fastrta

# RTA Workflow for Shale Gas Wells Exhibiting Continuous Linear Flow

The following describes the recommended workflow within F.A.S.T. RTA™ for analyzing shale gas reservoirs. The workflow involves using several different techniques, which together can be used to obtain a reliable interpretation and production forecast.

**Workflow Summary:**

**1) Wattenbarger Typecurve Analysis**

- Helps identify flow regimes
- Ensure data are properly filtered (outliers/noise removed)
- Use "Derivative" plot with Bourdet (0.2) setting
- Look for ½ slope in Derivative data
  **Note:** ½ slope may **NOT** be present in normalized rate data

**2) Specialized Analysis – Linear Plot**

- Confirms the presence of linear flow – should be a straight line
- Ensure options "Linear" and "Constant Pressure" are used
- For horizontal multi-frac'd wells, set "$x_f$" equal to **half** the effective well length
- The calculated permeability "$k$" represents an "effective permeability" for the stimulated reservoir volume (SRV)
- Positive y-intercept indicates apparent damage skin

**3) Flowing Material Balance**

- Estimates minimum or contacted gas-in-place (OGIP) and associated drainage area

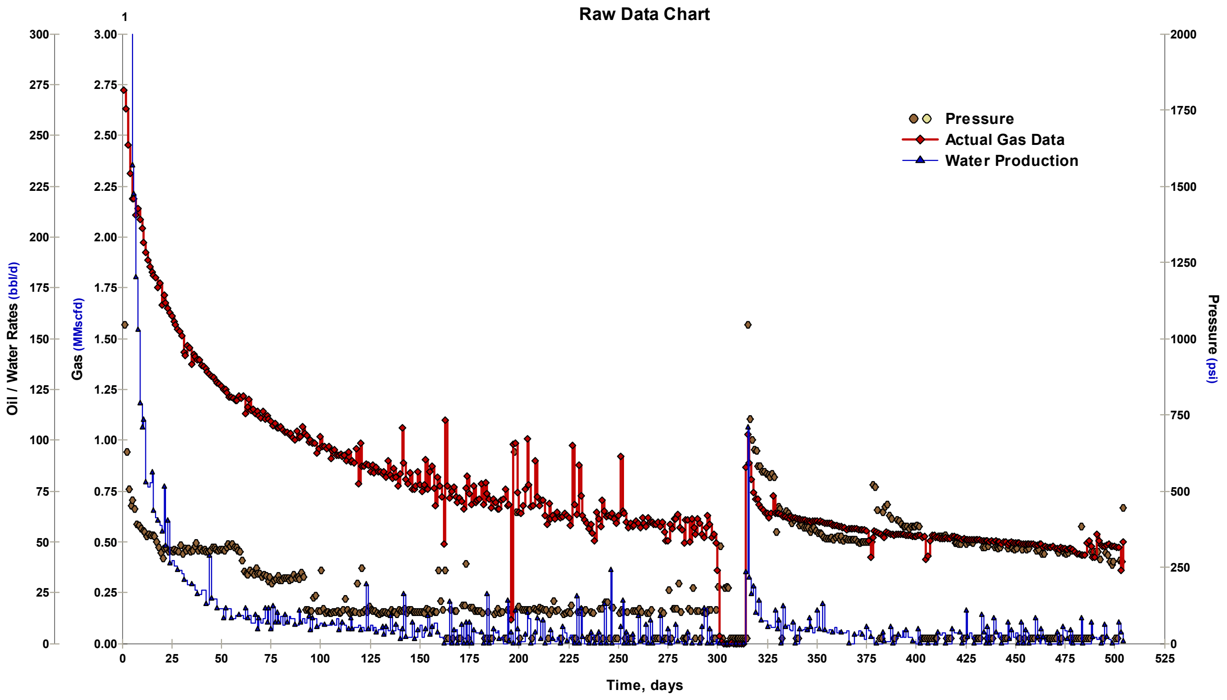
**4) Analytical Modeling/Forecasting**

- Helps to validate the interpretation
- Provides production forecasts for a range of different assumed drainage areas
- Seed the "Fracture" model using "$k$" and "$x_f$" from "Specialized Analysis"
- Set reservoir $x_e$ boundary to 2 * $x_f$, and set $y_e$ boundary to a value consistent with the OGIP determined from FMB
- Fine tune the history match by changing $k$ and $y_e$
- Run production Forecast using appropriate constraints
- Return to Fracture model and vary OGIP by varying $y_e$ boundary (ensure $y_w$ is set to ½ of $y_e$) to increasingly larger values, repeating the forecast for each run
- Plot the forecast results (EUR) against input reservoir volumes (OGIP)
- Upper limit of OGIP should be based on microseismic or well spacing

**5) Traditional**

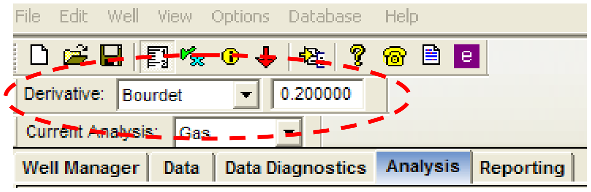
- Provides forecast in a standard form
- Use hyperbolic exponent "b" equal to 2 if you believe you have linear flow
- Use "Modified Hyperbolic" and set "$D_{lim}$" to a reasonable value (5% to 10%) or to such a value that the EUR is consistent with that of the analytical forecasts

## Example: Well 1



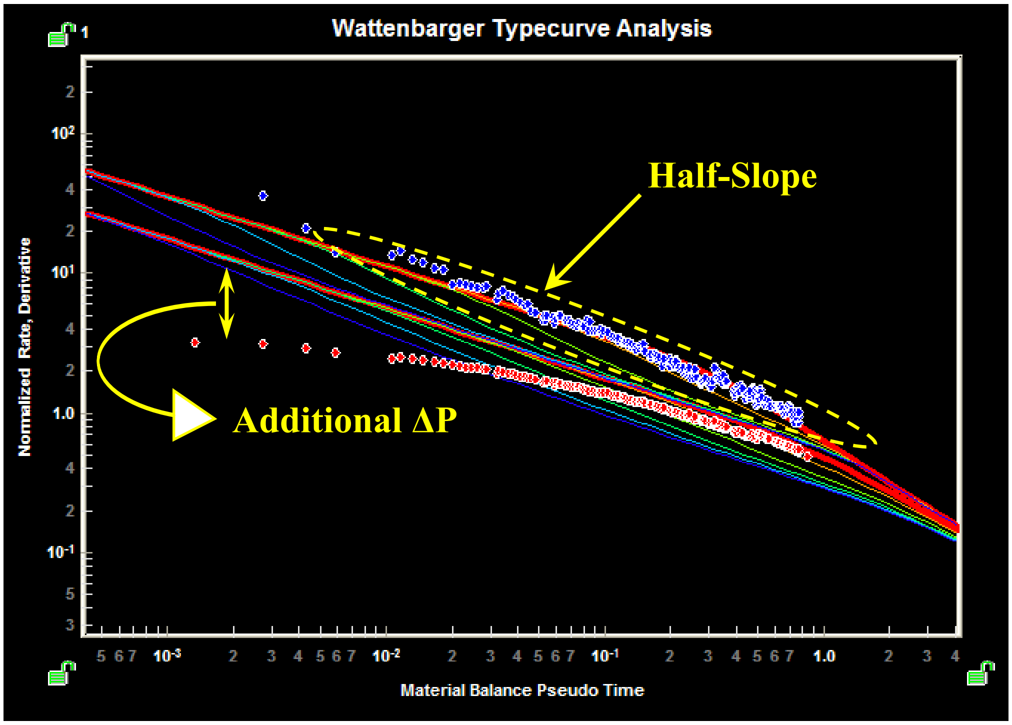
## Step 1: Wattenbarger Type Curve Analysis (Log-Log Plot)

Flow regime characterization is often possible by examining the data using Wattenbarger's typecurve analysis. In this technique, the normalized rate and the Derivative are plotted versus material balance time on a log-log plot. Linear flow is indicated if the Derivative is a "half-slope". Often, the early time rate data departs from the rate type curve, even though the derivative data matches the derivative type curve. This is an indication of an additional pressure drop, not accounted for in the Wattenbarger analysis. This pressure drop may be referred to as an apparent skin. The example well illustrates this scenario in the plot below. This additional pressure drop is caused by unaccounted-for effects such as: fracture face skin, choke skin, convergence skin, poor early-time pressure data, well clean-up, etc. In this case, the data has been filtered and a 'Bourdet' derivative of 0.2 has been selected to aid in revealing the observed half-slope. This technique should be considered to be a screening method rather than a quantitative analysis tool, and should be used in conjunction with **Step 2.**



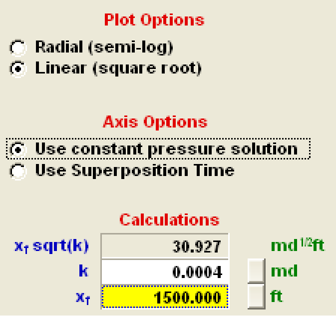
Derivative: Bourdet 0.200000

Current Analysis: Gas



## Step 2: Specialized Analysis – Linear Plot

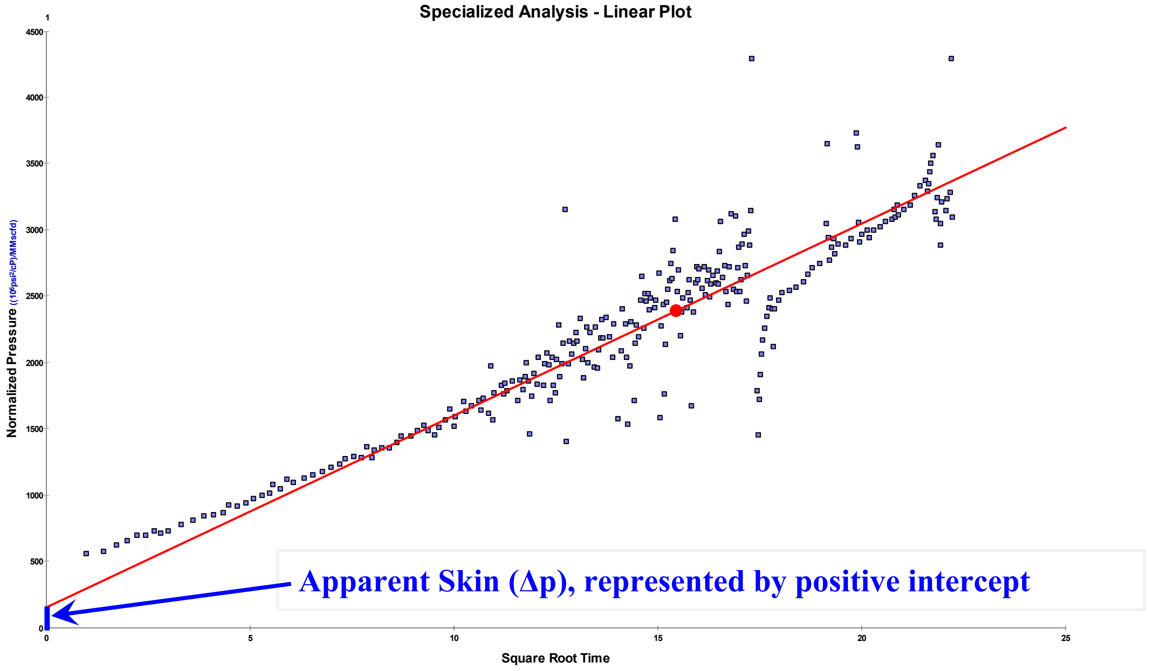
The Specialized Analysis module is used, in conjunction with **Step1** to confirm the presence of linear or radial flow. The half-slope segment of the log-log plot in the Wattenbarger derivative is equivalent to a straight line on the square root time specialized plot. Unlike radial flow, which yields the flow capacity *kh* (the product of permeability and net pay), linear flow yields the term of $A\sqrt{k}$ (the product of the cross-sectional area available to flow and the square root of permeability). From the slope of the straight line, and knowing values for other reservoir parameters, we can calculate $x_f\sqrt{k}$ (as area to flow is related to $x_f$ and *h*). In this example, half the completed length of the horizontal wellbore (½*3000 ft) is entered as the fracture length. The software will calculate an effective permeability ($k_{eff}$). This "effective permeability" is useable only in conjunction with the specified fracture length. It should not be interpreted as representing either the fractures or the matrix, but it is a meaningful combination of the two. It will be the value used as the initial input parameter for *k* in the analytical modeling (i.e. history matching) of this data set. The resulting additional ΔP observed in Wattenbarger is recognized on the linear plot as a positive ordinate-intercept (i.e. a value above the origin), identified on the plot below. For transient flow regimes other than linear flow, a different workflow is required.


Plot Options
○ Radial (semi-log)
● Linear (square root)

Axis Options
● Use constant pressure solution
○ Use Superposition Time

Calculations

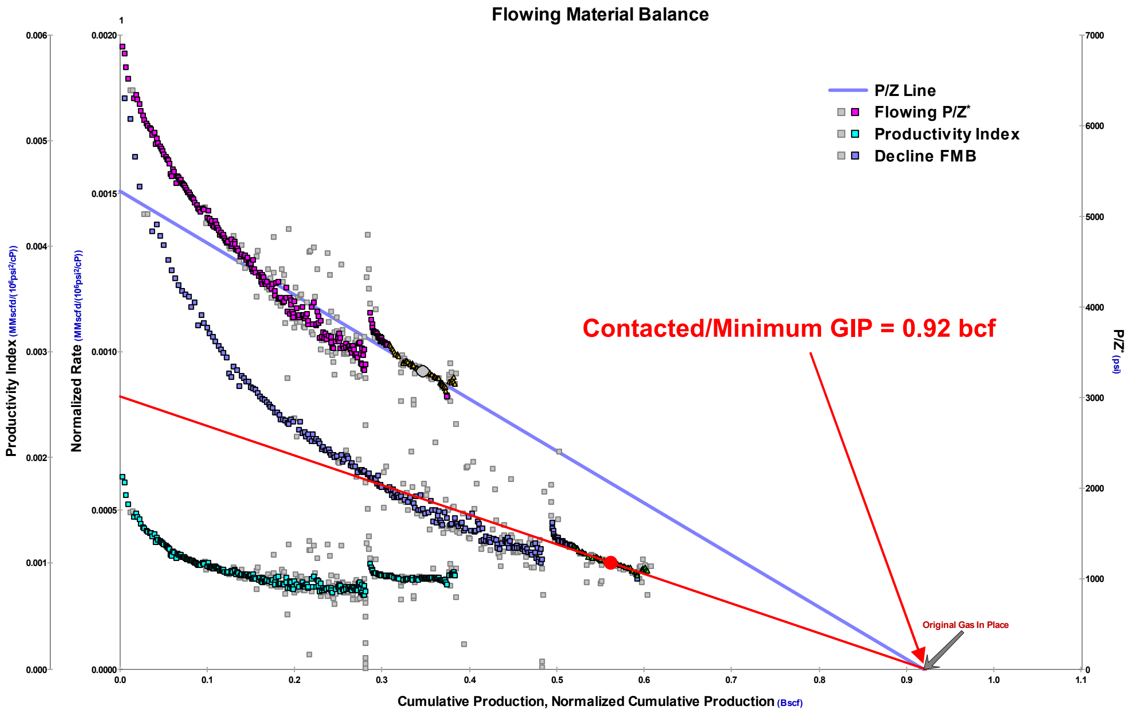
| | | |
|---|---|---|
| $x_f$ sqrt(k) | 30.927 | md $^{1/2}$ft |
| k | 0.0004 | md |
| $x_f$ | 1500.000 | ft |



Apparent Skin (Δp), represented by positive intercept

## Step 3: Flowing Material Balance

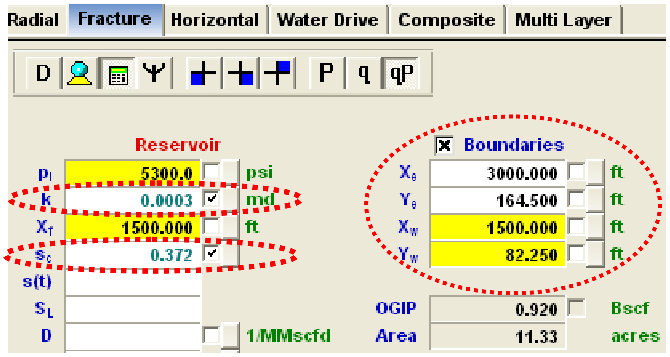
FMB is a technique that assumes the late-time data is in boundary dominated flow and therefore points towards an original-gas-in-place. For data that is suspected to be transient, the FMB module is still useful in that it provides an estimate of minimum (or contacted) gas-in-place.



Contacted/Minimum GIP = 0.92 bcf

## Step 4: History Matching

Analytical modeling using a Fracture Model is the final step in the interpretation of the data. Honoring the results from **Step 2**, input 1500 ft for $x_f$ (half the completed lateral length of the horizontal wellbore) and the $k$ determined in **Step 2**. Input a small value for skin, $s_c$ (say 1.0), to account for the intercept of the $\sqrt{t}$ straight line of **Step 2**. The boundaries of the reservoir are then set so that the flow regimes progress from linear flow directly to boundary dominated flow. To accomplish this, the reservoir length ($x_e$) is set to be exactly twice that of the fracture half length. The reservoir width ($y_e$) is adjusted to a value corresponding to the minimum-gas-in-place arrived at from the FMB method (**Step 3**). The fracture is positioned in the center of the model (as indicated by $x_w$ and $y_w$). Optimize the Model by iterating on $k$ and $s_c$. In this example, it can be seen that only a minor change to $k$ is required to obtain the best history match (from 0.0004 md to 0.0003 md) as presented in the figure below. Thus, the $x_f\sqrt{k}$ from **Step 2** is honored. These optimized parameters are used to generate the first history match of the pressure and rate data.



Reservoir

$p_i$ 5300.0 ☐ psi

k 0.0003 ☑ md

$X_f$ 1500.000 ☐ ft

$s_c$ 0.372 ☑

s(t)

$S_L$

D ☐ 1/MMscfd

☒ Boundaries

$X_e$ 3000.000 ☐ ft

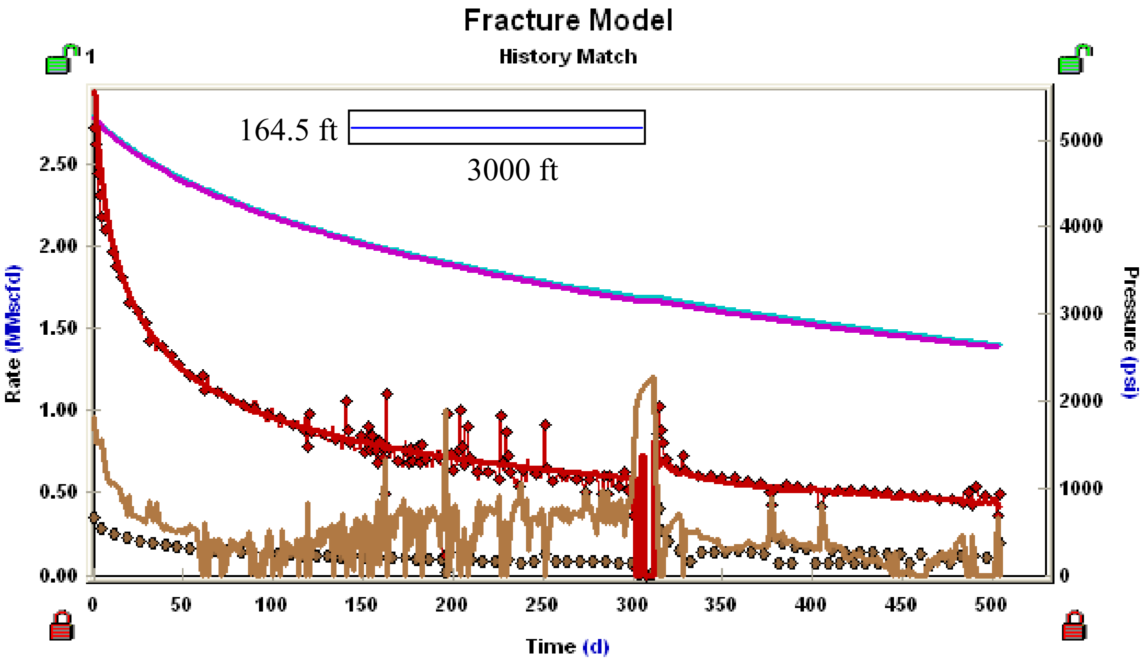
$Y_e$ 164.500 ☐ ft

$X_w$ 1500.000 ☐ ft

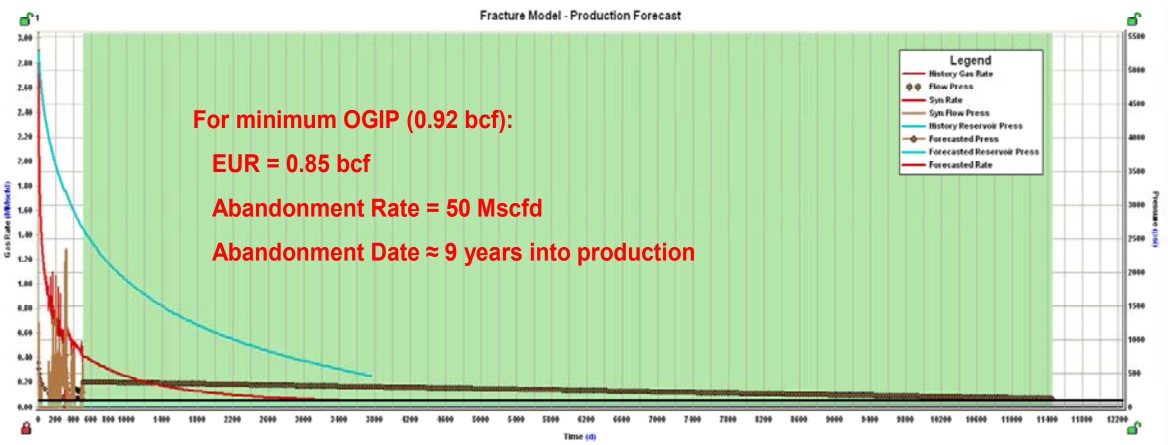
$Y_w$ 82.250 ☐ ft

OGIP 0.920 ☐ Bscf

Area 11.33 acres



Forecasting from this optimized model and using the **minimum** gas-in-place yields an EUR of 0.85 bcf as shown in the figure below.



For minimum OGIP (0.92 bcf):

EUR = 0.85 bcf

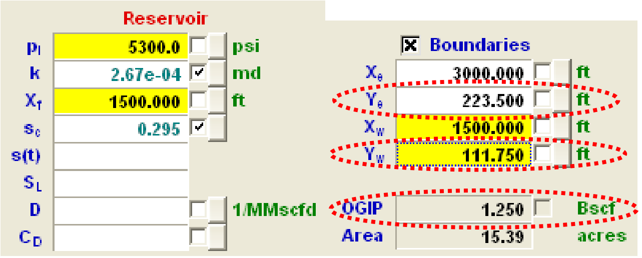
Abandonment Rate = 50 Mscfd

Abandonment Date ≈ 9 years into production

## Step 5: Determine EUR as a function of OGIP

Assuming the well is still in linear (transient) flow, recoverable reserves cannot be uniquely determined. Note also that the OGIP determined in **Step 3** (FMB), and used in **Step 4,** is the **minimum** value. Thus, it is appropriate to start with the minimum reservoir size, and progressively increase the drainage area, forecasting recoverable reserves for each case. This is done by increasing the reservoir width ($y_e$) to obtain larger reservoir sizes while adjusting the $y_w$ term to maintain the central position of the fracture within the model. The maximum OGIP (or largest $y_e$) is based on known stimulated volumes through microseismic mapping or well spacing.

A larger reservoir size (1.25 bcf) is shown below using the same reservoir parameters [*k*, *$x_f$* and *$s_c$*] as the optimized model. The corresponding history match is also presented. The history match did not change for models of reservoir sizes larger than this case.

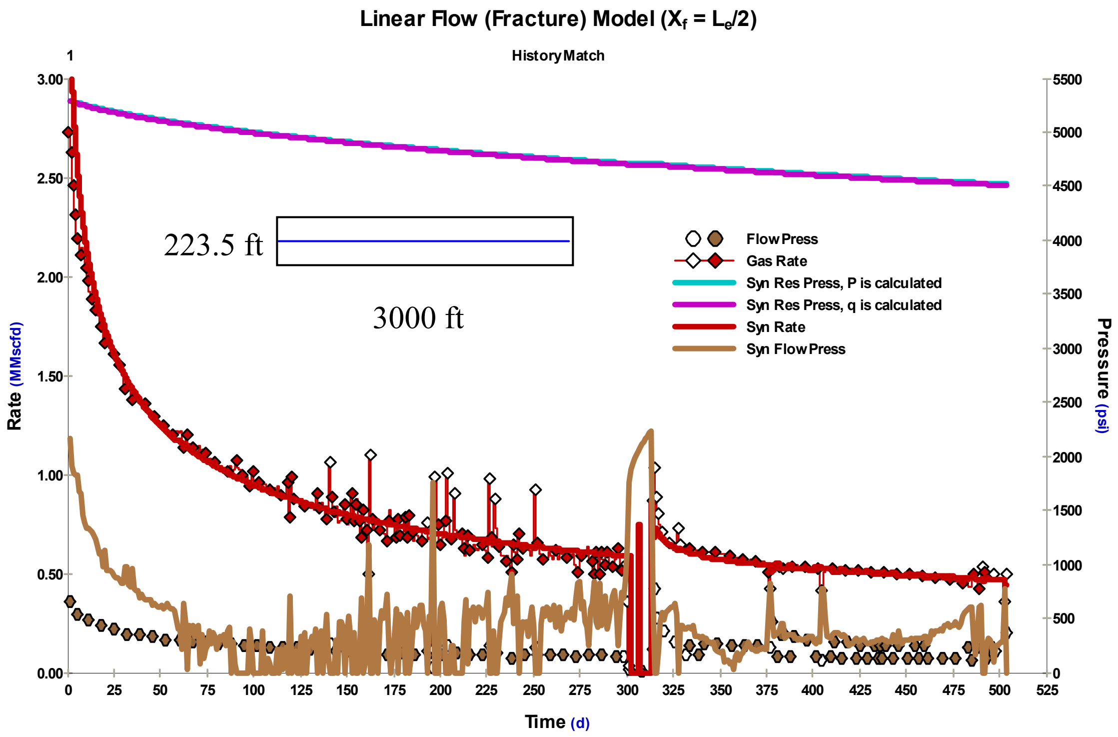


Reservoir

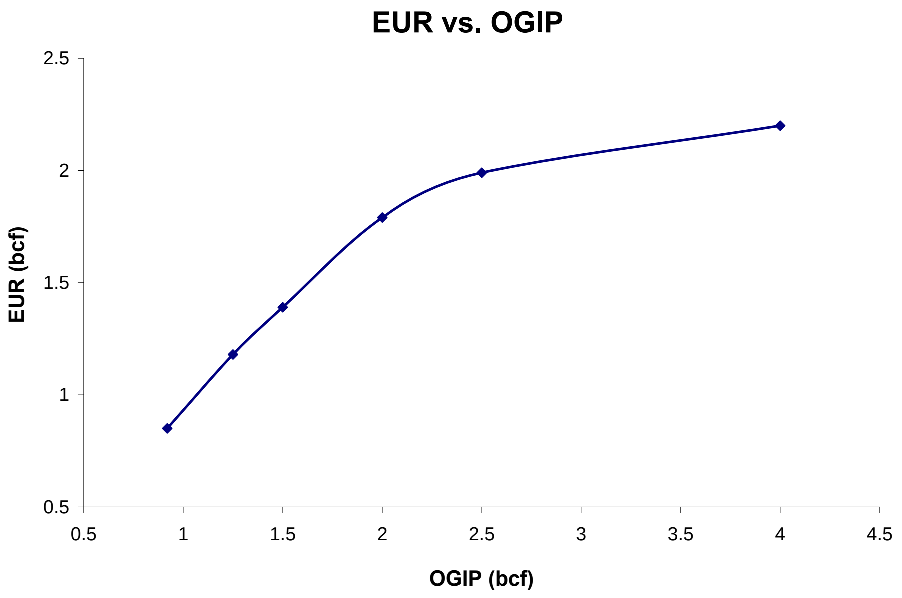
$p_i$ 5300.0 ☐ psi
k 2.67e-04 ☑ md
$X_f$ 1500.000 ☐ ft
$s_c$ 0.295 ☑
s(t)
$S_L$
D ☐ 1/MMscfd
$C_D$ ☐

☒ Boundaries

$X_e$ 3000.000 ☐ ft
$Y_e$ 223.500 ☐ ft
$X_w$ 1500.000 ☐ ft
$Y_w$ 111.750 ☐ ft
OGIP 1.250 ☐ Bscf
Area 15.39 acres

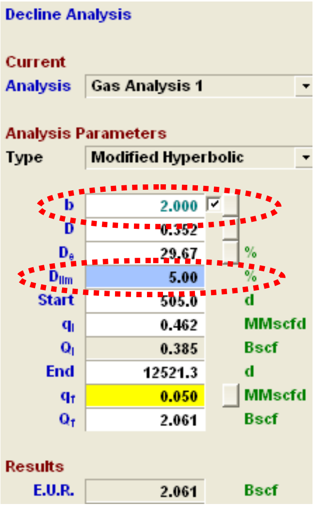


The following figure presents the expected ultimate recovery (EUR) of the well over 30 years as a function of drainage area size. The range in OGIP is constrained at the upper limit by well spacing or microseismic mapping (if available). This figure illustrates that incremental recovery diminishes as the drainage volume gets progressively larger (which is expected). It should be noted that this method assumes the effective permeability remains constant with increasing OGIP (which may not necessarily be the case if the effective drainage volume exceeds the stimulated zone).



## Step 6: Traditional Decline

Traditional decline does not provide any additional value that is not already available using the previous workflow. However, it is useful to include this method because it is the standard by which most companies evaluate and report reserves. Use the “Modified Hyperbolic” analysis type and history match the data using a “b” value of 2 (this is equivalent to linear flow). “$D_{lim}$” can be determined from experience (5% to 10% is reasonable) or iteratively by seeking to minimize the difference between Traditional EUR and EUR provided from the above workflow.



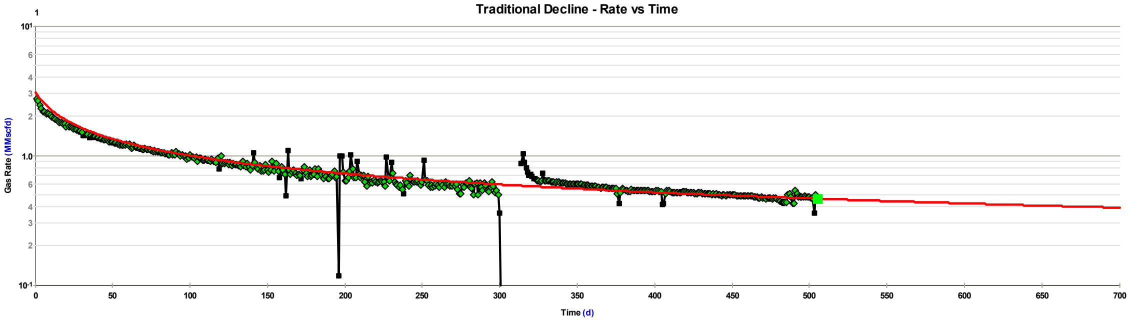
**Decline Analysis**

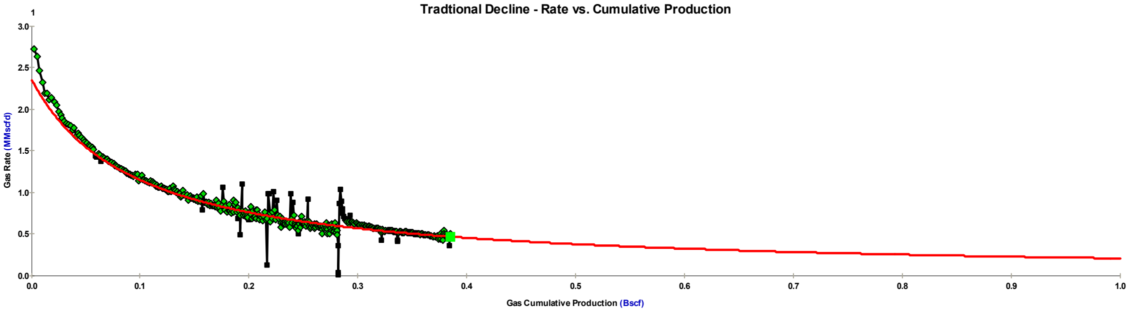
**Current**
Analysis: Gas Analysis 1

**Analysis Parameters**
Type: Modified Hyperbolic

| | | |
|---|---|---|
| b | 2.000 ☑ | |
| D | 0.352 | |
| $D_e$ | 29.67 | % |
| $D_{lim}$ | 5.00 | % |
| Start | 505.0 | d |
| $q_i$ | 0.462 | MMscfd |
| $Q_i$ | 0.385 | Bscf |
| End | 12521.3 | d |
| $q_f$ | 0.050 | MMscfd |
| $Q_f$ | 2.061 | Bscf |

**Results**
E.U.R.: 2.061 Bscf





## Future Development

The “Tight and Unconventional Gas Module” is scheduled for release later in 2010. The following two figures are plots which were generated using the new module. This new module will provide an easier and faster workflow for data analysis and forecasting of tight / unconventional wells exhibiting linear flow, but the same results can be achieved by following the previously presented procedure.