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Abstract

In this thesis the Ula Triassic reservoir has been analyzed using a method called “advanced production analysis”. In order to get an alternative perspective of the reservoir a different analysis method has been used. From the advanced production analysis the permeability-height kh, the skin factor S, the reservoir radius R_e and the stock tank oil initially in place STOIIP have been estimated. The flow regime of the reservoir has also been determined.

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Preface

This thesis is submitted to the University of Stavanger as part of a 5 years Master's Degree in Industrial Economics. It has been completed during the spring of 2012 on behalf of DONG E&P Norge AS. I would like to thank the company for giving me the opportunity to write this thesis, and for letting me take advantage of the knowledge and expertise present in their organization during my work.

I would like to thank the sub-surface team in DONG E&P Norge for interesting discussions and helpful advice, and give a special thanks to the external supervisor Vincent Penasse for good guidance during the whole process and for being a great resource and always available for discussions if needed. Special thanks to Oddbjørn Melberg who has contributed with relevant insights and comments whenever requested and to Cristian Masini and Temitope Ajetunmobi for being so helpful in the process of learning and understanding the simulation software Topaze.

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Also, thanks to William Harrar, Ingvild Kommedal, Kelly Tyler, Øystein Haga, Agnar Toft, Jon Arne Eike Toft, friends and family. I am very grateful to you all in your help toward the completion of the thesis.

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Acronyms

bbl	Barrel
BHFP	Bottom Hole Flowing Pressure
BHP	Bottom Hole Pressure
BU	Build-up
c	Compressibility
cP	CentiPoise
CT	Coil Tubing
D	Darcy
DD	Draw-down
DER	DERivative
Fig	Figure
ft	Feet
GLV	Gas Lift Valve
GOR	Gas-Oil Ratio
GR	Gamma Ray
K	Kelvin
lb	Pounds
lbm	PoundsMass
m	Meter
mD	Milli Darcy
MD	Measured Dept
mDft	Milli Darcy feet
MDSS	Measured Depth Sub Sea
MM	Million
NPD	Norwegian Petroleum Directorate
NPI	Normalized Pressure Integral
OFU	OilField Units
Pa	Pascal
PBU	Pressure Build Up
PLT	Production Logging Tool
PSS	Pseudo Steady State
PVT	Pressure Volume Temperature
R	Rankin
RFT	Repeat Formation Tester
s	Second
scf	Standard Cubic Feet
sg	Specific Gravity
SI	the International System of units
SS	Sub Sea
stb	Stock Tank Barrel
STOIIP	Stock Tank Oil Initially In Place
STOIP	Stock Tank Oil In Place
TD	True Depth
TVD	True Vertical Depth
TVDSS	True Vertical Depth Sub Sea
WH	Well Head

Nomenclature

		OFU	SI
b	hyperbolic exponent		
b_{pss}	y-intercept of normalized PSS equation for oil (also called the inverse productivity index)	psi/bbl	Pa/m^3
B	formation volume factor	bbl	m^3
c	compressibility	psi^{-1}	Pa^{-1}
DER	pressure derivative		
h	net pay	ft	m
k	permeability	mD	$H \cdot m^{-1}$
P	pressure	psi	Pa
ΔP	flowing pressure drop = P_i-BHP	psi	Pa
q	production rate	bbl/day	m^3/s
Q	cumulative production	bbl	m^3
r	radius	ft	m
s	saturation		
S	skin		
t	time	day	s
T	temperature	R	K
μ	viscosity	cP	Pa·s
ρ	density	lbm/ft^3	kg/m^3
φ	porosity		

Subscripts

avg	average
b	hyperbolic exponent
bh	bottom hole
bp	bubble point
c	material balance
d	derivative, delta
D	dimensionless
Dd	Fetkovich dimensionless time
e	reservoir
g	gas
i	initial, integral
max	maximum
min	minimum
n	normalized
o	oil
pss	pseudo steady state
res	reservoir
sep	separator
t	total
w	water, well
wa	apparent wellbore
wf	well flow
wh	well head
‘	the inverse

Figures

Tables

1 Introduction

Ula is an oil- and gas field located 270 kilometers southwest of Stavanger. It is a field in block 7 in the southern part of the North Sea (Fig. 1.1). BP Norge is the operator of the field and today’s stake is 80 percent. DONG E&P Norge is a partner of Ula and today’s stake is 20 percent (1).

The exploration in the North Sea started in 1966. In 1968 the jack-up rig Gulftide, built by the American oil company Gulf, drilled a well in the block 7/12 of the Ula field. Gulf owned 100 percent of the block at this time. The well turned out to be dry, and Gulf lost interest in the block. BP Norge bought a part of the block, and in 1976 the second exploration well was drilled with well 7/12-2. This resulted in the discovery of the Ula field. The core sample containing oil was found 73.8 meters under the point where Gulf had stopped drilling in 1968. The shale rock where Gulf had stopped drilling were later found to be the 120 meter thick cap rock over the Ula reservoir. Since BP Norge had a license proportion of 70 percent of the block at that time, it seemed natural that BP Norge became the operator of the field and that they were the main responsible company of the further development of the field (2). The production of the field started the 10th of October in 1986. At this time the field was expected to produce for 11-12 years. However, now, 25 years later, Ula is still producing and is expected to produce for many years to come. This is mostly due to investment in new technology (2).

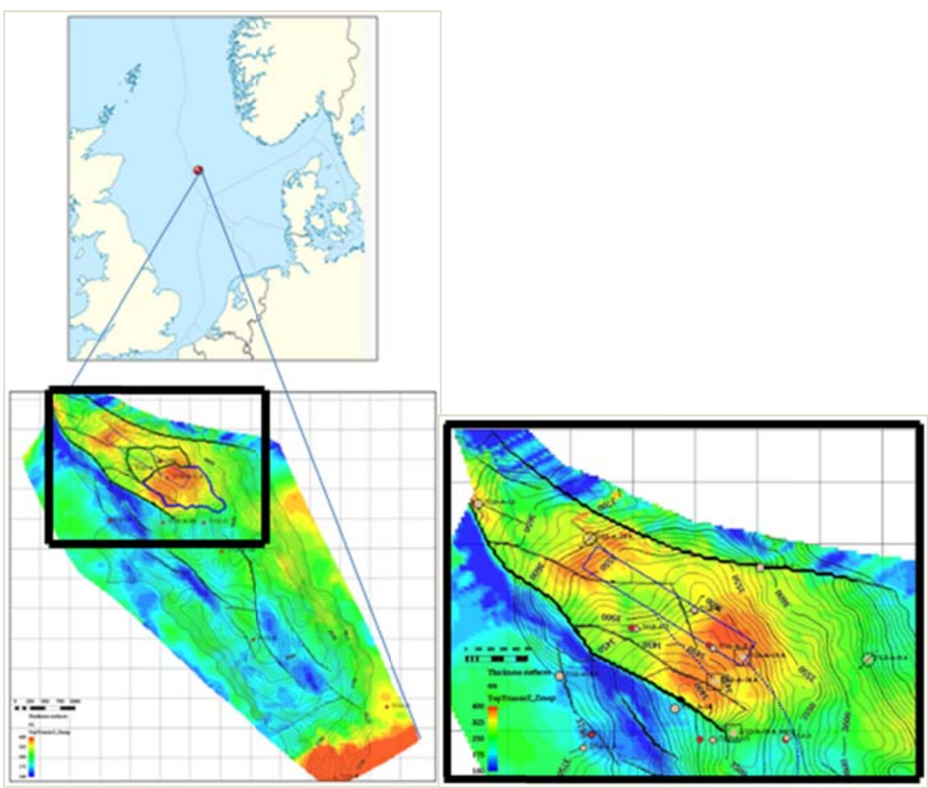

Figure 1.1: Map of the Ula Triassic reservoir (1; 2)

Up until now the Ula field has been producing from the Jurassic part of the field. The sediments in these reservoirs were deposited in a shallow marine environment. Today the producers are looking into whether the layer below the Jurassic reservoir, the Triassic reservoir, which was deposited in continental river deltas, can also be producible. Several wells have been drilled into the Triassic layer, and the data collected from them proves that hydrocarbons are present. The most promising formation is in the northern part of the field, the Skagerrak formation. Based on the information from the drill stem test of the two wells 7/12-6 and 7/12-2A the owners decided to perform an extended test from a third well in this part of the field. The objectives for this well were to decide the extension of the field and to determine the oil-in-place. The long term production well 7/12-A-3B was drilled in 2010, and a long term test has been conducted in it in the period from July 2010 until January 2012 (2).

1.1 Aims for the Report

This thesis addresses the Triassic part of the reservoir, and it aims to estimate main reservoir parameters to reaffirm how much oil is present in this reservoir. The analysis is done by using advanced production analysis[1], a method that uses production data for analyzing the reservoir. The data that is used is gathered from the long term production well 7/12-A-3B, as well as from the well 7/12-6. The reservoir has already been analyzed using geo model, well testing[2] and material balance plot, but advanced production analysis will be a different and additional method to well testing for estimating reservoir parameters as well as oil in place. The results from the advanced production analysis will be compared to already available estimates from geo model, well tests and material balance plot.

1.2 Outlay

In this thesis the reservoir Ula Triassic has been studied. In chapter 2.1 the exploration of the field is explained, and chapter 2.2 examines the aspects of drilling and well completion of well 7/12-A-3B. The information given in these chapters are important for understanding the choices that are made regarding the analysis, as well as providing an insight into the difficulties regarding analysis of this particular well. Advanced production analysis has been used in this thesis to analyze the production data from the well, and the methods by which this is achieved are studied in detail in chapter 3. Chapter 4 shows how the data used in the analysis is determined, and explains how the diagnostics of the data are performed. The advanced production analysis of the Ula Triassic reservoir is analyzed in chapter 5, followed by chapter 6 where the results of the analysis are being discussed.

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[1] Advanced production analysis is also called modern production analysis or rate transient analysis.

[2] Well testing is also called pressure transient analysis. The well test can be used when analyzing a pressure build-up.

2 Background

The main reservoir in the Ula field is from the Jurassic age. This reservoir was discovered in 1976 after drilling the well 7/12-2. Hydrocarbons were also found in the Triassic layer of this well, but this part of the reservoir was of poor reservoir quality. Since then, several wells have been drilled through the Jurassic layer and into the Triassic layer (Fig. 2.1).

2.1 Exploration of the Ula Triassic Reservoir

During the appraisal and production drilling of the Ula Jurassic field, the wells 7/12-6, 7/12-A-2A and 7/12-A-7 have given valuable information of the Triassic formation in the northern area of the Ula field. The logging-, coring- and drill stem test data from the wells have proved an oil column in a moderate quality oil bearing reservoir. Additionally, wells 7/12-6 and 7/12-2A have been production tested, but that did not give enough information to prove whether the field is commercial. Therefore a test production application was sent to the Norwegian Petroleum Directorate (NPD) for development and long term testing of a well, 7/12-A-3B, in the Triassic reservoir of the Ula field. A production permit was granted to test the well for 18 months, or up to 2.1 MMboe of production (3; 4; 5).

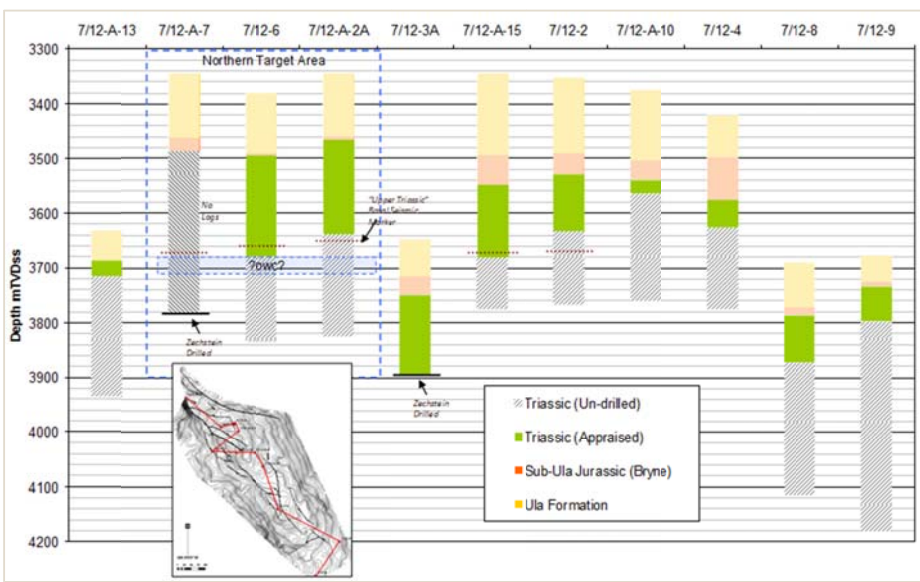


Figure 2.1: The wells drilled into Ula Triassic (2)

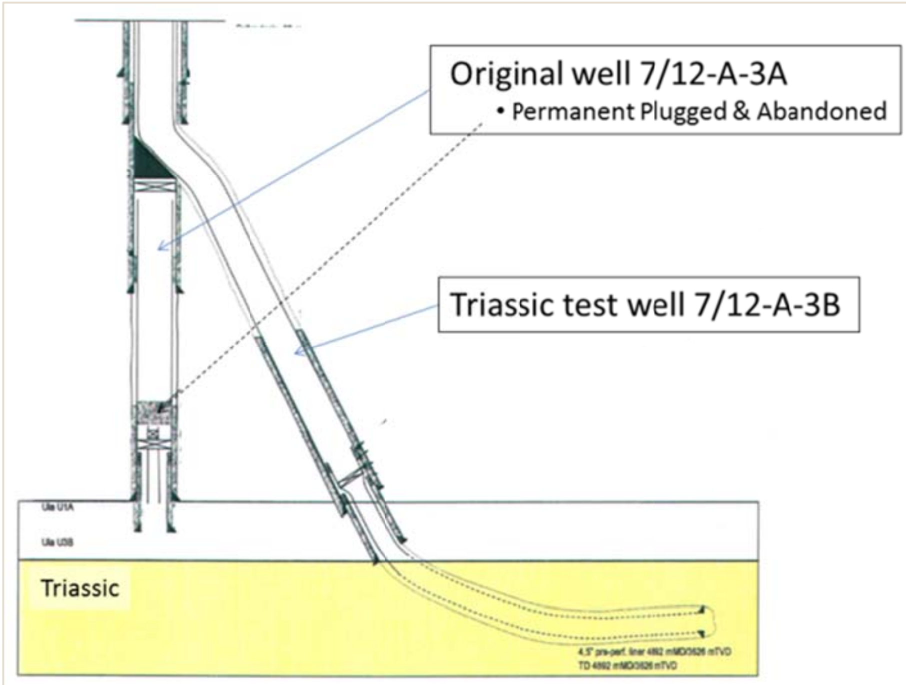


Figure 2.2: Wells 7/12-A-3A and 7/12-A-3B (6)

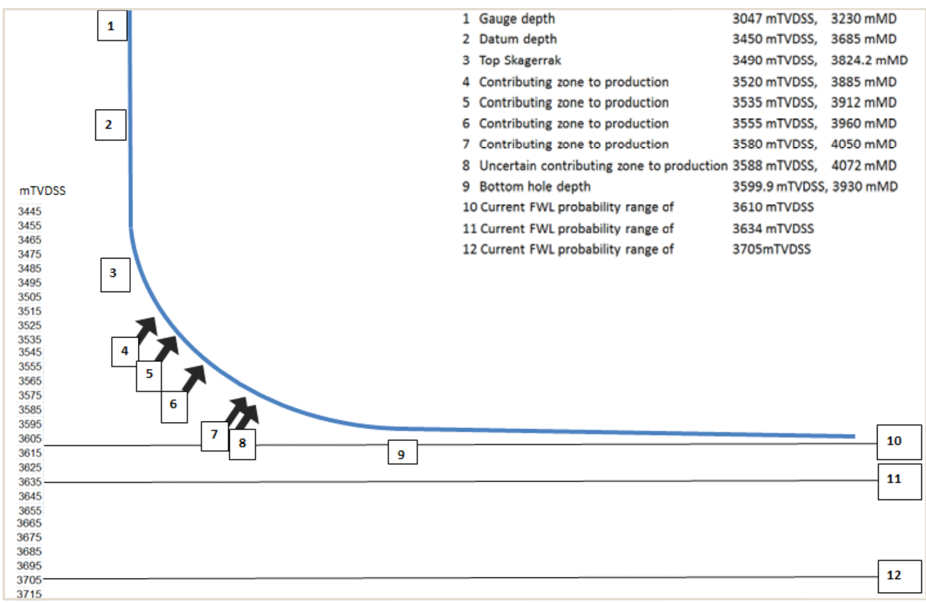


Figure 2.3: Cross section of well 7/12-A-3B (7; 8)

2.2 Well 7/12-A-3B

The horizontal well 7/12-A-3B was designed to be side tracked from the original well 7/12-A-3A and drilled and completed in the Triassic layer in the northern part of the Ula field (Fig. 2.2). The well was designed for long term testing and would be the first well to be completed as a Triassic oil producer in the Ula field. The production rate and bottom hole pressure data analyzed in this thesis is production data from well 7/12-A-3B.

2.2.1 Drilling the Well

In March 2010 the original well 7/12-A-3A was permanently abandoned and a sidetrack was performed by milling a window through the 13 3/8" casing at 4829 ft (Fig. 2.4). The 12 ¼" hole section was drilled to 16 ftTVD above the Ula Formation. A 9 5/8" casing was set to isolate the overburden formation. With reduced mud weight, the next hole section was drilled down to 16 ft above the top of the Triassic reservoir. A 7" liner was set at 12530 ft to isolate the Ula formation (6), and a 6” drill bit was used to drill the Triassic formation. This hole section started with a hole angle of 53 degrees and the inclination was increased to 90 degrees when entering the Triassic reservoir. When drilling this build section some good oil bearing sands were observed. These sand zones disappeared after reaching 90 degrees, i.e. the maximum inclination planned for this well. Therefore, the decision was made to increase the hole angle to 92 degrees, and it was later increased to 94 degrees in an attempt to find sand of the quality that was discovered higher up in the reservoir. At 15749 ft a decision was made to drop the inclination back to 90 degrees and the well TD was set to 16051 ft. The trajectory of the well is shown in Figure 2.5 (8).

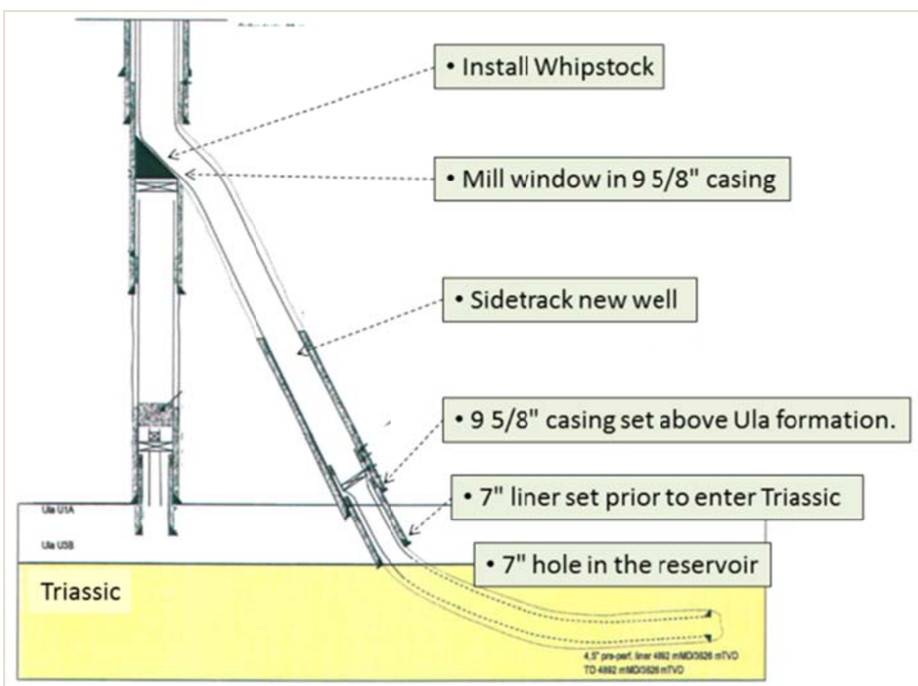


Figure 2.4: Casing sizes for well 7/12-A-3B (6)

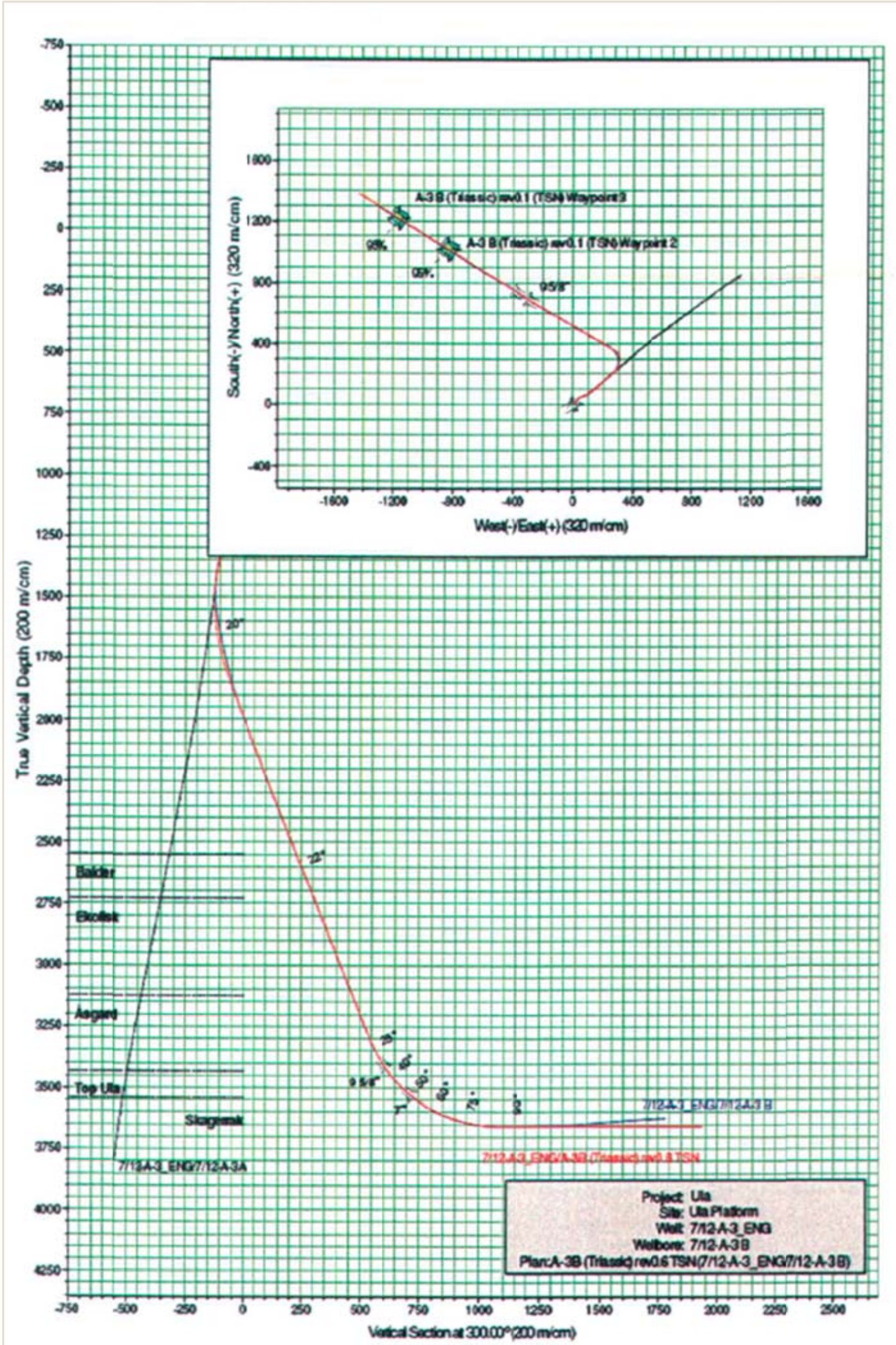


Figure 2.5: The trajectory of the well 7/12-A-3B (6)

2.2.2 Well Completion

The lower completion of the well 7/12-A-3B consists of a 7" wellbore, a 4 ½" pre-perforated liner that was successfully installed in the 7" wellbore and a 4 ½" x 7" liner hanger. Two major changes were made to the original program prior to running the lower completion. Several thin mud stone layers were encountered when drilling the reservoir section. The mud stone became unstable and therefore it was decided to under ream the 6" hole to 7" prior to running the completion.

The plan was to include swell packers in the completion string to isolate water zones and mud stone layers, but these were not included due to the unstable reservoir formation and the sever doglegs created when drilling this hole (8).

The Upper Completion was run on 5 ½" and 4 ½" tubing, and consists of the following parts (8):

- Tubing Conveyed Down Hole Safety Valve
- Chemical Injection Valve
- Concentric Annular Safety Valve
- 3 ea. Side Pocket Mandrel with Gas injection valve installed
- Down Hole Gauge Carrier
- Production Packer

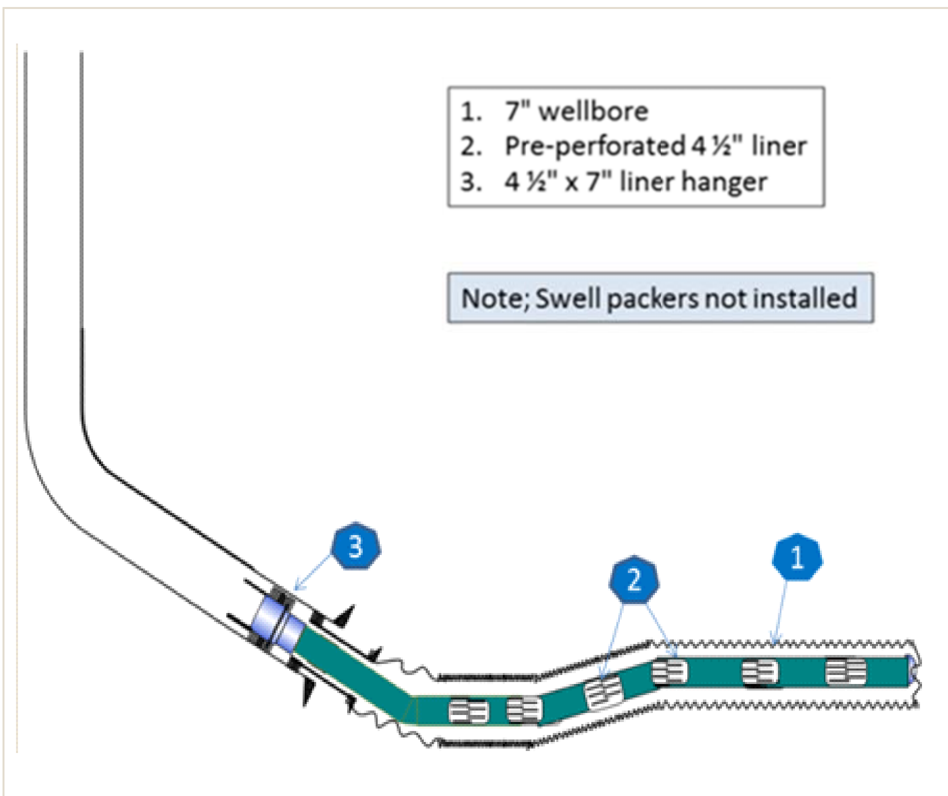


Figure 2.6: Lower completion

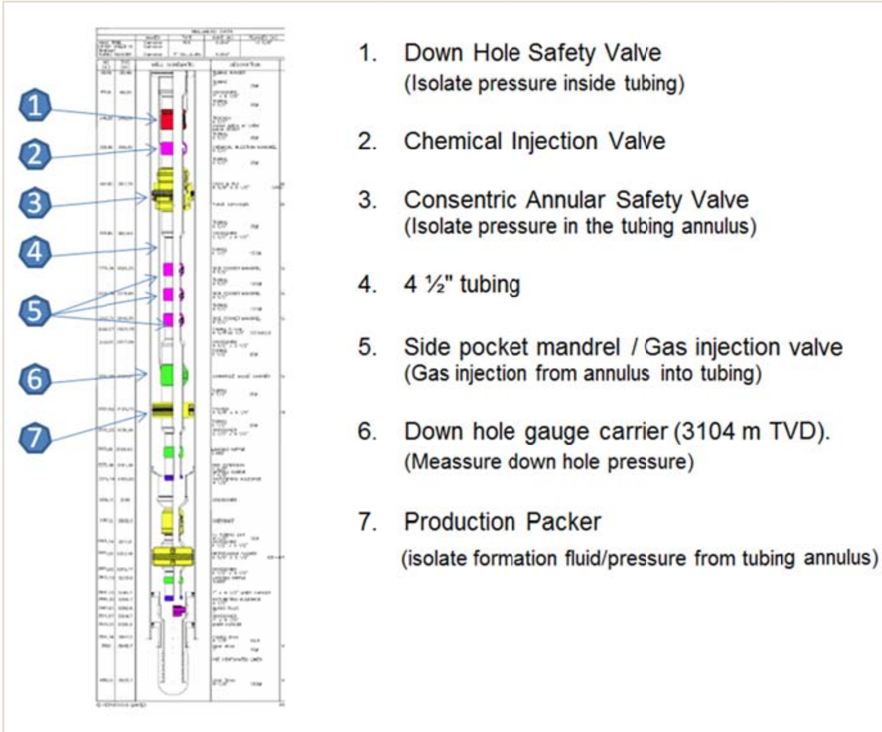


Figure 2.7: Upper completion (8)

3 Advanced Production Analysis

Production data is rate- and pressure data collected from a producing well. Production data are often quite noisy (7), and are therefore usually averaged over time periods, often several days, in order to get rid of some of the noise.

Advanced production analysis makes it possible to analyze production data when both the rates and the bottom hole pressures are changing. This is an improvement from the conventional production analysis where the bottom hole flowing pressure is assumed to be constant. Advanced production analysis is an evaluation utility that can provide estimates of recoverable reserves and fluids-in-place and well inflow performance like kh and skin. This method uses mathematics that are very similar to well testing, but the focus is different, since the advanced production analysis is focusing on long term rate transient data[3], while well testing is focused on short term pressure transient data[4] (8; 9).

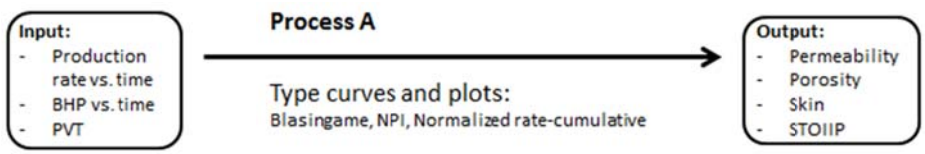
In 1945, Arps developed a way of analyzing production data by using decline curves. This is valid for the boundary dominated flow period.[5] Later, in the 1960's, Fetkovich improved the Arps analysis technique to be valid also for transient flow.[6] He created type curves[7] to match with the rate versus time data. The type curves assume constant bottom hole flowing pressure (BHFP) during the transient and the boundary dominated flow. Blasingame improved the method of Fetkovich by plotting normalized rate versus material balance time[8]. By plotting the production data with respect to normalized pressure and material balance time, and matching it to the Fetkovich type curve, it could be used for both variable rate- and variable bottom hole pressure with time. Agarwal and Gardner improved the Blasingame type curves by making a type curve where the transition between transient and boundary dominated flow became clearer. Blasingame improved the Agarwal-Gardner type curves by making the NPI type curve. NPI type curves uses dimensionless well test analysis parameters instead of dimensionless production analysis parameters. The intention with this type curve is also to reduce the noise from the production data.

Advanced production analysis methods are based on conventional production analysis. Therefore, to fully understand the advanced production analysis methods, it is important to understand the purpose of the conventional production analysis methods. The Arps plot and the Fetkovich type curves are assuming the bottom hole flowing pressure to be constant, which means that they belong to the conventional production analysis. Blasingame type curve, Agarwal/Gardner type curve, NPI type curve and normalized rate-cumulative plot do not require the

[3] With "rate transient" data, the rate is changing with time.
[4] With "pressure transient" data, the rate is assumed to be constant.
[5] Boundary dominated flow: The flow regime when the flow has reached all the boundaries in the reservoir.
[6] Transient flow: The flow regime when the flow has not reached all the boundaries in the reservoir yet.
[7] Type curves are dimensionless graphical curves used for finding the best matching curve for the available data.
[8] Material balance time = Cumulative production / Rate, t_c=Q/q

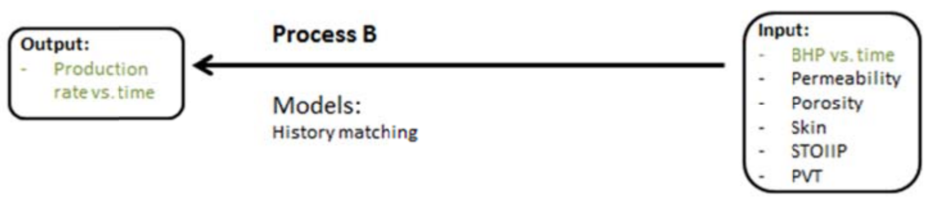
assumption of constant bottom hole pressure, and therefore belong to the advanced production analysis (8; 9).

Type curves and plots of advanced production data use the input of production rate versus time, bottom hole pressure (BHP) versus time and PVT to estimate permeability, porosity, skin and stock tank oil initially in place (STOIIP) (naming this process A) (12).

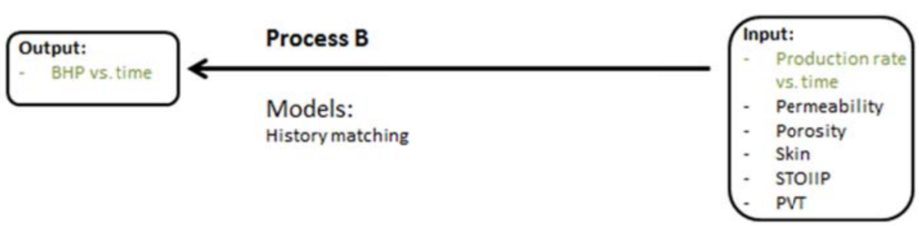


All type curves and plots of advanced production analysis assume single phase flow in a volumetric reservoir[9]. Some new advanced type curves have been developed for aquifers, but this is beyond the scope of this study.

History match modeling is the inverse of type curves and plots. The input to this model is production rate versus time or BHP versus time, permeability, porosity, skin, STOIIP and PVT data. A model of production rate versus time or BHP versus time and PVT is generated (naming this process B) (12).



or



If either the type curves and plots (Process A) or the history match plot (Process B) match the provided data, the results gained are acceptable, but the results will be more accurate if matches are obtained in both (12). If the model and the analysis don't match, it indicates that the model in use is too simple, and that a more advanced model is needed.

The type curves and plots in this chapter do not contain data from the Ula Triassic reservoir.

[9] "Volumetric reservoirs may be considered closed systems that do not receive significant pressure support or fluid influx from outside sources, such as water influx from aquifers." (29)

3.1 Process A: Type Curves and Plots

For type curves and plots, the input data of flowing rate and BHP versus time is used to generate the parameters.

3.1.1 Arps Traditional Decline Analysis

Arps decline curves are used to estimate the ultimate recovery (EUR) (13). Decline curve equations are only valid when the reservoir flow has reached its boundaries, during boundary dominated flow. The Arps analysis can be plotted in different plots; rate versus time plot (q vs. t) (Fig. 3.1) and semi-log rate versus time plot (q vs. t). (Fig. 3.2). (9)

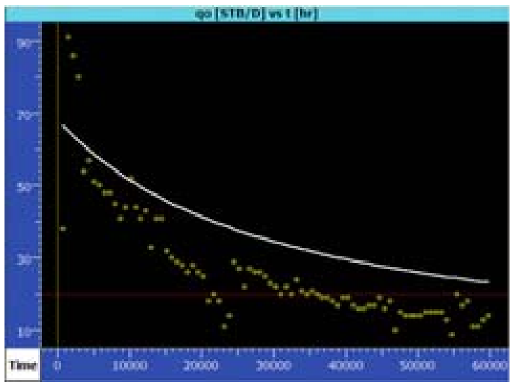


Figure 3.1: Arps plot, rate versus time (9)

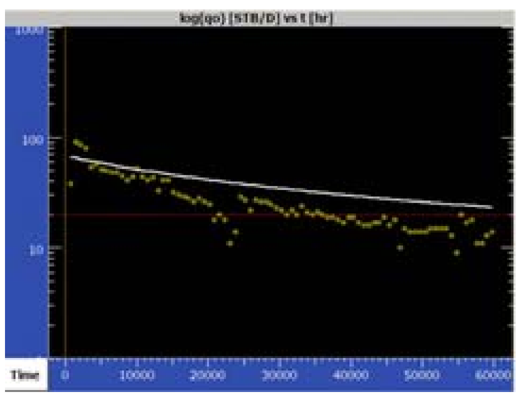


Figure 3.2: Arps plot, semi-log rate versus time (9)

The stems in the Arps decline curves, rate versus time, are characterized by the factor b. The different values of b are often characterized by different types of fluid conditions.

$b = 0$:	Single phase liquid production and high pressure gas
$0.1 < b < 0.4$:	Solution gas drive oil reservoirs
$0.4 < b < 0.5$:	Most gas wells (excluding tight gas)
$b = 0.5$:	Oil wells under effective edge water drive
$0.5 < b < 0.9$:	Layered, composite, connected reservoirs

(13)

These decline curve analysis methods that Arps invented have been the conventional technique for analyzing and forecasting of well production for many years (10). Arps empirical rate-time equations are:

Exponential decline curve (b=0):	$q(t)=\frac{q_i}{e^{D\cdot t}}$
Hyperbolic decline curves (0<b<1):	$q(t)=\frac{q_i}{[1+b\cdot D_i\cdot t]^{1/b}}$
Harmonic decline curve (b=1):	$q(t)=\frac{q_i}{[1+D_i\cdot t]}$

Exponential decline rate:	$D=-\frac{(\frac{\Delta q}{\Delta t})}{q}$
Hyperbolic decline rate:	$D_i=\frac{D}{q_i^b}\cdot q^b$
Harmonic decline rate:	$D_i=\frac{D}{q_i}\cdot q$

(11)

The strengths of this method are that it is easy to use and easy to apply. Arps decline curves can be used even if the BHP is changing and give a production forecast, however lacking relation to reservoir parameters like kh and STOIIP (13).

The limitations of this method are that it is non-unique, as several b-values could be used, leading to a large number of potential EURs. This method does not predict fluids-in-place, and it cannot disassociate production conditions from reservoir analysis (13).

3.1.2 Fetkovich Type Curve

Fetkovich saw the opportunity to expand the Arps decline curve analysis. The differences between the Arps plot and the Fetkovich type curves are shown in Table 3.1.

The Arps decline curves are only valid during boundary dominated flow, and Fetkovich extended these curves to be valid also for the transient flow region (Fig. 3.3). He introduced type curves to the analysis of production data applicable to both the transient part of the data and the boundary dominated flow period. Type curves are used for finding the best matching curve for the available data.

Traditional decline consists of exponential-, hyperbolic- and harmonic decline curves. Arps had already developed the decline rate (q(t)) for the boundary dominated flow, and what Fetkovich did was to make the decline rates dimensionless (q_{Dd}) by dividing the rate by the initial rate, and by making the time dimensionless (t_{Dd}) by multiplying the D_i factor with time:

$$q_{Dd}=\frac{q}{q_i} \qquad \text{and} \qquad t_{Dd}=D_i \cdot t \qquad (10)$$

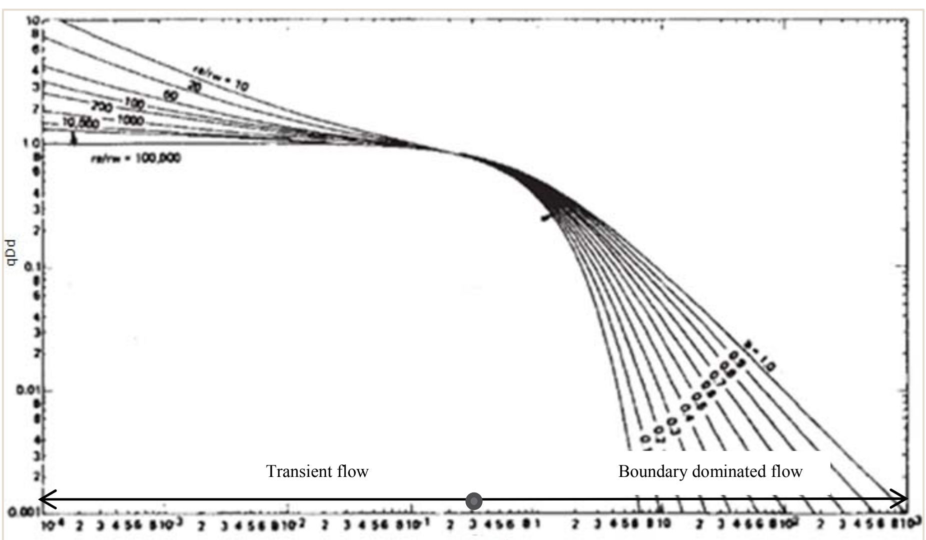


Figure 3.3: Fetkovich type curves (10)

When using the Fetkovich type curve analysis, the flow rate (q) from the production data is plotted versus time (t) on a log-log scale. The data is then matched to the Fetkovich type curve with dimensionless decline rate (q_{Dd}) versus dimensionless decline time (t_{Dd}).

Boundary dominated flow regime:

Dimensionless decline curve for b > 0: $q_{Dd}=\frac{1}{(1+b\cdot t_{Dd})^{1/b}}$

Dimensionless decline rate for b = 0: $q_{Dd}=\frac{1}{e^{t_{Dd}}}$

Transient flow regime:

Dimensionless rate: $q_{Dd}=\frac{141.2\cdot q\cdot \mu\cdot B}{k\cdot h\cdot (p_i-p_{wf})}\left[\ln\left(\frac{r_e}{r_w}\right)-\frac{1}{2}\right]$

Dimensionless decline time: $t_{Dd}=\frac{\frac{0{,}00634\cdot k\cdot t}{\varphi\cdot \mu\cdot c_t\cdot r_w^2}}{\frac{1}{2}\left[\ln\left(\frac{r_e}{r_w}\right)-\frac{1}{2}\right]\left[\left(\frac{r_e}{r_w}\right)^2-1\right]}$

(10; 11)

This method is useful for non-volumetric reservoirs[10] with two or more mobile phases. Like the Arps plots the stems during the boundary dominated flow regime is characterized by the factor b. The stems in the transient flow regime are characterized by the dimensionless reservoir radius, $r_{eD}=\frac{r_e}{r_w}$ (13) .

Fetkovich type curves consist of one transient part and one boundary dominated part. The type curves in the boundary dominated flow regime, which is based on Arps decline curves, depend on the value b. The type curves in the transient flow regime depend on the size of the reservoir. Low value of $(\frac{r_e}{r_w})$ corresponds to a low permeable reservoir. A high value of $(\frac{r_e}{r_w})$ corresponds to a high permeable reservoir, and wells with large positive skin factors (12).

The transient flow regime and the boundary dominated flow regime intersect at the dimensionless time 0.3 in the Fetkovich type curve. All data plotted earlier than this occurred during the transient flow in the reservoir, and the data plotted after this time happened in the boundary dominated flow in the reservoir.

The strength of this method is that it does not require flowing pressure data. In addition, it does not assume that one flow regime is more dominant than another,

[10] A non-volumetric reservoir is a reservoir where one or more of the following (aquifer impact, rock-, shale- or water compressibilities) are considered significant (30).

like the modern methods do by using material balance time. It is the empirical nature of the method that makes it versatile (7).

The Fetkovich type curve also has its limitations. In the work done by Fetkovich, as in the work done by Arps, there is an assumption of the historical operating conditions remaining constant in the future (13). The BHP has to be fairly constant, and the well behavior and the drainage area of the considered well are also assumed to be constant (7). Hyperbolic decline curves are very similar in shape, and therefore the shapes of these decline curves are not unique.

3.1.3 Blasingame Type Curve

The Blasingame type curve is one of the type curves from advanced production analysis (Fig. 3.4). Because of the log-log axis this type curve is most useful for examining the period of the transition from transient to boundary dominated flow. Blasingame improved the work of Fetkovich by introducing the material balance time, t_c, and he also used normalized values, like normalized rate $\left(\frac{q}{\Delta p}\right)$ and normalized pressure $\left(\frac{\Delta p}{q}\right)$. This was done for the reservoir to be analyzed independently of production (back pressure) constraints. This modern analysis is valid for single-phase volumetric reservoirs. The analysis works best when dealing with production- and flowing pressure data of good quality (13).

Blasingame tried to come up with an analysis method that was not limited by the assumption of constant BHP. In 1993 Blasingame and Palacio figured out that plotting the normalized rate versus material balance time will yield a straight line similar to the Fetkovich type curve harmonic stem, b=1 (13). Rates plotted like this are matched towards the Blasingame type curve that consists of dimensionless rate- and time curves in Fetkovich format (13). By using this method for plotting the data there was no need for the BHP to be assumed constant (13).

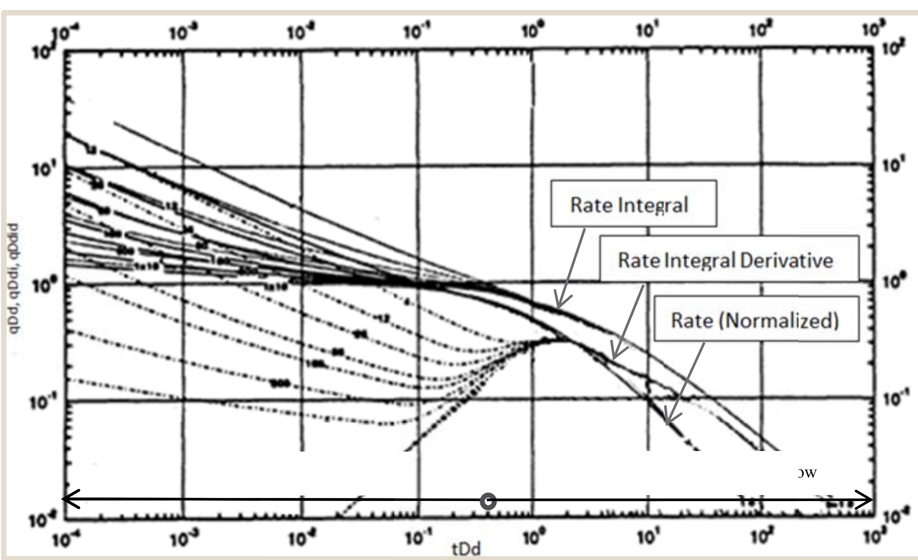


Figure 3.4: Blasingame type curves (13)

The rate integral and the rate integral derivative functions were introduced by McCray (13). The normalized rate-integral of the data is plotted and matched to a normalized rate integral type curve, and the normalized rate integral derivative of the data is calculated, plotted and matched to a normalized rate-integral derivative type curve (13).

The calculations below are valid for liquid. It is also possible to do these calculations for gas by using different equations, but then other constraint needs to be taken into account.

The data are plotted like this:

Normalized rate	$\frac{q}{\Delta p}=\frac{q}{p_i-p_{wf}}$
Normalized rate integral	$\left(\frac{q}{\Delta p}\right)_i=\frac{\int_0^{t_c}\frac{q}{\Delta p}dt_c}{t_c}$
Normalized rate integral derivative	$\left(\frac{q}{\Delta p}\right)_{id}=\frac{d\left(\frac{q}{\Delta p}\right)_i}{d\ln(t_c)}=\frac{d\left(\frac{q}{\Delta p}\right)_i}{d\,t_c}\cdot t_c$
versus: Material balance time	$t_c=\frac{Q}{q}$

(14; 11)

The dimensionless type curves for the data to be mached with:

<u>Transient flow regime:</u>	
Dimensionless rate	$q_{Dd}=\frac{141.2\cdot q\cdot\mu\cdot B}{k\cdot h\cdot(p_i-p_{wf})}\left[\ln\left(\frac{r_e}{r_w}\right)-\frac{1}{2}\right]$
<u>Boundary dominated flow regime:</u>	
Dimensionless rate	$q_{Dd}=\frac{1}{(1+b\cdot t_{Dd})^{1/b}}$
Dimensionless rate integral function:	$q_{Ddi}=\frac{1}{t_{Dd}}\int_0^{t_{Dd}}q_{Dd}(t)dt$
Dimensionless rate integral derivative function:	$q_{Ddid}=-t_{Dd}\frac{dq_{Ddi}}{dt_{Dd}}=q_{Ddi}-q_{Dd}$
versus: Dimensionless decline time (t_{Dd}):	$t_{Dd}=\frac{\frac{0.00634\cdot k\cdot t}{\varphi\cdot\mu\cdot c_t\cdot r_w^2}}{\frac{1}{2}\left[\ln\left(\frac{r_e}{r_w}\right)-\frac{1}{2}\right]\left[\left(\frac{r_e}{r_w}\right)^2-1\right]}$

(10; 13)

The strength of the rate integral is the smoothness of the plot. Rate integral derivative does not readily display the different flow regimes, but it is useful for pattern recognition.

This type curve also has its limitations. Rate integral calculations are very sensitive to early-time errors because of the log-log axis (13).

3.1.4 Normalized Pressure Integral (NPI) Type Curve

The normalized pressure integral (NPI) type curve was developed by Blasingame in 1989, and its main purpose is to get a clear transition between transient and boundary dominated flow (Fig. 3.5). This type curve analysis is the inverse of the Blasingame type curve, and instead of pointing downwards like the rest of the production data type curves, it points upwards like the well test type curves. This is done exclusively for the visualization of it. People who are used to look at well data type curves will find this way of graphing type curves more familiar.

This method differs from the Blasingame method because it uses normalized pressure rather than normalized rate. Normalized pressure from the production data is plotted versus material balance time, and matched with dimensionless parameters used in well testing, dimensionless pressure versus dimensionless time. Then the normalized pressure integral is plotted and the normalized pressure integral derivative is plotted. The plots are matched to the type curves, respectively dimensionless pressure integral and dimensionless pressure integral derivative (13).

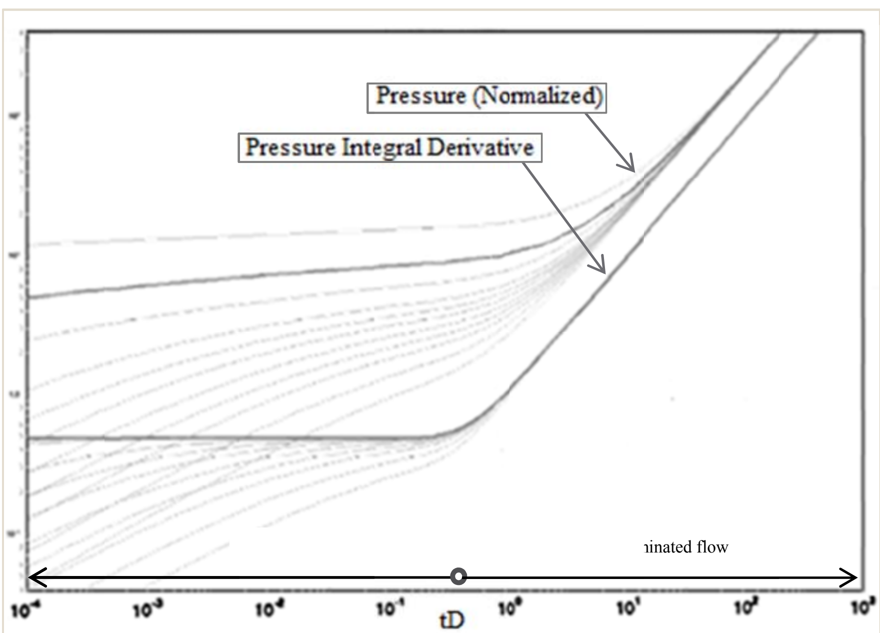


Figure 3.5: Normalized pressure integral (NPI) type curves (13)

The equations below are valid for liquid. The data are plotted as follows:

Normalized pressure	$\frac{\Delta p}{q}=\frac{p_i-p_{wf}}{q}$
Normalized pressure integral	$\left(\frac{\Delta p}{q}\right)_i=\frac{1}{t_c}\int_0^{t_c}\frac{\Delta p}{q}d(t)$
Normalized pressure integral derivative	$\left(\frac{\Delta p}{q}\right)_{id}=\frac{d\left(\frac{\Delta p}{q}\right)_i}{d\ln(t_c)}$
Versus: Material balance time	$t_c=\frac{Q}{q}$

(15)

The dimensionless type curves for the data to be matched with:

Dimensionless pressure used in well testing and in NPI	$P_D=\frac{k\cdot h\cdot(p_i-p_{wf})}{141.2\cdot q\cdot B\cdot\mu}$
Dimensionless pressure integral function	$P_{Di}=\frac{1}{t_D}\int_0^{t_D}p_D(t)dt$
Dimensionless pressure integral derivative function[11]	$P_{Did}=t_D\cdot\frac{dp_{Di}}{dt_D}=p_D-p_{Di}$
Versus: Dimensionless time (t_D)	$t_D=\frac{0.000264\cdot k\cdot t}{\varphi\cdot\mu\cdot c_t\cdot r_w^2}$

(15; 16)

Since the NPI type curves have a different appearance than the other production analysis type curves they provide an opportunity for comparison of the results, which is of important value.

[11] Also called pressure integral difference function.

3.1.5 Normalized Rate-Cumulative Plot

The plots are more suitable for quantitative analysis of reserves then the type curves. The plots are cartesian, meaning that they do not consist of log-log scales like the type curves do (13). The normalized rate-cumulative plot[12] is an advanced production analysis plot (Fig. 3.6).

This plot is only valid when the flow in the reservoir has reached its boundaries (17). It is an analytical model which is a complimentary method to decline curves (13). This plot uses pressure normalized rate versus normalized cumulative production to make a simple linear plot that extrapolates to fluids-in-place (13). The following describes the normalized rate-cumulative plot for oil in a volumetric circular reservoir.

Y-axis:

Pressure normalized rate:

$$\frac{q}{\Delta p} = \frac{1}{b_{pss}} - \frac{B_o \cdot Q_o}{B_{oi} \cdot c_t \cdot N \cdot \Delta p \cdot q \cdot b_{pss}}$$

$$b_{pss} = 141.2 \frac{Bo \cdot \mu}{k \cdot h} \left[\ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4} \right]$$

X-axis:

Normalized cumulative production:

$$Q_n = \frac{Q_o}{c_t \cdot \Delta p}$$

(13; 18)

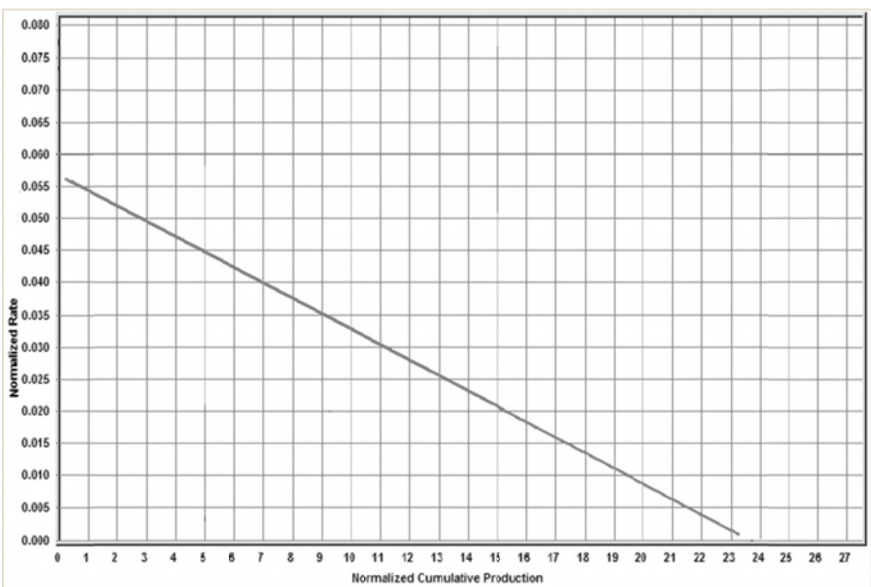


Figure 3.6: Normalized rate-cumulative plot (13)

[12] Also called the flowing material balance plot (22).

The strengths of the normalized rate-cumulative plot are that it is an easy and intuitive method. It provides an analytical fluids-in-place estimate without requiring shut-in pressures, and has a better resolution for boundary dominated flow than any of the existing type curve methods. Since the late-time data on type curves tend to be compressed, because of the log-log format of the axis, the linear scale axis in the normalized rate-cumulative plot makes this method superior to type curves when it comes to estimating fluids-in-place.

The limitation is that this method, compared to Blasingame- and NPI type curves, is only focusing on boundary dominated flow.

3.2 Process B: History Match Plot

Process B is the part containing history matching. A history plot does not consist of any real diagnostics; it is just an optimization process (9). This process consists of two parts. The first is when the input of BHP versus time, permeability, porosity, skin, STOIIP and PVT data are used to find the best model to fit the production rate versus time (Fig. 3.7). The second part consists of using input of production rate versus time, permeability, porosity, skin, STOIIP and PVT data to find the best model to fit the BHP versus time (Fig. 3.8). In Topaze these processes are performed simultaneously, resulting in a plot showing the output of BHP at the top, and a plot showing the output of the production rate at the bottom (Fig. 3.9). Finally this simulated model is matched to the measured data, to determine whether there is a good fit. This is called history matching (Fig. 3.10). (21)

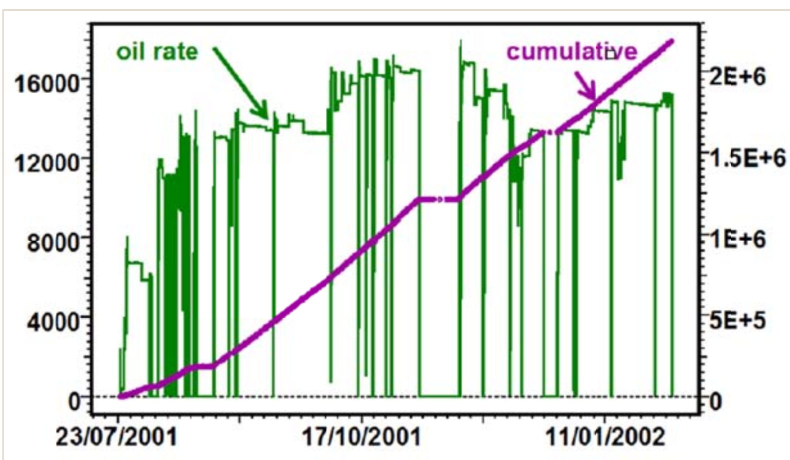


Figure 3.7: History plot, where the production rate is the output (21)

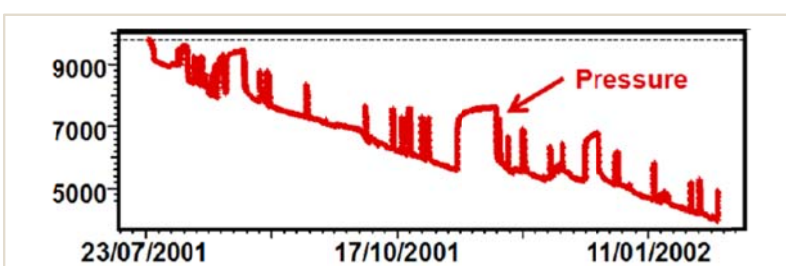


Figure 3.8: History plot, where the BHP is the output (21)

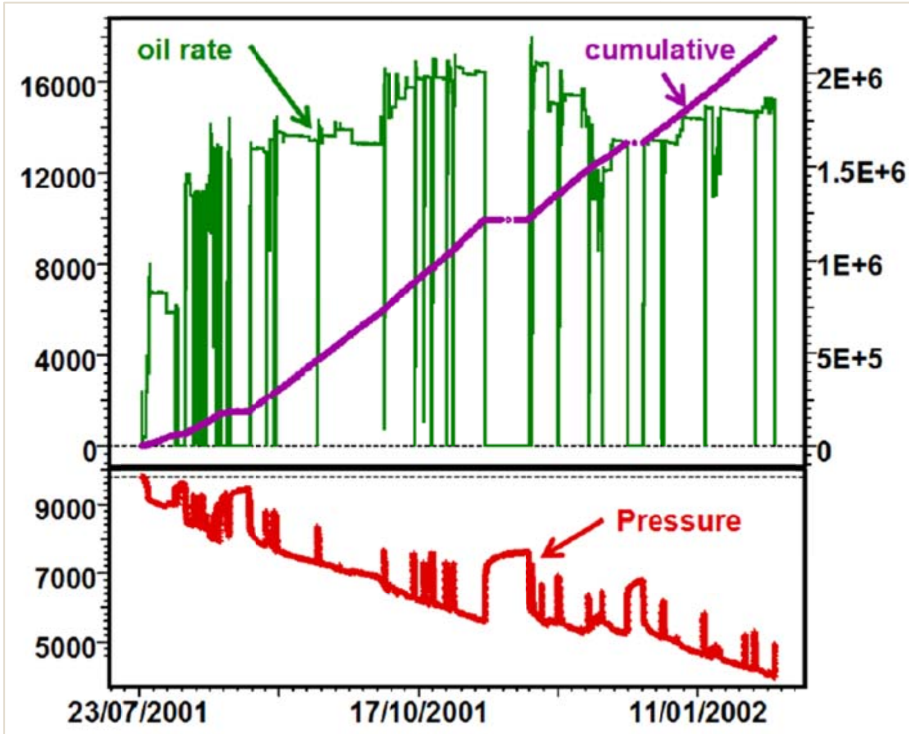


Figure 3.9: History plot (21)

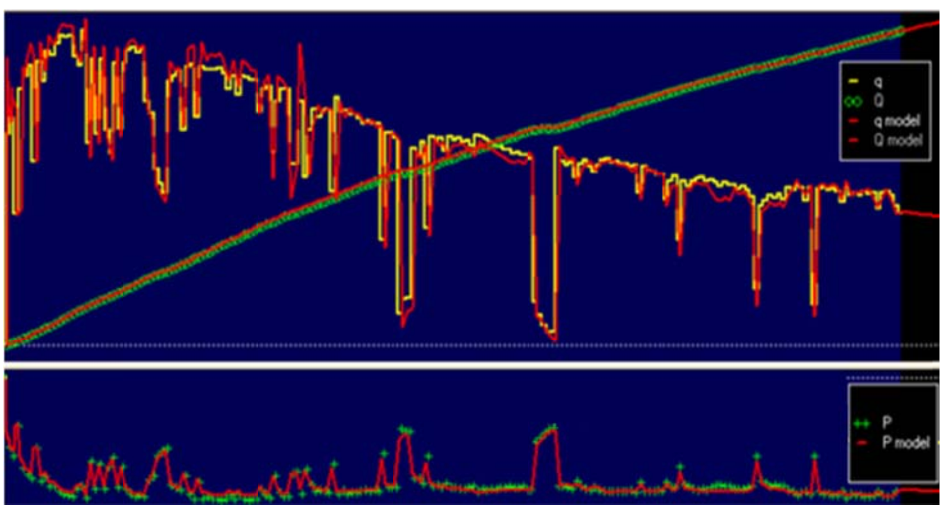


Figure 3.10: History match plot (7)

4 Method

Usually production data analysis is performed by starting with a simple model and adding further complexity if needed (7). Therefore all the plots and type curves presented in this thesis are based on a simple reservoir, assuming a vertical well in a circular bounded reservoir.

4.1 Rate-, Pressure- and PVT data

The rate- and pressure data used in this thesis is production data from well 7/12-A-3B. The PVT data used in this thesis comes from the well 7/12-6, which is a representative well for the Triassic reservoir. This well has the most complete dataset that is available for the Triassic reservoir and it is also valid for the well 7/12-A-3B. The entire reservoir is assumed to contain the same reservoir fluid (4).

4.1.1 Well

The well 7/12-A-3B is a horizontal well, but production logs indicate that it is only producing from the heel (19). Therefore, for this project, a vertical unfractured well model is used.

4.1.2 Reservoir

The reservoir is assumed to be circular. The circular reservoir model was chosen to fulfill the assumption of a simple reservoir.

4.1.3 Well Radius and Tubing ID

The well radius and the tubing ID (Inner Diameter) are found from the wellbore schematics (8):

Well radius, r_w: = 0.2916 ft

Tubing I.D: = 0.3267 ft

4.1.4 Pay Zone

Through pressure build-up analysis the total kh was found to be 125 mDft, with an average permeability, k, of 0.6 mD (19). Then the height of the pay zone is estimated to:

$$h=\frac{kh}{k}=\frac{125\ \text{mDft}}{0.6\ \text{mD}}=208\ \text{ft}$$

4.1.5 Initial Pressure

In Figure 4.1 the data of initial pressure versus mTVDSS (meters true vertical depth, subsea) for the different wells in the Ula Triassic reservoir is plotted. The green dots represent the well 7/12-A-3B. The top perforation at 11546 ftTVDSS / 3520 mTVDSS is chosen to be the datum depth in this thesis (5). Using the pressure recorded from the RFT (Repeat Formation Tester) graph (fig. 4.1) at 3541 mTVDSS and the oil gradient, the initial pressure at datum is calculated to be 6729 psi. This is based on the following calculation:

RFT depth:	3541 mTVDSS
Datum:	3520 mTVDSS
Delta depth:	(3541 - 3520) mTVDSS = -21 mTVDSS
Oil gradient:	$0.7\ \mathrm{g/cm^3} = \left(\frac{\left(\left(\frac{0.7\mathrm{g}}{\mathrm{cm}^3}\cdot 1000\right)\mathrm{kg/m^3}\cdot 9.81\right)\mathrm{Pa/m}}{101325}\right)\mathrm{bar/m}$
	= 0.0678 bar/m
Delta pressure gravity:	-21 mTVDSS · 0.0678 bar/m = -1.42 bar
	-1.42 bar · 14.5 =-20.6366 psi
RFT depth pressure:	6750 psi
Initial pressure at datum:	6750 psi + (-20.6366) psi = 6729 psi

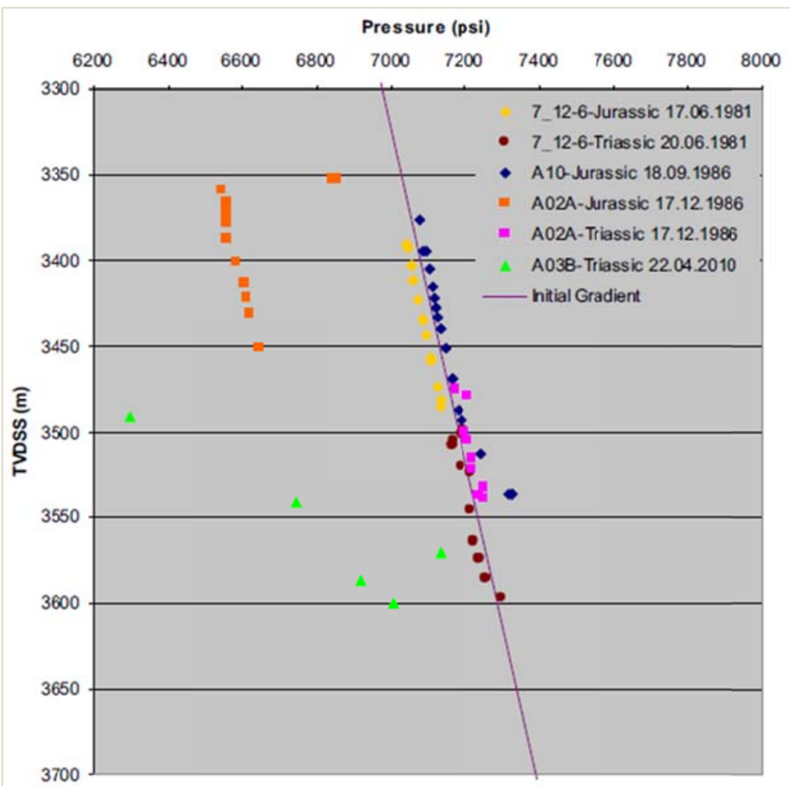


Figure 4.1: RFT graph (19)

4.1.6 Datum Correction

A bottom hole gauge has recorded the bottom hole pressure throughout the testing period (4). The gauge has been located in the tubing string at 9997 ftTVDSS (4). Before entering the pressure data into the simulation program, they have to be adjusted to the datum depth. This is done by a special function in Topaze (Fig. 4.2a; Fig. 4.2b).

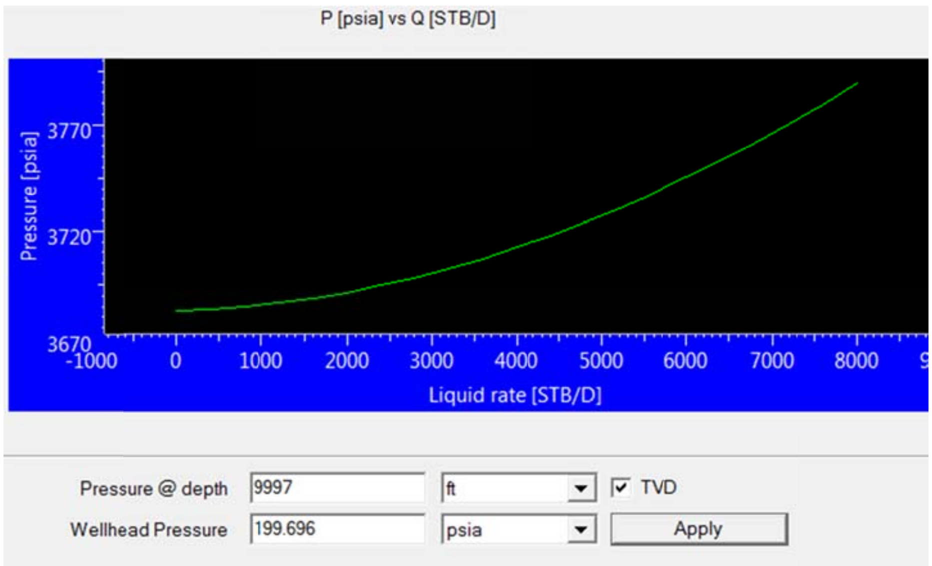


Figure 4.2a: Pressure at the gauge depth

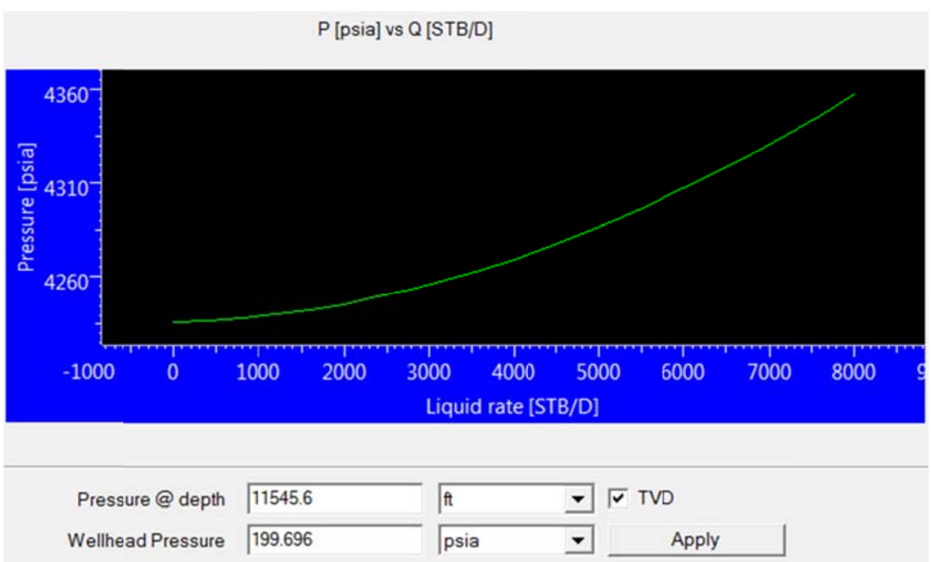


Figure 4.2b: Pressure at the datum depth

4.1.7 Reservoir Properties

The fluid properties have been stable during the production period of 18 months (19). Due to lack of data there is an assumption that the reservoir fluid is the same throughout the reservoir (4). The density (Fig. 4.3), viscosity (Fig. 4.4), oil compressibility (Fig. 4.5) and formation volume factor (Fig. 4.6) are found in the PVT report for the well 7/12-A-3B (20). The values are plotted versus pressure in Topaze. This is marked by the red dots in the graphs presented below. Topaze uses this data to make best fit to the data, resulting in the yellow lines. The well has been producing over the bubble point pressure of 1697 psi (4). The production rates and the BHP data are gathered from the well 7/12-A-3B.

The required reservoir properties for running the simulation program, Topaze, are listed in tables 4.1 and 4.2.

Table 4.1: Rock properties from the Ula Triassic reservoir, from well 7/12-6

Rock properties		Oil field units	SI-units
Porosity	Φ	0.14	0.14
Formation compressibility	c_f	$3.00E^{-6}$ psi^{-1}	$4.35E^{-7}$ kPa^{-1}
Water saturation	S_w	0.4	0.4

(4)

Table 4.2: Fluid properties from the Ula Triassic reservoir, from well 7/12-A-3B

Fluid properties		Oil field units (at: 760 °R, 7397 psi)	SI-units (at: 421.9 K, $5.1E^7$ Pa)
Formation Volume Factor	Bo	1.63 RB/stb	1.63 m^3/Sm^3
Oil viscosity	μ	0.413 cp	$4.13 \cdot 10^{-4}$ Pa·s
Oil density	ρ	248.50 lb/bbl	708.60 kg/m^3
Gas Oil Ratio (from a 3 stage flash)	GOR	467 scf/stb	87 Sm^3/Sm^3

(20; 4)

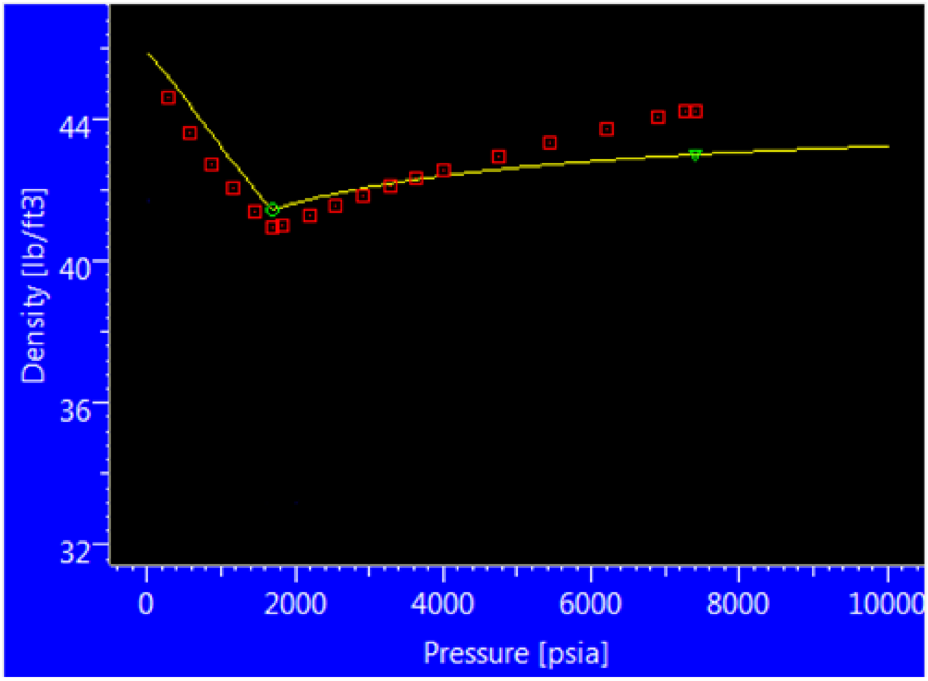


Figure 4.3: Density at 760 °R

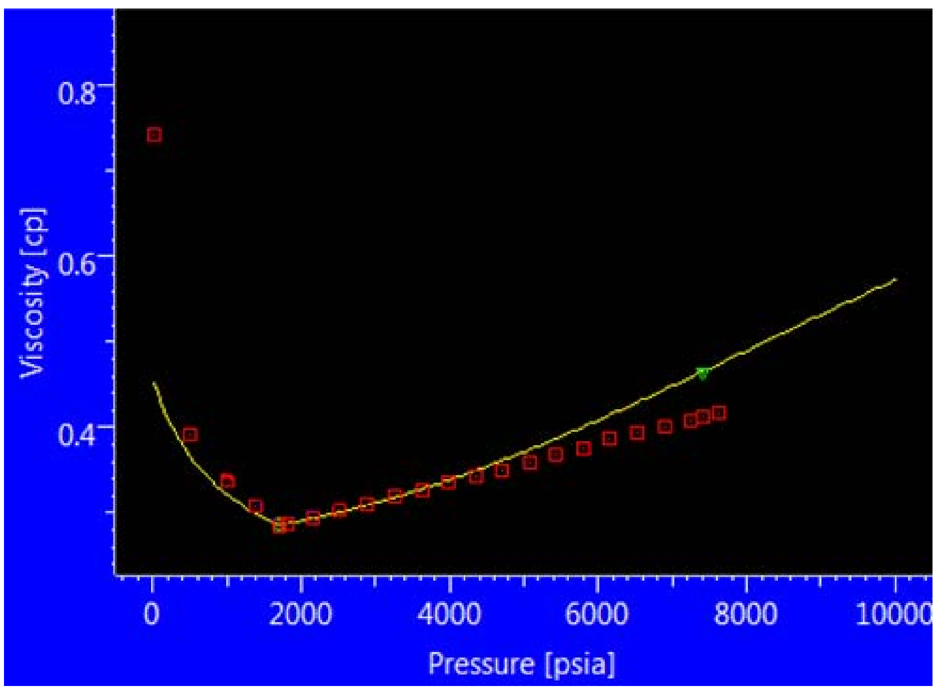


Figure 4.4: Viscosity at 760 °R

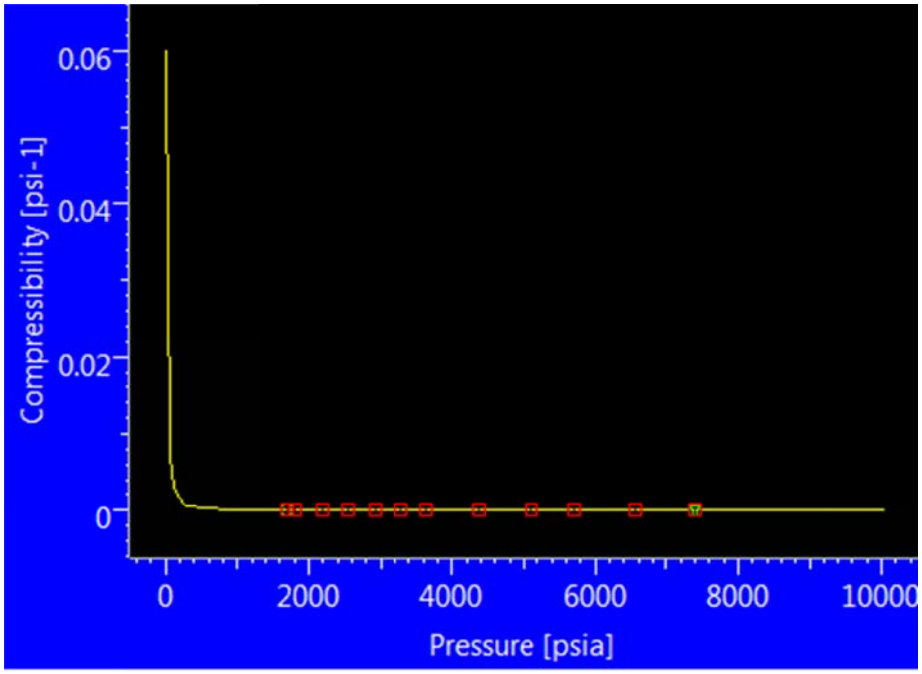


Figure 4.5: Oil compressibility at 760 °R

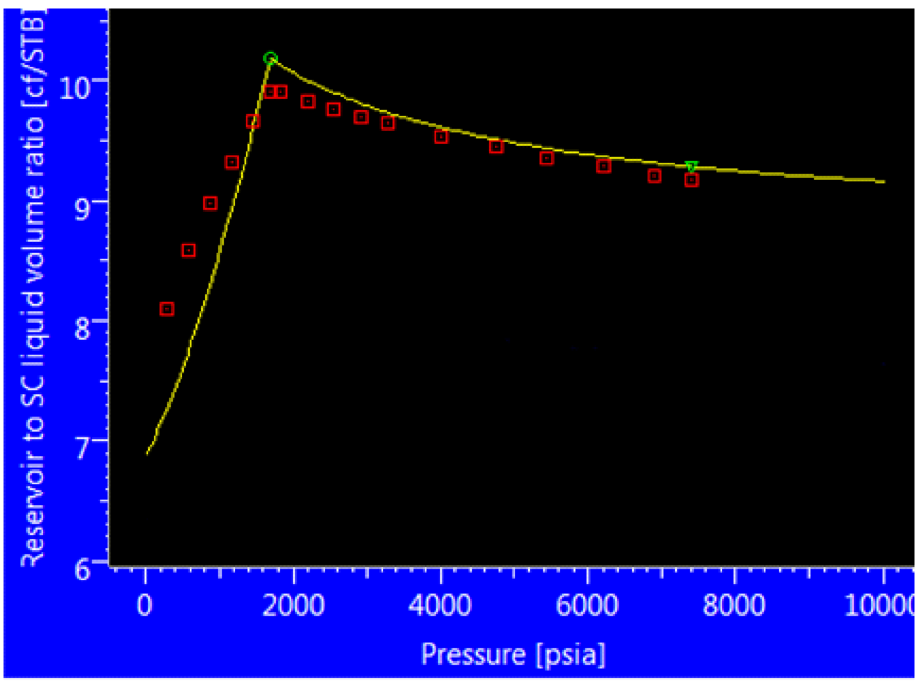


Figure 4.6: Formation volume factor at 760 °R

4.2 Data Preparation

Production data are typically very noisy (7). After putting the data into Topaze the noise needs to be reduced as much as possible before the simulation can start. This is primarily done by physically moving the flow data so that it matches the pressure data. This change is done in the history matching plot, making sure that both the start (Fig. 4.7; Fig. 4.8) and the end (Fig. 4.9; Fig. 4.10) of a pressure build up matches the shut in- and flowing data.

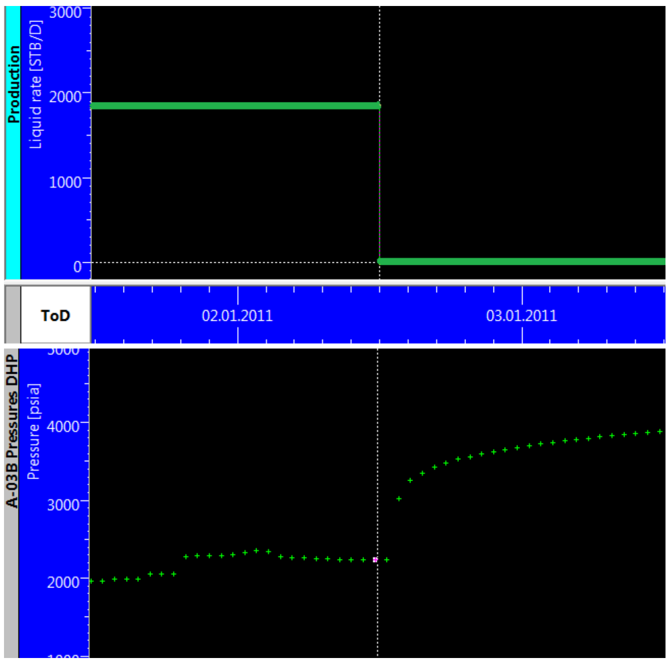


Figure 4.7: In the start of a PBU, before adjusting

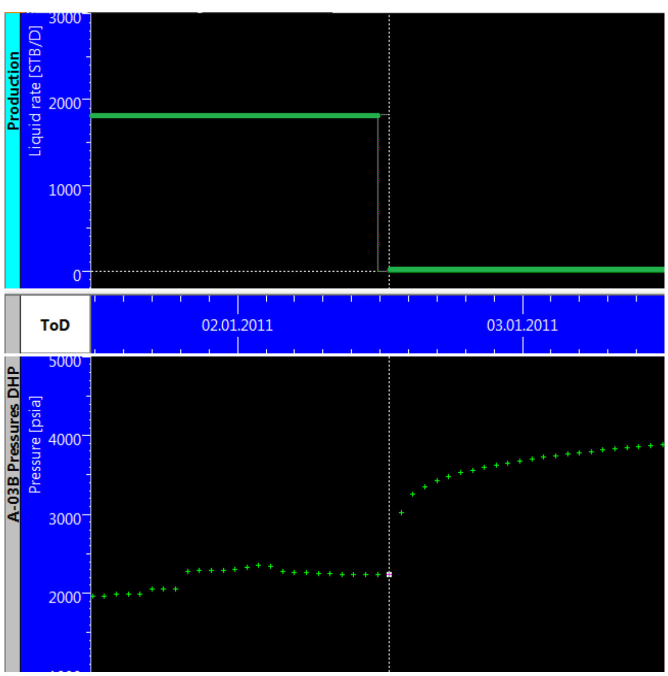


Figure 4.8: In the start of a PBU, after adjusting

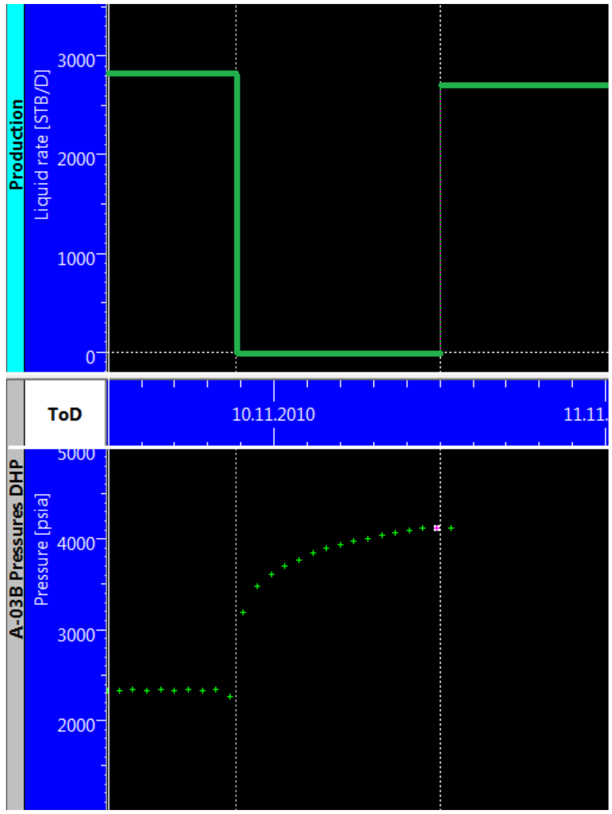


Figure 4.9: In the end of a PBU, before adjusting

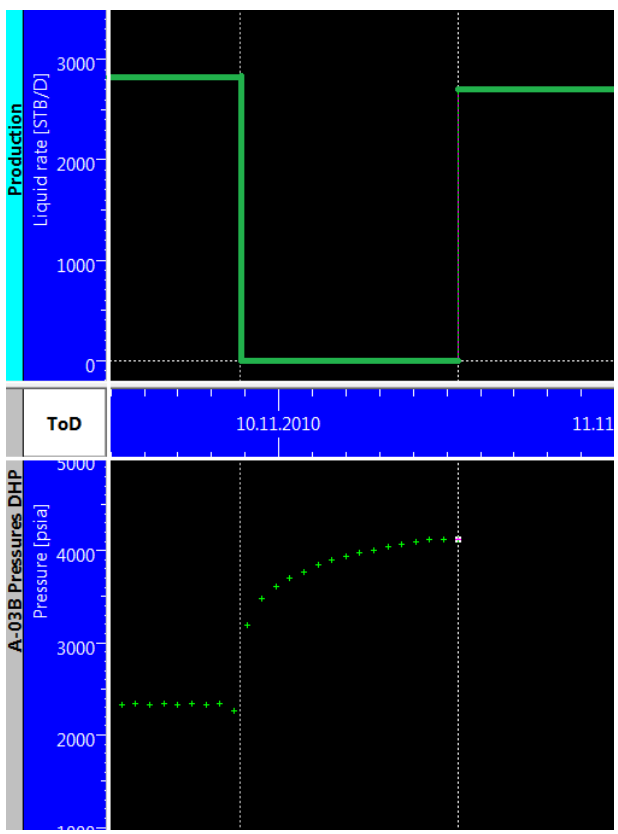


Figure 4.10: In the end of a PBU, after adjusting

Another possibility is to manually remove the noisy data, shown in Figure 4.11. To reduce the noise even more the filtering tool can be used (Fig. 4.12; Fig. 4.13). This tool simplifies the rate input by merging flow periods where the rate difference is small or when the rate difference is below a certain threshold. The flow periods where the rate difference was less than one percent was merged and consequently the total number of flow periods was reduced. This also leads to a less noisy data set.

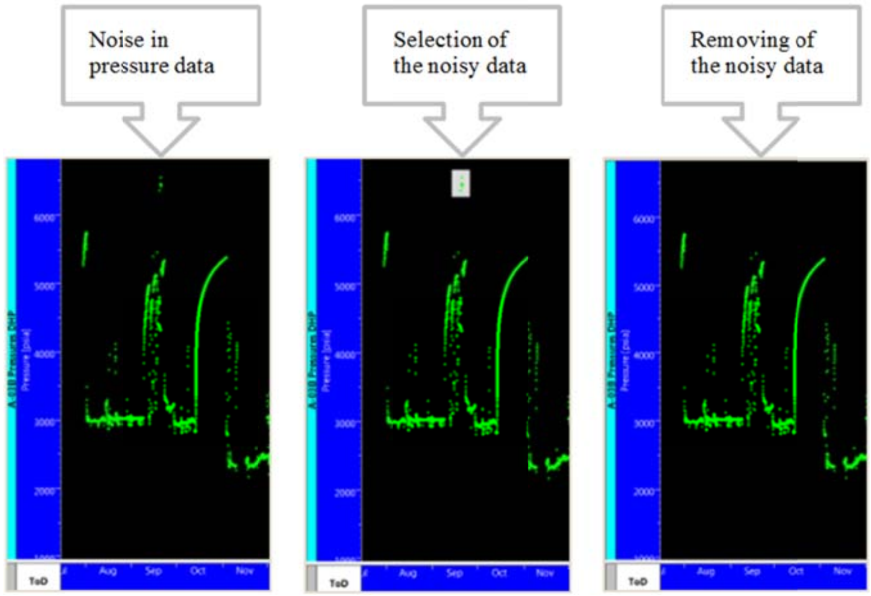


Figure 4.11: Removing of the noisy data points

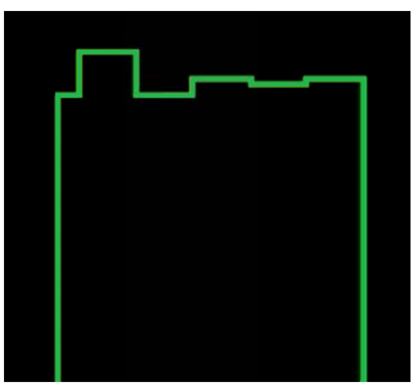


Figure 4.12: A section of the rate data before using the filter

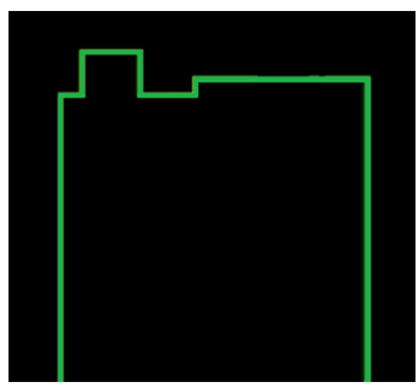


Figure 4.13: A section of the rate data after using the 1% filter

5 Analysis Results

When analyzing the well 7/12-A-3B both process A and process B are utilized. In process A the NPI plot, the Blasingame plot, the Blasingame type curves and the normalized rate cumulative plot are used. In process B the history match is used.

5.1 History Matching

The test production of well 7/12-A-3B started the 25th of July 2010 and has performed successfully during 18 months. There have been a total of 45 well tests up to Jan 1st 2012, and 21 of the pressure build-ups performed have been interpreted (4). These pressure build-ups are listed in table 5.1. In Figure 5.1 the production rate and the BHP from the production well 7/12-A-3B are plotted versus time.

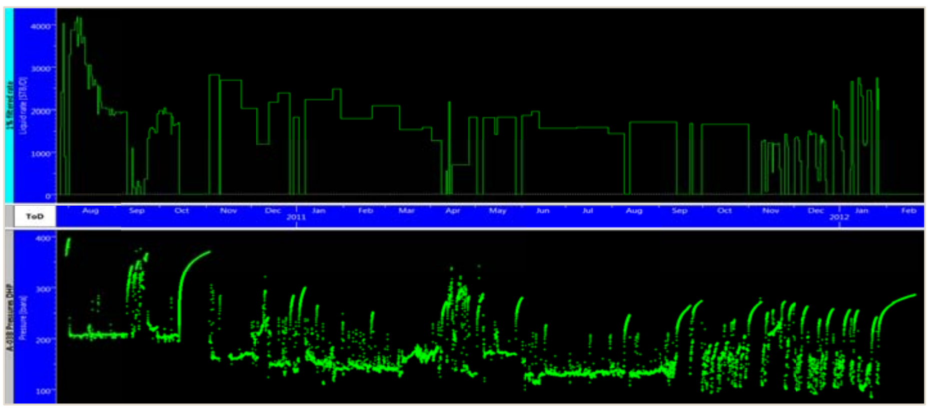


Figure 5.1: Well production- and bottom hole pressure history

Table 5.1: Pressure build-ups, well 7/12-A-3B

Date	Operation	Duration	Commentary
27.07.2010	Shut in after clean up		
29.07.2010	Initial PBU		
16.08.2010	Plant shut down	2 hrs	too short for analysis
20.08.2010	Plant shut down	5 hrs	too short for analysis
09.09.2010	PLT/PVT well shut in	82 hrs	
08.10.2010	Plant shut down	5 hrs	too short for analysis
14.10.2010	Long PBU shut in	19 days	
27.12.2010	Plant shut down	48 hrs	
02.01.2011	Plant shut down	95 hrs	
14.01.2011	Plant shut down	21 hrs	too short for analysis
19.02.2011	Plant shut down	24 hrs	too short for analysis
08.04.2011	PBU prior to CT clean out	75 hrs	noise in P-data
01.05.2011	Shut in during CT operations	100 hrs	too much noise in P-data
27.05.2011	PBU after CT clean out	103 hrs	
08.08.2011	PBU	3 days	
13.09.2011	PBU	8 days	unstable rate before PBU
31.10.2011	PBU	8 days	unstable rate before PBU
12.11.2011	PBU	1 ½ days	unstable rate before PBU
27.11.2011	PBU	3 days	unstable rate before PBU
06.12.2011	PBU	4 days	unstable rate before PBU
23.12.2011	PBU	4 days	unstable rate before PBU

(4)

Based on the input data in process B, a history match plot can be used to optimize a match for the data (Fig. 5.2). The corresponding values are listed in table 5.2.

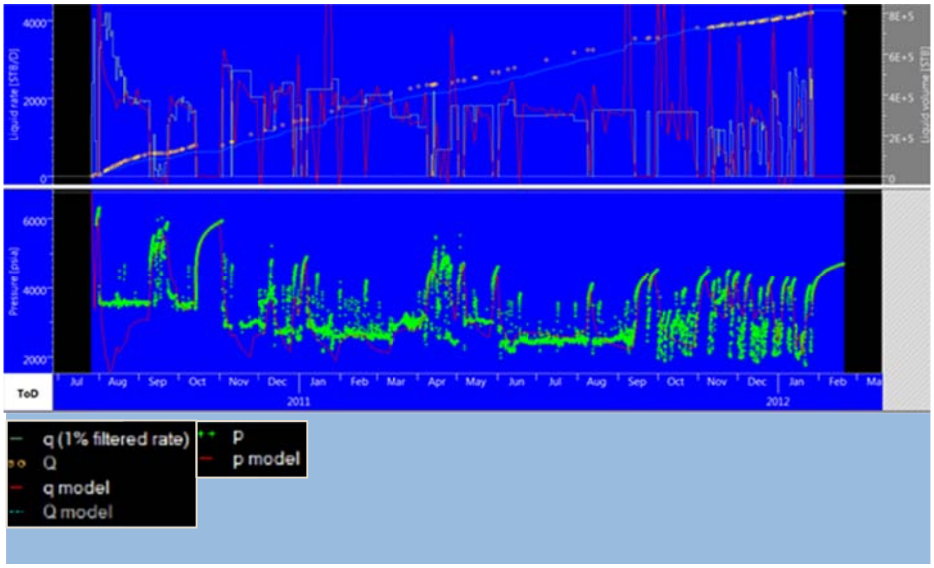


Figure 5.2: History match plot – Ula Triassic, Well 7/12 A-3B

Table 5.2: Results from the history match plot

Values: History match plot	
T_{min}	36 hr
T_{max}	13812 hr
Skin	-4.15
kh	169 mDft
k	0.847 mD
P_i	6729 psi
STOIIP	16.4 MMstb
STOIP	15.6 MMstb
$Q_{o(max)}$	0.802 MMstb
R_e	1700 ft

This model fits the major build-ups (Fig. 5.3), and it also reflects most of the BHFP (Fig. 5.4). It is important to find a match that fits the flowing pressures, since the well is being analyzed by production analysis. The history match plot does not give a good match for the flowing period of August 2010 (Fig. 5.5). The clean-up in July 2010 and the imprecise measurements in the beginning of the production could have this impact on the BHP. The gas lift was installed in December 2010, and after this time the model seems to fit the flowing periods. The gas lift rate is typically 1.75 MMscf/d when the production is stable.

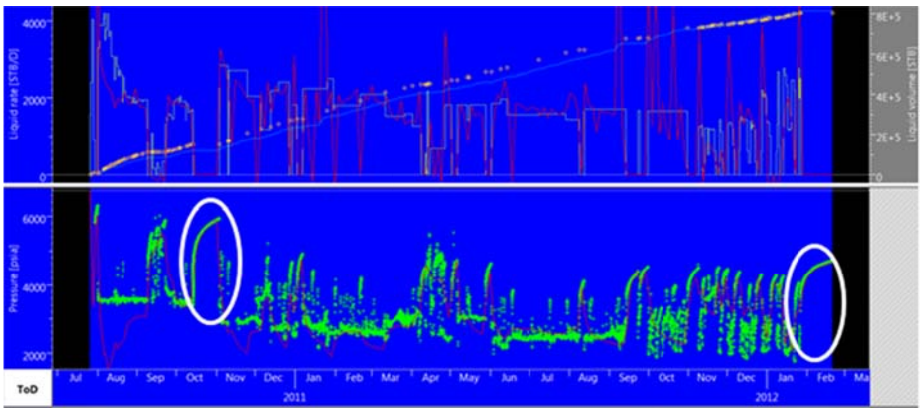


Fig. 5.3: History match – The two longest lasting build ups

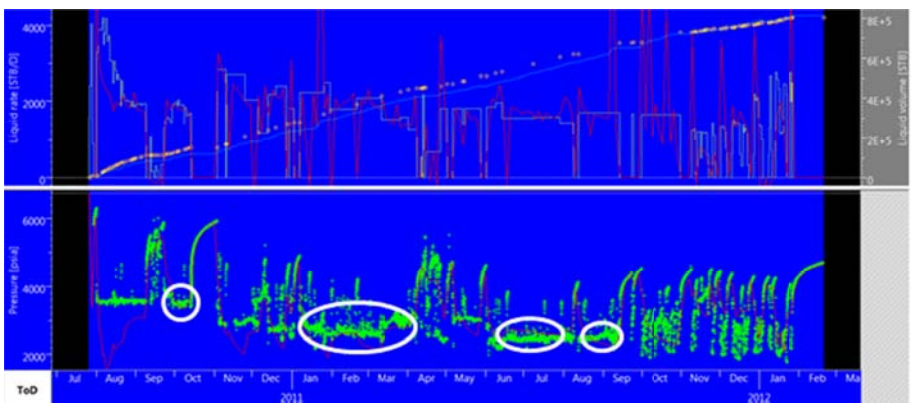


Figure 5.4: History match plot – The flowing periods

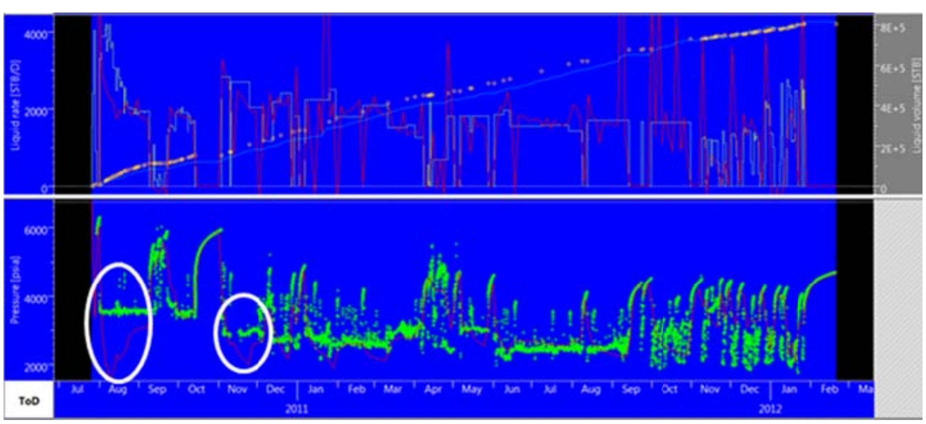


Figure 5.5: History match plot– Not a good match for the flowing periods in the beginning of the production

The first major pressure build-up is the pressure build-up that started the 14th of October 2010, and lasted for 19 days (Fig. 5.6). It has been analyzed using well testing methods, and has given valuable information about the reservoir in the early stage of the test period.

In May 2011 there was a sudden increase in BHFP (Fig. 5.7). This was due to a coil tubing clean out campaign from the 8th of April to the 5th of May 2011. The sump in the bottom of the well, from 4125 mMD to 4475mMD, was probably filled with water. The water in the sump may have restricted the flow from the toe section of the well. During the well testing period the PLT log confirmed that the well was only producing from the heel (4). The intension of the coil tubing campaign was to clean out the well to the toe to improve the production from the well. The well was cleaned out to total depth of the well (4880 mMD). (5) During the coil tubing campaign the water that was possibly present in the sump was temporarily removed. The following increase in fluid production can explain the temporary increase in BHFP.

After cleaning out the well, a PLT log was run in the hole to determine the production zones in the reservoir. Again the logs indicated that the flow only came from the heel (4). The sump was probably again filled with water and the bottom hole pressure decreased to the same well pressure as prior to the clean out (21).

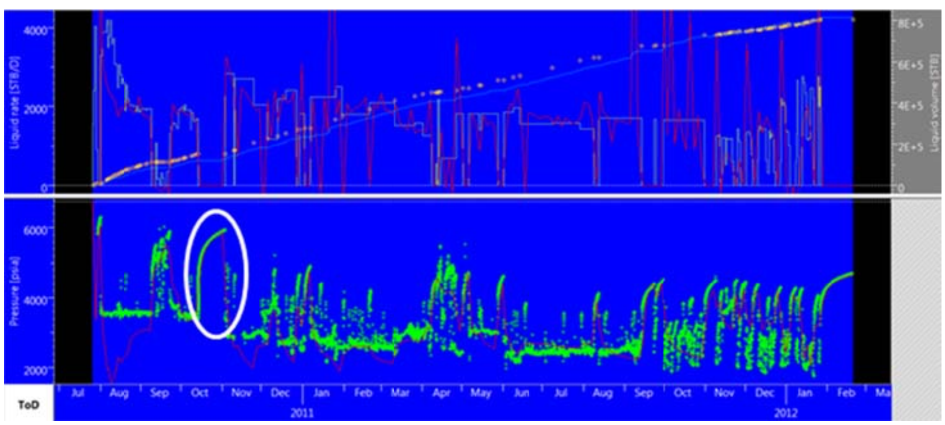


Figure 5.6: History match plot – The 19 days pressure build-up

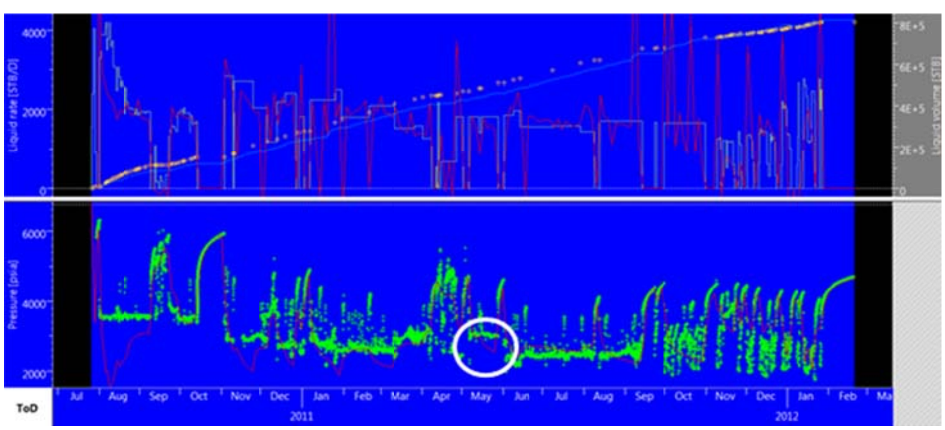


Figure 5.7: History match plot – Increase in bottom hole pressure

After September 2011 the well production became unstable (Fig. 5.8). The pressure data from this period contains a lot of noise, resulting in a model that does not reach the tops of the build-ups, nor the bottom of the flowing periods. This unstable production is due to water production and the gas lift not working properly (4; 19).

In February 2012 the well was closed in, thereby starting a three months pressure build-up. This pressure build-up is the build-up in the end of the production test (Fig. 5.9). This is the pressure build-up that lasted for three months from February to April 2012. The analysis of this pressure build-up will provide with even more information of the reserves in the reservoir. This is the first pressure build-up done on the Triassic field that has lasted for multiple months.

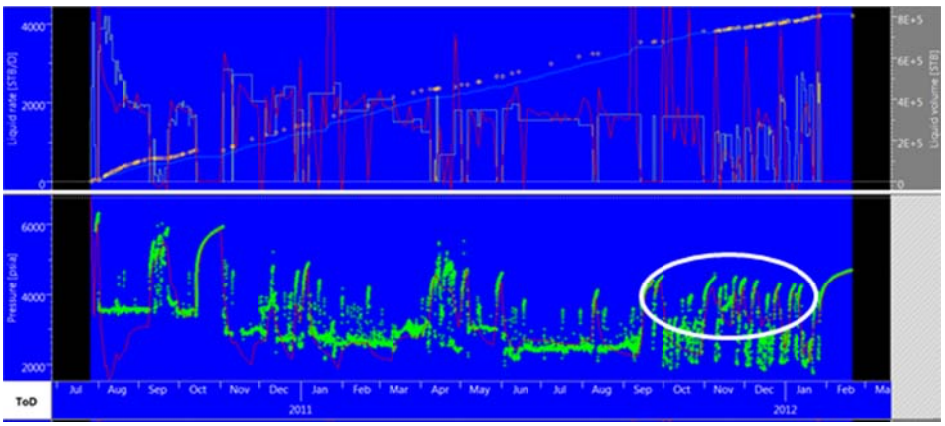


Figure 5.8: History match plot – Unstable flow

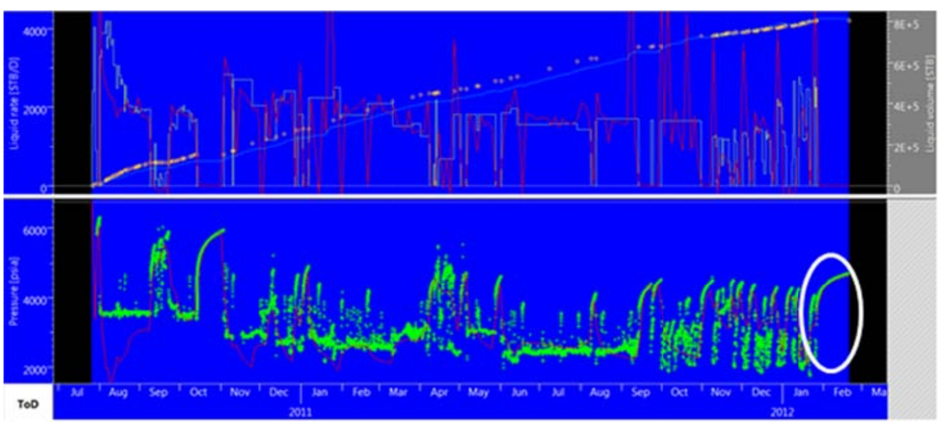


Figure 5.9: History match plot – The final build-up

The model does not fit the cumulative production graph other than in the beginning and in the end (Fig. 5.10). This could be the result of the choice of a too simple model. However, there is a match in the end of the production period, and that is the most important regarding the final results.

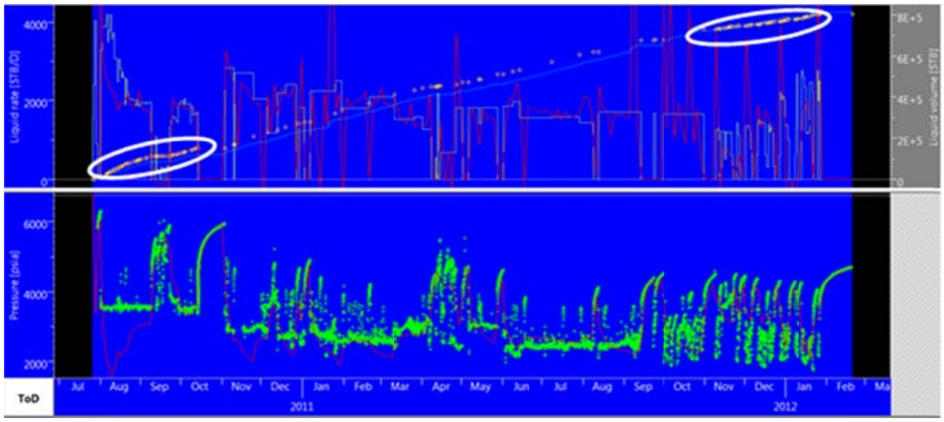


Figure 5.10: History match plot – The cumulative production curve matches the data in the beginning and end of the production

5.2 Normalized Pressure Integral (NPI) Plot

When performing a history match, Topaze proposes a corresponding NPI plot[13] based on the values determined by the history match. A NPI plot is based on the same equations as the NPI type curves, but provides an equation that is more consistent with the data provided. The NPI plot shown below is the solution that Topaze provides for the 7/12-A-3B data based on the results obtained from the history match plot in chapter 5.1 (Fig. 5.11).

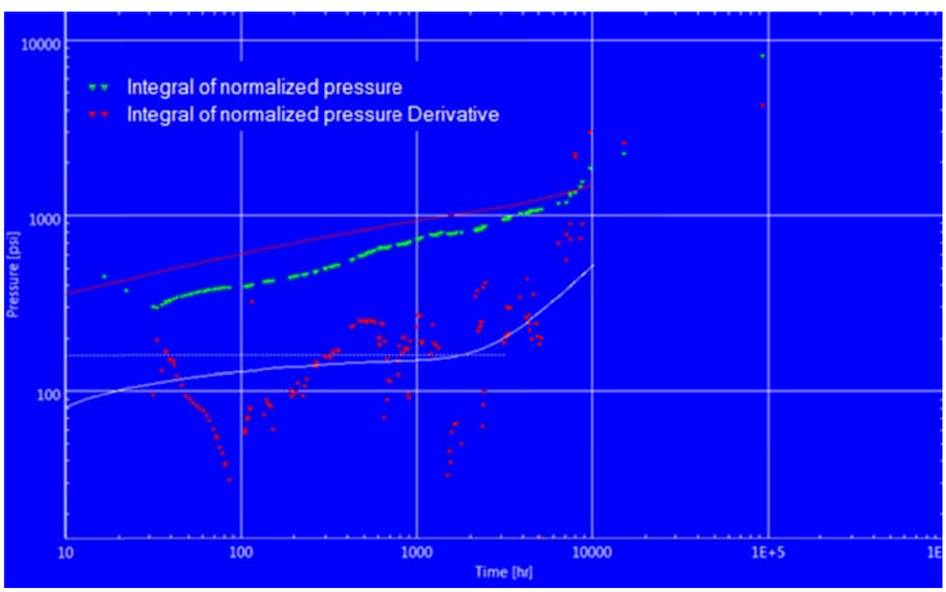


Figure 5.11: NPI plot – Ula Triassic, Well 7/12-A-3B

[13] The NPI plot is called log-log plot in Topaze.

Looking at the NPI plot of the Triassic reservoir it is clear that a match has not been made (Fig. 5.12). A circular boundary reservoir model for the Triassic reservoir is probably not advanced enough for this type of reservoir, with a complex well like 7/12-A-3B. This simple model will not be able to match both the history match and the NPI plot at the same time. Table 5.3 presents the values from the NPI-plot.

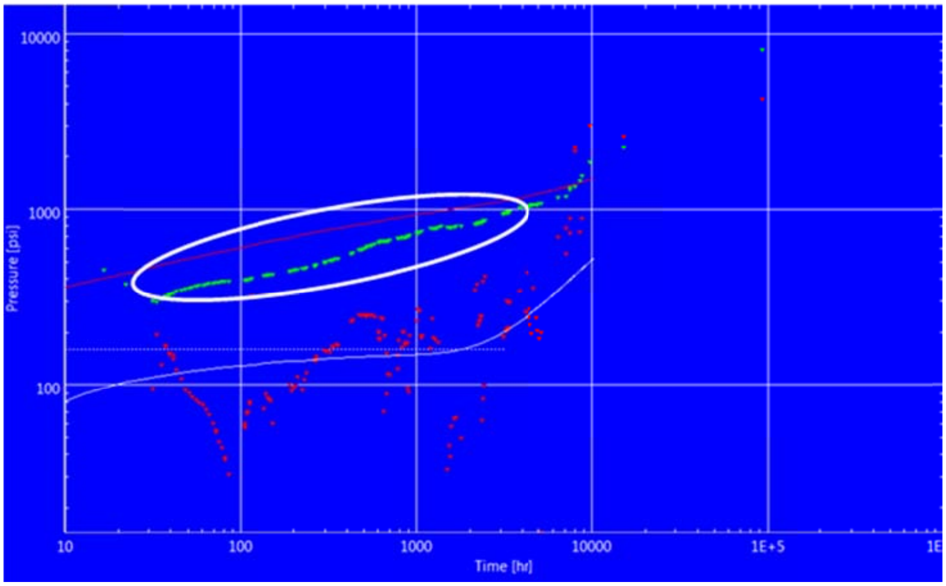


Figure 5.12: NPI plot – Not a proper match

Table 5.3: Results from the NPI plot

Values: NPI plot	
T_{min}	36 hr
T_{max}	13812 hr
Skin	-4.15
kh	169 mDft
k	0.847 mD
P_i	6729 psi
STOIIP	16.4 MMstb
STOIP	15.6 MMstb
$Q_{o(max)}$	0.802 MMstb
R_e – no flow	1700 ft

The main purpose of this plot is to get a clear transition between transient and boundary dominated flow. Even though the model does not fit the data properly, it shows the characteristic angle that marks the transition towards the boundary dominated flow (Fig. 5.13, Fig. 5.14). Therefore the reservoir seems to be in a boundary dominated flow period.

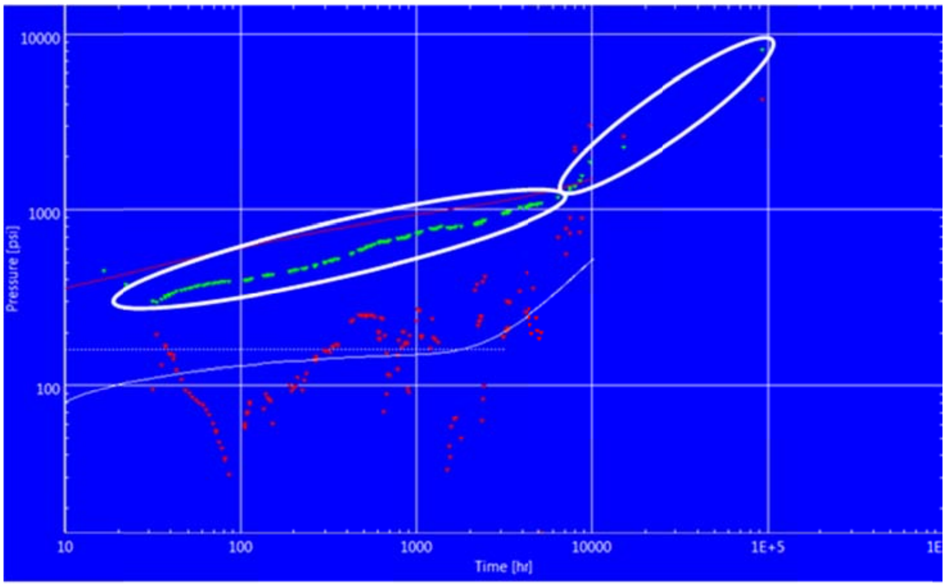


Figure 5.13: NPI plot –The transition between transient and boundary dominated flow in the normalized pressure integral curve

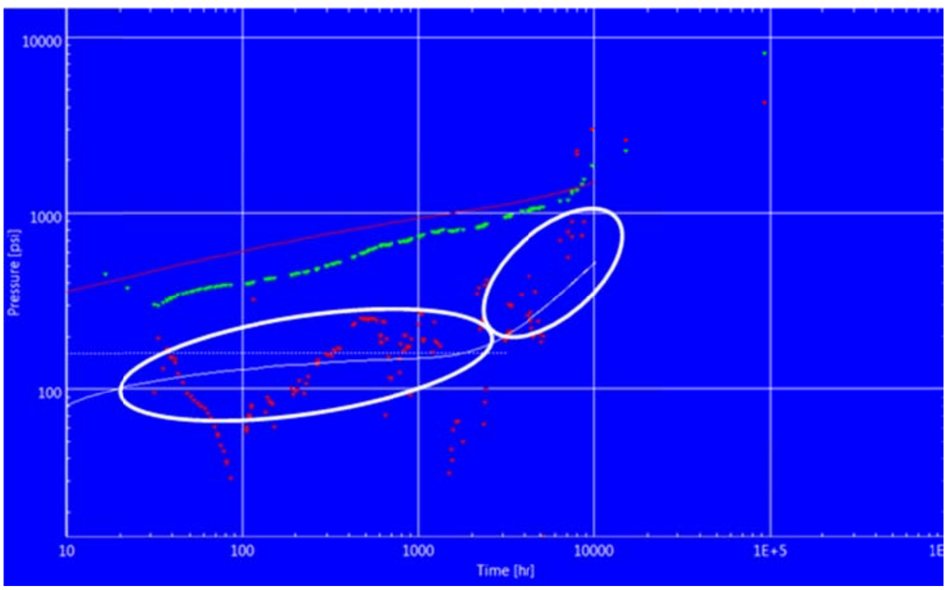


Figure 5.14: NPI plot – The transition between transient and boundary dominated flow in the normalized pressure integral derivative curve

5.3 Blasingame Plot

Similar to the NPI plot, a Blasingame plot made in Topaze is a plot that the program makes based on the current history match. The Blasingame plot is based on the same equations as the Blasingame type curves, but provides an equation that is more consistent with the data provided (Fig. 5.15). The values presented by the Blasingame plot are listed in table 5.4.

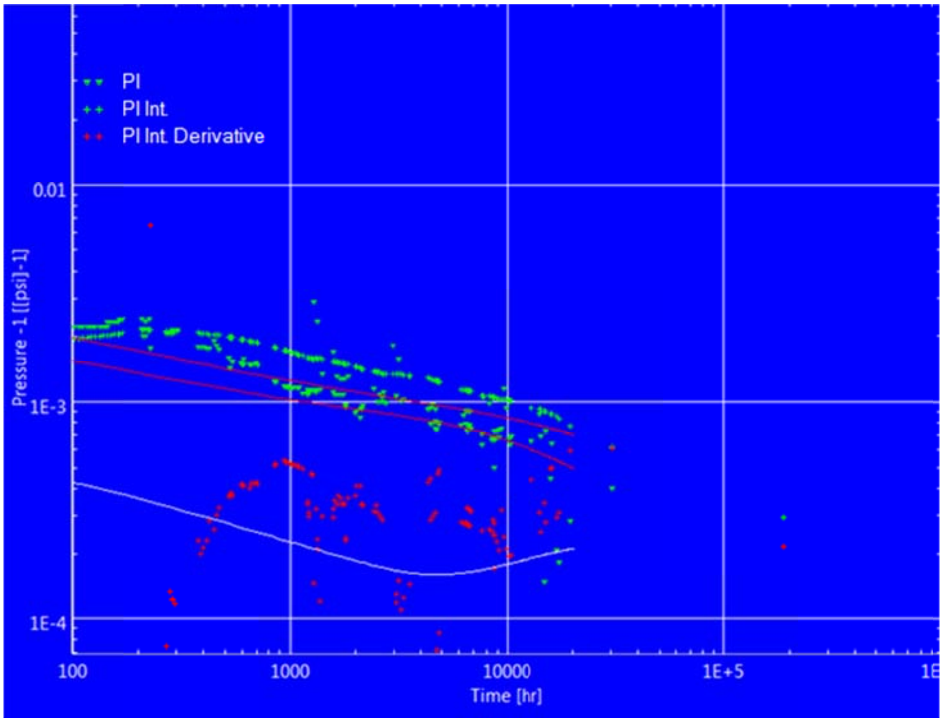


Figure 5.15: Blasingame plot – Ula Triassic, Well 7/12-A-3B

Table 5.4: Results from the Blasingame plot

Values: Blasingame plot	
T_{min}	36 hr
T_{max}	13812 hr
Skin	-4.15
kh	169 mDft
k	0.847 mD
P_i	6729 psi
STOIIP	16.4 MMstb
STOIP	15.6 MMstb
$Q_{o(max)}$	0.802 MMstb
R_e – no flow	1700 ft

Since the Blasingame plot in Topaze is not independent, but is related to the history match, the optimal solution is for them to correspond. In this case that doesn't occur (Fig. 5.16). This is probably because the model used is too simple for this case.

The strength of a Blasingame plot is that it gives information about whether or not the reservoir has reached boundary dominated flow. The data shown in this Blasingame plot has the typical angle, thereby showing that the reservoir has probably reached its boundary dominated flow (Fig. 5.17).

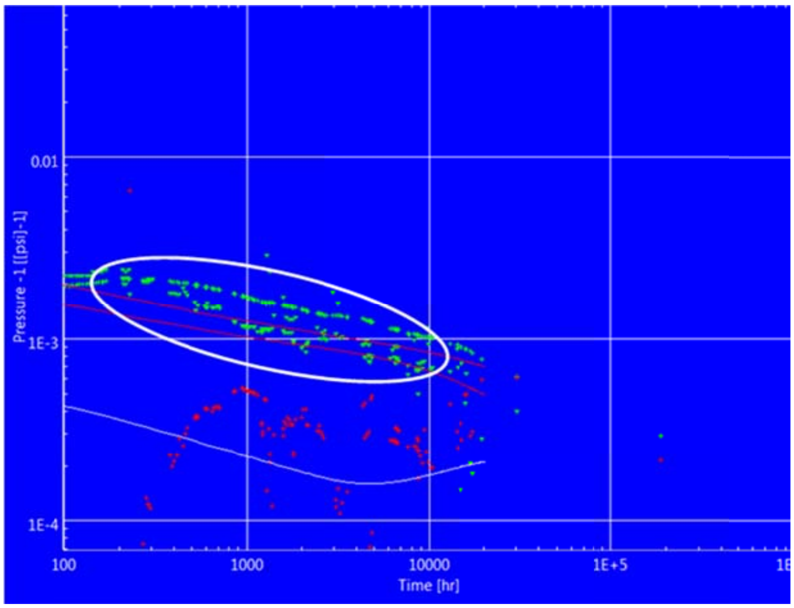


Figure 5.16: Blasingame plot – Not a proper match

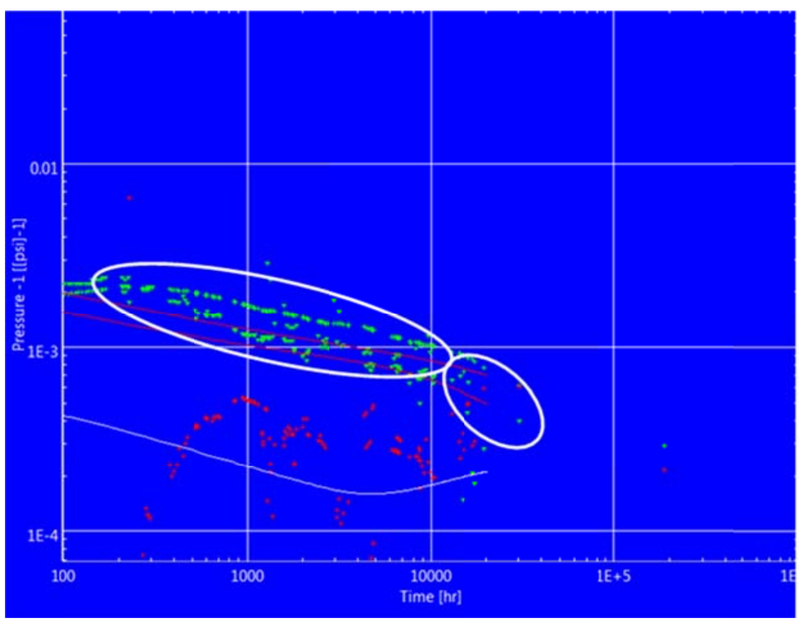


Figure 5.17: Blasingame plot – The transition between transient and boundary dominated flow

5.4 Blasingame Type Curve

In Topaze the Blasingame type curve is independent of the history match. This provides the opportunity of trying a different match (Fig. 5.18). The data is manually correlated to the type curve that seems to fit. The values provided by the type curves are given in table 5.5.

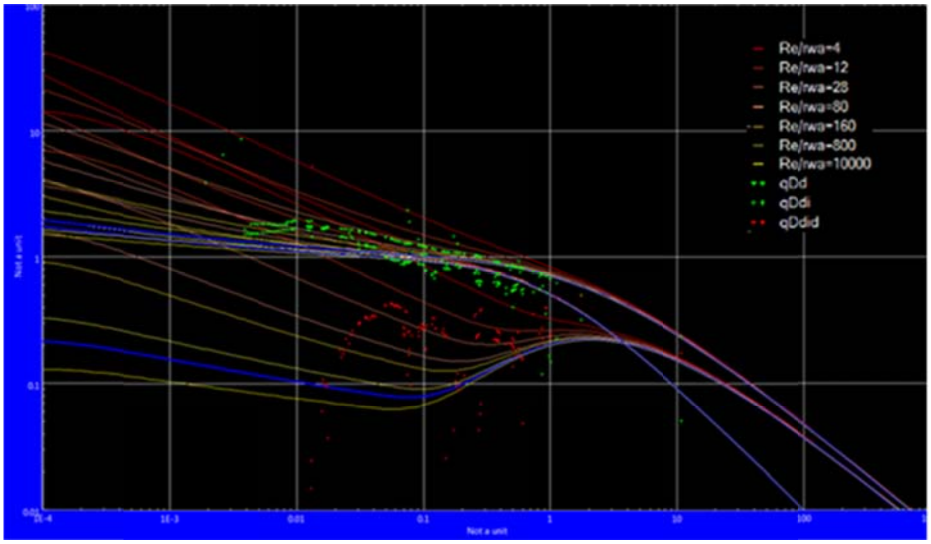


Figure 5.18: Blasingame type curve: Ula Triassic, Well 7/12/A-3B

Table 5.5: Results from the Blasingame type curves

Values: Blasingame type curve	
STOIIP	17.7 MMstb
STOIP	16.9 MMstb
R_e	1760 ft
r_{wa}	0.86 ft
kh	476 mDft
Skin	-0.388

The Blasingame type curve consists of three different type curves; the normalized rate curves (Fig. 5.19), the normalized rate integral curves (Fig. 5.20) and the normalized rate integral derivative curves (Fig. 5.21). Combining the type curves makes it possible to get an even better match than simply matching the different type curves separately.

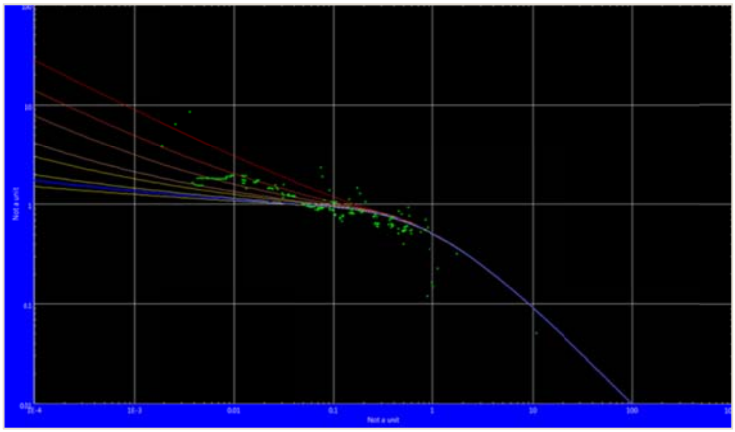


Figure 5.19: Blasingame type curve – Normalized rate curves

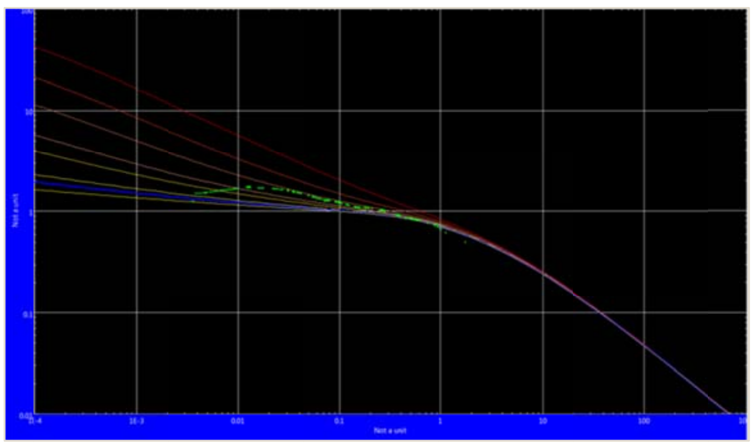


Figure 5.20: Blasingame type curve – Normalized rate integral curves

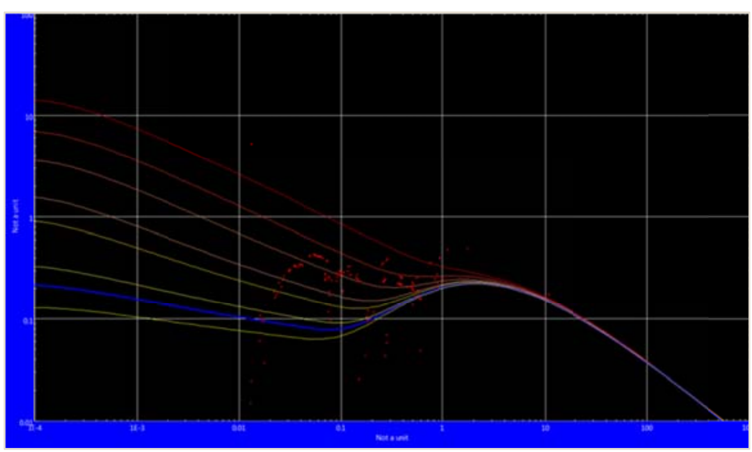


Figure 5.21: Blasingame type curve – Normalized rate integral derivative curves

The transition between the transient flow period and the boundary dominated flow period is happening where the normalized rate data goes from several curves to become only one single curve (Fig. 5.22). A downward concavity with a slope of -1 illustrates that the reservoir is in boundary dominated flow.

Another interesting aspect is the different stems in the transient part of the type curve. If the data follows one of the highest and steepest stems it is an indication of low skin, while if the data follows one of the lowest stems it is an indication of high skin and a damaged well. The data from the Triassic follows stem R_e/r_{wa}=28. This is one of the high stems, and corresponds to a kh=476 mDft and a skin factor S=-0.388, i.e. low skin (Fig. 5.23).

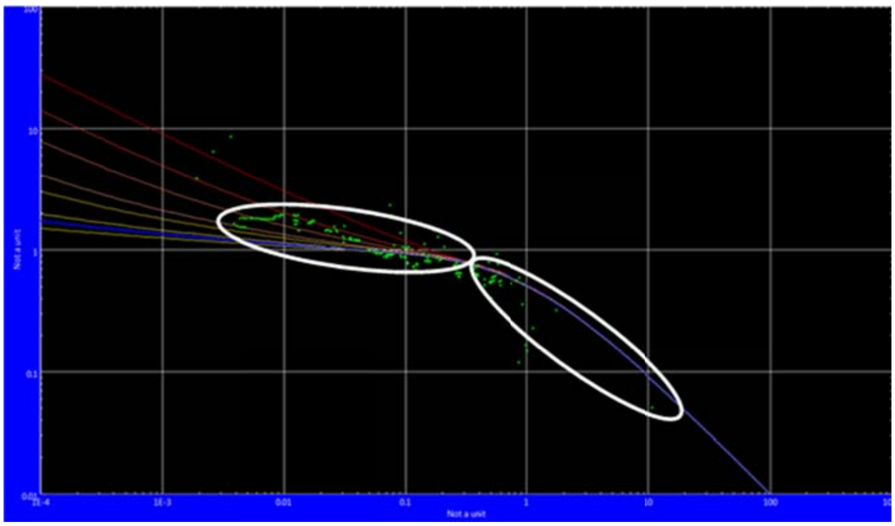


Figure 5.22: Blasingame type curve – The transition between transient and boundary dominated flow

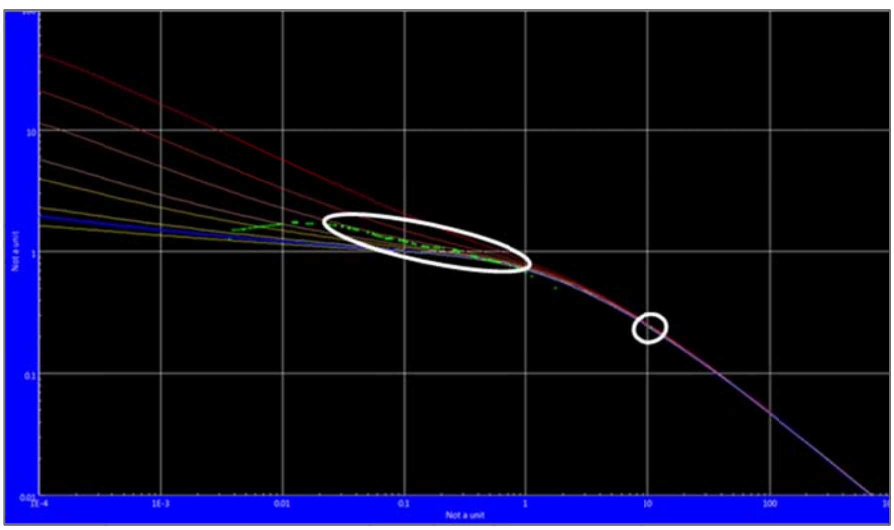


Figure 5.23: Blasingame type curve – The data follows stem R_e/r_{wa}=28

The type curve also shows that in boundary dominated flow the data tends to go below the boundary dominated stem (Fig. 5.24). This is an indication of instabilities in the wellbore which are causing pressure losses to exceed what the correlations would give as a result. Because of the normalized rate versus material balance way of plotting the data, all the data is forced to match the same line during boundary dominated flow. After the angle that marks the transition between transient and boundary dominated flow, the data curve from the well 7/12-A-3B is bending downwards compared to the type curve of 45 degrees. This is typically due to unstable flow in the well and liquid loading problems. These types of problems are common in production data. A behaviour like this can cause the curve to decrease as it should be in boundary dominated flow even though it is not, and consequently estimate a too early time for the transition to occur. This can result in a misinterpretation of the data and cause an underestimation of the reserves. The production data from the well 7/12-A-3B shows that it started producing unstably in September 2011. This might be the reason for the data curve decreasing earlier than expected.

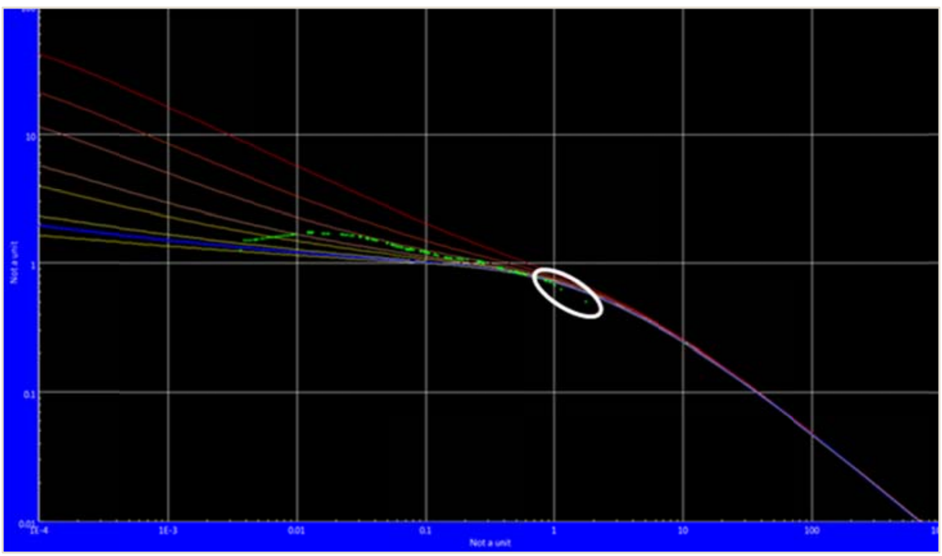


Figure 5.24: Blasingame type curve – The boundary dominated data is bending too early

In the beginning the data curve of the normalized rate is increasing with time (Fig. 5.25). The normalized rate integral data is much smoother, making it much easier to match, and the same behavior is seen from this curve (Fig. 5.26). This is an indication of a well clean-up. It is not possible for a reservoir to get an increase in the productivity index without a mechanical influence. In this case the well was cleaned up in April 2011.

In Blasingame type curves the derivative is taken of the normalized integral rates instead of taking the derivative of the pure normalized rates. The intension is to get a less noisy result. In this case the data seems to be too noisy to get any valuable information from this particular type curve.

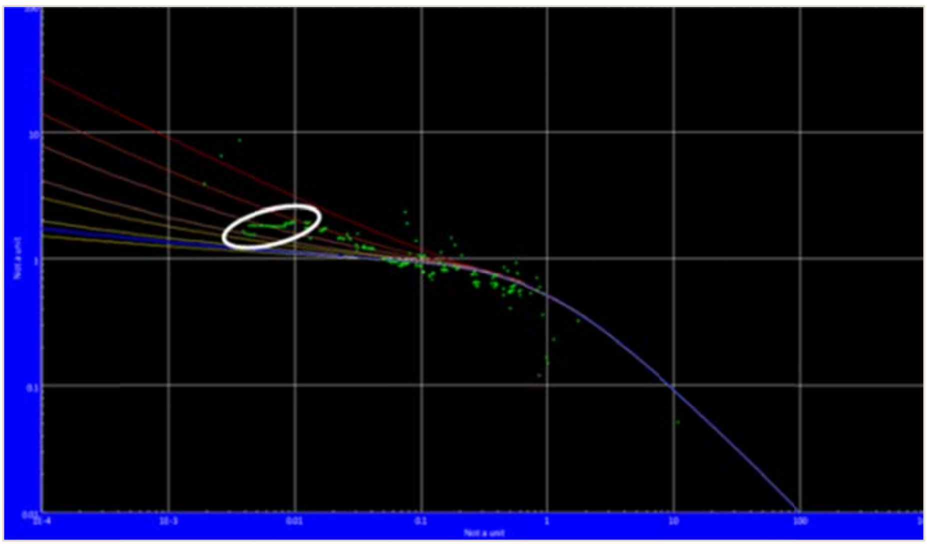


Figure 5.25: Normalized rate type curve –Transient data increasing with time

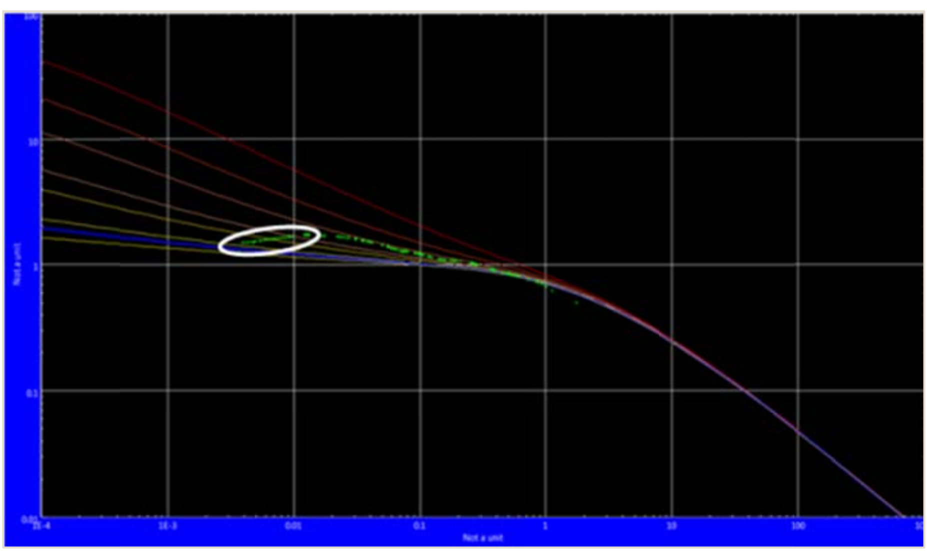


Figure 5.26: Normalized rate integral type curve – Transient data increasing with time

5.5 Normalized Rate-Cumulative Plot

The normalized rate-cumulative plot is independent of the other plots and type curves used in Topaze. This gives another way of comparing the data. By manually constructing a line through the data points, the plot gives a STOIIP that is very similar to the one developed using history matching (Fig. 5.27). This plot can be used when the reservoir has reached the boundary dominated flow. The data points given in the initial trend, pointing 1.6 MMstb, are from the production in August 2010. At this time the reservoir had not reached boundary dominated flow, and has therefore not been taken into account when making this match. If the reservoir is in boundary dominated flow the normalized rate-cumulative plot should make a straight line. By extrapolating this line the large liquid volume of the reservoir can be read from the x-axis. The large liquid volume in this case is the oil and water in the reservoir. The normalized rate-cumulative plot gives a large liquid volume of 26.4 MMstb. Assuming that the reservoir contains 40% water and 60% oil (19), the amount of oil in place is 15.3 MMstb. The values obtained through the normalized rate-cumulative plot are listed in table 5.6.

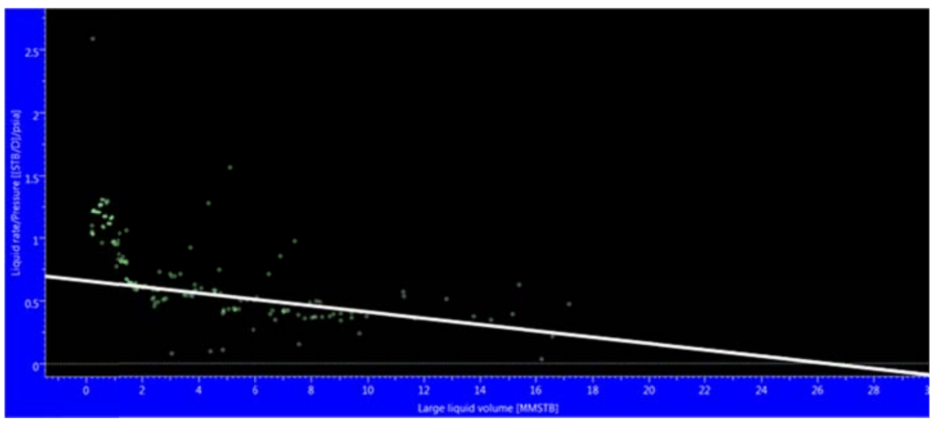


Figure 5.27: Normalized rate-cumulative plot: Ula Triassic, Well 7/12-A-3B

Table 5.6: Results from the normalized rate-cumulative plot

Values: Normalized rate-cumulative plot	
T_{min}	36 hr
T_{max}	13812 hr
P_i	6729 psi
PV	45.3 MMb
STOIIP	16.1MMstb
STOIP	15.3 MMstb

6 Conclusion

This thesis has focused on the production data from the well 7/12-A-3B in the Ula Triassic reservoir. The production data from this well has been analyzed using the advanced production analysis program Topaze.

6.1 Results

History plot (Process B):

Input parameters of a kh of 169 mDft, a skin value of -4.15, a reservoir radius of 1700 ft and a STOIIP of 16.4 MMstb are used. A reasonable match is achieved in the history match plot.

Type curves and plots (Process A):

The NPI plot and the Blasingame plot measured by Topaze based on the current history match did not give a complete match between the model made by Topaze and the specified data. Still these plots are useful, because they indicate that the well 7/12-A-3B is in a boundary dominated flow period, due to the characteristic inclination of the curve.

The Blasingame type curve, which is independent of the history match, gives an output of a reservoir radius of 1760 ft and a negative skin value of -0.388. The normalized rate-cumulative plot and the Blasingame type curve give similar results, with outputs of a STOIIP of 16.1 MMstb and 17.7 MMstb respectively. The kh predicted in the Blasingame type curve is 476 mDft.

The results from the advanced production analysis of well 7/12-A-3B are listed in table 6.1. Matches were not obtained in both process A and process B. However, process A and process B show similarities. Both the history match and the Blasingame type curve, provide an understanding of the Ula Triassic reservoir as a low permeable reservoir. The negative value of the skin factor indicates flow enhancement near the wellbore compared to a vertical well model. This is expected, because the well is deviated at the heel.

Table 6.1: Results from the advanced production analysis of the Ula Triassic reservoir

Model	kh (mDft)	Skin	R_e (ft)	STOIIP (MMstb)
-Input of the history match plot	169	-4.15	1700	16.4
-Output of the normalized rate/ cumulative plot	-	-	-	16.1
-Output of the Blasingame type curve	476	-0.388	1760	17.7

The work done in this thesis has improved the efficiency of the workflow of the company by:

- Increasing employees' knowledge and best practices of advanced production analysis.
- Optimizing analysis of the data gathered from permanent down-hole gauges.

Based on the work presented in this thesis, the company has decided to continue using the advanced production analysis to analyze one of their gas condensate fields.

6.2 Results Compared to Geo Model, Well Testing and Material Balance Plot

Prior to this project a geo model, a well test analysis and a material balance plot have been made. Compared with advanced production analysis from this thesis a better understanding of this complex field can be achieved. The results from the different models are presented in table 6.2.

A kh of 125 mDft, is estimated from well test analysis (19). According to these tests the reservoir is most likely a low permeable reservoir, which corresponds to the result of a low value kh of 169 mDft, seen in the history match.

From well testing a negative skin value of S=-0.8 has been measured. This corresponds to the negative skin values estimated in the advanced production analysis, S=-4.15 from the history match and S=-0.388 from the Blasingame type curve.

Table 6.2: Results from the different analysis methods

	Geo model	Well test	Material balance plot	Advanced production analysis
Input	seismic	q, c_t, BHP, PVT	q, $\bar{p}$, c_t, PVT	q, c_t, BHP, PVT
Results:				
-STOIIP (MMstb)	6.5 – 810		27 – 31	16.1 – 17.7
-kh (mDft)		125		169 – 476
-S		-0.8		-4.15 – -0.388

(19)

6.3 Future Work

This is the first advanced production analysis that has been performed for well 7/12-A-3B and for the Operating Company supporting this work. This thesis has provided information regarding the simplest model. Further work with more complex models will probably give improved results. Looking at the history match, there is still not a perfect match with the NPI plot and the Blasingame plot. To get a better match with the NPI plot and the Blasingame plot a rectangular boundary reservoir model could be used instead of a circular model. By doing so the well in the model could be located in different positions and not in the middle of the reservoir, which might have a positive influence on the results. The interpretations of the logs from the reservoir indicate several faults. This is a case that Topaze can take into account, and this can also be a good improvement of the model. Even though the well is horizontal, a vertical well model is used when analyzing the production data. A better match would probably be achieved by using a horizontal model rather than a vertical one.

The last couple of months show that there might be a higher water cut than previously expected in the Ula Triassic reservoir. By taking a higher value of the water cut into account when doing the advanced production analysis, the results would probably be more accurate.

6.4 Advanced Production Analysis

For advanced production analysis to be reliable, data of good quality is necessary. The production data from well 7/12-A-3B contains a lot of noise. Especially in the last 5 months of production the quality of the production data is quite noisy. The noise in the production data is an inhibiting factor, but despite the large amount of noise in the production data from this well, the advanced production analysis provides some interesting information about the reservoir that can be compared to results from other types of analysis. With that said, it is important to keep in mind that no method is completely accurate for any reservoir. However, the analysis becomes more reliable when multiple methods are used. Different analyzing methods used together will give a better understanding of the field, so the advanced production analysis should be used together with other types of analysis. The focuses of the methods are not the same, and different methods used together can give a complete understanding of the reservoir.

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Appendix A: PVT analysis from Final Report, PVT Analysis of BHS Oil Sample from Well A-03B, Ula (24)

Constant Mass Expansion of Reservoir Fluid, Bottle no.: 820876

Table 0-1: Results from Constant Mass Expansion of reservoir fluid, bottle no.: 820876

Bubble point pressure:		117.0 bar	
Reservoir temperature:		**Error!**	
Sampling depth:		3300 m RKB	
Pressure bar		Relative volumes $V_S/V_{S,BP}$	Isothermal compressibility bar^{-1}
524.4		0.9236	1.150E-04
510.0	**P_{RES}**	**0.9255**	**1.210E-04**
501.2		0.9258	1.246E-04
475.5		0.9293	1.351E-04
451.7		0.9332	1.447E-04
427.6		0.9368	1.544E-04
393.9		0.9419	1.677E-04
375.5		0.9443	1.749E-04
351.8		0.9485	1.840E-04
326.6		0.9528	1.936E-04
302.0		0.9572	2.028E-04
276.0		0.9620	2.124E-04
251.0		0.9672	2.214E-04
225.9		0.9727	2.304E-04
201.5		0.9781	2.389E-04
176.0		0.9844	2.477E-04
151.2		0.9914	2.560E-04
125.3		0.9989	2.645E-04
117.0	**P_{BP}**	**1.0000**	**2.672E-04**
110.5		1.0222	
95.8		1.0902	
74.5		1.2658	
56.4		1.5595	
44.9		1.8978	

Differential Liberation of Reservoir Fluid, Bottle no.: 820876

Table 0-2: Results from Differential Liberation of reservoir fluid, bottle no.: 820876

Pressure		B_o	R_s	Oil density
bar		m³/Sm³	Sm³/Sm³	kg/m³
524.4		1.6308		710.0
510.0	**P_{RES}**	**1.6342**		**708.6**
501.2		1.6347		708.3
475.5		1.6410		705.6
451.7		1.6479		702.7
427.6		1.6543		700.0
393.9		1.6633		696.2
375.5		1.6675		694.4
351.8		1.6750		691.3
326.6		1.6825		688.3
302.0		1.6903		685.1
276.0		1.6987		681.7
251.0		1.7080		678.0
225.9		1.7176		674.2
201.5		1.7272		670.4
176.0		1.7383		666.1
151.2		1.7506		661.5
125.3		1.7638		656.5
117.0	**P_{BP}**	**1.7658**	**149.1**	**655.8**
100.0		1.7221	136.1	663.0
80.0		1.6601	117.6	673.5
60.3		1.5988	99.4	684.2
40.0		1.5302	82.3	698.9
20.0		1.4433	60.1	714.6
1.0		1.1462	0.0	742.3

Appendix B: Presentation of Advanced Production Analysis

Type Curves

Master's Thesis

Sylviann Eike Toft

Date: 11.04.12

Fetkovich – Blasingame – Agarwal/Gardner – Normalized pressure integral

Fetkovich | Blasingame | Agarwal/Gardner | Normalized pressure integral

Improvement:
-Type curves valid for transient and boundary dominated flow

Type curves:

Dimensionless decline rate in the **boundary dominated** flow regime

$$qDd = \frac{1}{(1 + b \cdot tDd)^{\wedge}(1/b)}$$

Dimensionless decline **time**

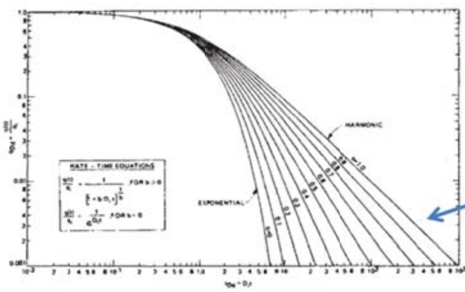
$$tDd = \frac{\frac{0.00634 \cdot k \cdot t}{\varphi \cdot \mu \cdot ct \cdot rw^2}}{\frac{1}{2}\left[\ln\left(\frac{re}{rw}\right) - \frac{1}{2}\right]\left[\left(\frac{re}{rw}\right)^2 - 1\right]}$$

Plot:

Rate q

versus

Time t



Empirical

In oil field units | LogLog plot

Fetkovich | Blasingame | Agarwal/Gardner | Normalized pressure integral

Improvement:
-Type curves valid for transient and boundary dominated flow

Type curves:

Dimensionless decline rate in the **transient** flow regime

$$qDd = \frac{141{,}2 \cdot q \cdot \mu \cdot B}{k \cdot h \cdot (pi - pwf)}\left[\ln\left(\frac{re}{rw}\right) - \frac{1}{2}\right]$$

Dimensionless decline **time**

$$tDd = \frac{\frac{0.00634 \cdot k \cdot t}{\varphi \cdot \mu \cdot ct \cdot rw^2}}{\frac{1}{2}\left[\ln\left(\frac{re}{rw}\right) - \frac{1}{2}\right]\left[\left(\frac{re}{rw}\right)^2 - 1\right]}$$

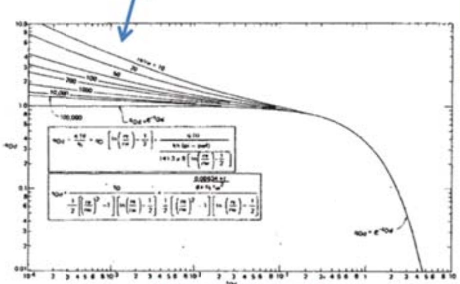
Plot:

Rate q

versus

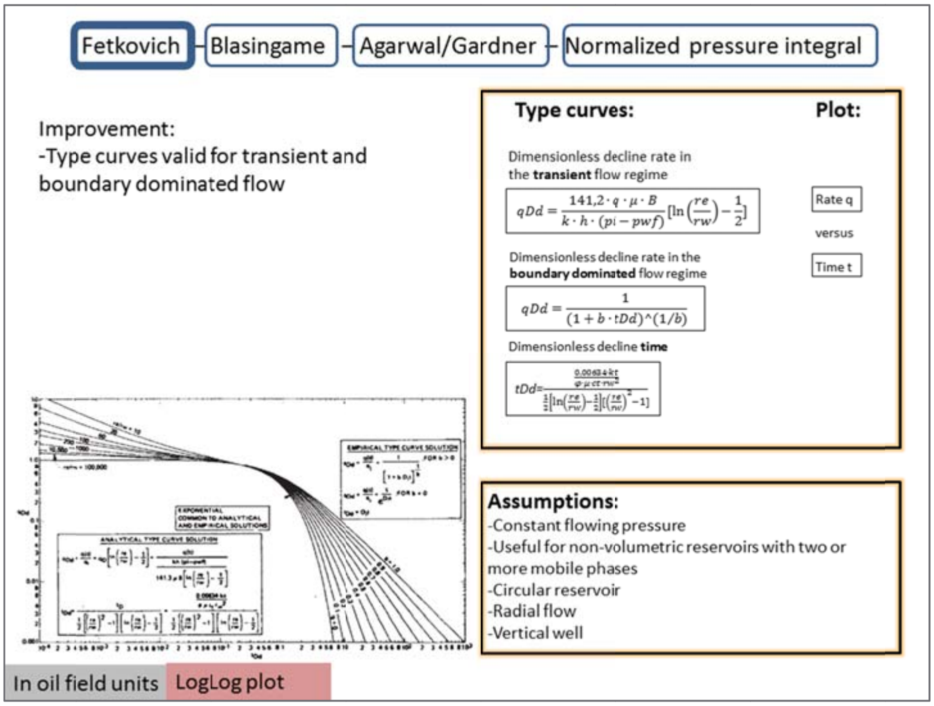
Time t

Analytical

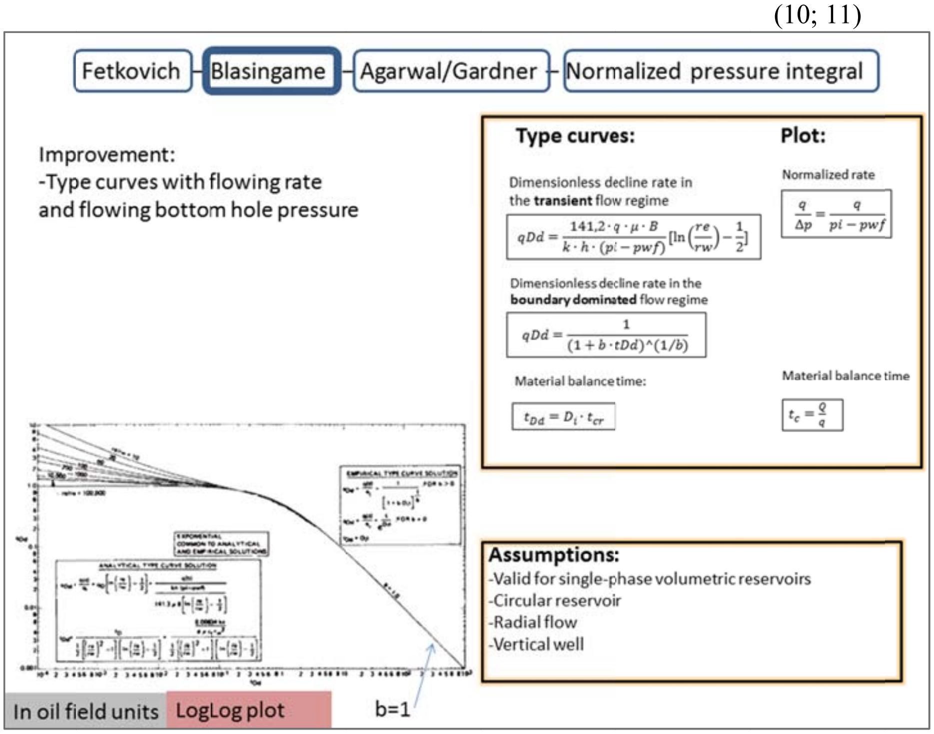


In oil field units | LogLog plot

D



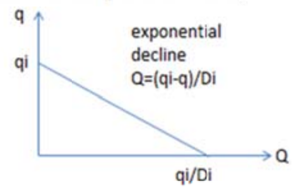
(10; 11)



(10; 11; 13; 14)

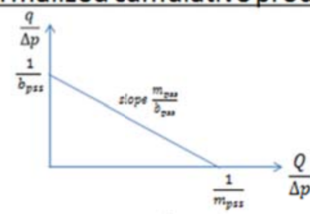
Constant bottom hole pressure

Conventional rate vs. Cumulative production



Changing rate and bottom hole pressure

Normalized rate vs. Normalized cumulative production



$$\frac{q}{\Delta p} = \frac{1}{b_{pss}} - \frac{m_{pss}}{b_{pss}} \frac{Q}{\Delta p}$$

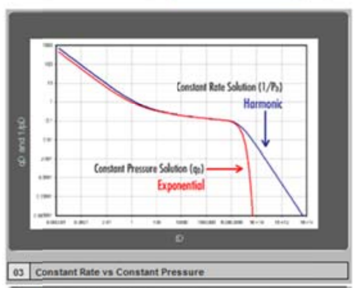
$$bpss = 141{,}2 \frac{Bo \cdot \mu}{k \cdot h} [\ln\left(\frac{re}{rw}\right) - \frac{3}{4} + s]$$

$$m_{pss} = \frac{1}{N \cdot ct}$$

- *Pseudo steady state only*
- *Plot is linear if mpss and bpss are constant: single phase oil, P>Psat, volumetric, no gas cap, no aquifer, uniform reservoir*

In oil field units | Cartesian plots

Fetkovich – Blasingame – Agarwal/Gardner – Normalized pressure integral



Now plotting against material balance time

- Constant pressure solution and constant rate solutions, plotted against time.

Material balance time:

$$\boxed{t_{Dd} = D_i \cdot t_{cr}}$$

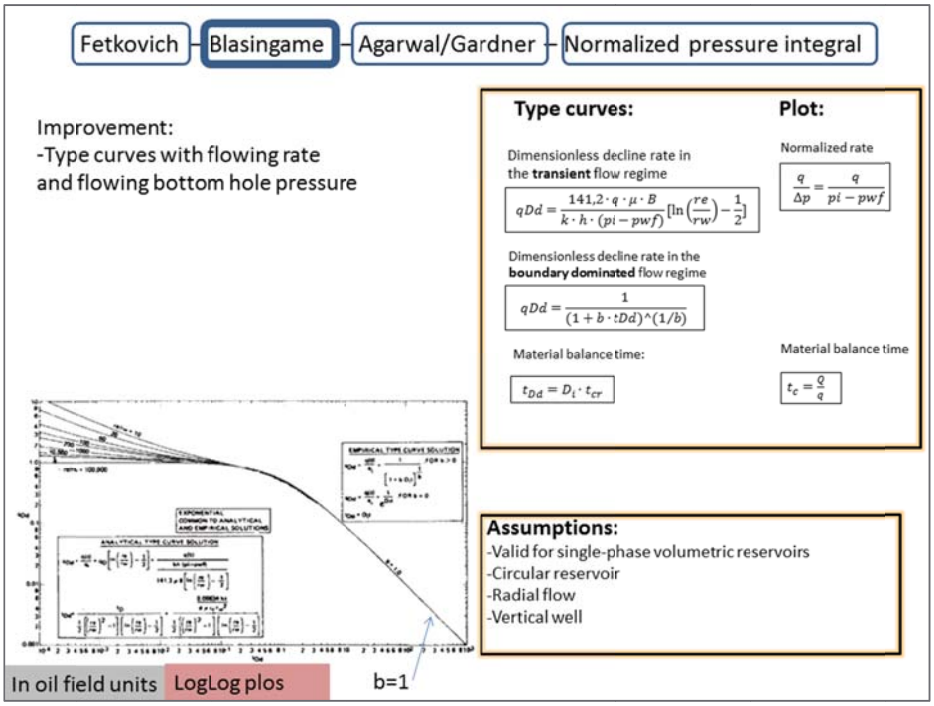
$$D_i = \frac{1}{c_t N b}$$

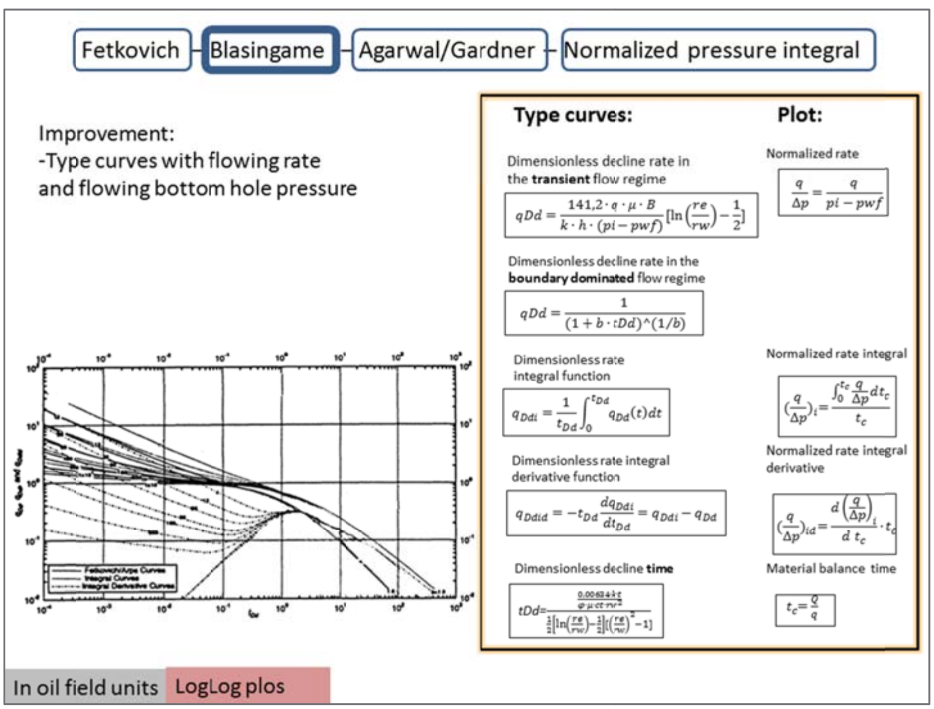
$$t_{cr} = \frac{Q(t)}{q(t)}$$

- The constant pressure solution plotted against material balance time is very similar to the constant rate solution.

In oil field units | LogLog plos

(10)


Fetkovich
Blasingame
Agarwal/Gardner
Normalized pressure integral
Improvement:
-Type curves with flowing rate and flowing bottom hole pressure
Type curves:
Dimensionless decline rate in the **transient** flow regime
$qDd = \frac{141{,}2 \cdot q \cdot \mu \cdot B}{k \cdot h \cdot (pi - pwf)} [\ln\left(\frac{re}{rw}\right) - \frac{1}{2}]$
Dimensionless decline rate in the **boundary dominated** flow regime
$qDd = \frac{1}{(1 + b \cdot tDd)^\wedge(1/b)}$
Material balance time:
$t_{Dd} = D_i \cdot t_{cr}$
Plot:
Normalized rate
$\frac{q}{\Delta p} = \frac{q}{pi - pwf}$
Material balance time
$t_c = \frac{Q}{q}$
Assumptions:
-Valid for single-phase volumetric reservoirs
-Circular reservoir
-Radial flow
-Vertical well
In oil field units
LogLog plos
b=1


Fetkovich
Blasingame
Agarwal/Gardner
Normalized pressure integral
Improvement:
-Type curves with flowing rate and flowing bottom hole pressure
Type curves:
Dimensionless decline rate in the **transient** flow regime
$qDd = \frac{141{,}2 \cdot q \cdot \mu \cdot B}{k \cdot h \cdot (pi - pwf)} [\ln\left(\frac{re}{rw}\right) - \frac{1}{2}]$
Dimensionless decline rate in the **boundary dominated** flow regime
$qDd = \frac{1}{(1 + b \cdot tDd)^\wedge(1/b)}$
Dimensionless rate integral function
$q_{Ddi} = \frac{1}{t_{Dd}} \int_0^{t_{Dd}} q_{Dd}(t)dt$
Dimensionless rate integral derivative function
$q_{Ddid} = -t_{Dd} \frac{dq_{Ddi}}{dt_{Dd}} = q_{Ddi} - q_{Dd}$
Dimensionless decline **time**
Plot:
Normalized rate
$\frac{q}{\Delta p} = \frac{q}{pi - pwf}$
Normalized rate integral
$(\frac{q}{\Delta p})_i = \frac{\int_0^{t_c} \frac{q}{\Delta p} dt_c}{t_c}$
Normalized rate integral derivative
$(\frac{q}{\Delta p})_{id} = \frac{d\left(\frac{q}{\Delta p}\right)_i}{d\, t_c} \cdot t_c$
Material balance time
$t_c = \frac{Q}{q}$
In oil field units
LogLog plos

Dimensionless parameters

Production Analysis

Dimensionless decline rate

$$qDd = \frac{141{,}2 \cdot q \cdot \mu \cdot B}{k \cdot h \cdot (pi - pwf)}\left[\ln\left(\frac{re}{rw}\right) - \frac{1}{2}\right]$$

Dimensionless decline time

$$tDd = \frac{\frac{0.00634 \cdot k \cdot t}{\varphi \cdot \mu \cdot ct \cdot rw^2}}{\frac{1}{2}\left[\ln\left(\frac{re}{rw}\right) - \frac{1}{2}\right]\left[\left(\frac{re}{rw}\right)^2 - 1\right]}$$

Well Test Analysis

Dimensionless pressure in well test analysis

$$pD = \frac{k \cdot h \cdot (p_i - p_{wf})}{141{,}2 \cdot q \cdot \mu \cdot B}$$

Dimensionless rate used in **Agarwal/Gardner type curves**

$$qD = \frac{1}{pD} \qquad qD = \frac{141{,}2 \cdot q \cdot \mu \cdot B}{k \cdot h \cdot (p_i - p_{wf})}$$

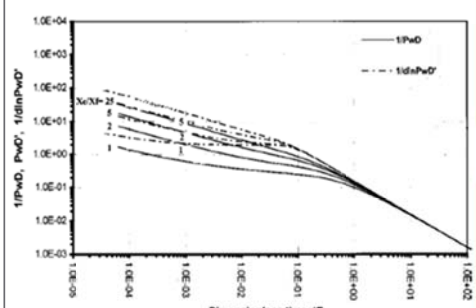
Dimensionless time

$$tD = \frac{0{,}000264 \cdot k \cdot t}{\varphi \cdot \mu \cdot ct \cdot (rw)^2}$$

In oil field units

Fetkovich – Blasingame – **Agarwal/Gardner** – Normalized pressure integral

Improvement:
-Make a clear transition between transient and boundary dominated flow



Type curves:

Dimensionless rate

$$qD = \frac{141{,}2 \cdot q \cdot \mu \cdot B}{k \cdot h \cdot (p_i - p_{wf})}$$

The inverse pressure derivative

$$\frac{1}{d\ln(P_wD')} = \frac{\frac{1}{d\,p_{wD}}}{d\ln(t_D)}$$

Dimensionless time

$$tD = \frac{0{,}000264 \cdot k \cdot t}{\varphi \cdot \mu \cdot ct \cdot (rw)^2}$$

Plot:

Normalized rate

$$\frac{q}{\Delta p} = \frac{q}{pi - pwf}$$

The inverse pressure derivative

$$\frac{1}{DER} = \frac{1}{\left(t_c \cdot \frac{d\left(\frac{\Delta p}{q}\right)}{d(t_c)}\right)}$$

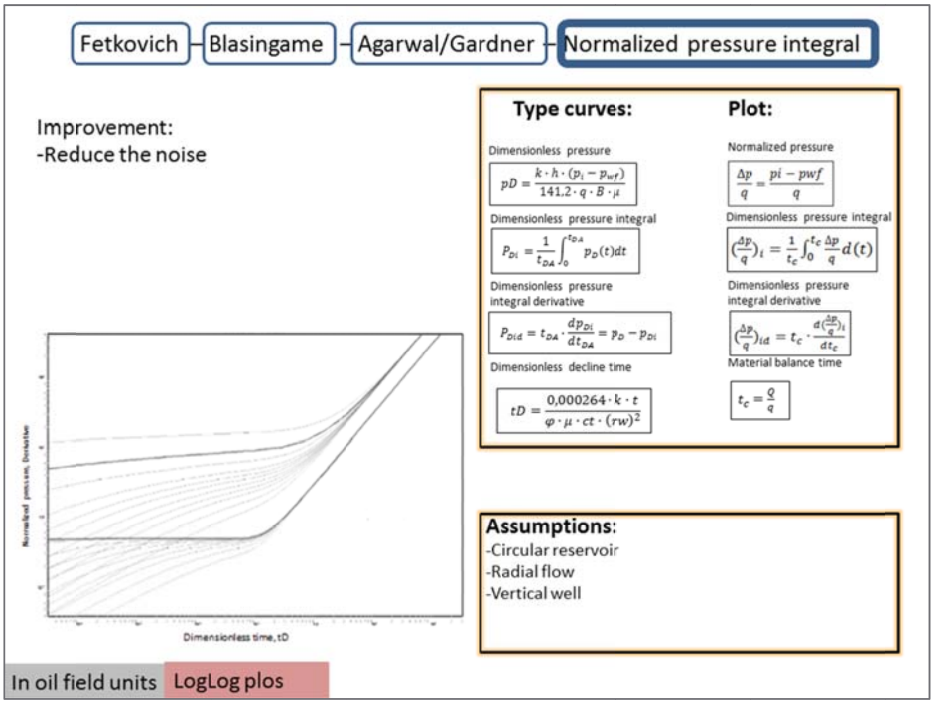
Material balance time

$$t_c = \frac{Q}{q}$$

Assumptions:
-Valid for single-phase volumetric reservoirs
-Circular reservoir
-Radial flow
-Vertical well

In oil field units | LogLog plos

H


Fetkovich
Blasingame
Agarwal/Gardner
Normalized pressure integral
Improvement:
-Reduce the noise
Type curves:
Dimensionless pressure
$pD = \frac{k \cdot h \cdot (p_i - p_{wf})}{141{,}2 \cdot q \cdot B \cdot \mu}$
Dimensionless pressure integral
$P_{Di} = \frac{1}{t_{DA}} \int_0^{t_{DA}} p_D(t) dt$
Dimensionless pressure integral derivative
$P_{Did} = t_{DA} \cdot \frac{dp_{Di}}{dt_{DA}} = p_D - p_{Di}$
Dimensionless decline time
$tD = \frac{0{,}000264 \cdot k \cdot t}{\varphi \cdot \mu \cdot ct \cdot (rw)^2}$
Plot:
Normalized pressure
$\frac{\Delta p}{q} = \frac{pi - pwf}{q}$
Dimensionless pressure integral
$(\frac{\Delta p}{q})_i = \frac{1}{t_c} \int_0^{t_c} \frac{\Delta p}{q} d(t)$
Dimensionless pressure integral derivative
$(\frac{\Delta p}{q})_{id} = t_c \cdot \frac{d(\frac{\Delta p}{q})_i}{dt_c}$
Material balance time
$t_c = \frac{Q}{q}$
Normalized pressure, Derivative
Dimensionless time, tD
Assumptions:
-Circular reservoir
-Radial flow
-Vertical well
In oil field units
LogLog plos

(8; 15; 16)