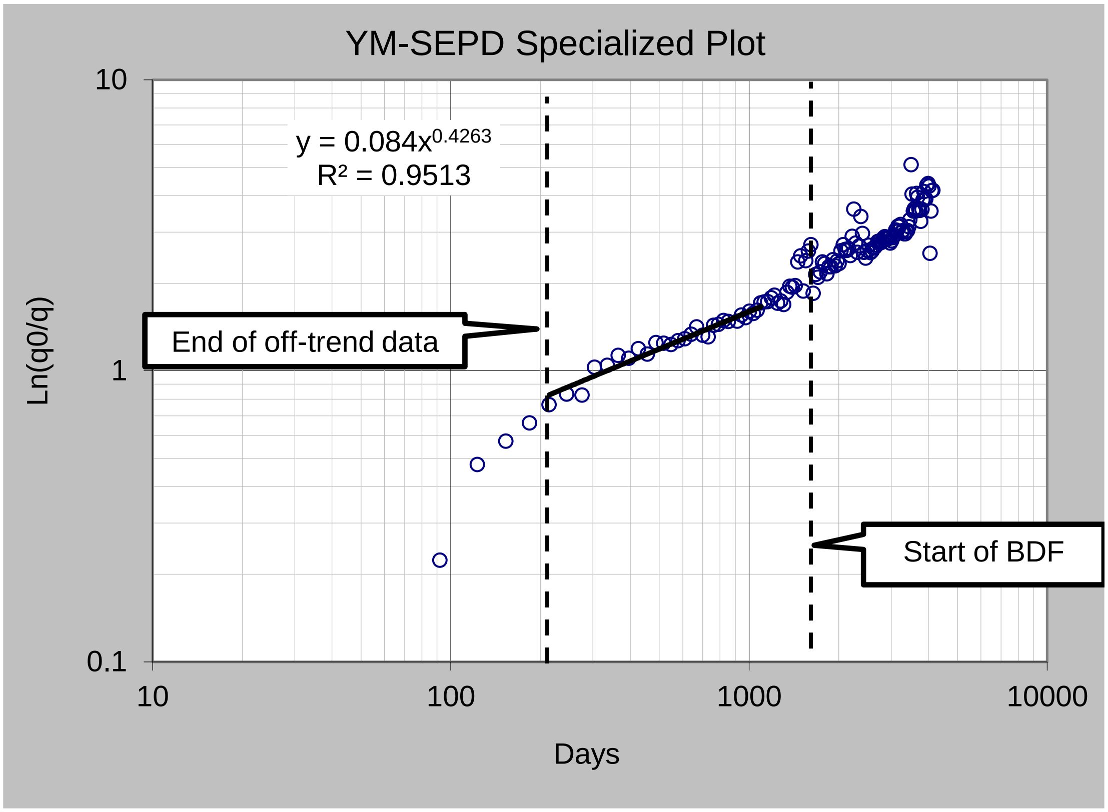

Figure 23. YM-SPED specialized plot for wet gas well example.

Table 10. SEPD parameters and estimated EUR for wet gas well.

Method	n	τ	q_i (MSCF/D)	EUR (MMSCF)	%error of EUR
YM-SEPD	0.4263	333.725	2242	1517	14.49
YM-SEPD+Arps	0.4263	333.725	2242	1410	6.42
SEPD-All	0.5260	466.478	1985	1423	7.40
SEPD	0.4213	296.76	2401	1505	11.96
SEPD+Arps	0.4213	296.76	2401	1404	5.96
Actual Data	---	---	---	1325	---

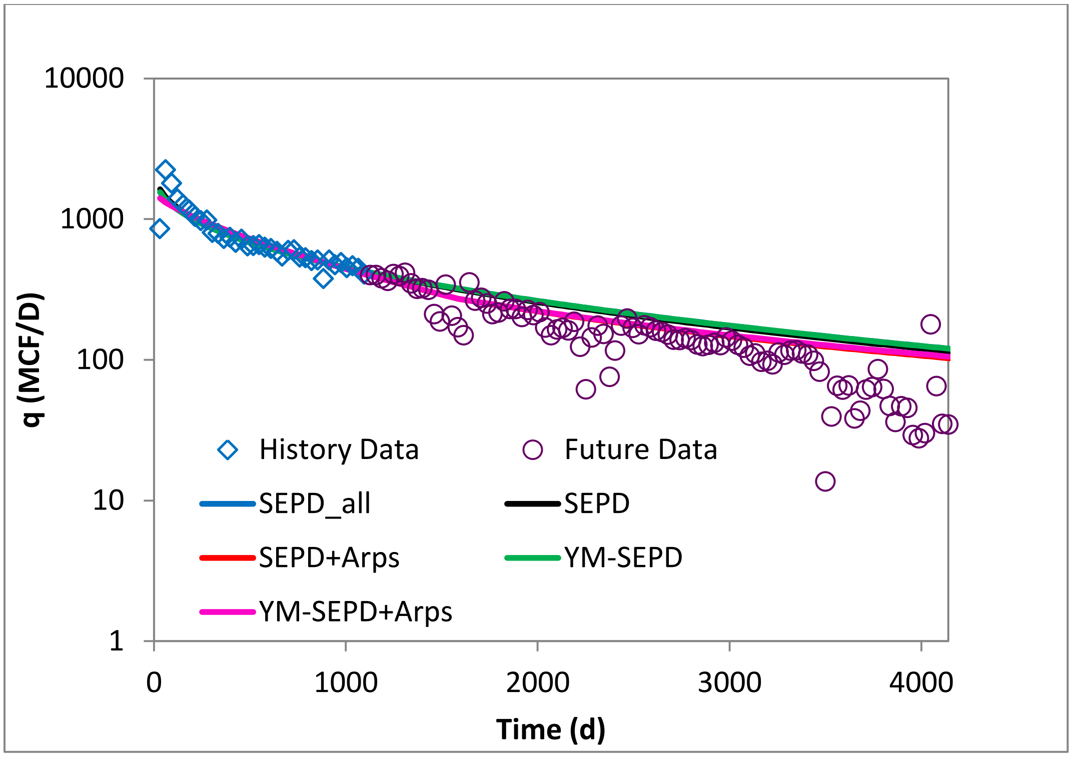

Figure 24 Production rate of the wet gas well and the forecast by different methods.

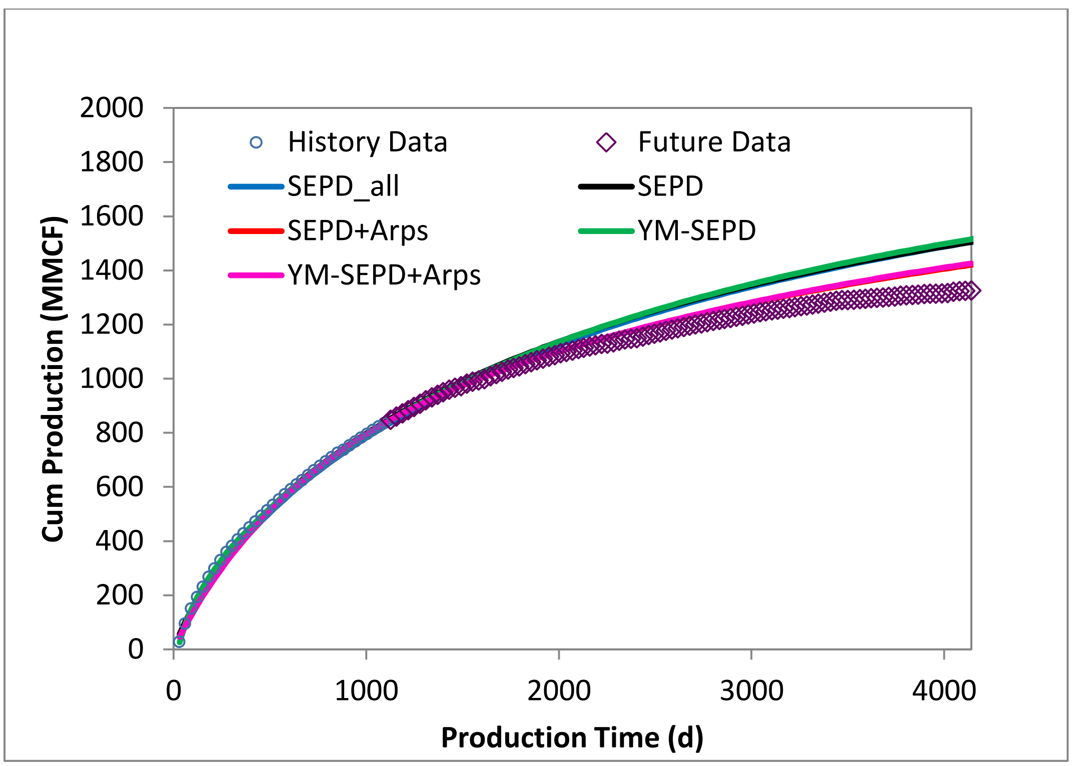

Figure 25. Cumulative production of wet gas well and the forecast by different methods.

3.2.3 Simulated retrograde gas well

3.2.3.1 Reservoir, well, fluid properties

A synthetic retrograde gas well production profile is generated. The properties of reservoir, fluid, and well are listed in Table 11. Reservoir fluid's PVT characterization is shown in Figure 26 (Yu et al. 2013).

Table 11. Properties of reservoir, fluid and well in the synthetic retrograde gas well.

Reservoir Pressure	7000 psia
Reservoir Temperature	350 ℉
Permeability	0.01 md
Porosity	6%
Water Saturation	35%
Net Pay	50 ft
Oil Gravity	47.6 API
Horizontal Well Length	6265 ft
Number of Stages	10
F_{CD}	17
Fracture Half-Length	250 ft
Flowing Pressure	800 psia
CGR	151 bbls/MMscf

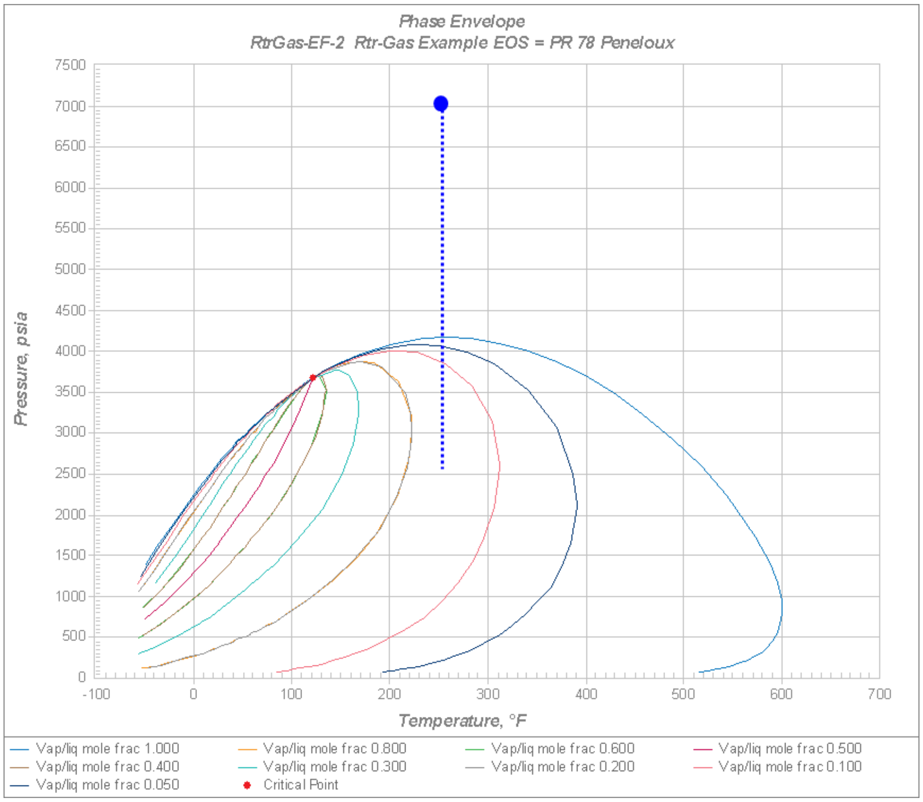

Figure 26. PVT envelope for retrograde gas well example.

3.2.3.2 Flow regime diagnostic plot

From the MBT chart (Figure 27), we can observe that the well entered BDF after 25000 MBT days (3400 days in reality). Therefore, for the SEPD+Arps and YM-SEPD+Arps methods, the model is switched at 3400 days. YM-SEPD specialized plot used to determine the parameters of n and τ is illustrated below (Figure 15). Only the first three year data were used to fit a straight line. And any data off the trend were excluded for the fitting. BDF data, if any, were also excluded for using in the plot. Trendline indicates the portion of the data used for fitting.

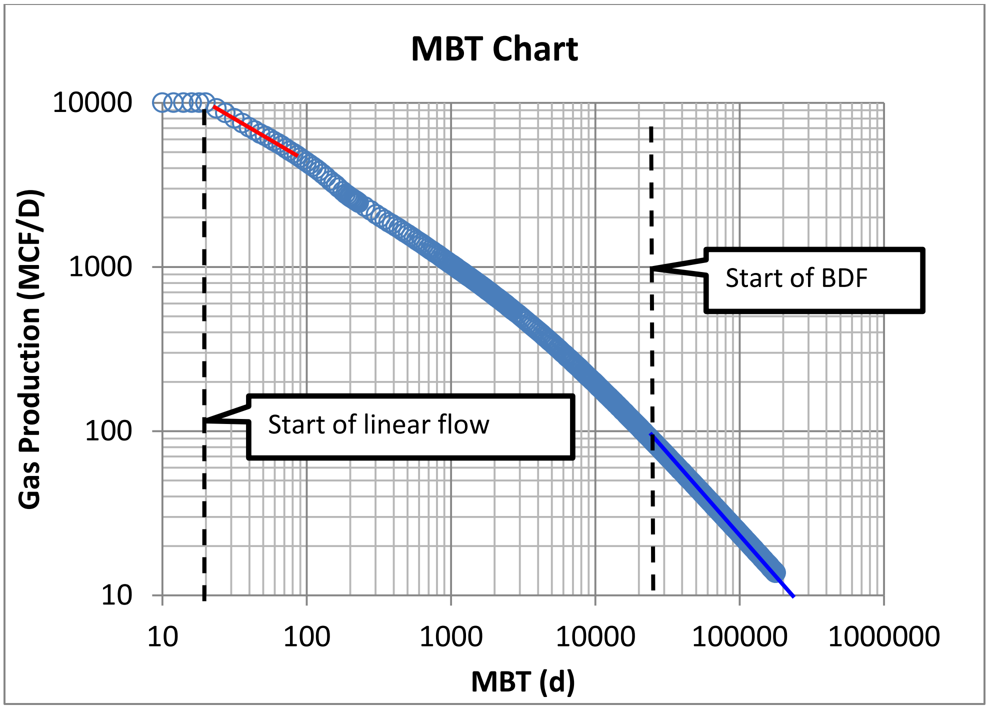

Figure 27. MBT diagnostic plot of gas production for synthetic retrograde gas well. Red line represents the negative half slope line and blue line represents the negative unit slope line.

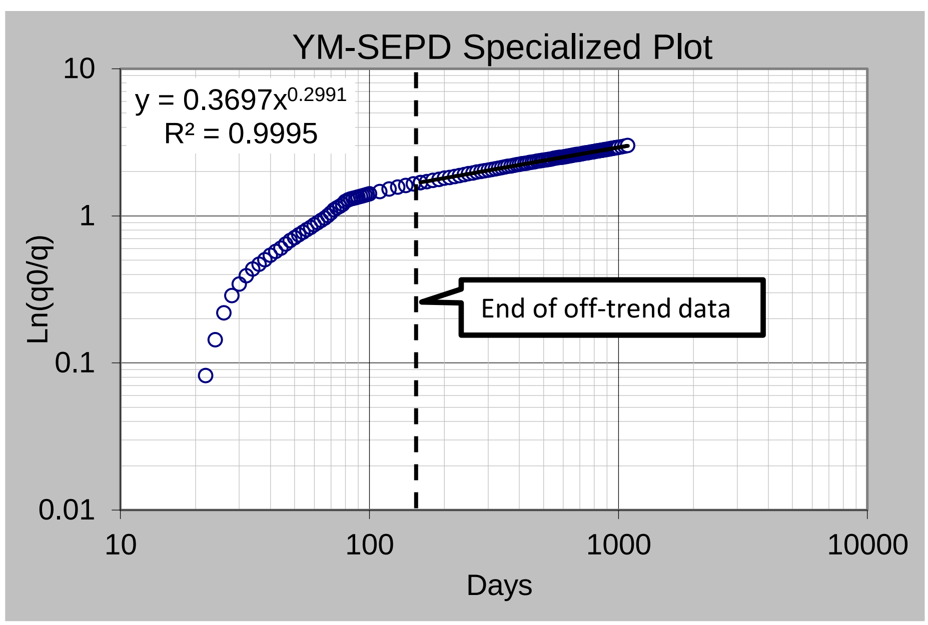

Figure 28. YM-SPED specialized plot for gas production of synthetic retrograde gas well.

3.2.3.3 EUR forecast results

EUR of gas production for the synthetic retrograde well predicted by different methods are summarized in Table 12 below. YM-SEPD and YM-SEPD+Arps overestimated the well production with a 3.35% error and 3.11% error, respectively. Both SEPD and SEPD+Arps underestimated the production with an error of -3.93% and -3.68%, respectively. In this example, switching to Arps equation after the well entered BDF did not affect much to the forecast of the well's production. SEPD-All underestimated the production and provided the poorest forecast among all the methods.

Table 12. SEPD parameters and estimated EUR of gas production for synthetic retrograde gas well.

Method	n	tau	q_i (MSCF/D)	EUR (MMSCF)	%error of EUR
YM-SEPD	0.2991	31.10	10000	2525	3.35
YM-SEPD+Arps	0.2991	31.10	10000	2501	2.37
SEPD-All	0.2687	2.024	37307	2277	-6.79
SEPD	0.2387	2.39	33792	2347	-3.93
SEPD+Arps	0.2387	2.39	33792	2316	-5.20
Model				2443	

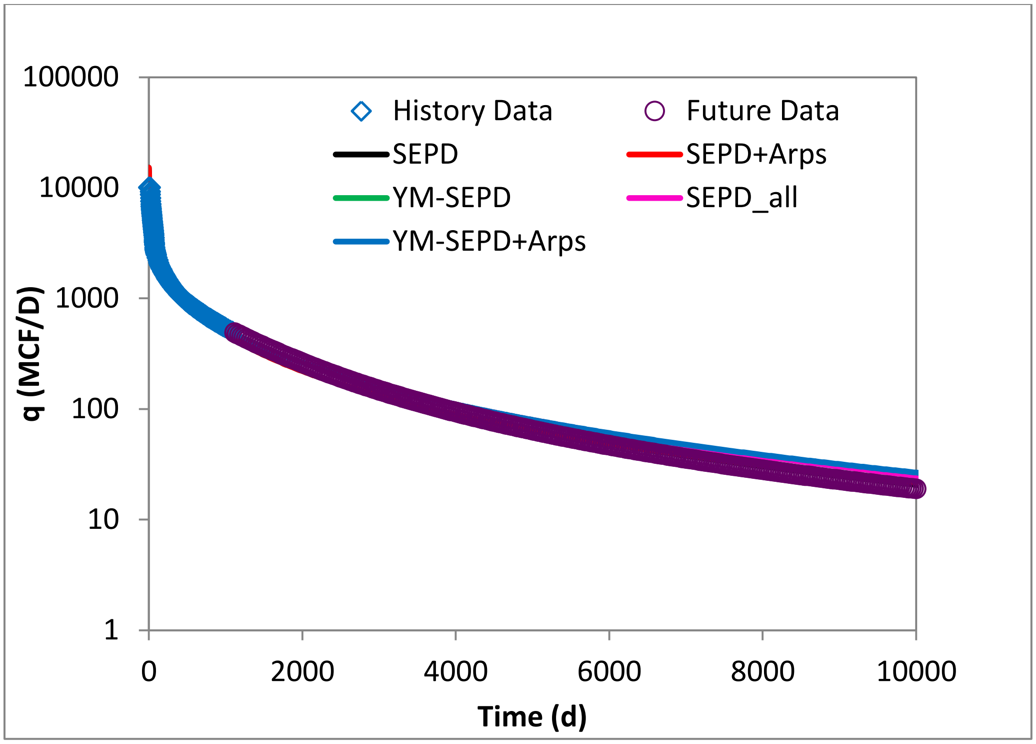

Figure 29. Gas production rate of the synthetic retrograde gas well and the forecast by different methods.

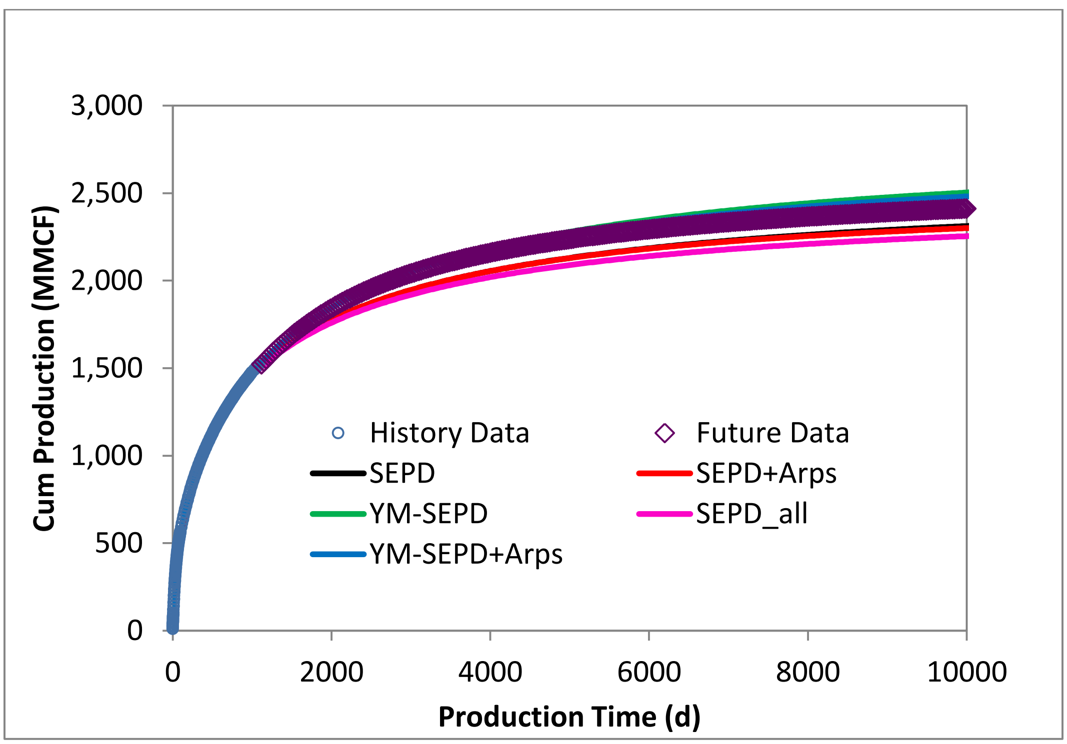

Figure 30. Gas cumulative production of synthetic retrograde gas well and the forecast by different methods.

3.2.4 Retrograde gas field well

3.2.4.1 Reservoir, well, fluid properties

The retrograde gas well field example is also from WCB. Production data were obtained from public database. The well has been producing for almost 10 years. Properties of reservoir, fluid and well are listed in Table 13. The first three year production data were used for history matching to predict the future production.

Table 13. Properties of reservoir, fluid and well in the retrograde gas well field example.

Reservoir Pressure	1815 psia
Reservoir Temperature	140 ℉
Permeability	<0.1 md
Porosity	6.3%
Water Saturation	12%
Net Pay	59.1 ft
Oil API	56
Horizontal Well Length	2014 ft

3.2.4.2 Flow regime diagnostic plot

MBT chart (Figure 31) showed that the well entered BFD at 8500 MBT days (2780 days in reality time). For method SEPD+Arps and YM-SEPD+Arps, the working equation is switched at 2780 days.

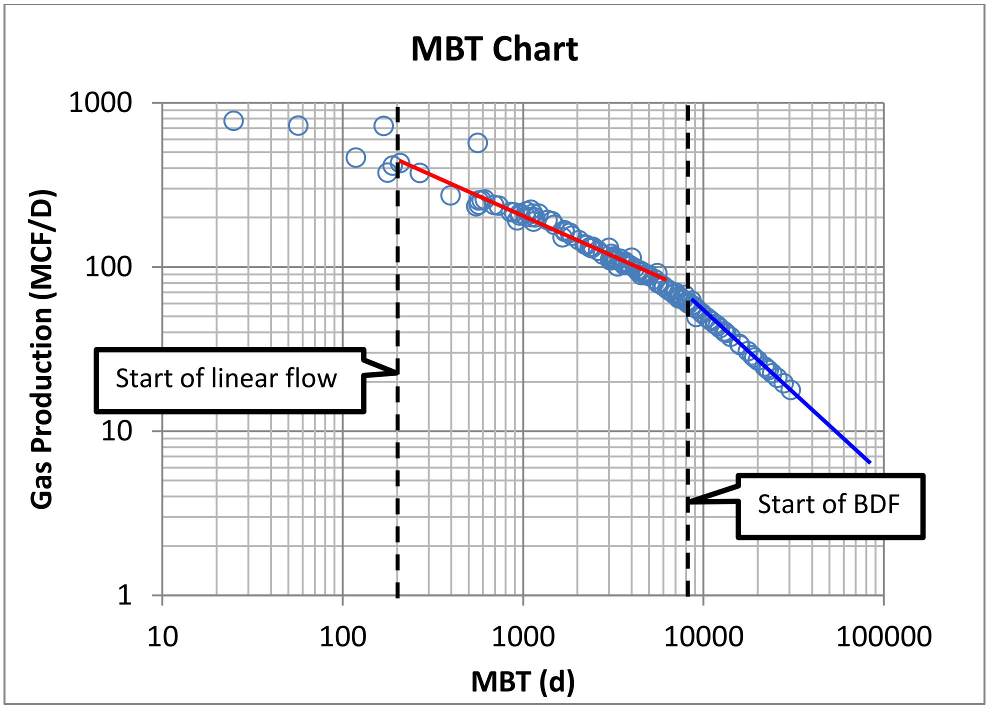

Figure 31. MBT diagnostic plot of gas production for retrograde gas well field example. Red line represents the negative half slope line and blue line represents the negative unit slope line.

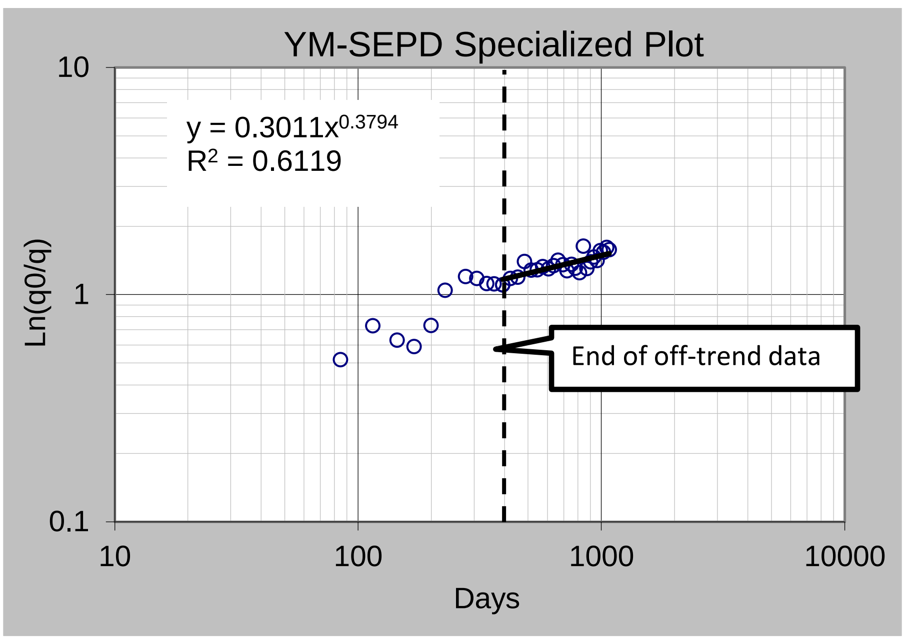

Figure 32. YM-SPED specialized plot for gas production of retrograde gas well field example.

3.2.4.3 EUR forecast results

EUR of gas and oil production for the synthetic retrograde well predicted by different methods are summarized in below (Table 14, Figure 33, Figure 34). YM-SEPD and YM-SEPD+Arps overestimated the well production with a 5.88% and 4.96% error, respectively. SEPD and SEPD+Arps overestimated the production with errors of 13.24% and 13.42%, respectively. SEPD-All overestimated the production by 14.7%.

Table 14. SEPD parameters and estimated EUR of gas production for retrograde gas well field example.

Method	n	τ	q_i (MSCF/D)	EUR (MMSCF)	%error of EUR
YM-SEPD	0.3794	312.48	774.8	576	5.88
YM-SEPD+Arps	0.3794	312.48	774.8	571	4.96
SEPD-All	0.1982	7.9461	2288	624	14.70
SEPD	0.1982	7.3137	2361	616	13.24
SEPD+Arps	0.1982	7.3137	2361	615	13.05
Model				544	

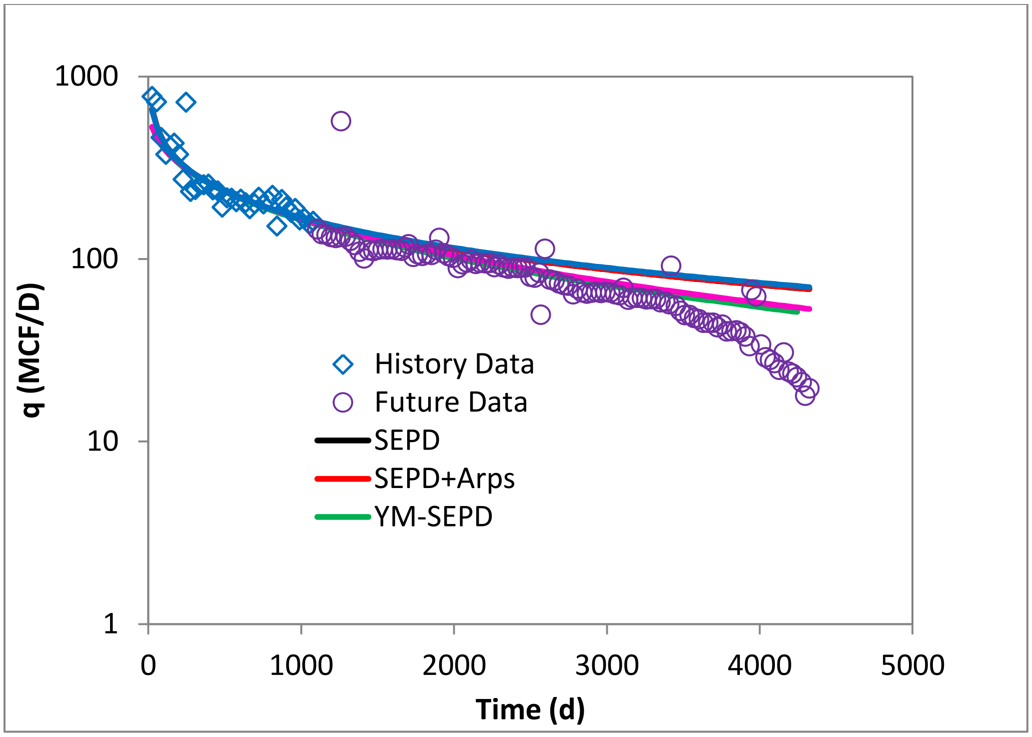

Figure 33. Gas production rate of the retrograde gas well field example and the forecast by different methods.

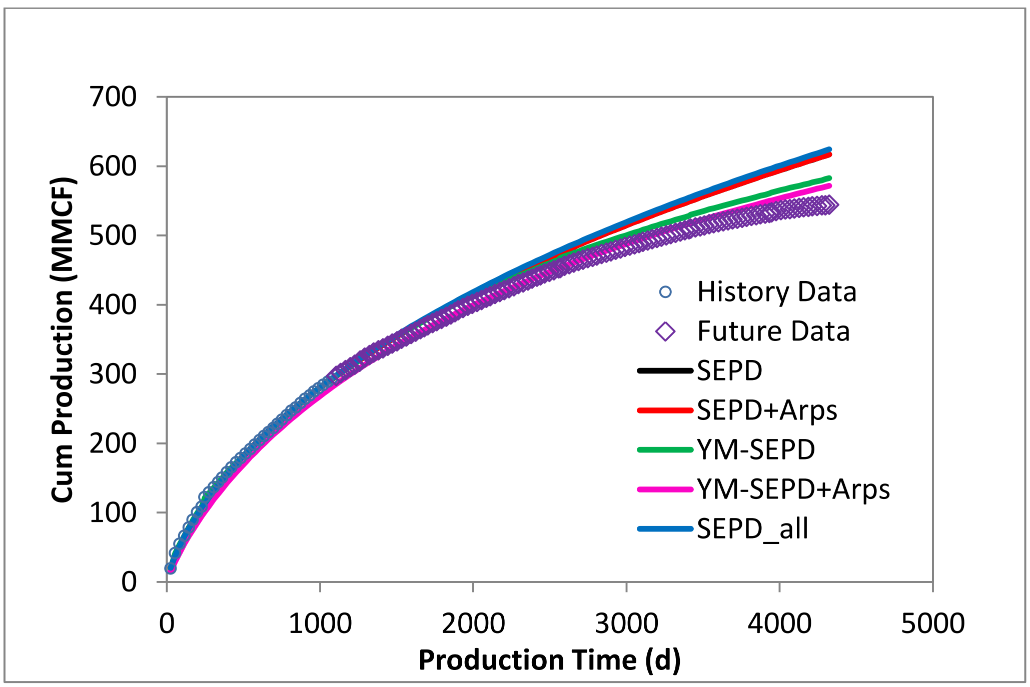

Figure 34. Gas cumulative production of the retrograde gas well field example and the forecast by different methods.

In summary, YM-SEPD gave the best results for all the examples studied here. When excluding the early off-trend data, SEPD gave results comparable to YM-SEPD. Especially for the synthetic cases, YM-SEPD and SEPD methods both forecast the production with small errors. Although the working parameters of two models are completely different for all cases, the values estimated by the two models are very similar. But when including all the production data, as many people do in practice, SEPD tends to forecast the production with bigger error. On the other hand, YM-SEPD is much easier to use than SEPD. As mentioned above, YM-SEPD avoids the problems introduced by the regression routine in Excel Solver.

It is also noted that although sometimes, switching from SEPD to Arps after the well entering BDF gives a better estimation of the well production, in several cases, switching the working equation does not affect the final estimate much. For example, in the wet gas case, the EUR of the well estimated by SEPD is 1505 MMSCF, while the EUR of the well estimated by SEPD+Arps is 1421 MMSCF, which is 5.6% less. In the synthetic retrograde gas case, the EUR of the well estimated by SEPD is 2347 MMSCF, while the EUR of the well estimated by SEPD+Arps is 2353 MMSCF, which only has 0.2% difference. For the wet gas case, the difference between the results provided with and without switching is bigger than the retrograde gas case, this might be because for the retrograde case, BDF happened very late in the well's life, and when BDF happens, most of the reserve has already been produced. So switching the equation to Arps does not bring too much difference to the final result.

3.3 Effect of q_i on EUR forecast when applying YM-SEPD

One of the assumptions when applying YM-SEPD is to set q_i as the highest production rate observed in the production history. But this value may not be and often will be less than the real production rate at time 0. In order to analyze the effect of q_i on EUR forecast, a factor of "x" is introduced to the SEPD equation,

$$ln\left[\frac{xq_0}{q(t)}\right] = \tau^{-n}t^n \text{ and} \tag{15}$$

$$q_i = xq_0, \tag{16}$$

where q_0 is the highest production rate observed in the production history. The value of "x" is arbitrarily set between 1 and 4 to see how sensitive it is that EUR varies with q_i. We used wet gas case as an example. A chart of EUR vs. a is shown below (Figure 35). When "a" is equal to 1, EUR of the well is 1517 MMSCF, while with "a" of 4 (q_i is 4 times as the highest rate observed), EUR of the well is 1673 MMSCF, which is 10.28% higher. Figure 36 and Figure 37 also represent the YM-SEPD plots with x equal to 1 and 4, respectively. They illustrate that there is no obvious shape change in the plot after x is increased. Therefore, the EUR forecast is not very sensitive to q_i, and the assumption of setting q_i as the highest observed rate is sound.

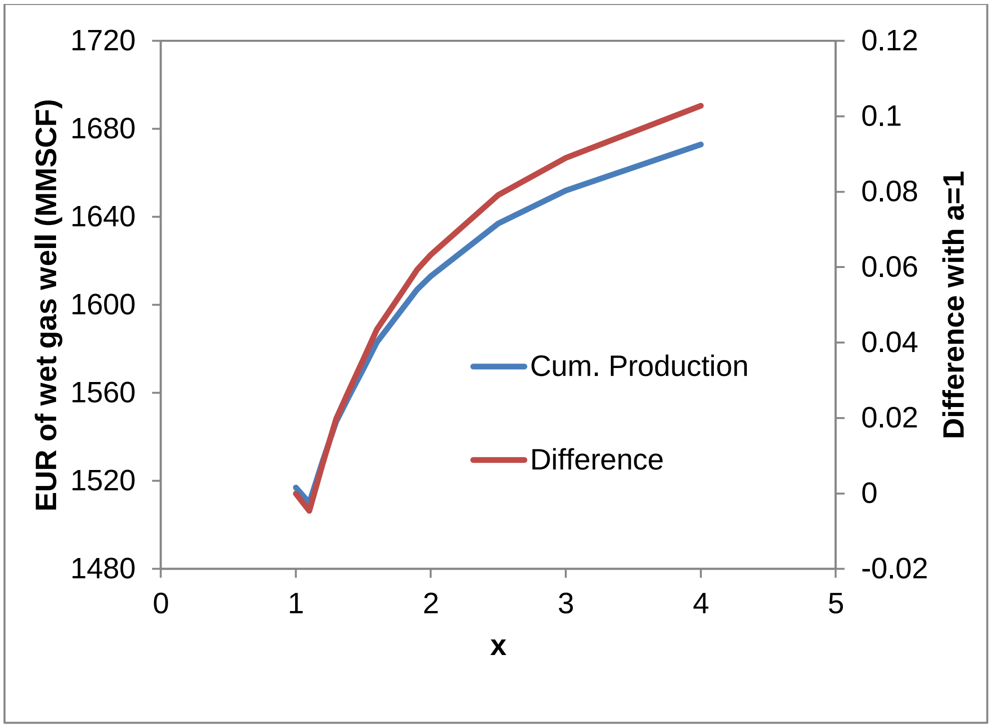

Figure 35. Effect of a on EUR of wet gas well.

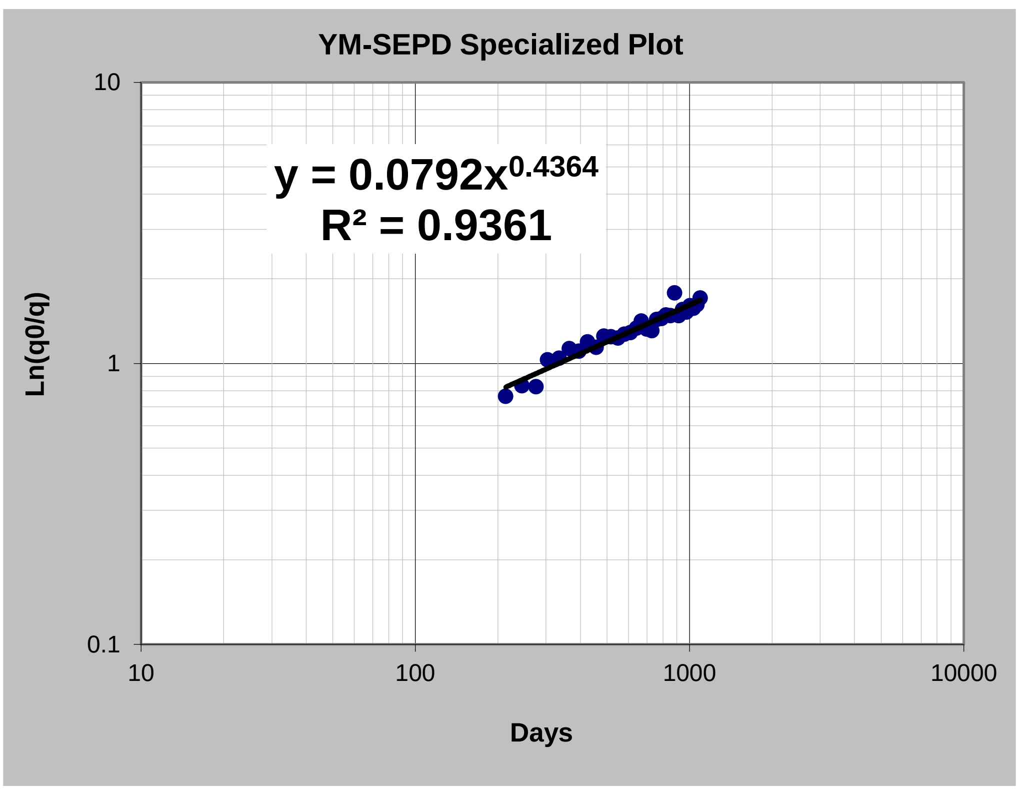

Figure 36. YM-SEPD plot with x equal to 1.

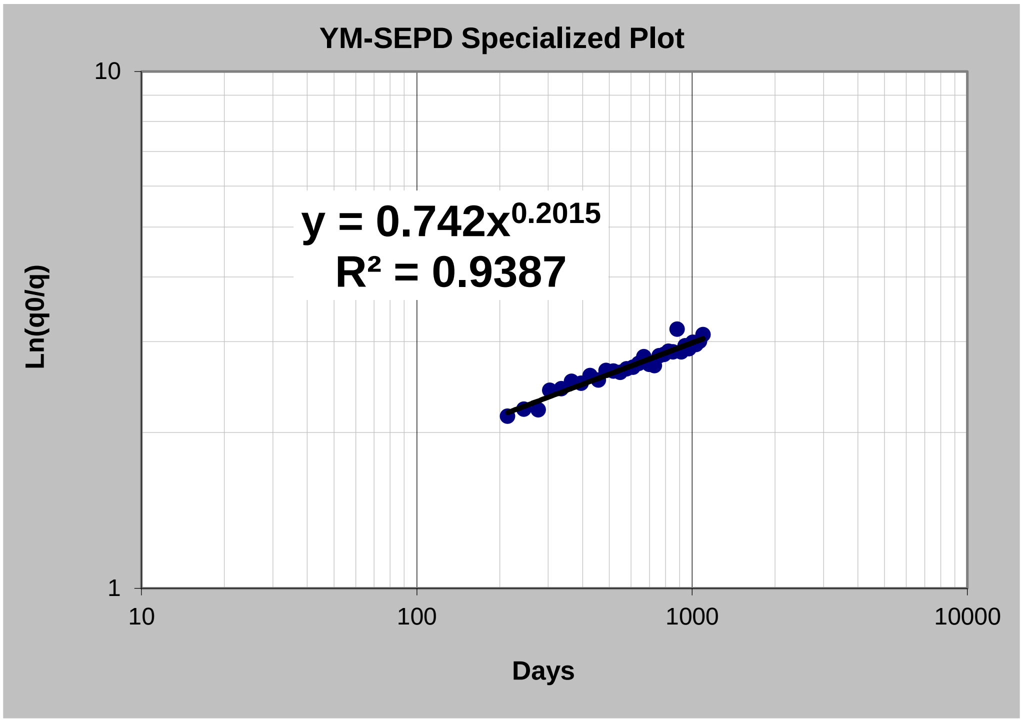

Figure 37. YM-SEPD plot with x equal to 4.

Chapter 4 Conclusions

This study generally compared four different empirical decline methods to forecast the production of shale gas well, with special emphasis on different forms of the SEPD model. The following conclusions can be drawn:

- When excluding the early off-trend data, the SEPD model is more reliable for forecasting the production of shale gas wells compared with Arps and Duong models. YM-SEPD and SEPD gave comparable results for all the examples studied here.
- When all production data are included for curve fitting, SEPD usually provides a poor forecast of the well production.
- With an illustrative specialized plot, YM-SEPD is easier to use than SEPD.
- Switching from SEPD or YM-SEPD to Arps after the well enters BDF gives a better estimation of the well production. But when BDF happens very late in the well's life (which is common for shale gas wells), switching to Arps does not cause too much difference in the final result. This is because when BDF appears, most of the EUR has already been produced.
- When applying YM-SEPD, EUR does not vary much with changing q_i, so the assumption of setting q_i as the highest observed rate causes no important inaccuracies.
- More thorough studies are required to confine the conditions for YM-SEPD applications. In this study, only wells in Barnett Shale and WCB were studied, therefore, when applying the method discussed here in other reservoirs, more detailed studies designed for the specific reservoir are required.

- This is only a start for the study of production forecasts in unconventional formations, and more studies are needed for this topic.

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