Well test analysis milestones:

Value tied to power in Identification and Verification

	ANALYSIS METHOD	IDENTIFICATION	VERIFICATION
50's	Straight lines	Poor	None
70's	Pressure Type Curves	Fair (limited)	Fair to Good
80's	Pressure Derivative	Very Good	Very Good
00's	Deconvolution	Much better	Same as derivative

Deconvolution

- Deconvolution transforms variable rate pressure data

  into a constant rate initial drawdown

  with a duration equal to the total duration of the test

- It yields directly the corresponding pressure derivative

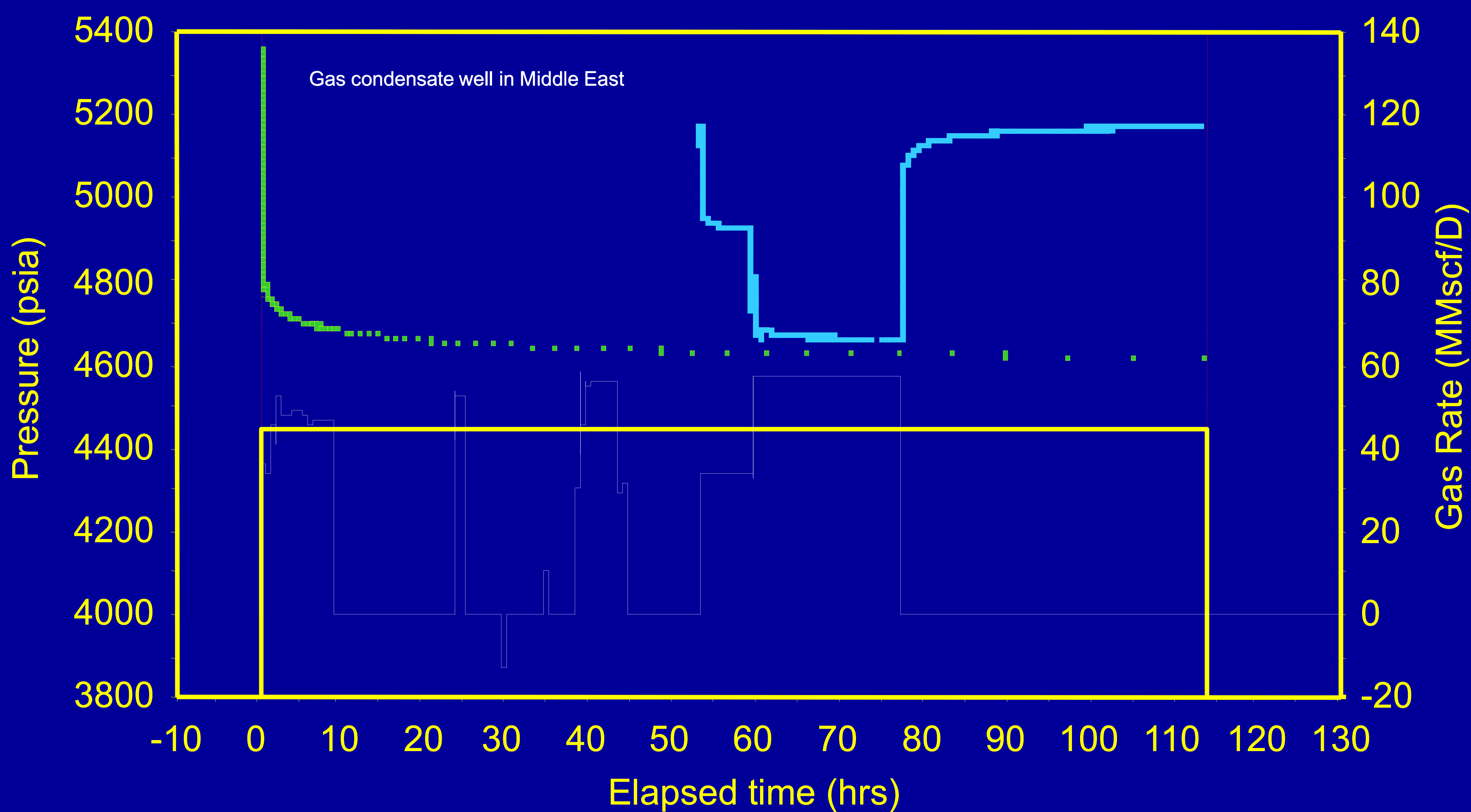
  normalized to a unit rate

- This derivative is free from:

  distortions due to the pressure derivative calculation algorithm

  errors introduced by incomplete or truncated rate histories

Deconvolution



DECONVOLUTION: PRINCIPLE

Convolution Integral: $p = p_i - \int_0^t q(\tau) \frac{\Delta p(t-\tau)/q}{dt} d\tau \quad = p_i - q * g$

$$g = \frac{\Delta p(t-\tau)/q}{dt}$$ Impulse response

The goal of well test analysis is to 'deconvolve' the rates from the pressure response by inverting the above relationship in order to estimate the response function g(t), from which a well and reservoir model can be inferred.

Because of noisy observational well test data, such a deconvolution is a minimization problem.

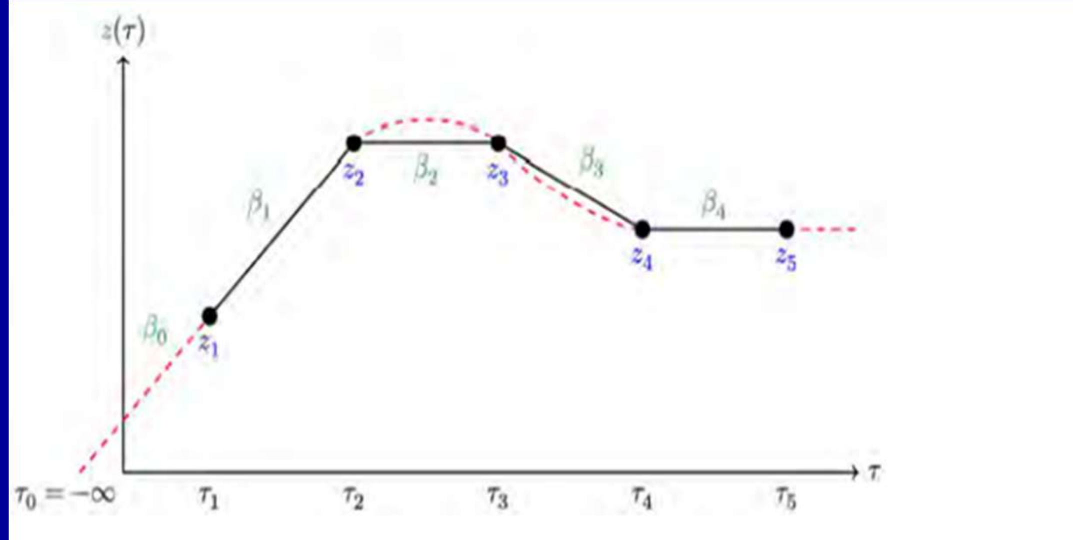
One of the key decisions in the development of a deconvolution methodology is to determine an appropriate representation, or proxy-model, for g(t).

This proxy-model should be sufficiently flexible

- to account for any shape that may be encountered in practice,
- while excluding shapes that are not physical, i.e. are not solutions of the diffusivity equation

TOTAL LEAST SQUARES (TLS)

In the TLS approach (von Schroeter et al. 2001-2004), the proxy-model is a piecewise linear function or linear spline (Fig. 21), parameterised by a sequence of points in space, which are joined to form the response:



—Response function representation and parameterisation for TLS deconvolution.

While this provides the required shape flexibility, the diffusivity equation solution restriction requires the introduction of a curvature parameter λ in the total least-squares optimization:

$$E(\hat{z}, \hat{p}_i, q, \phi, \lambda, \rho, \upsilon) = \phi \underbrace{\|\widehat{\Delta p}(\hat{z}, \hat{q}) - \Delta p\|^2}_{\text{pressure match}} + \lambda \underbrace{\|K(\hat{z})\|^2}_{\text{curvature penalty}} + \rho \underbrace{\|\hat{p}_i - p_i\|^2}_{\text{initial pressure match}} + \underbrace{\upsilon \|\hat{q} - q\|^2}_{\text{rate match}}$$

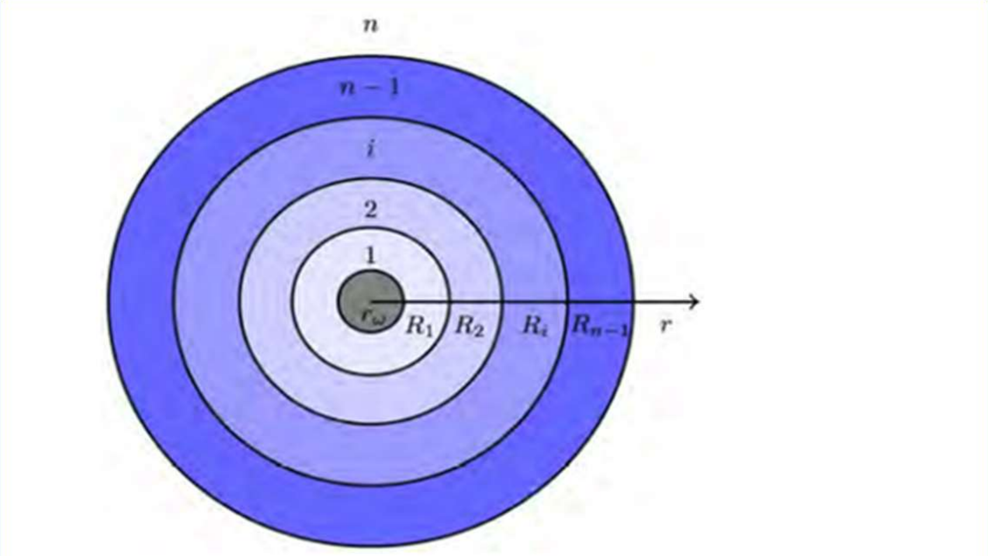
λ must be specified before performing the deconvolution but defaults values and rules of thumb are available (see Gringarten, 2010).

The uncertainty in the deconvolution can be evaluated with the Monte Carlo method (Cumming et al. 2013) by generating estimated response functions by deconvolution over the range of possible values of uncertain well test data (initial pressure, pressures, rates, etc).

BAYESIAN DECONVOLUTION

In the Bayesian approach, the probability distribution of the response parameters is conditioned on the information observed during the well test.

The proxy-model (Cumming et al. 2020) is a multi-region radial composite (MRRC), which meets both the required shape flexibility and the diffusivity equation solution restriction.



Proxy-model for Bayesian deconvolution (multi-region radial composite)

Each n-region in this model has 3n parameters: two global parameters (the time match, TM, and the pressure match, PM); the wellbore storage coefficient and skin group (C_De^{2S}); and three parameters for each transition between regions (a dimensionless radius parameter, R_D, a mobility ratio, M, and a diffusivity ratio, η).

As is the case for λ in the TLS case, the number of regions of the MRRC proxy-model must be specified before performing the deconvolution, which requires some experimentation.

BAYESIAN DECONVOLUTION

The essence of the Bayesian approach is to define plausible ranges - or, more precisely, probability distributions - for each of the six response parameters before introducing the data.

These are known as prior distributions : they are chosen to be sufficiently broad to encompass almost all expected physical behaviours but are bounded to prohibit non-physical results.

Ranges (i.e. probability distributions) for the rate and pressure histories, and for the initial pressure are also required to determine the likelihood of any given response model. They can be obtained directly from the gauge specifications (Cumming et al. 2013) which provide information on the size of the associated observational errors.

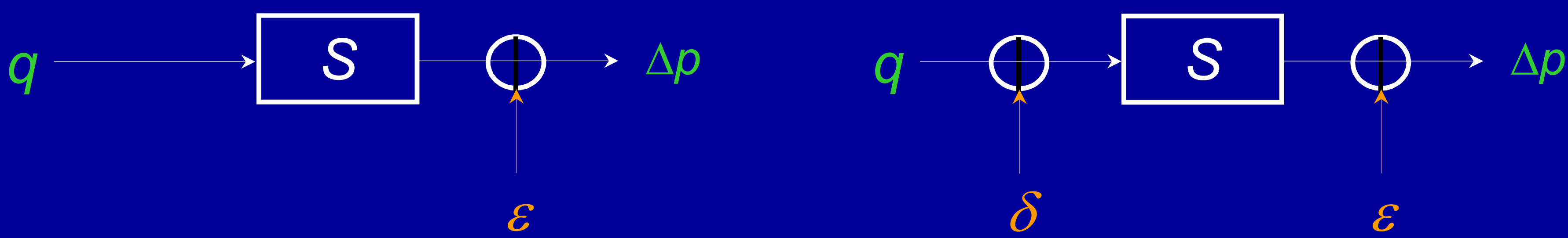
The objective of the Bayesian deconvolution is then to synthesise the information from the observed histories with the structure of the model and distributions for its parameters: the goal is to identify probability distributions of the model parameters that are appropriate for this data set (and hence also the deconvolved derivative response itself).

Deconvolution: principle

Convolution Integral: $$p = p_i - \int_0^t q(\tau)\frac{\Delta p(t-\tau)/q}{dt}\,d\tau = p_i - q * g$$

$$g = \frac{\Delta p(t-\tau)/q}{dt}$$ Impulse response

Deconvolution: error models



Least Squares

- Standard in previous methods
- Pressure errors only

Total Least Squares

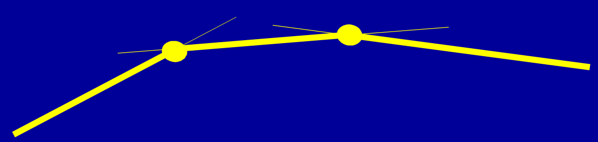
- Standard in Signal Processing
- Errors in both pressure and rate
- Joint estimate of rate correction and pressure response

Deconvolution (Non-linear Total least squares)

$$E = \left\| (p_i - y * g) - p \right\|_2^2 + \nu \left\| y - q \right\|_2^2 + \lambda \left\| D z - k \right\|_2^2$$

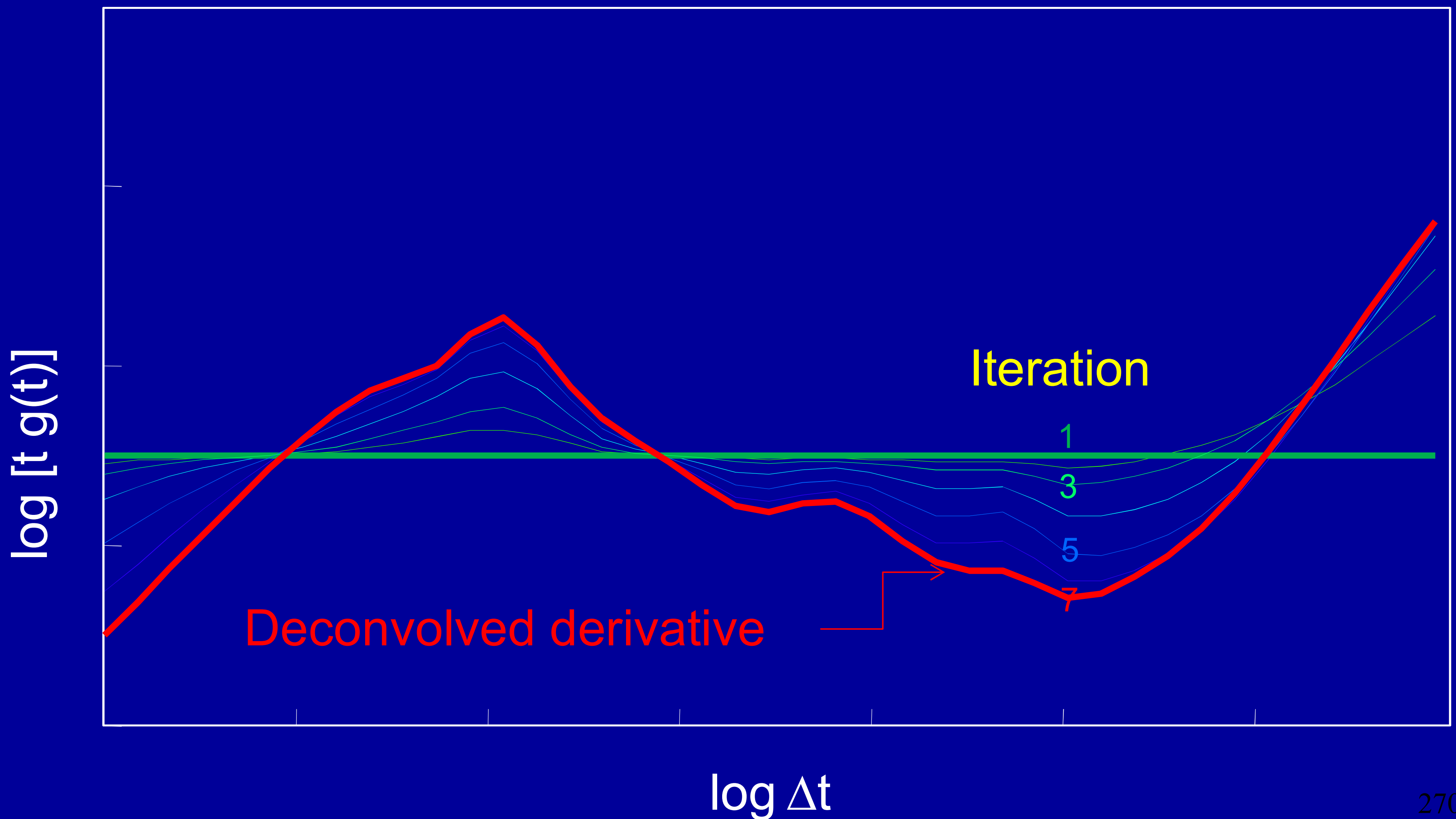
pressure match   rate match   curvature

- Data: *p*, *q*
- Curvature operator: matrix *D*, vector *k*
- ν: rate relative weight λ: regularization (curvature relative weight)
- Guess *g* and p_i ,   discretize *g* into *C(z)*,   calculate *y*



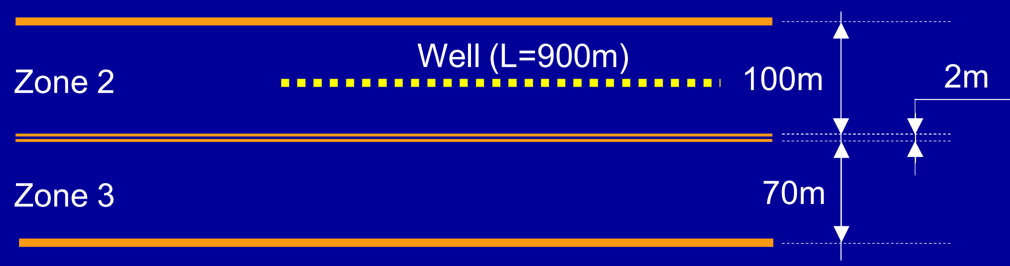
- Then minimize *E* over p_i , *y*, *z*

Deconvolution iterations

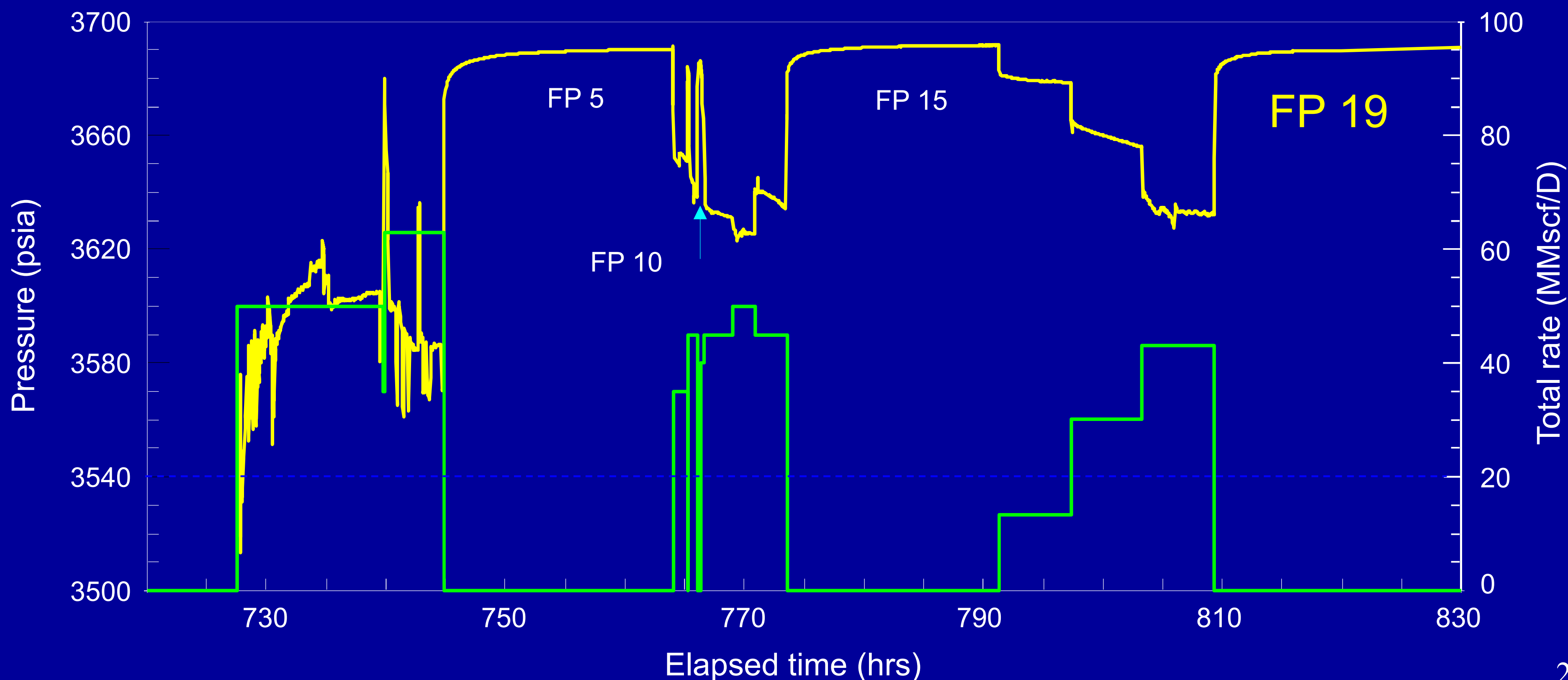


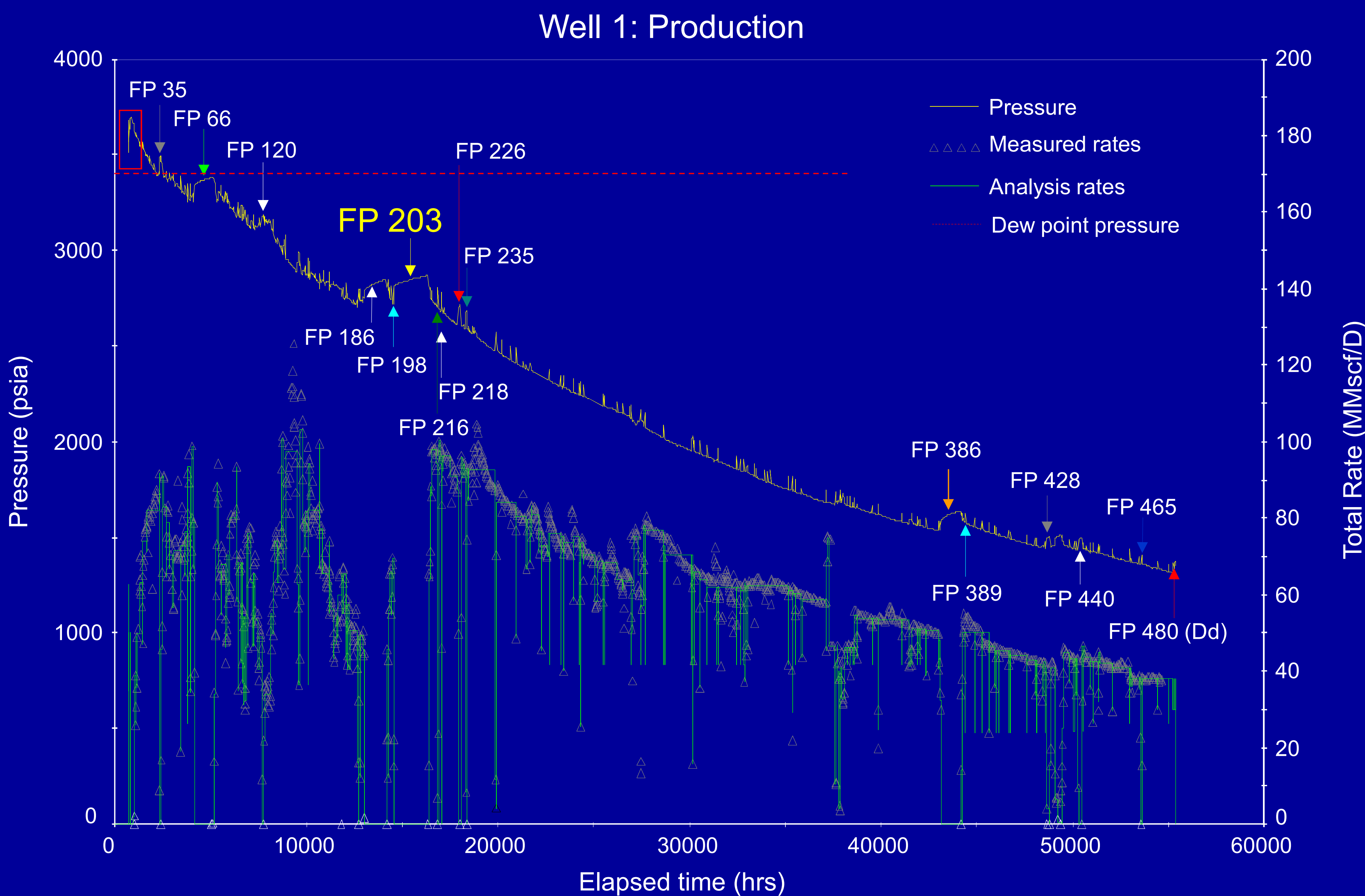
Example of deconvolution

Well 1 schematic

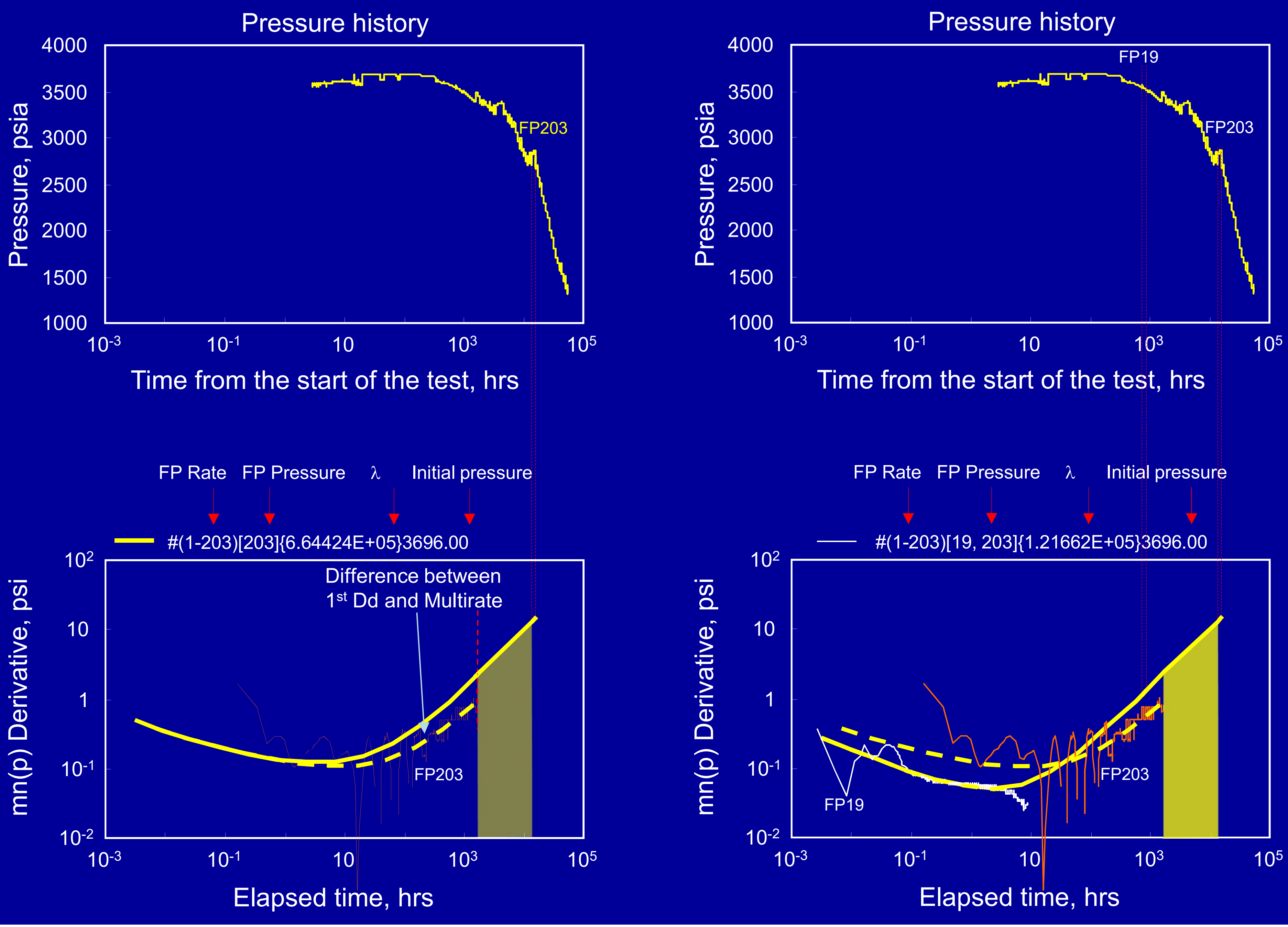


Well 1 : DST

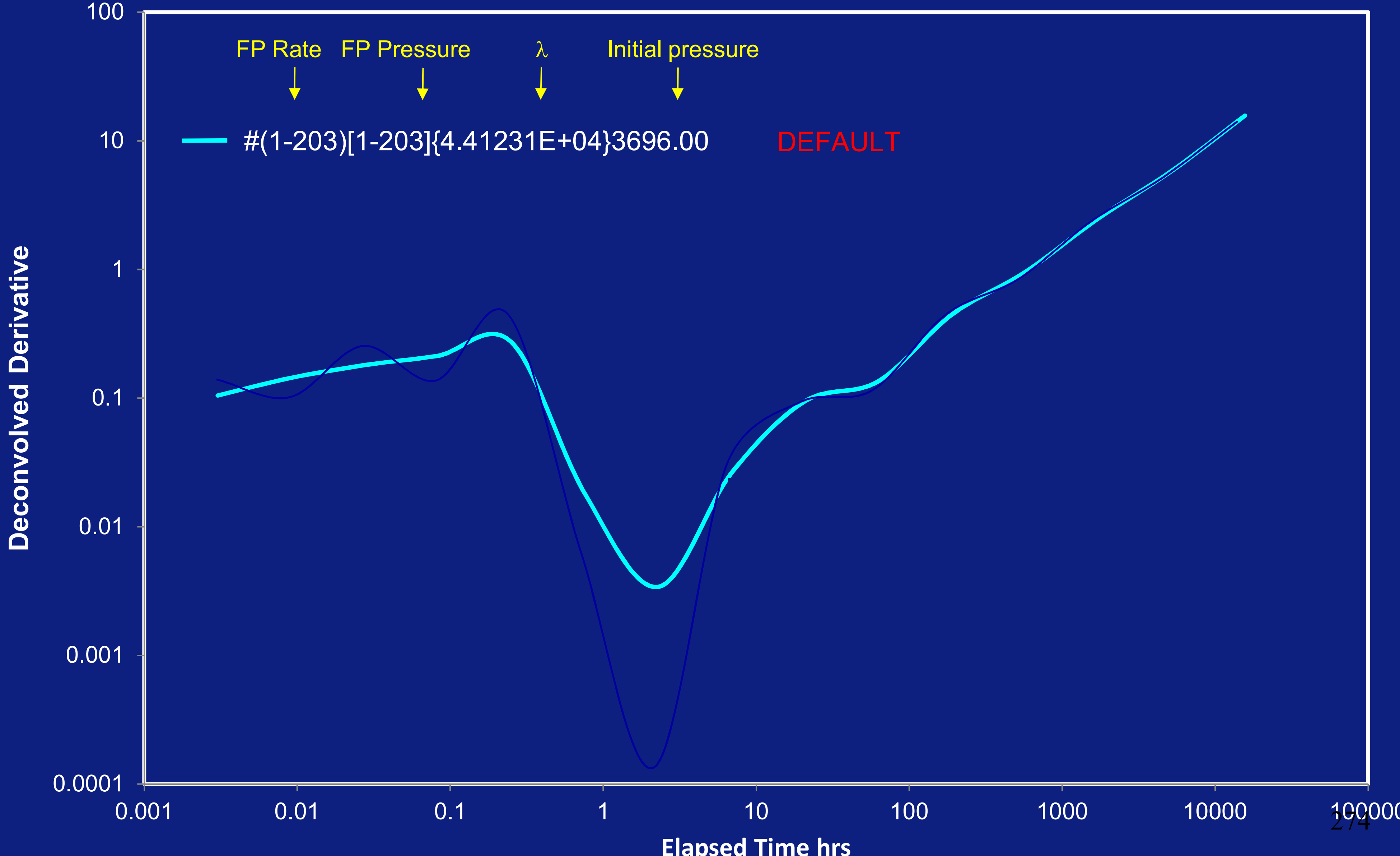



Well 1: Production
Pressure (psia)
Total Rate (MMscf/D)
Elapsed time (hrs)
Pressure
Measured rates
Analysis rates
Dew point pressure
FP 35
FP 66
FP 120
FP 226
FP 203
FP 235
FP 186
FP 198
FP 218
FP 216
FP 386
FP 428
FP 465
FP 389
FP 440
FP 480 (Dd)
4000
3000
2000
1000
0
200
180
160
140
120
100
80
60
40
20
0
10000
20000
30000
40000
50000
60000

Construction of the deconvolved derivative

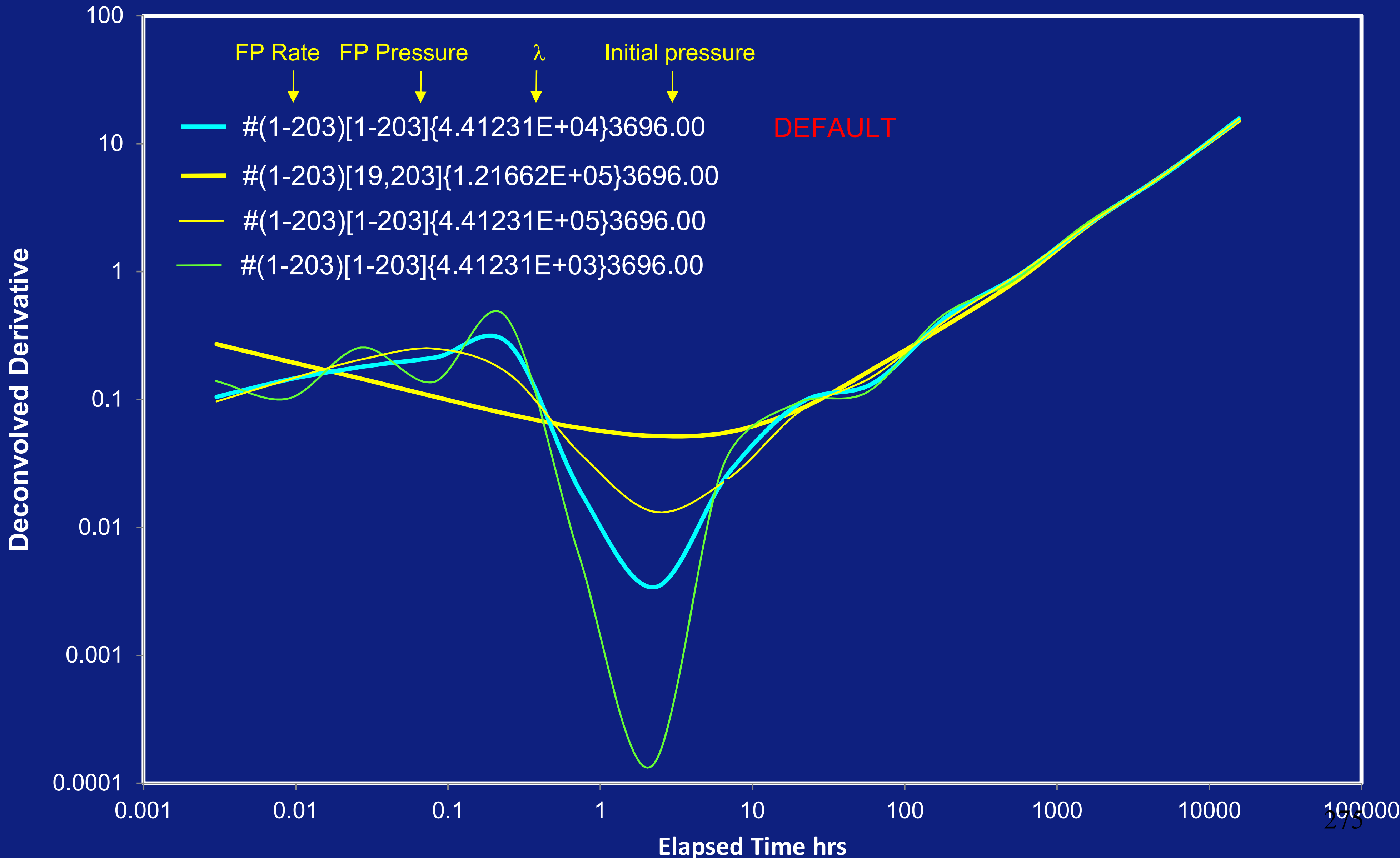


Impact of λ



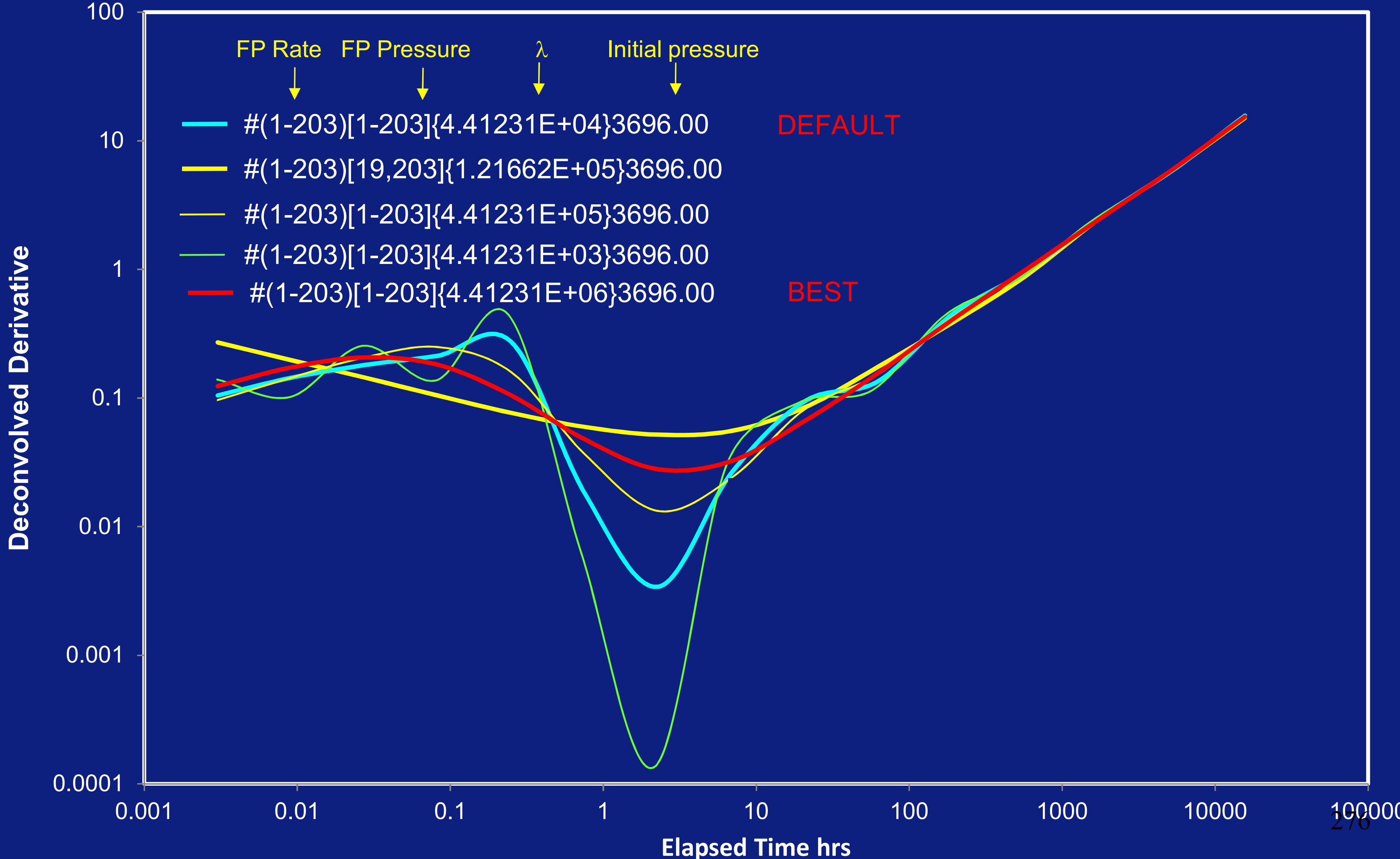
FP Rate
FP Pressure
λ
Initial pressure
#(1-203)[1-203]{4.41231E+04}3696.00
DEFAULT
Deconvolved Derivative
100
10
1
0.1
0.01
0.001
0.0001
0.001
0.01
0.1
1
10
100
1000
10000
100000
Elapsed Time hrs

Impact of λ



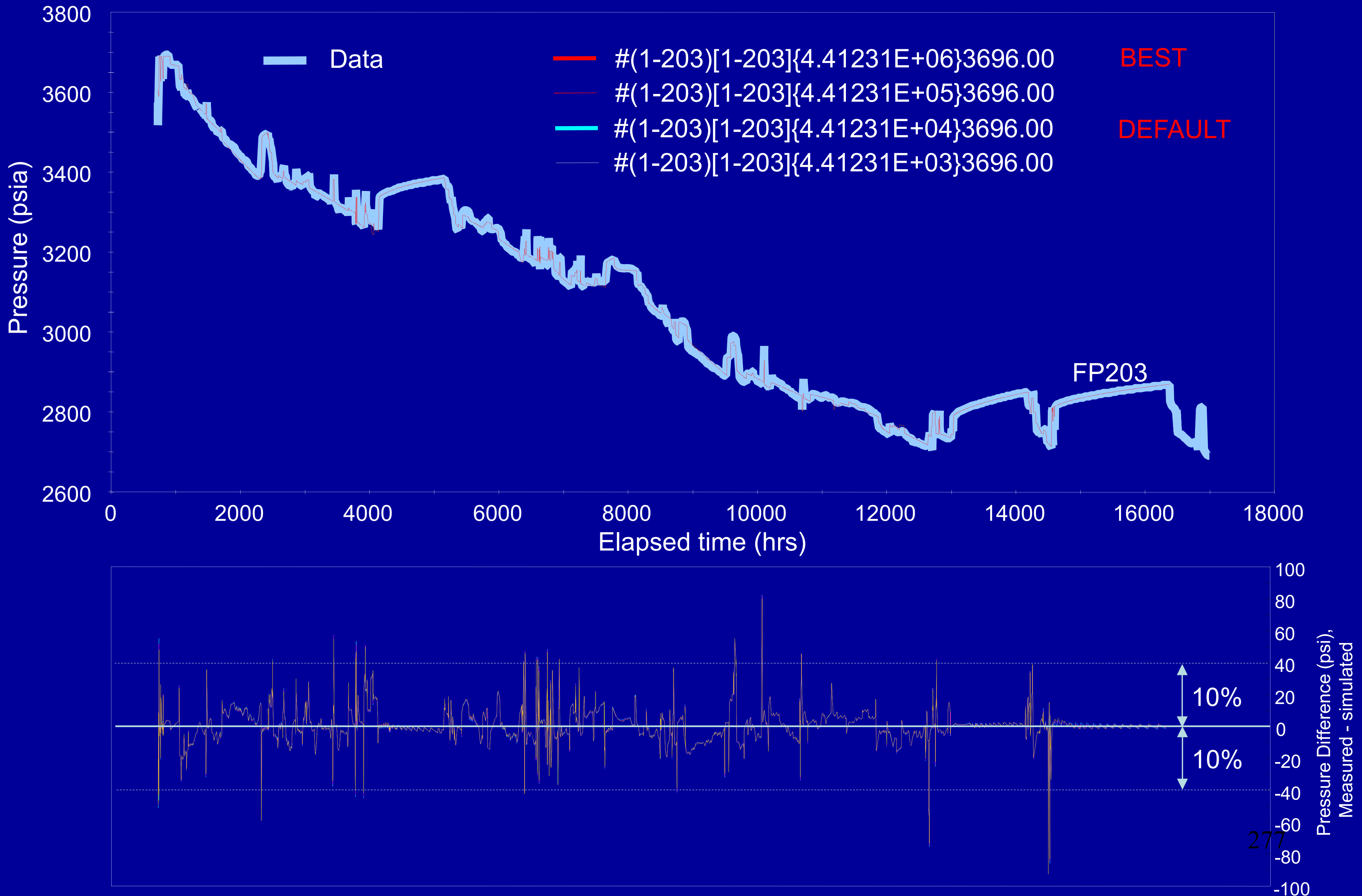
FP Rate
FP Pressure
λ
Initial pressure
#(1-203)[1-203]{4.41231E+04}3696.00
DEFAULT
#(1-203)[19,203]{1.21662E+05}3696.00
#(1-203)[1-203]{4.41231E+05}3696.00
#(1-203)[1-203]{4.41231E+03}3696.00
100
10
1
0.1
0.01
0.001
0.0001
0.001
0.01
0.1
1
10
100
1000
10000
100000
Deconvolved Derivative
Elapsed Time hrs

Impact of λ

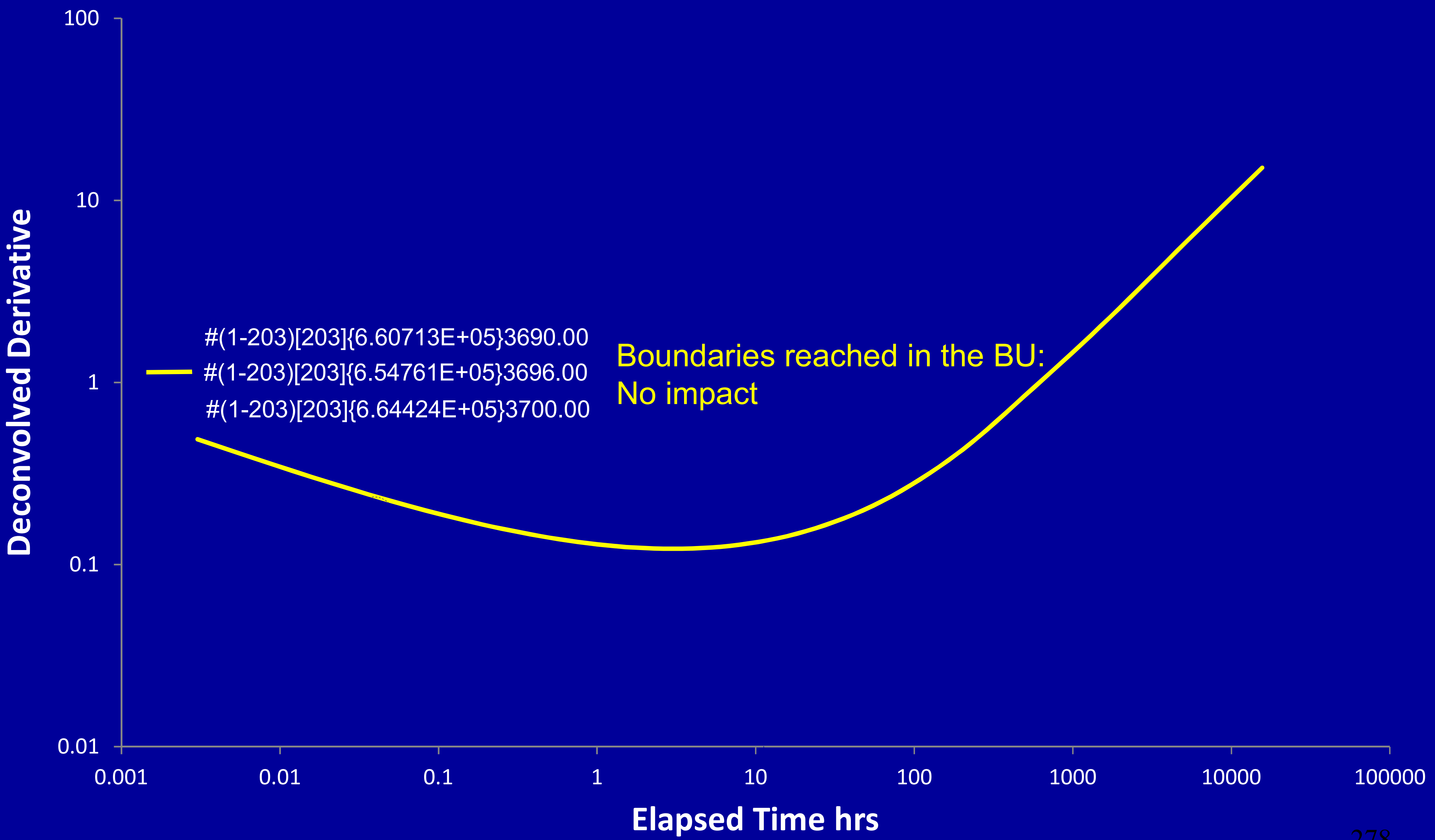


FP Rate
FP Pressure
λ
Initial pressure
#(1-203)[1-203]{4.41231E+04}3696.00
DEFAULT
#(1-203)[19,203]{1.21662E+05}3696.00
#(1-203)[1-203]{4.41231E+05}3696.00
#(1-203)[1-203]{4.41231E+03}3696.00
#(1-203)[1-203]{4.41231E+06}3696.00
BEST
Deconvolved Derivative
100
10
1
0.1
0.01
0.001
0.0001
0.001
0.01
0.1
1
10
100
1000
10000
100000
Elapsed Time hrs

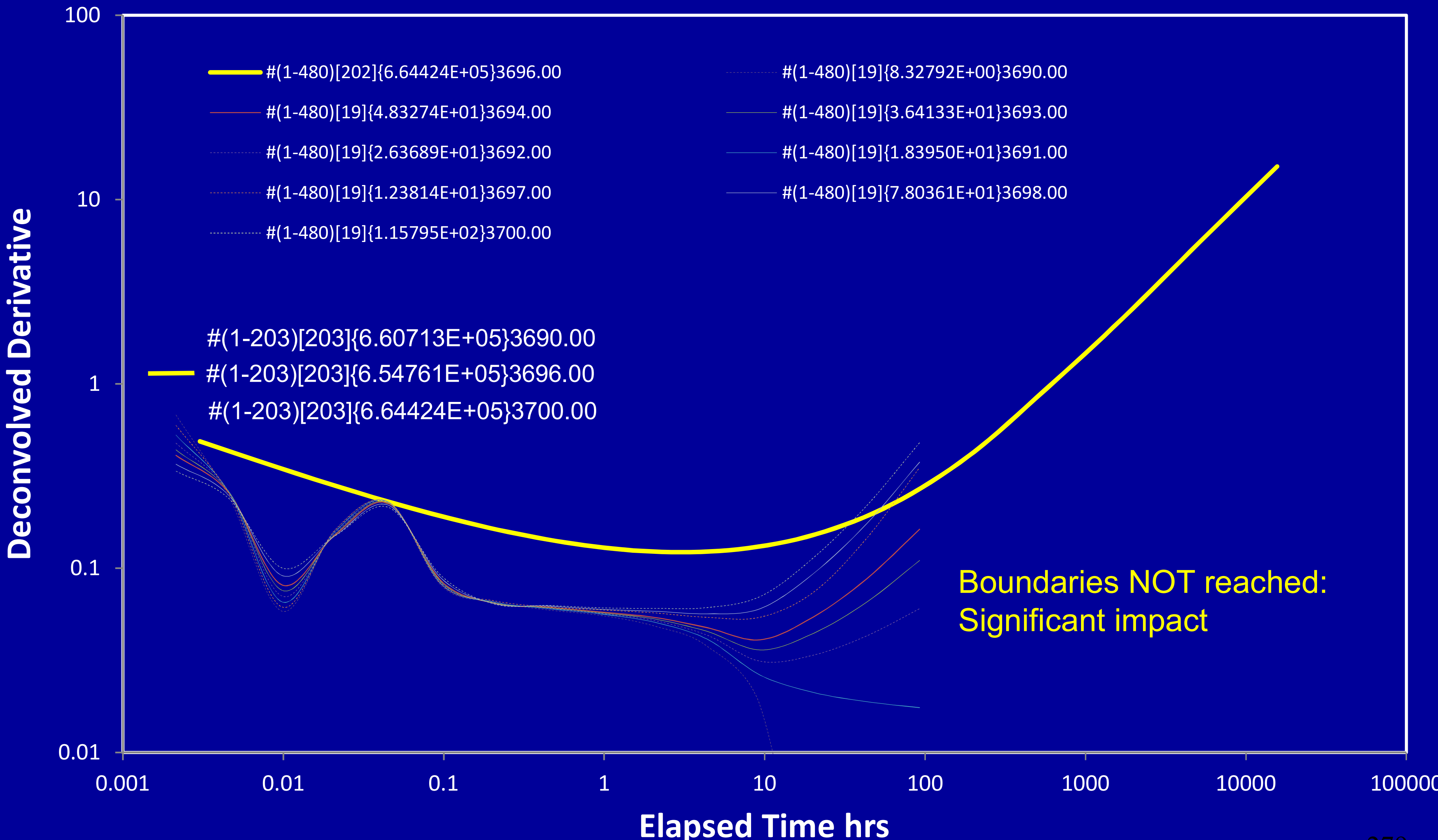
Verification



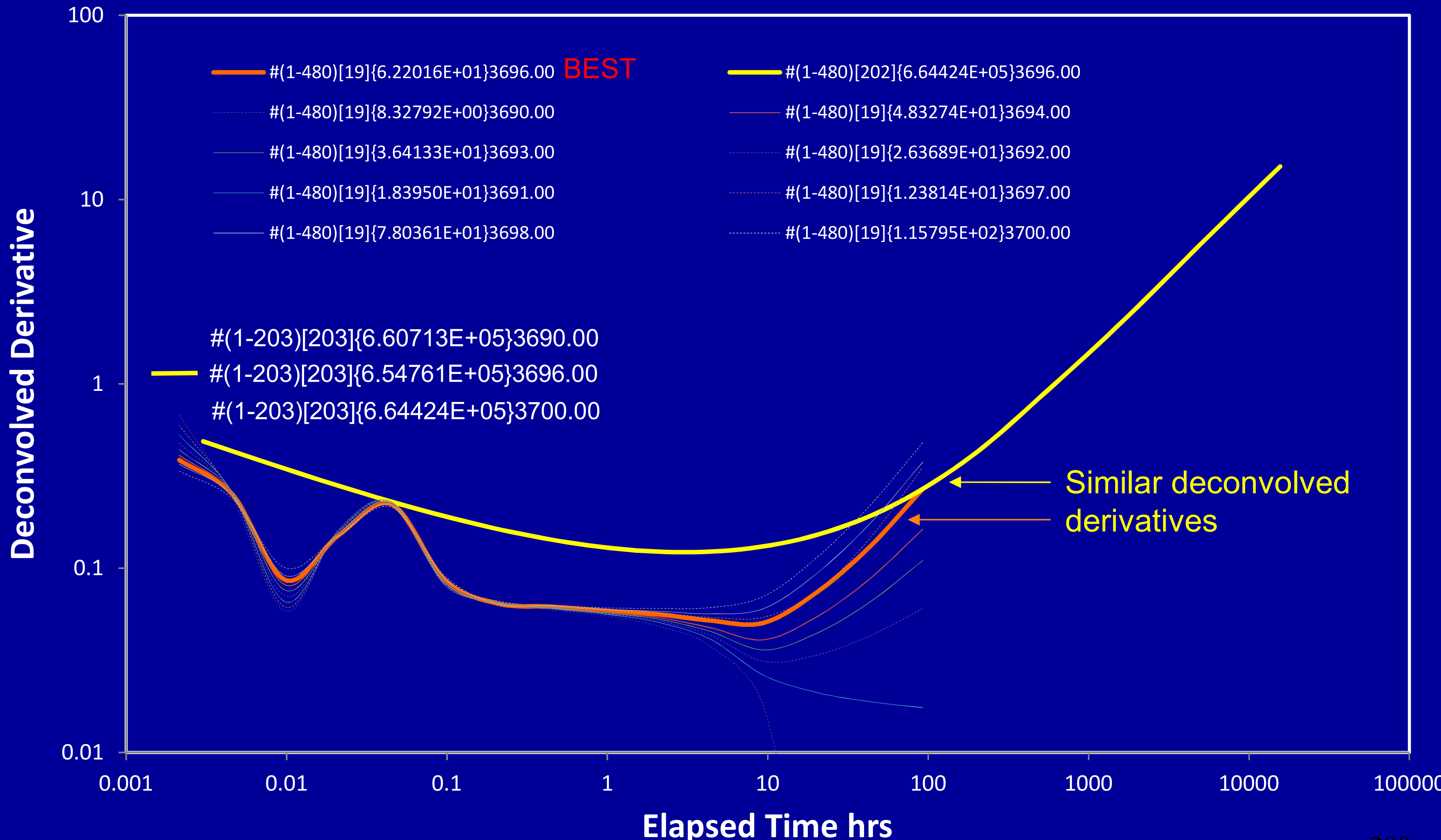
Impact of initial pressure



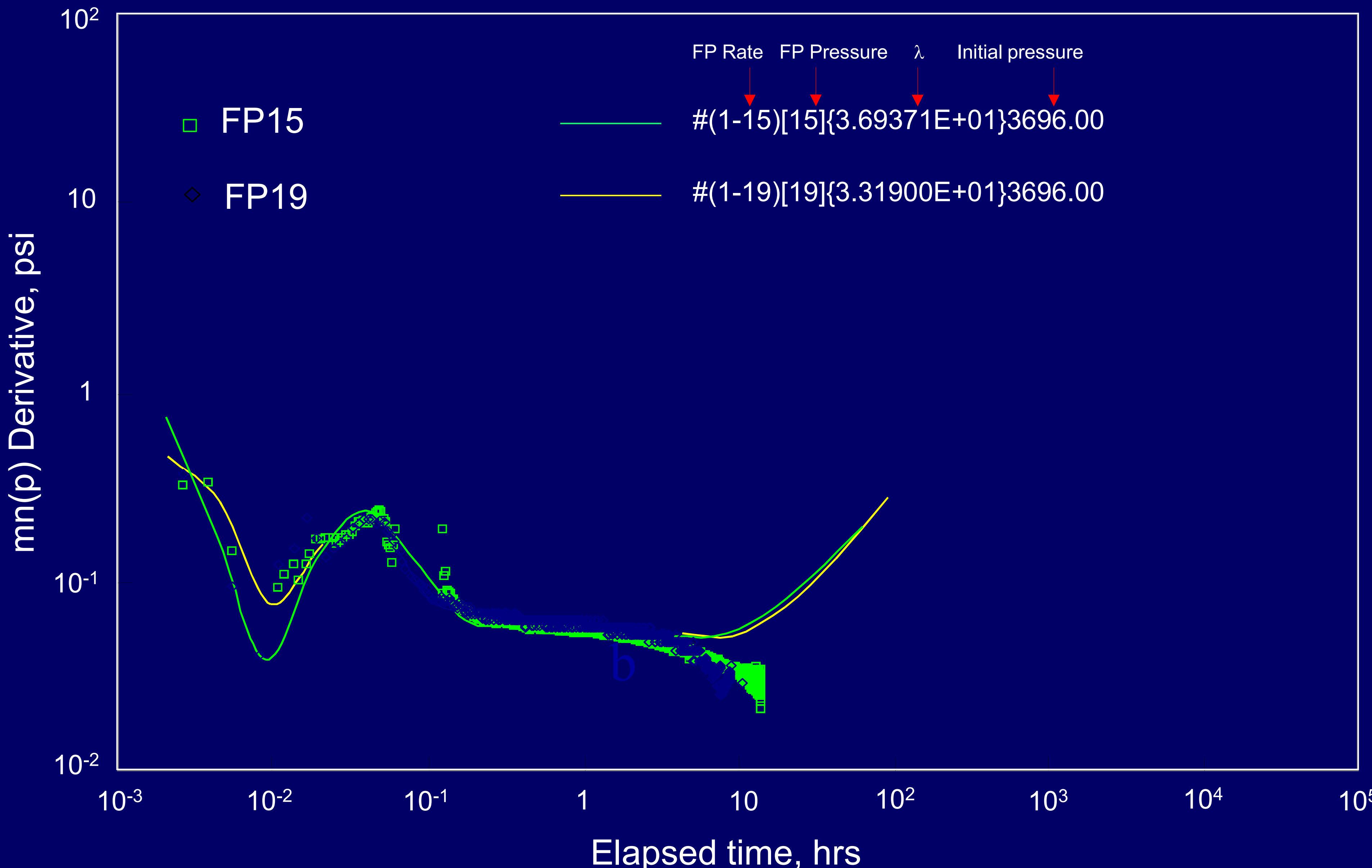
Impact of initial pressure



Impact of initial pressure



Verification of initial pressure



Deconvolution

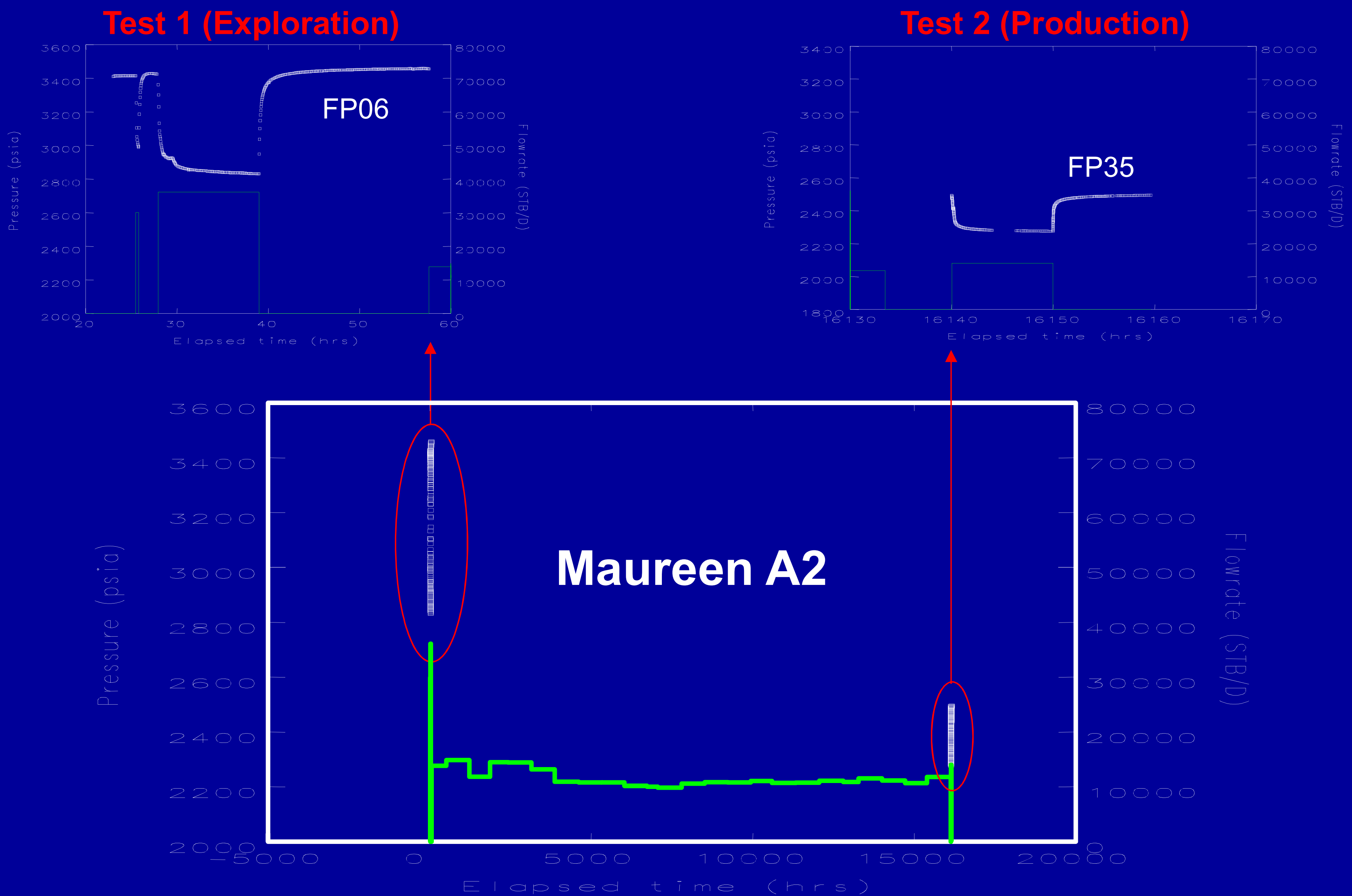
- Construction of deconvolved derivatives

- Main benefits

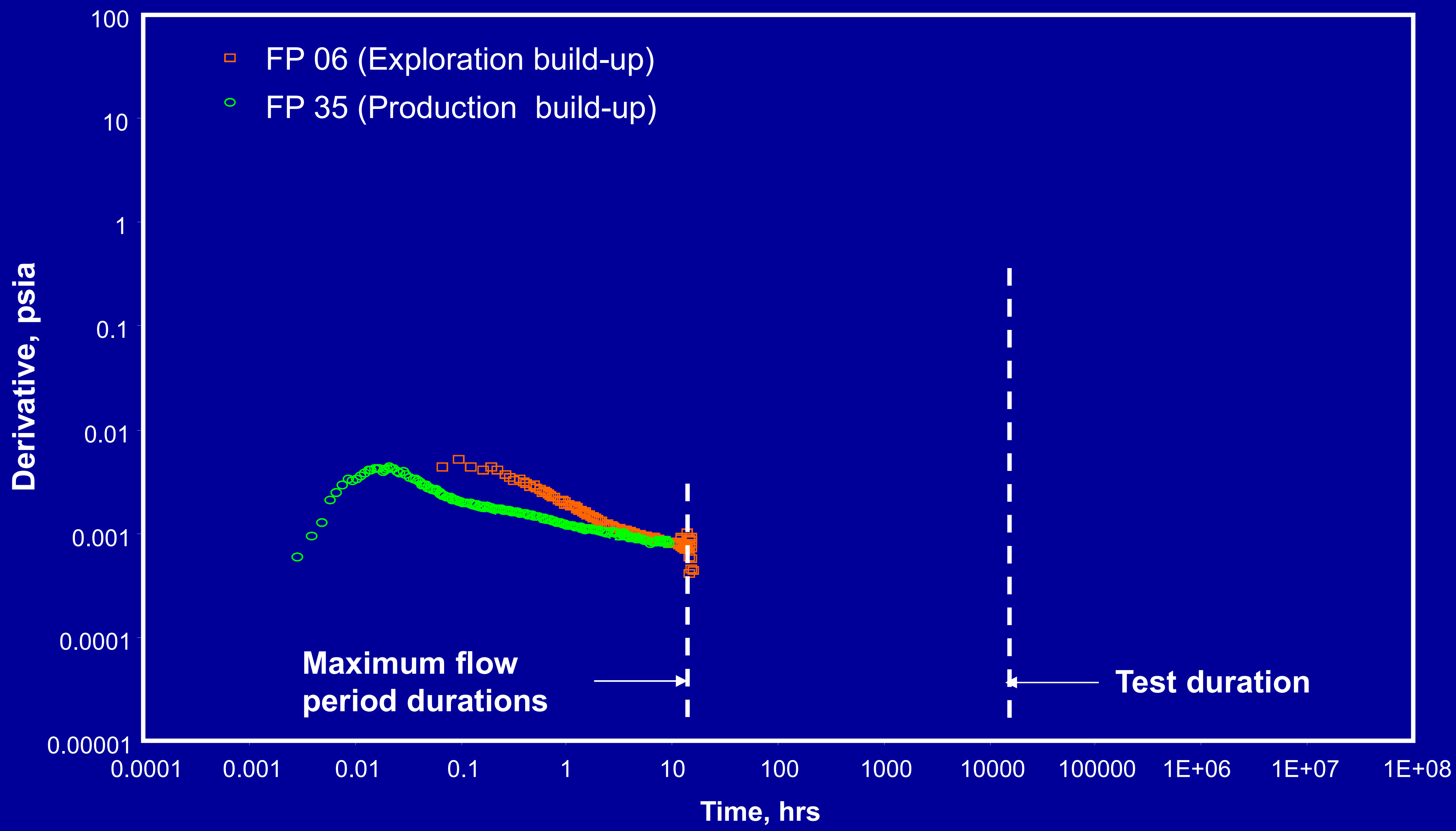
  - Increased radius of investigation
    (compared to conventional build up analyses)

  - Correction of erroneous rates

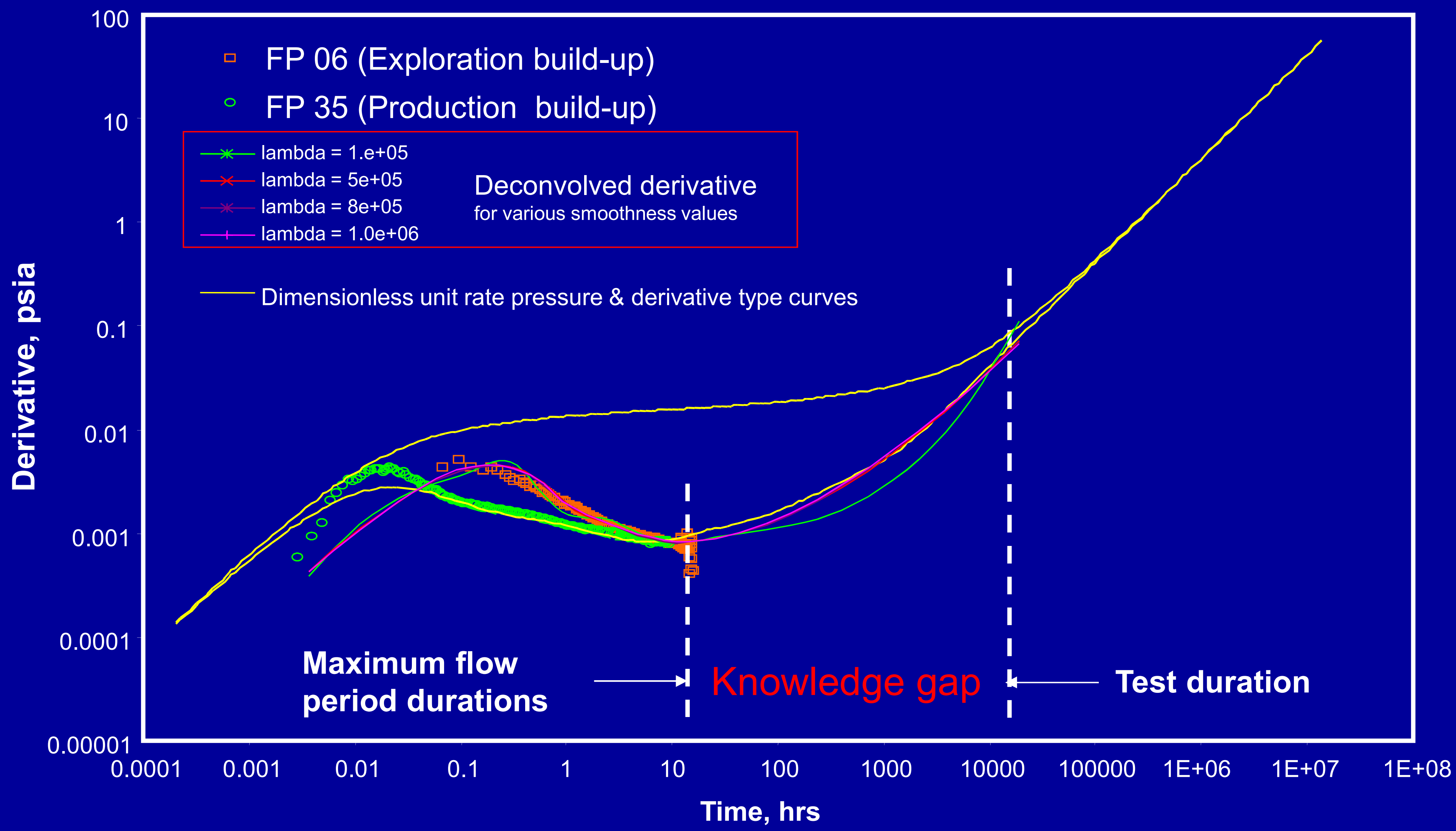
Deconvolution: boundary identification



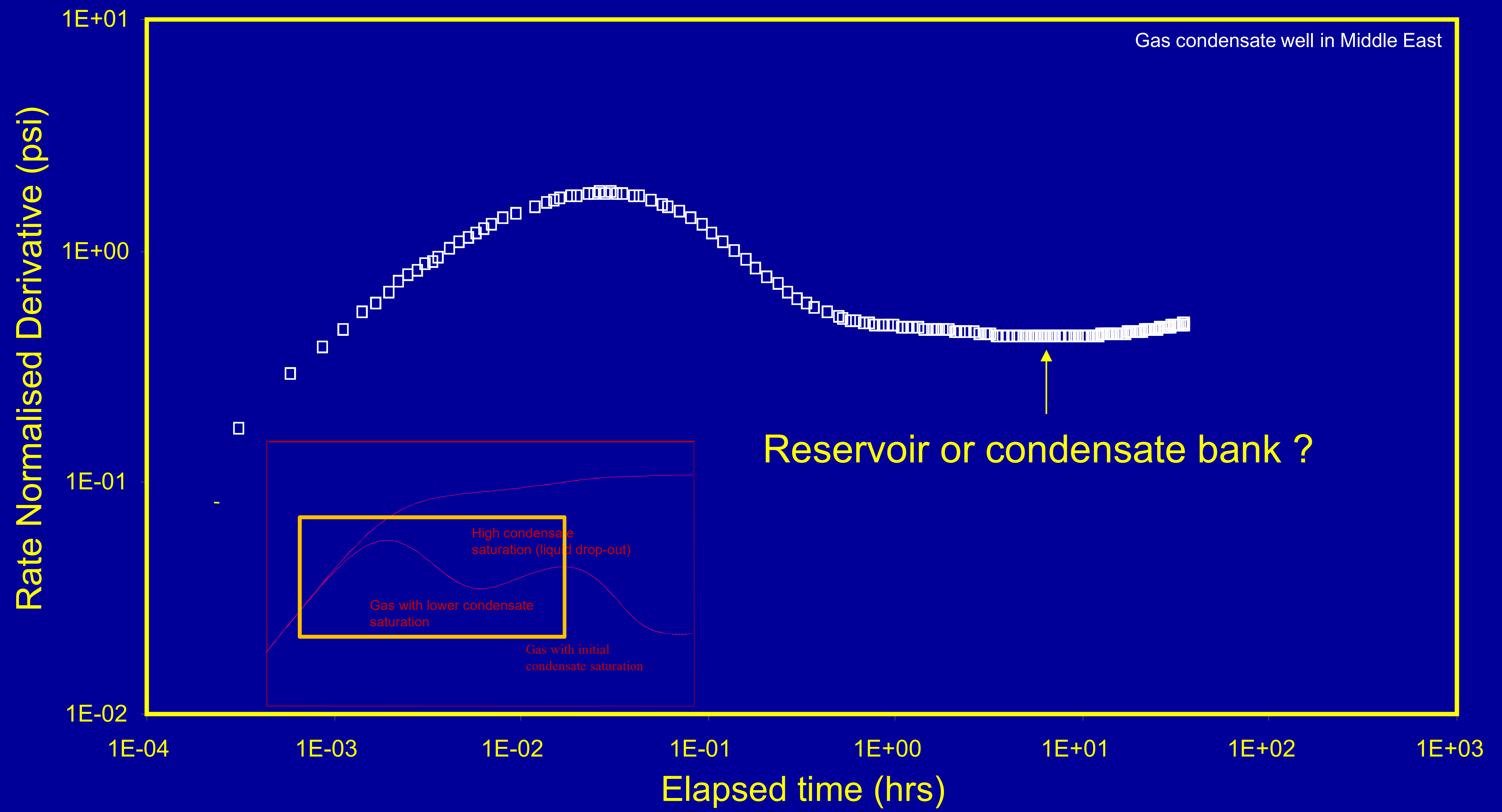
Deconvolution: boundary identification



Deconvolution: boundary identification

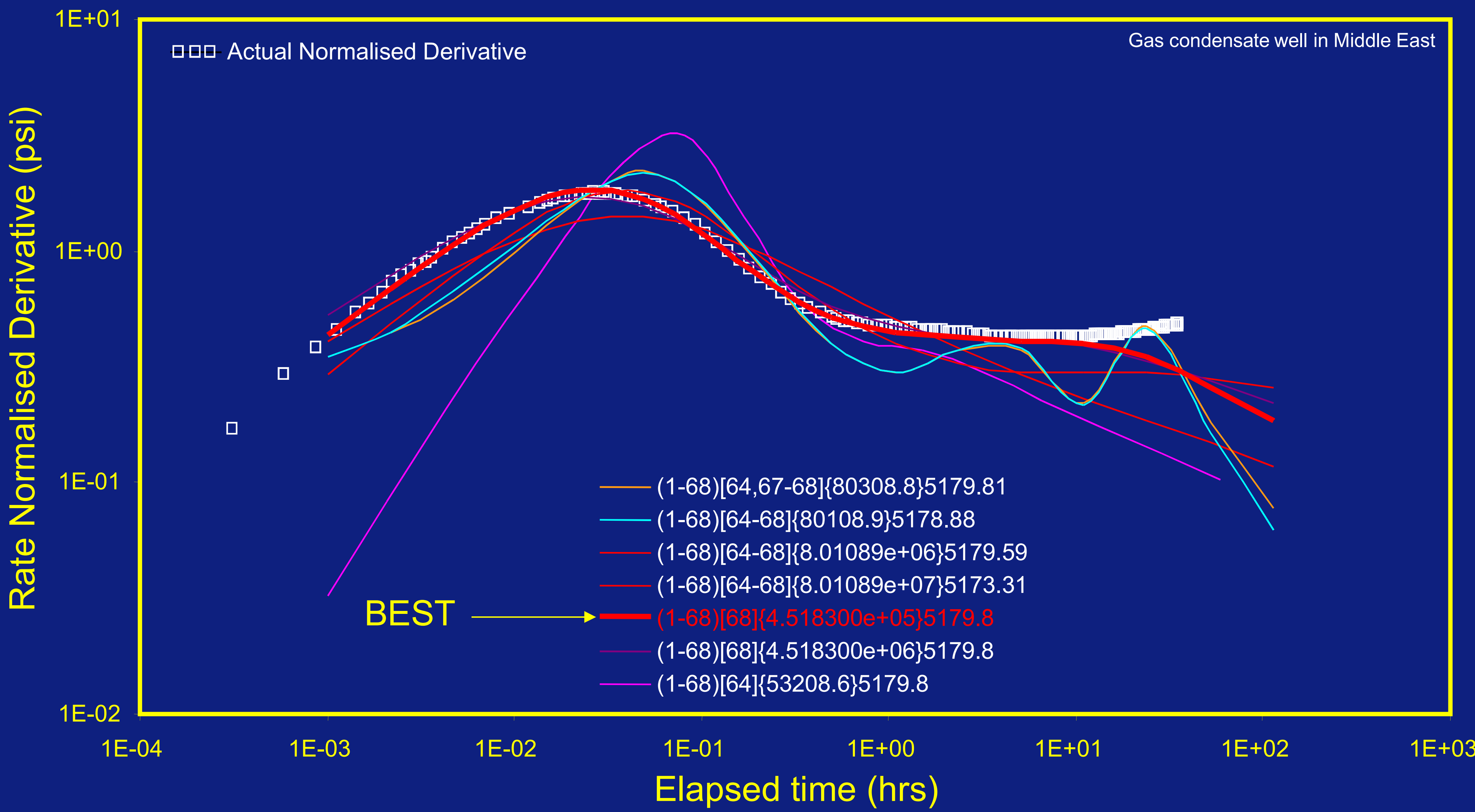


Deconvolution: Flow regime identification

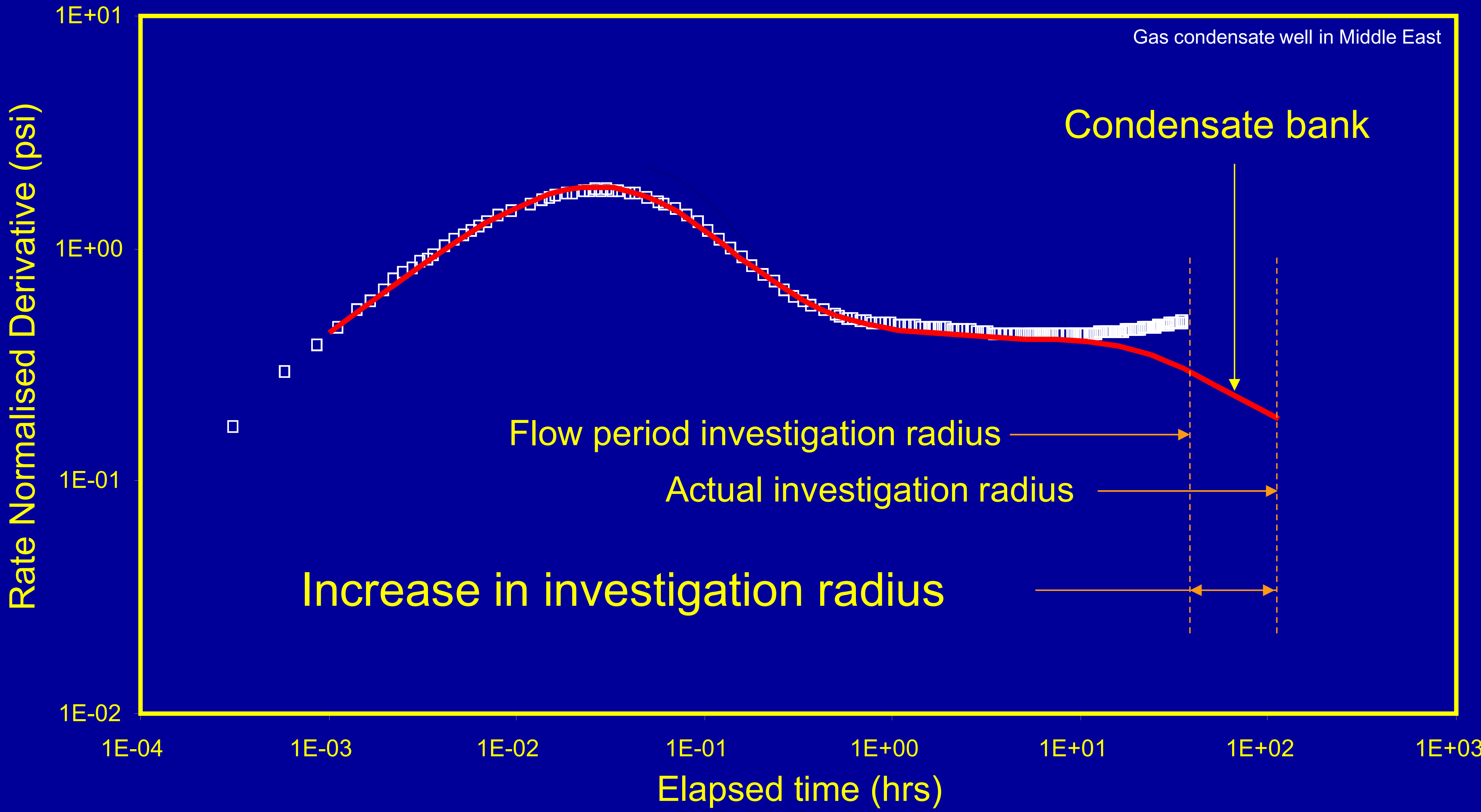


SPE102079

Deconvolution: flow regime identification

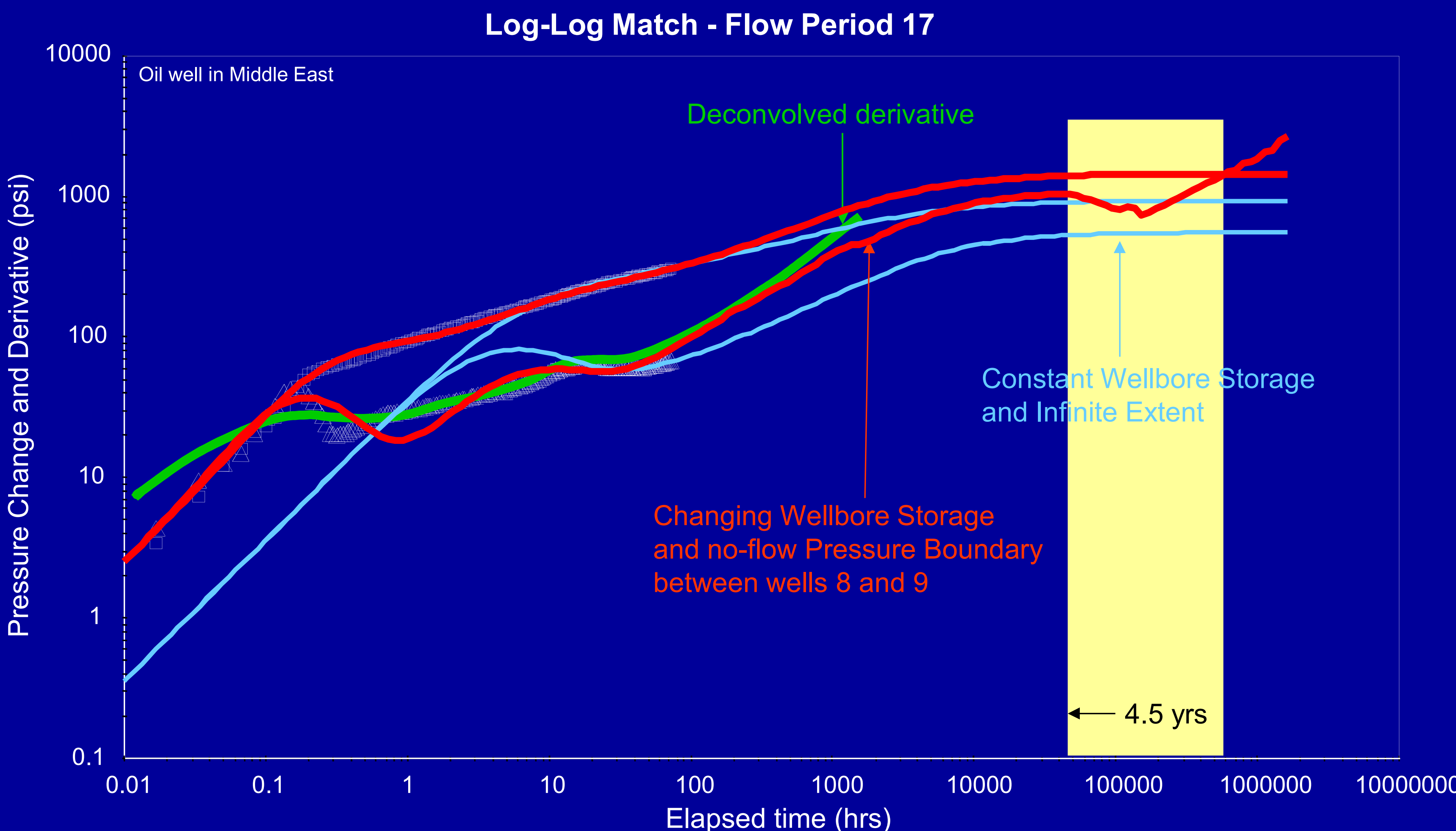


Deconvolution: Increase in investigation radius

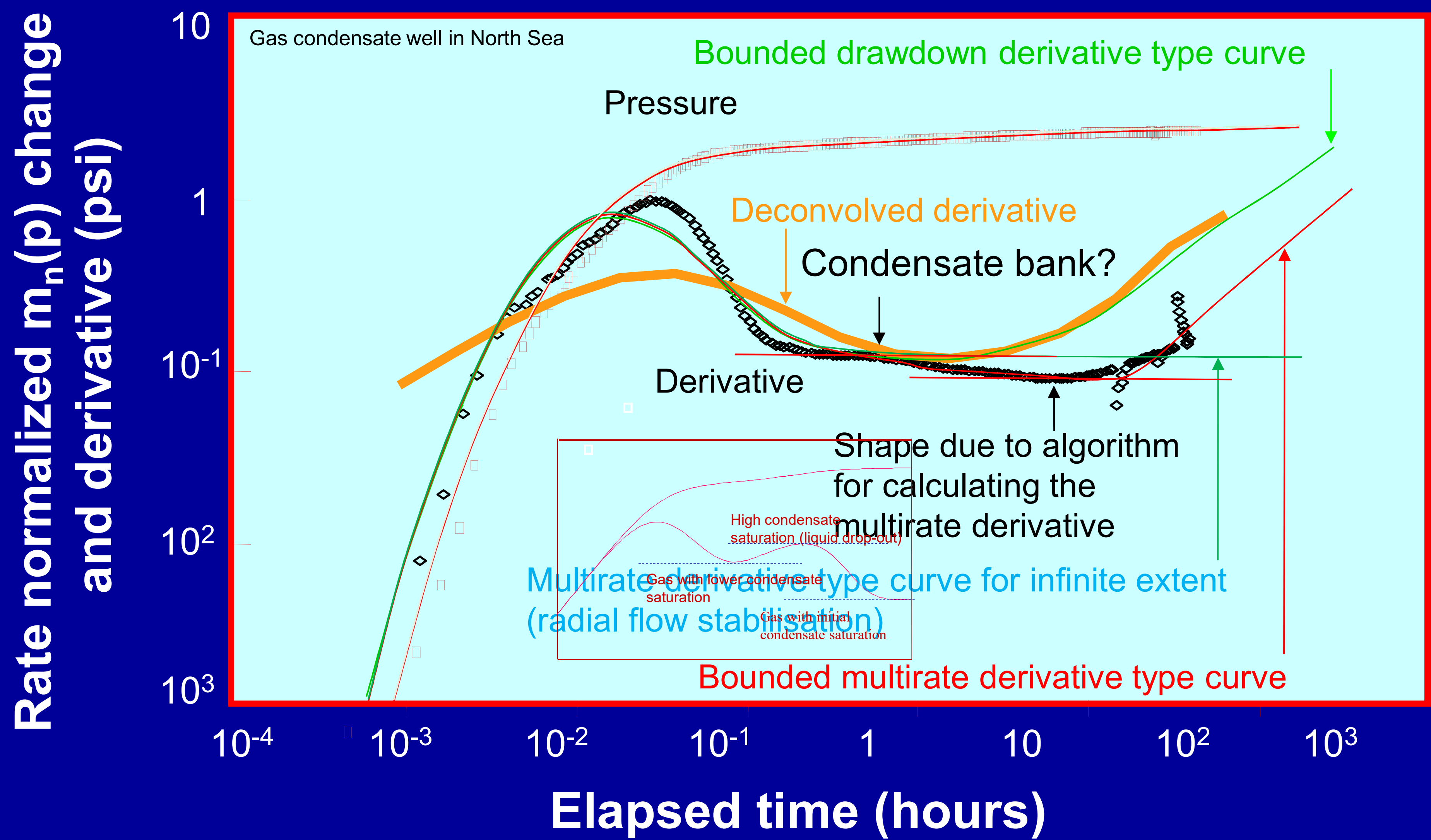


SPE102079

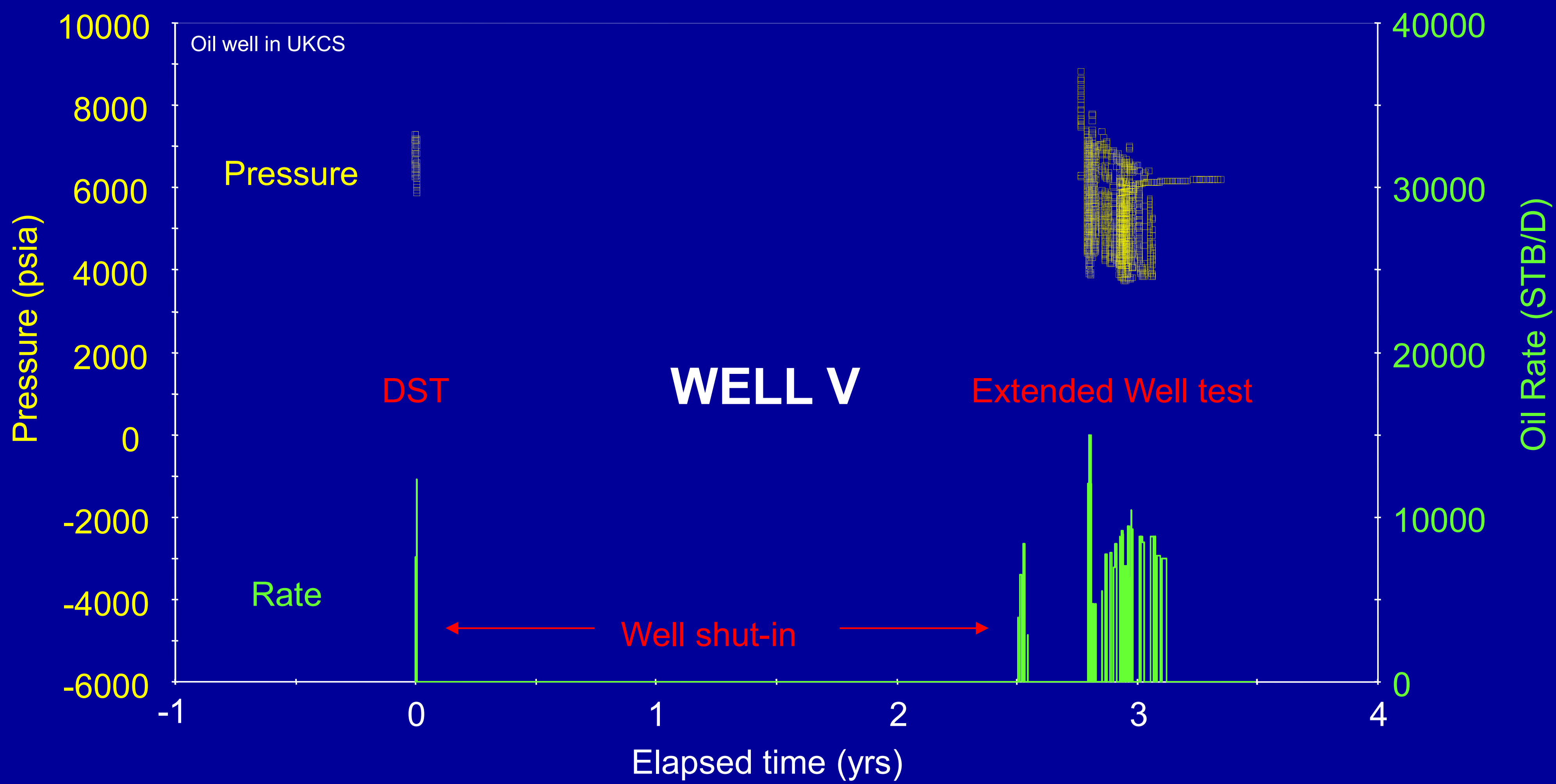
Multi-branch horizontal well



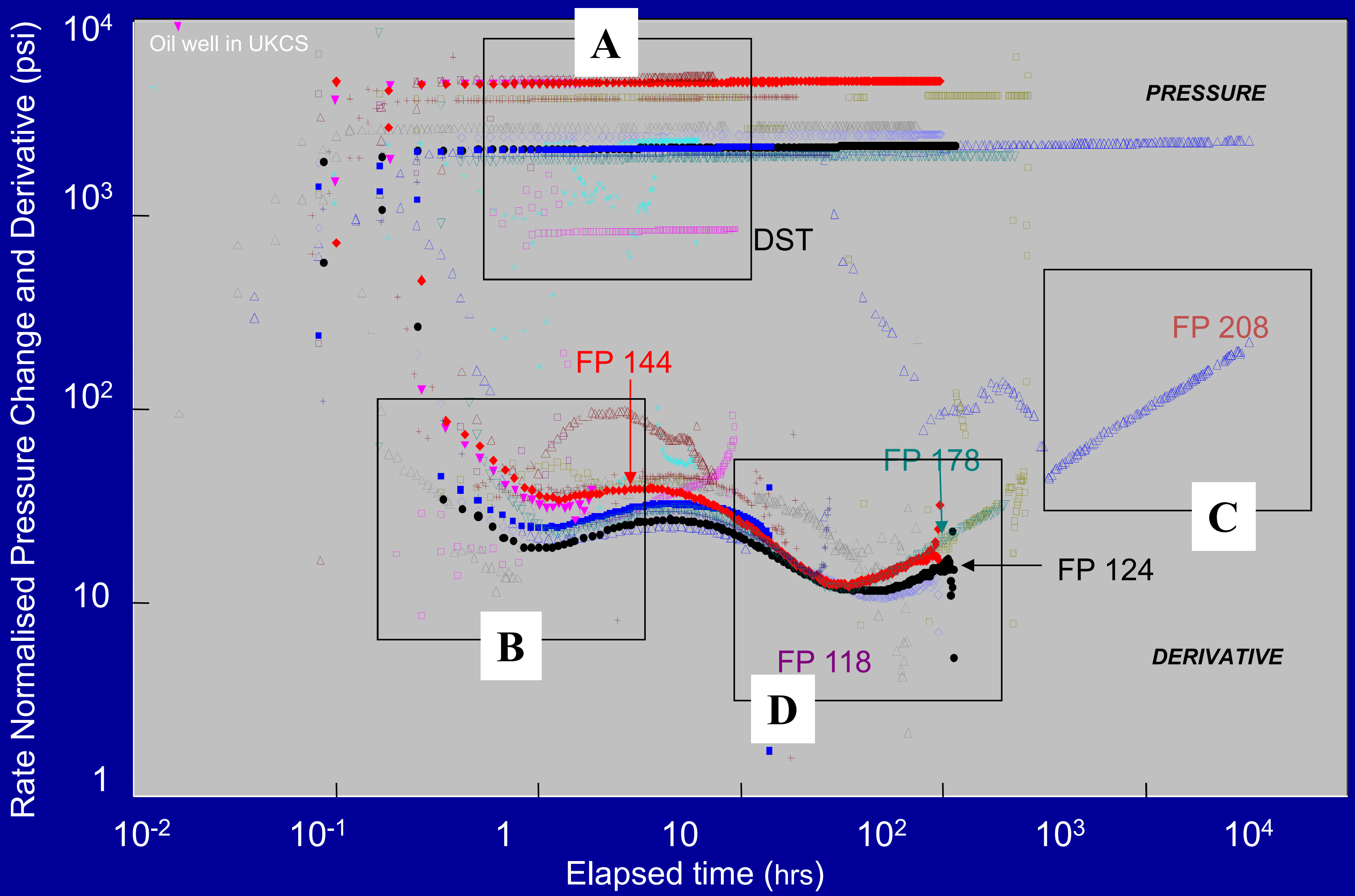
Effect of derivative calculation



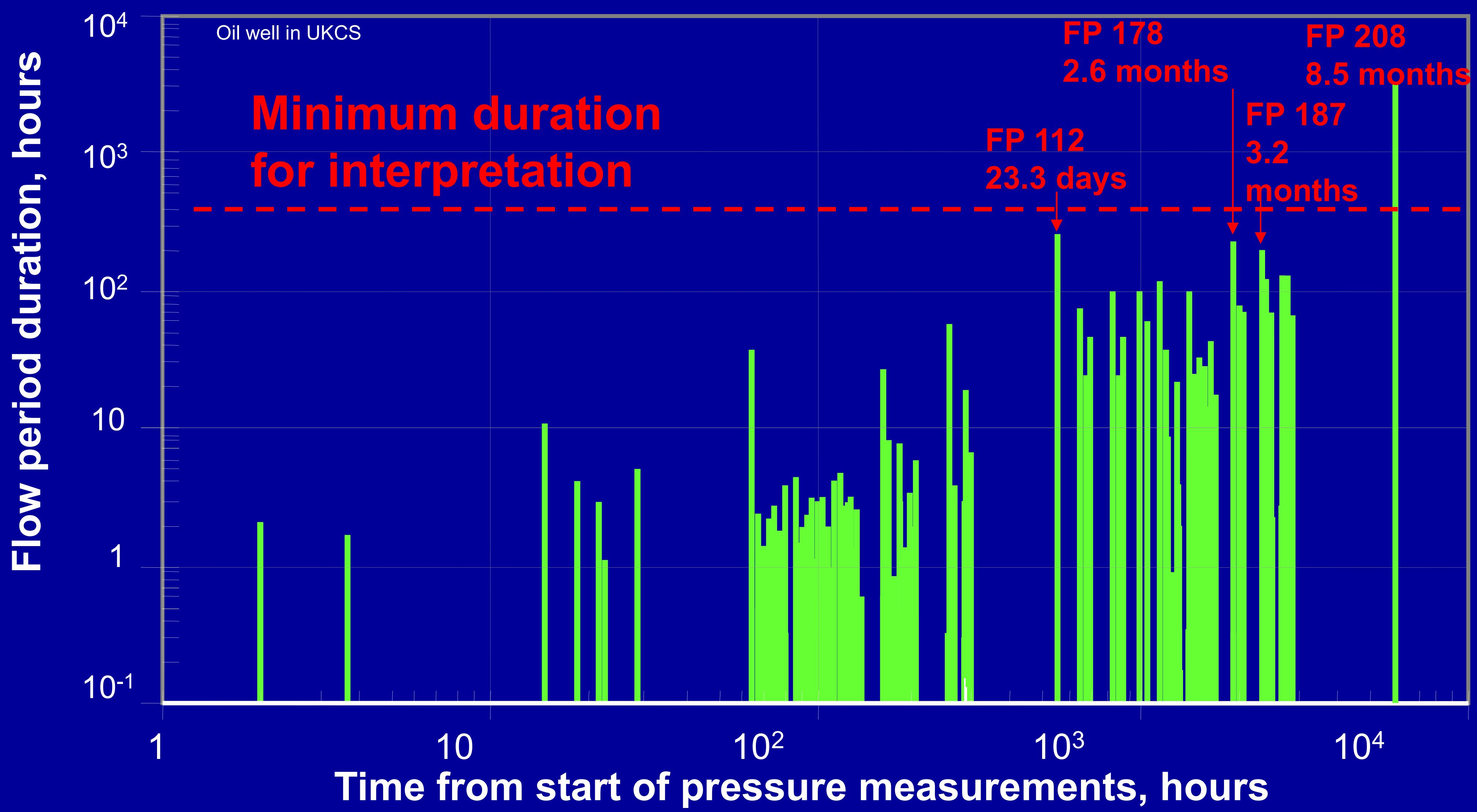
Extended test



Extended test

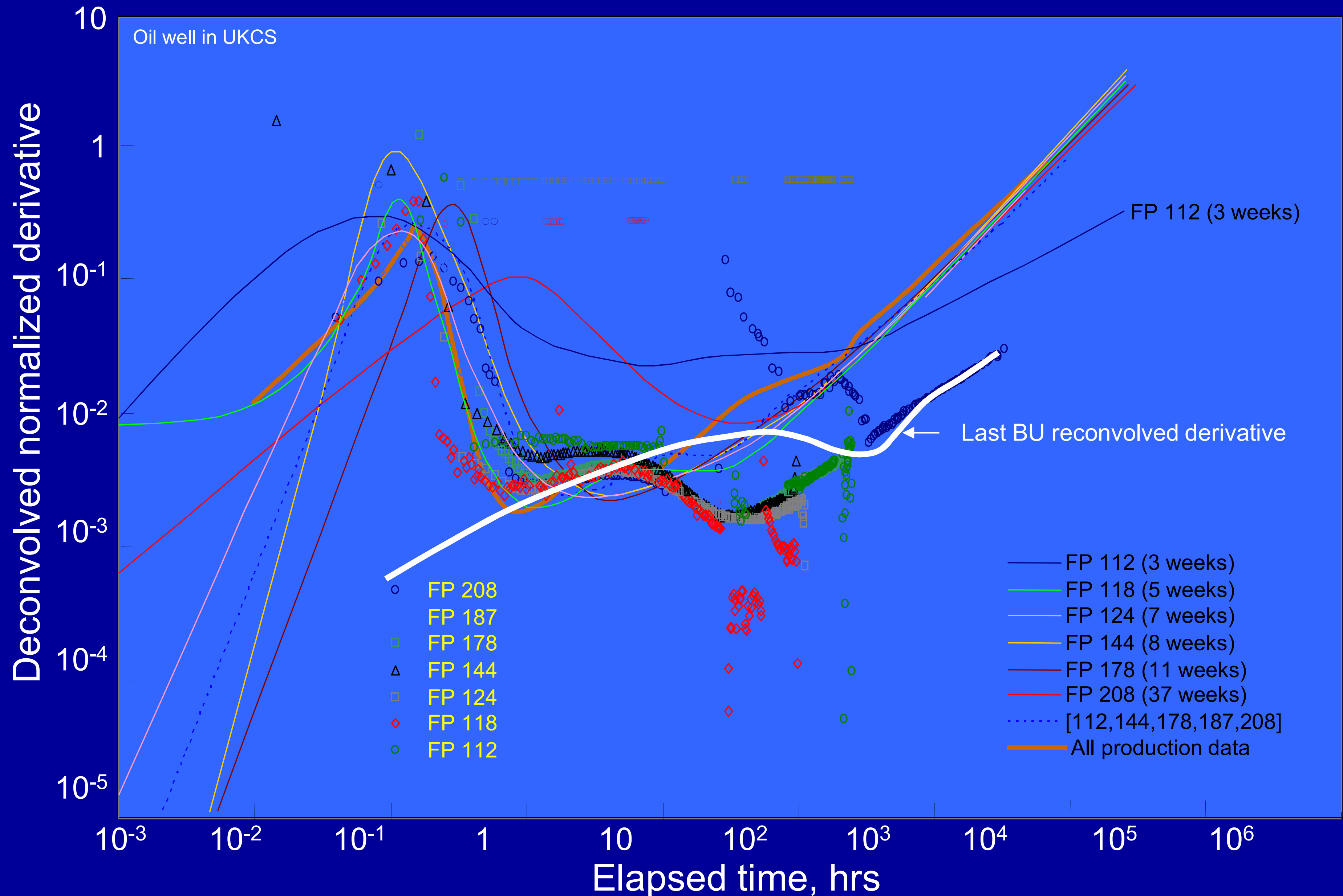


Shortening of reservoir limit tests

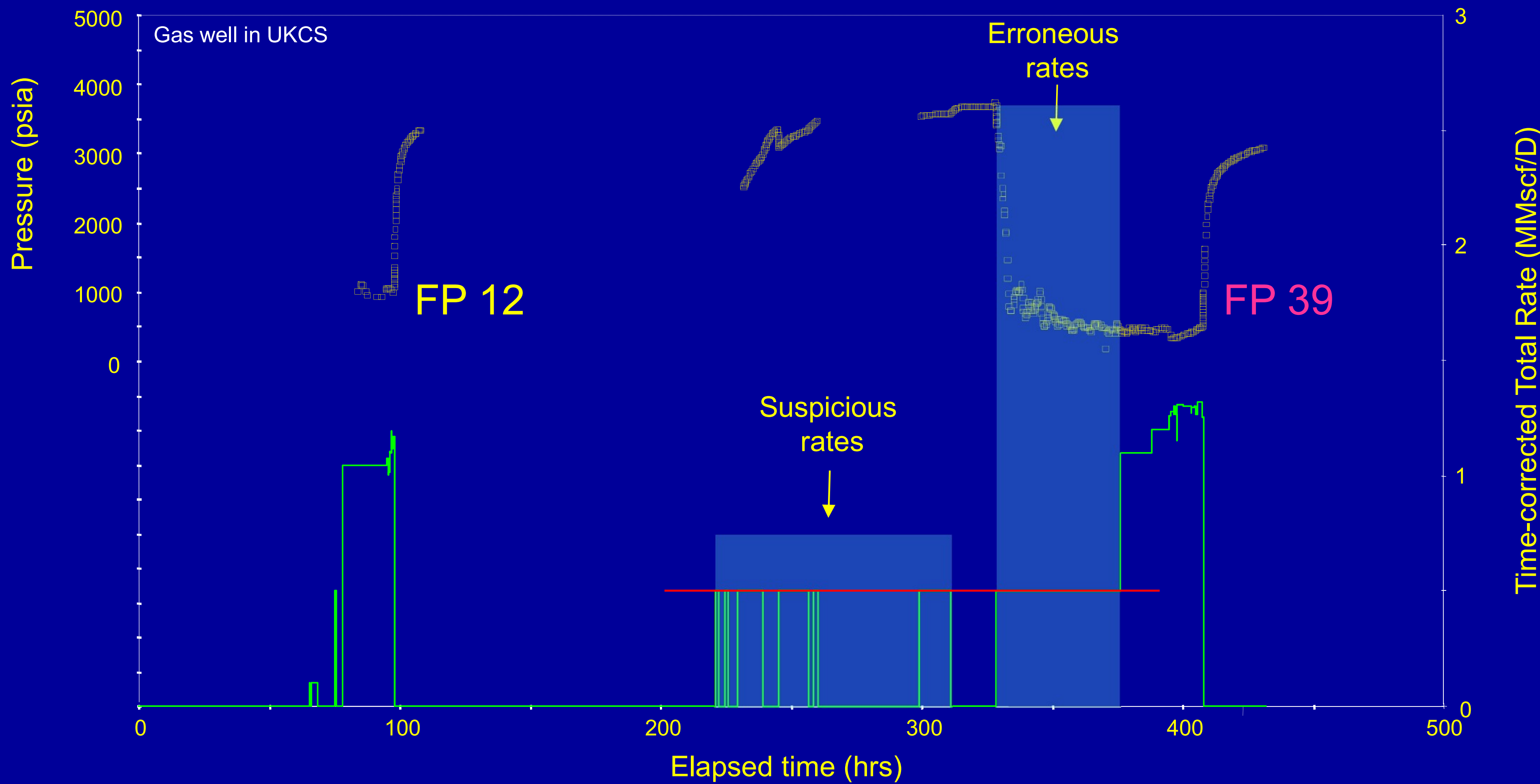


SPE 93988

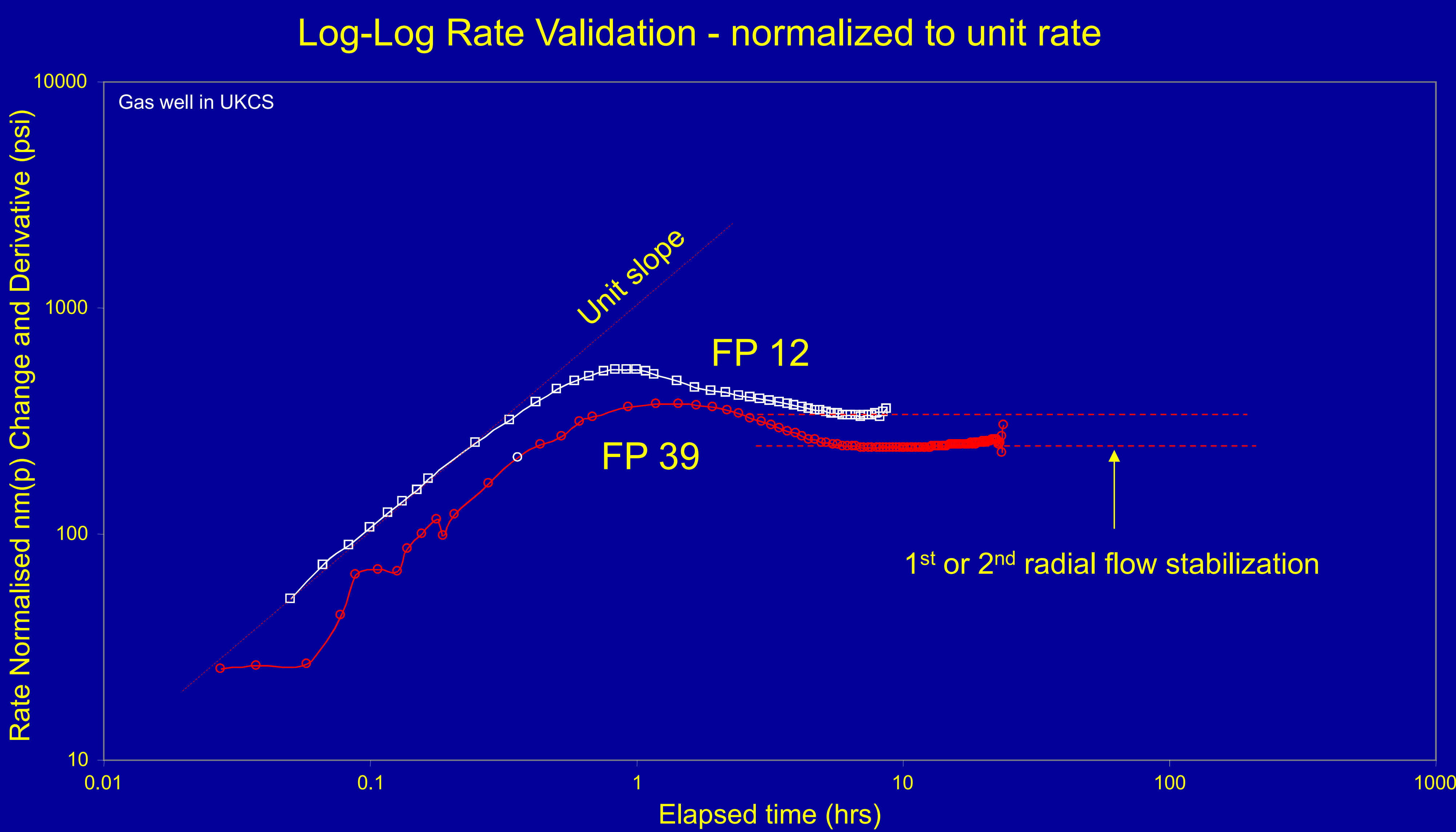
Shortening of reservoir limit tests



Rates from deconvolution (3)

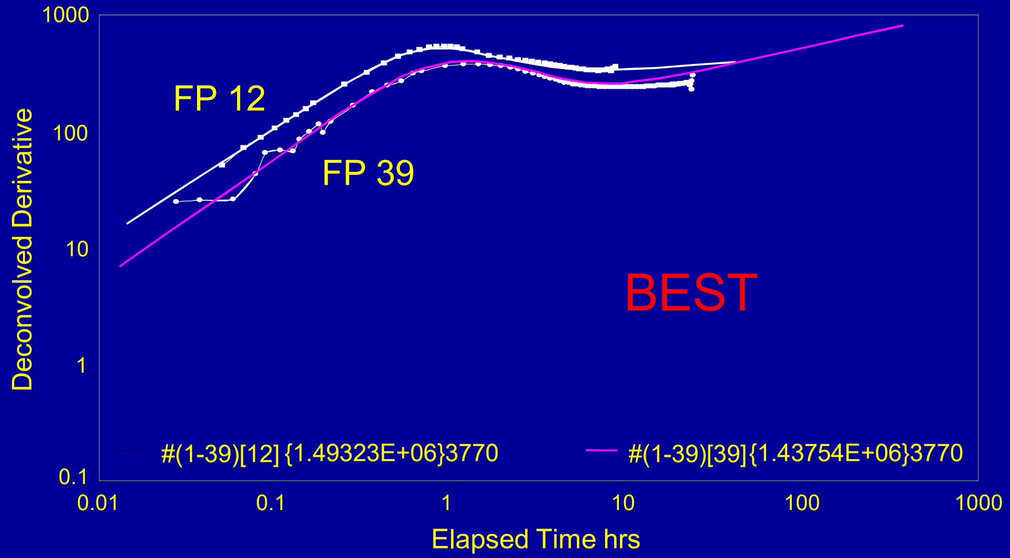


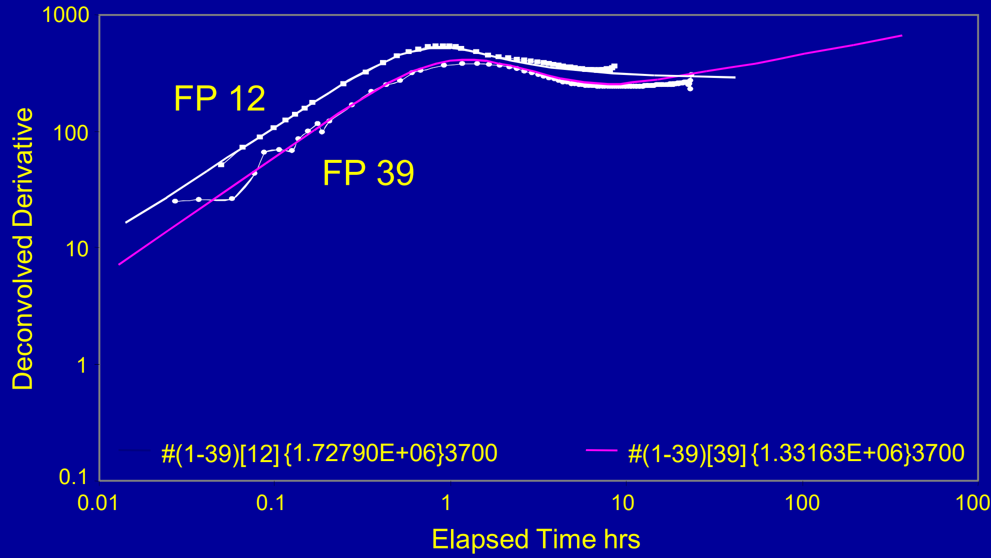
Rates from deconvolution (3)

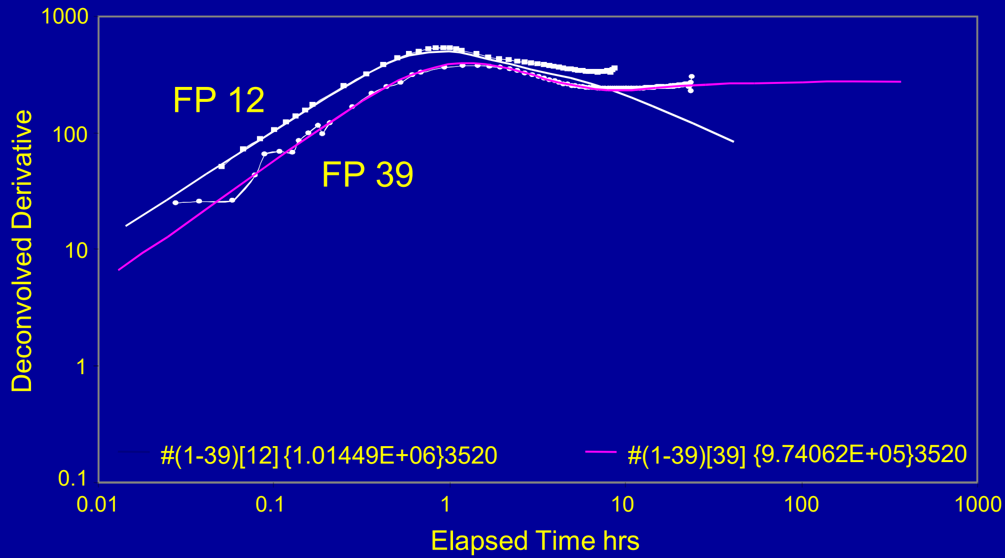


Rates from deconvolution (3)

p_i from Deconvolution of the build ups, FP 12 and 39

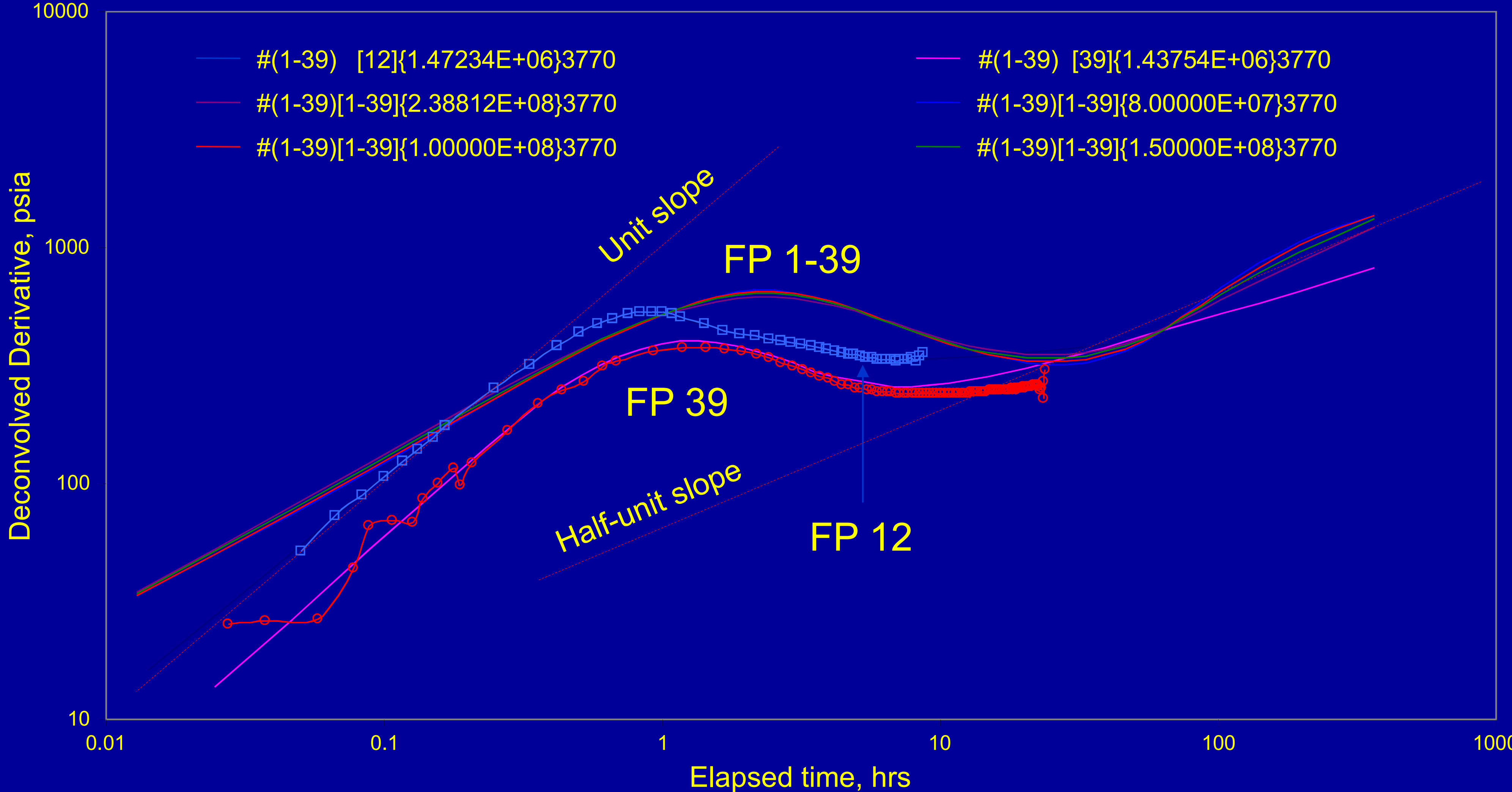




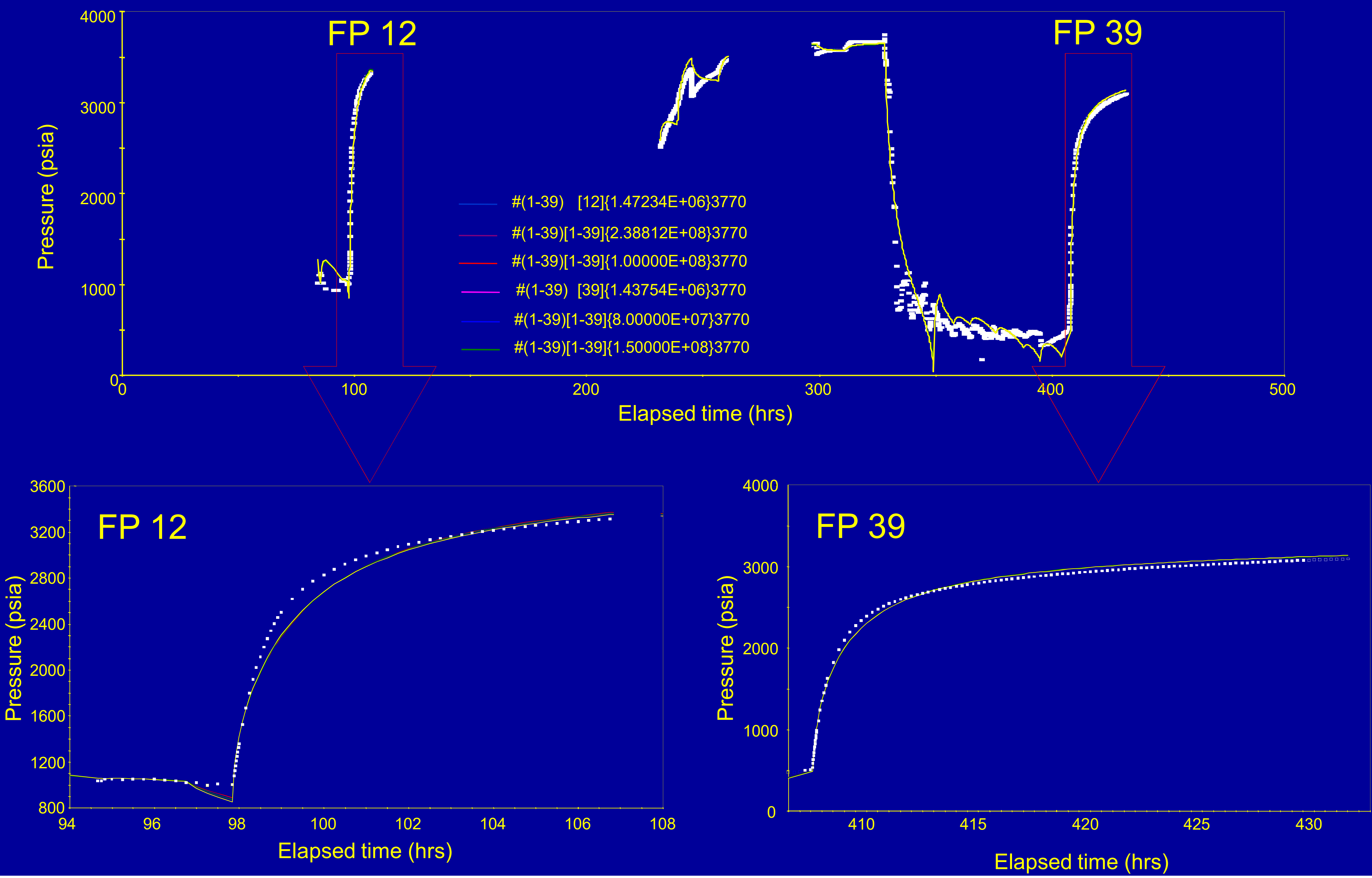


Rates from deconvolution (3)

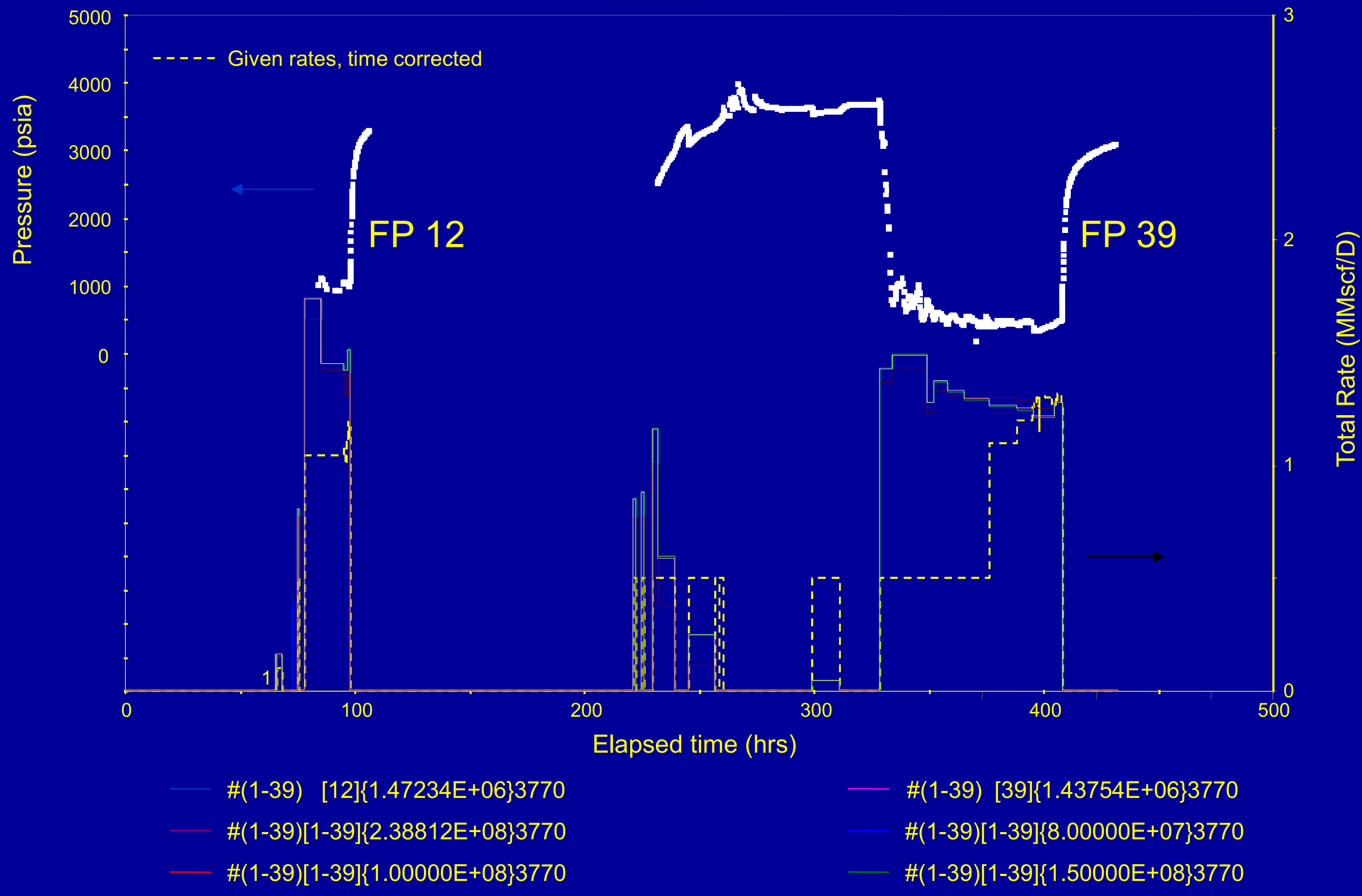
Deconvolution of the entire pressure history (FP 1 to 39)



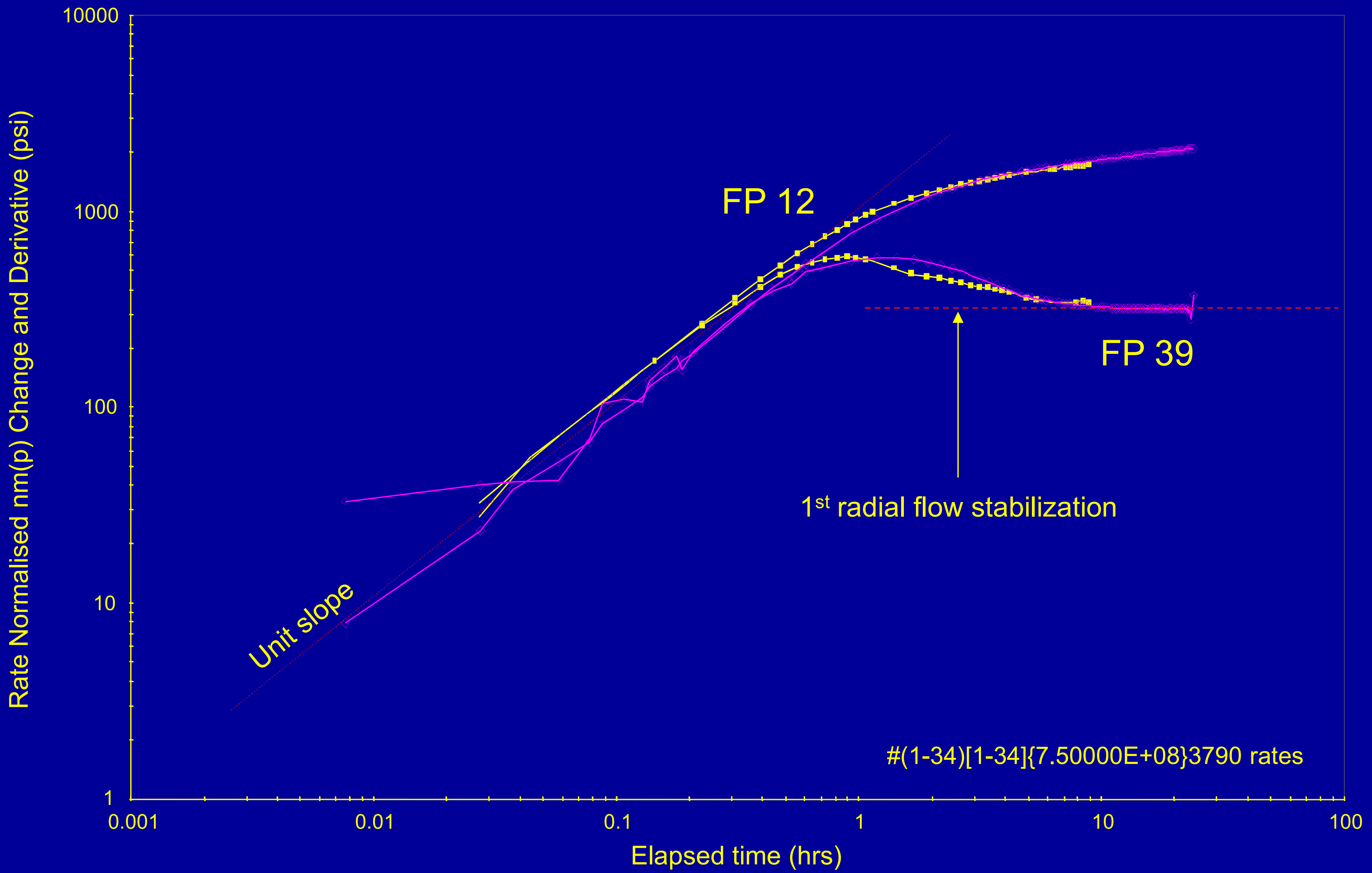
Verification of Deconvolution with pressure match



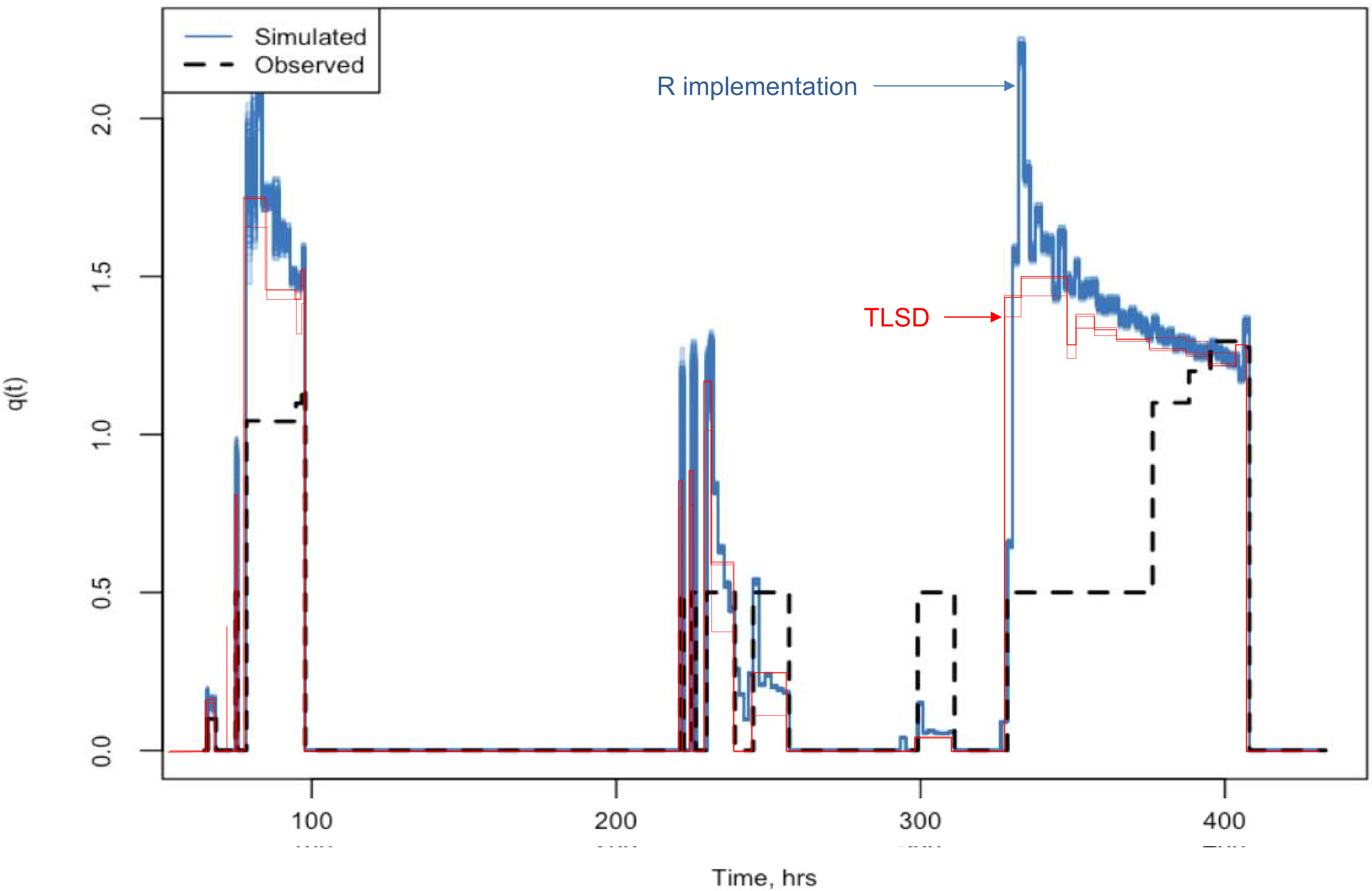
Deconvolution adapted rates

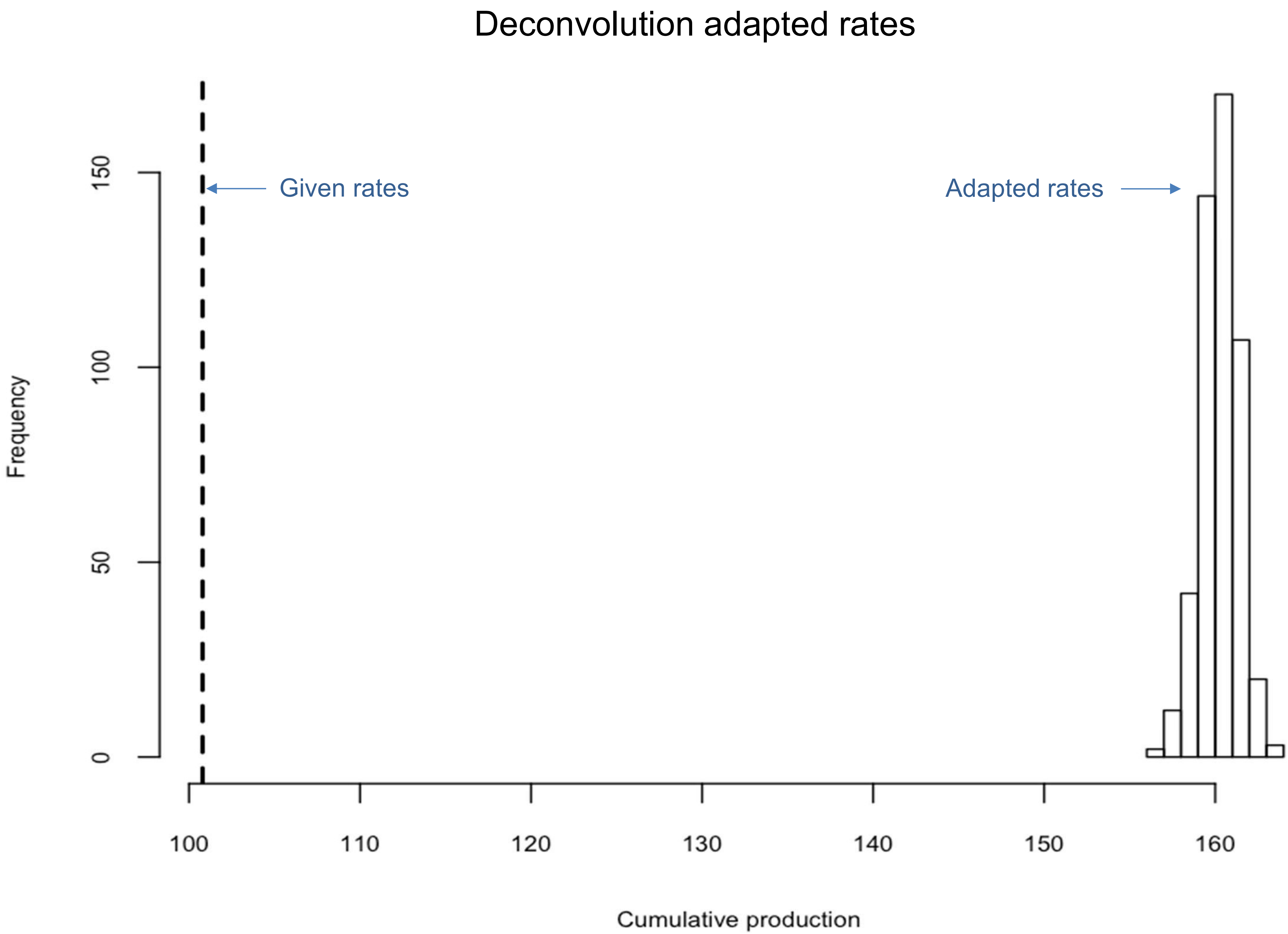


Log-Log Rate Validation normalized to Flow Period 12

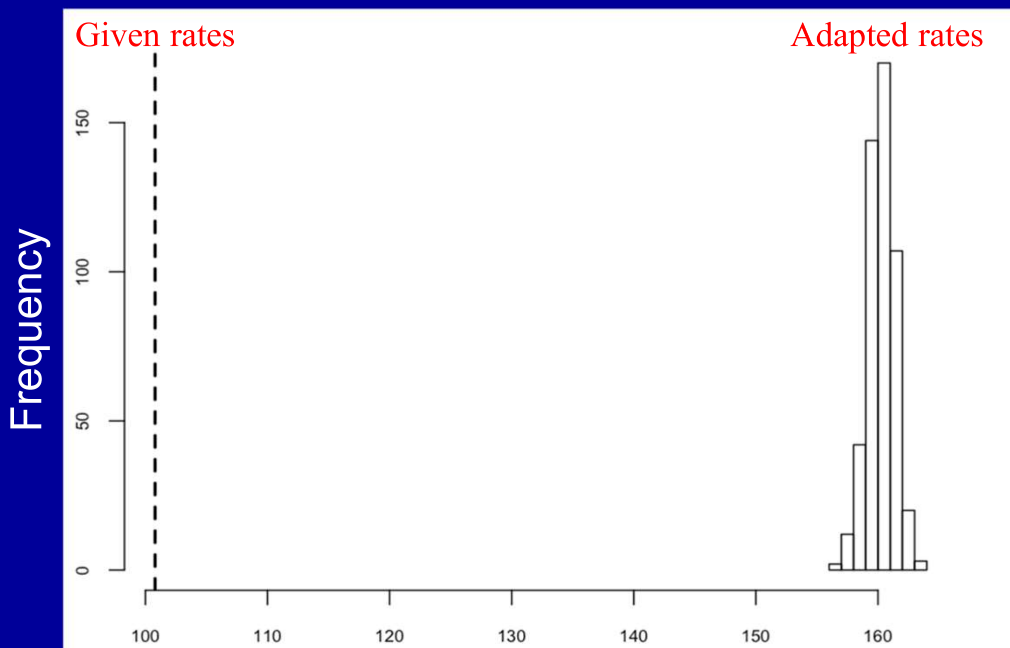


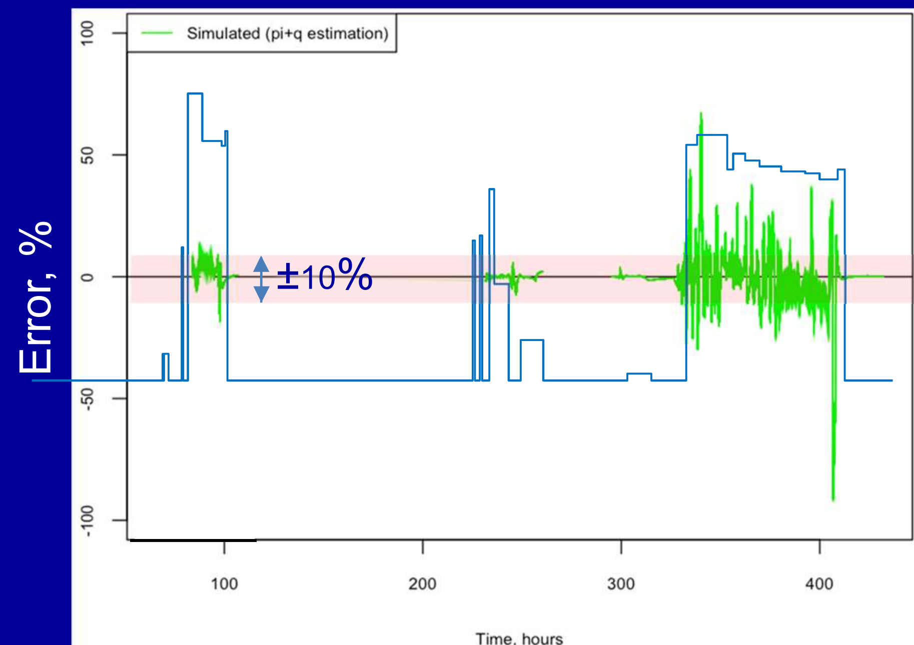
Deconvolution adapted rates

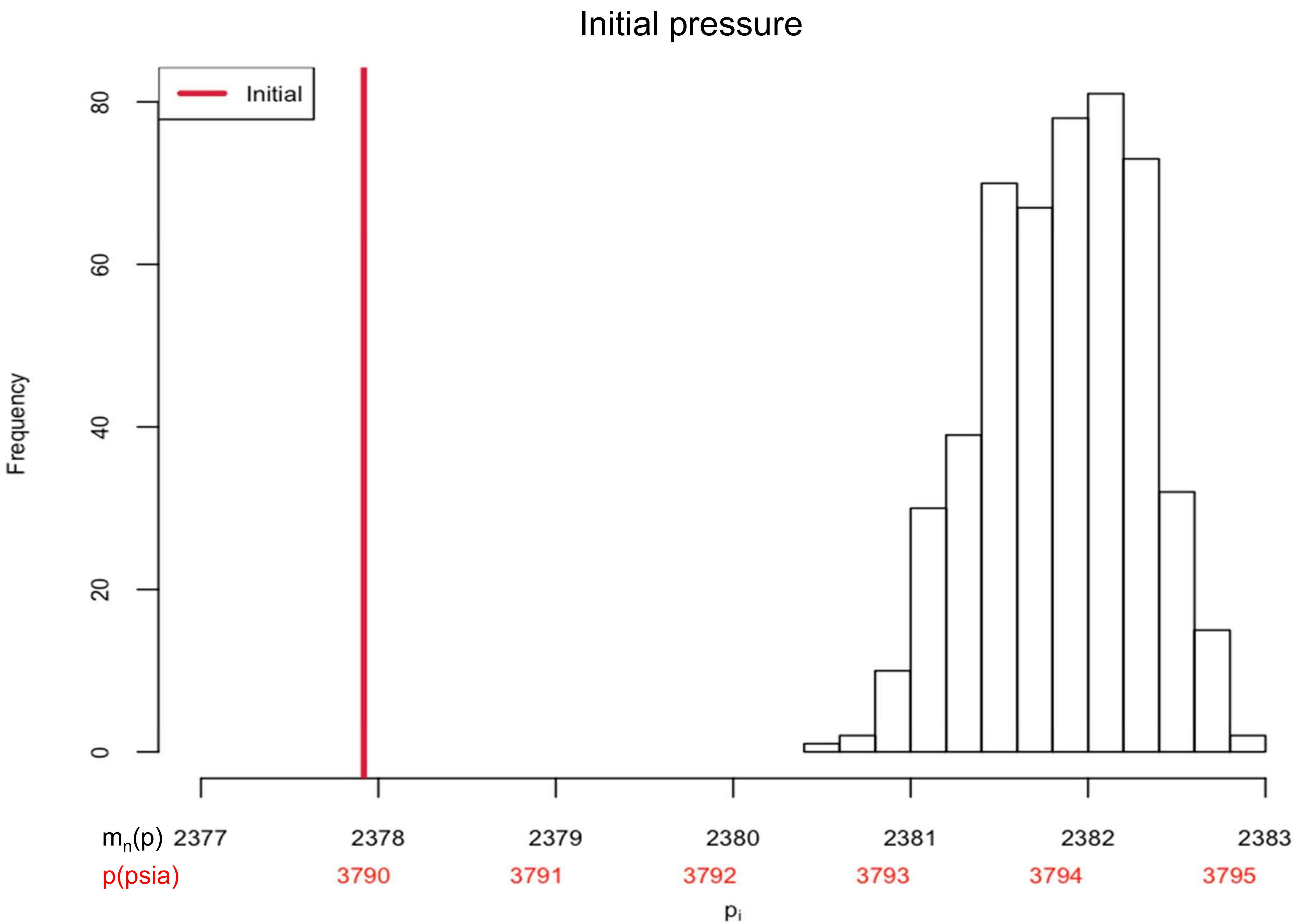



Deconvolution adapted rates
Given rates
Adapted rates
Frequency
0
50
100
150
100
110
120
130
140
150
160
Cumulative production

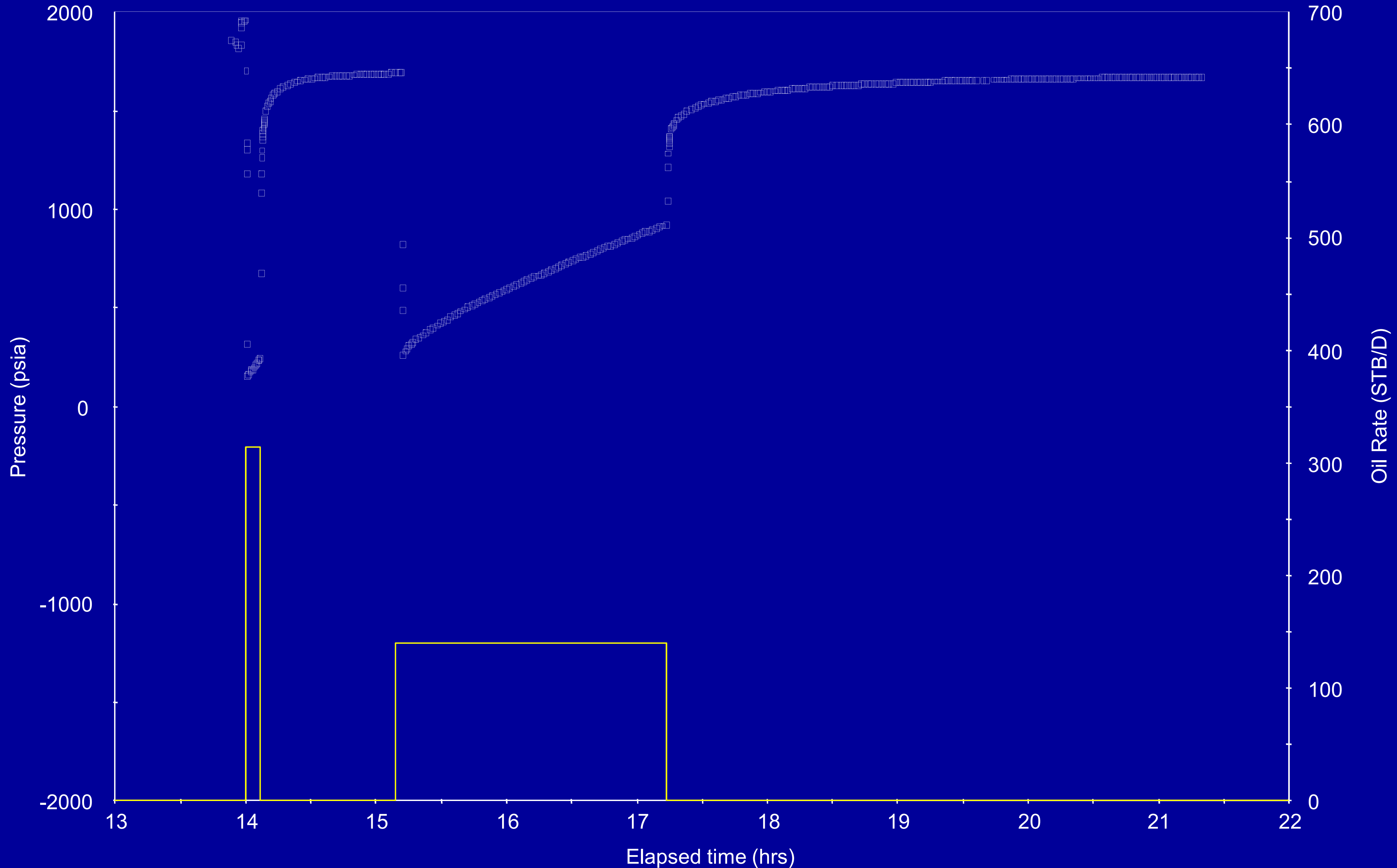
Deconvolution adapted rates



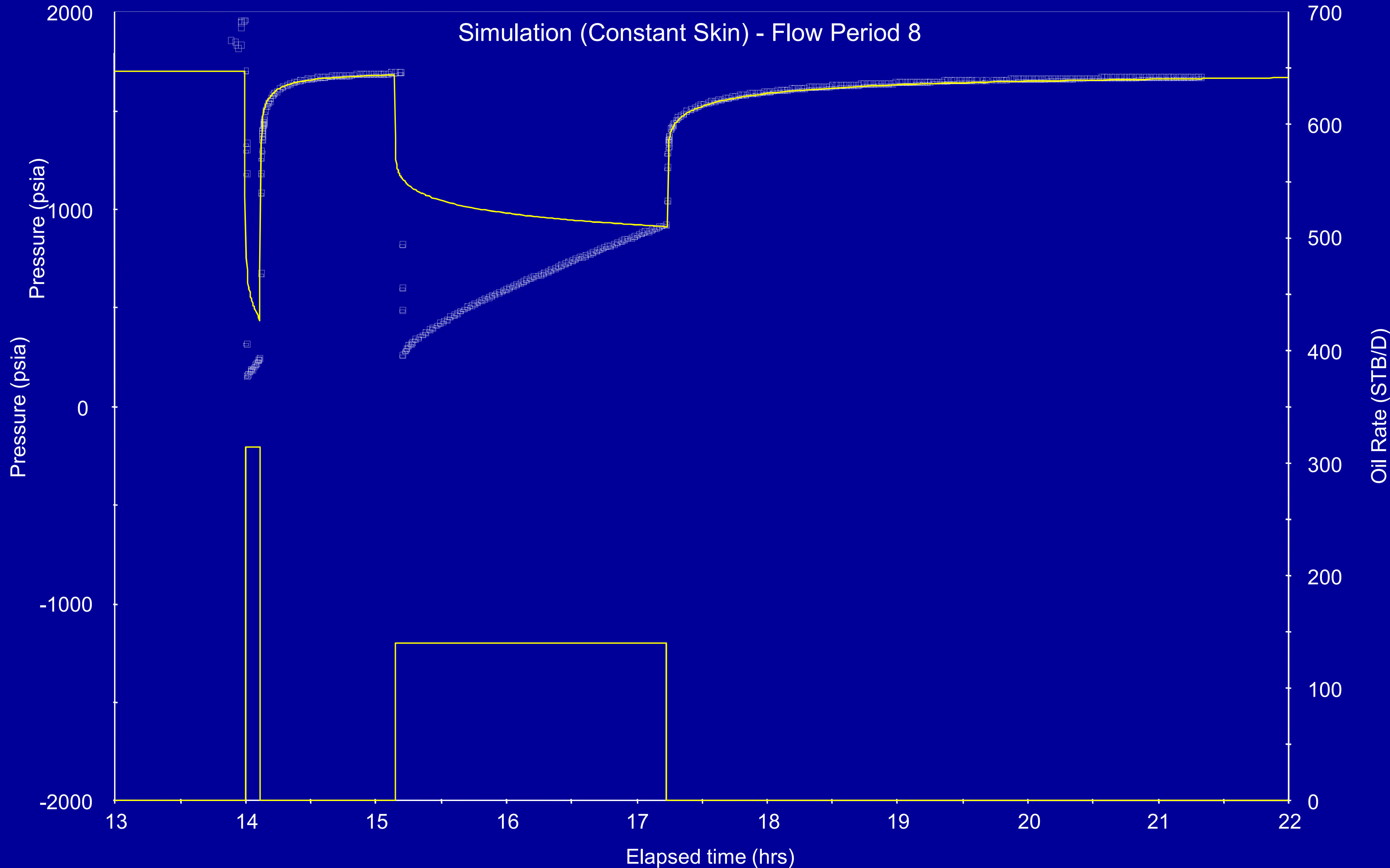



Initial pressure
Initial
Frequency
0
20
40
60
80
mn(p) 2377
2378
2379
2380
2381
2382
2383
p(psia)
3790
3791
3792
3793
3794
3795
pi

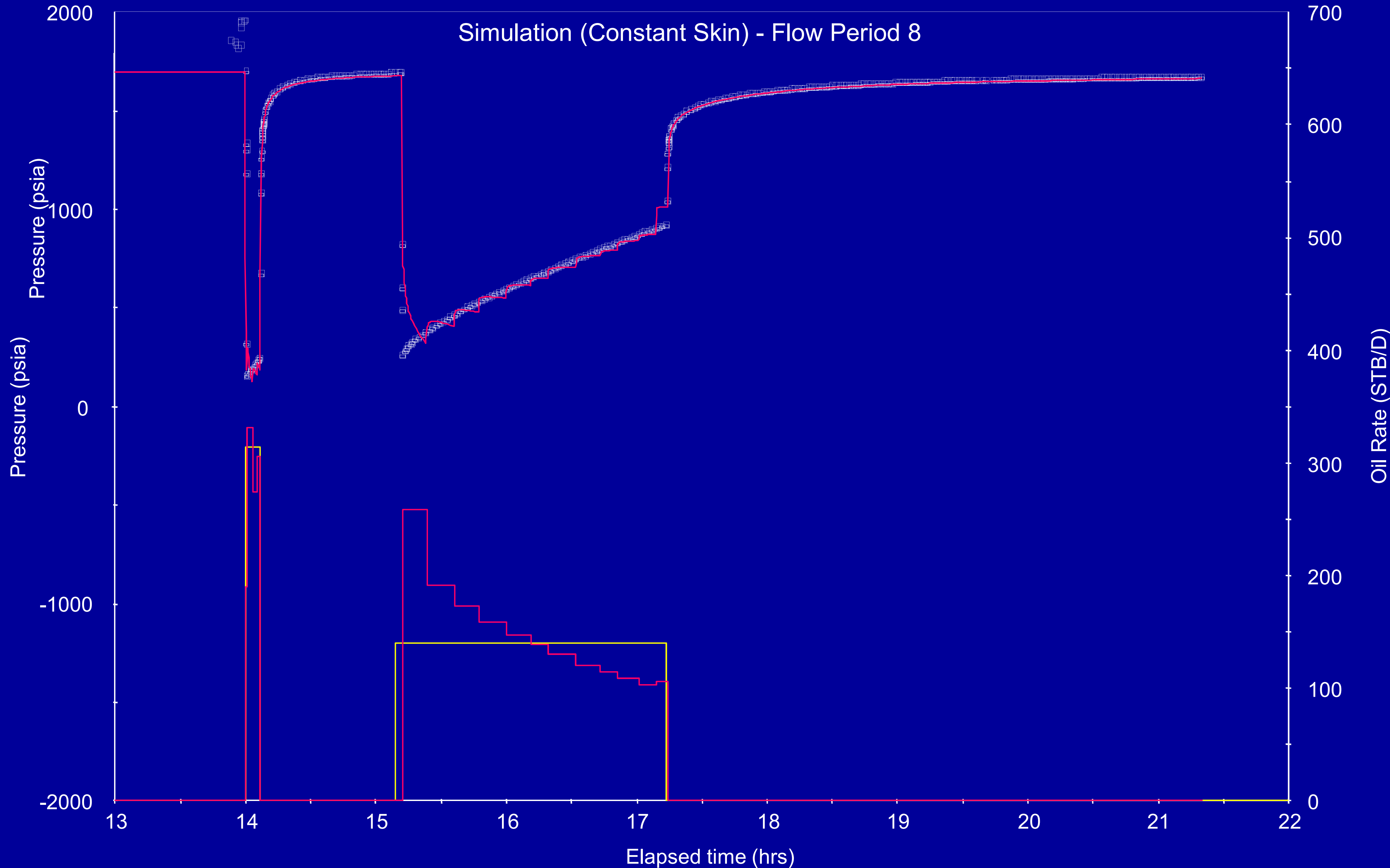
Rates from deconvolution (1)

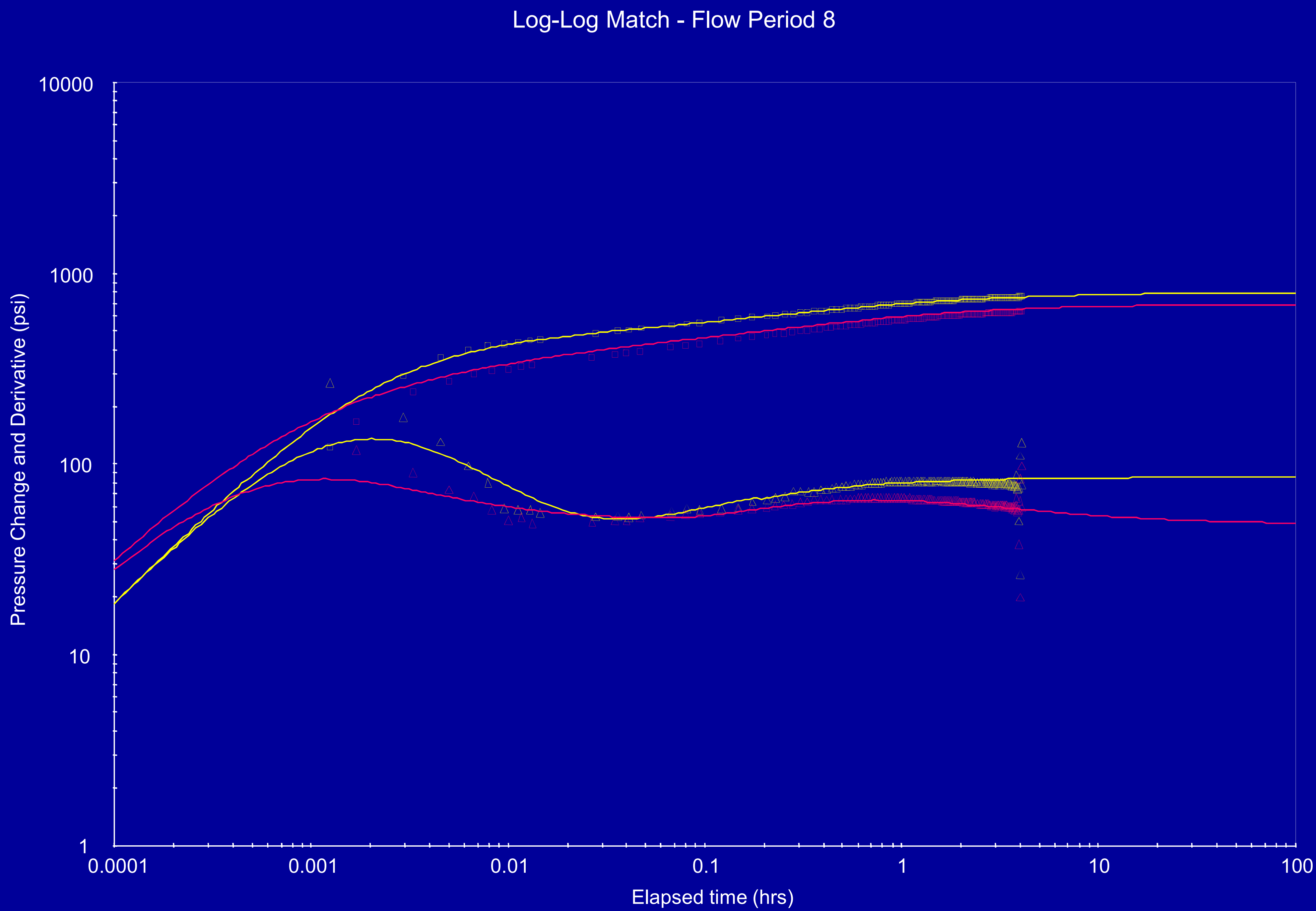


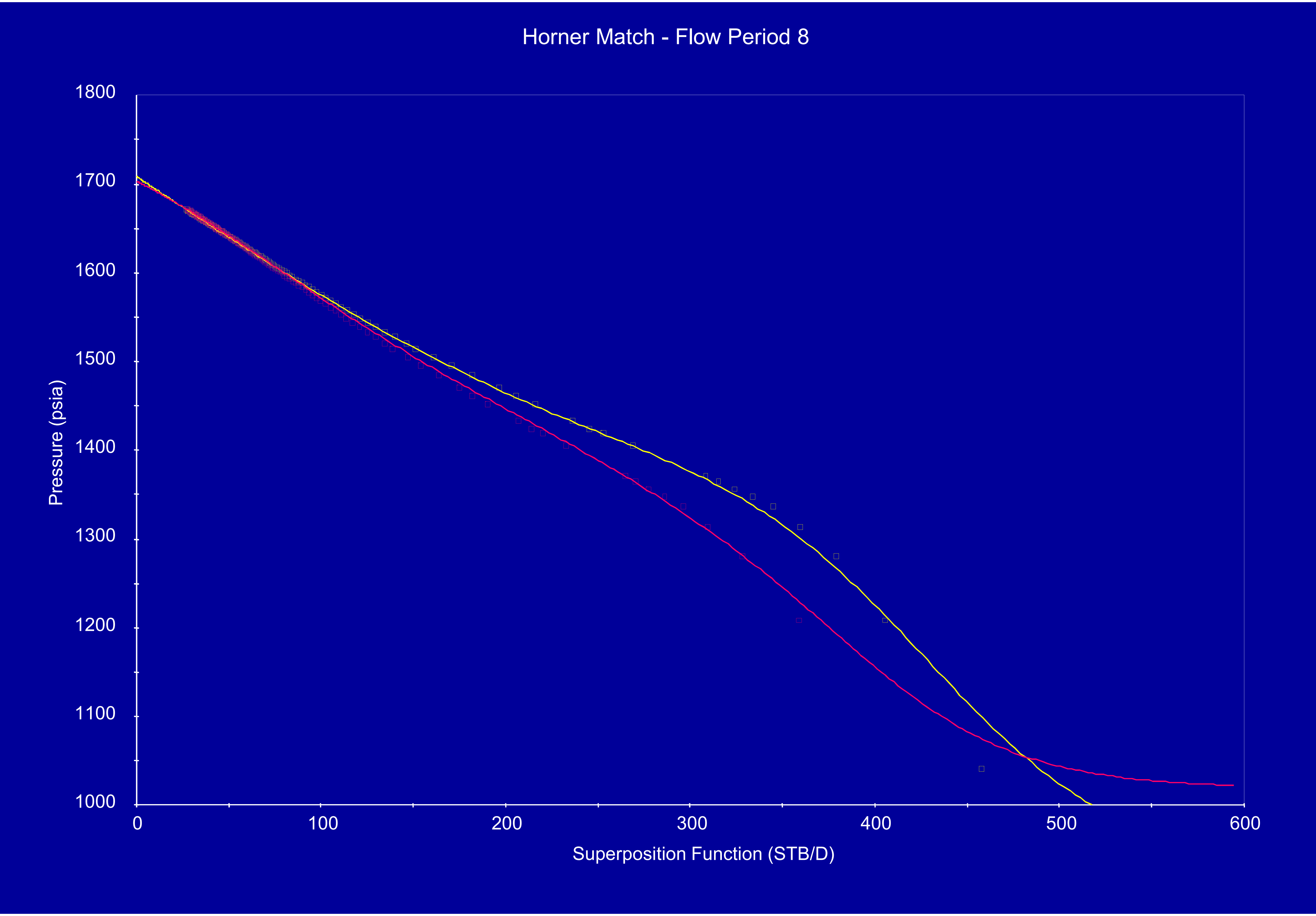
Rates from deconvolution (1)



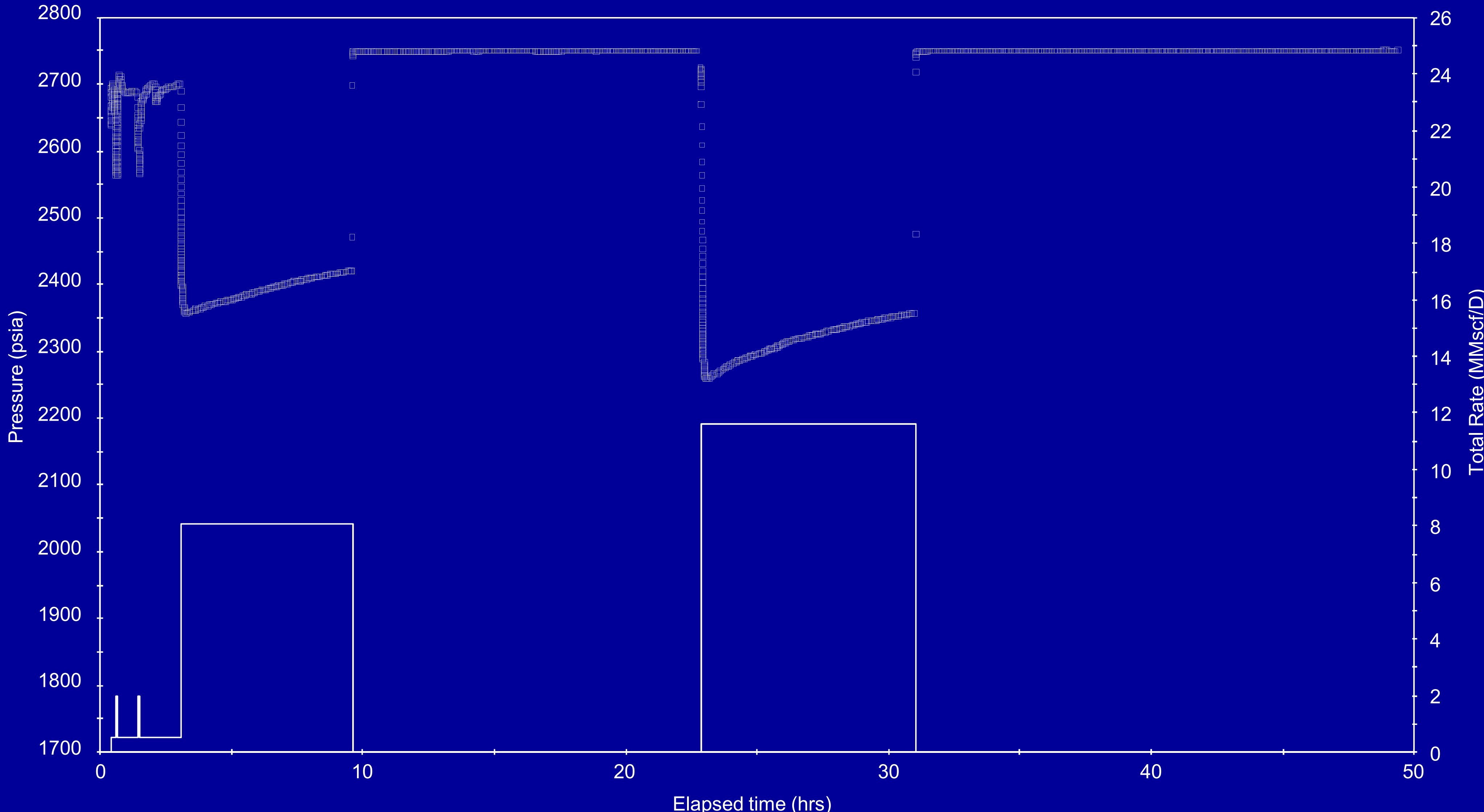
Rates from deconvolution (1)



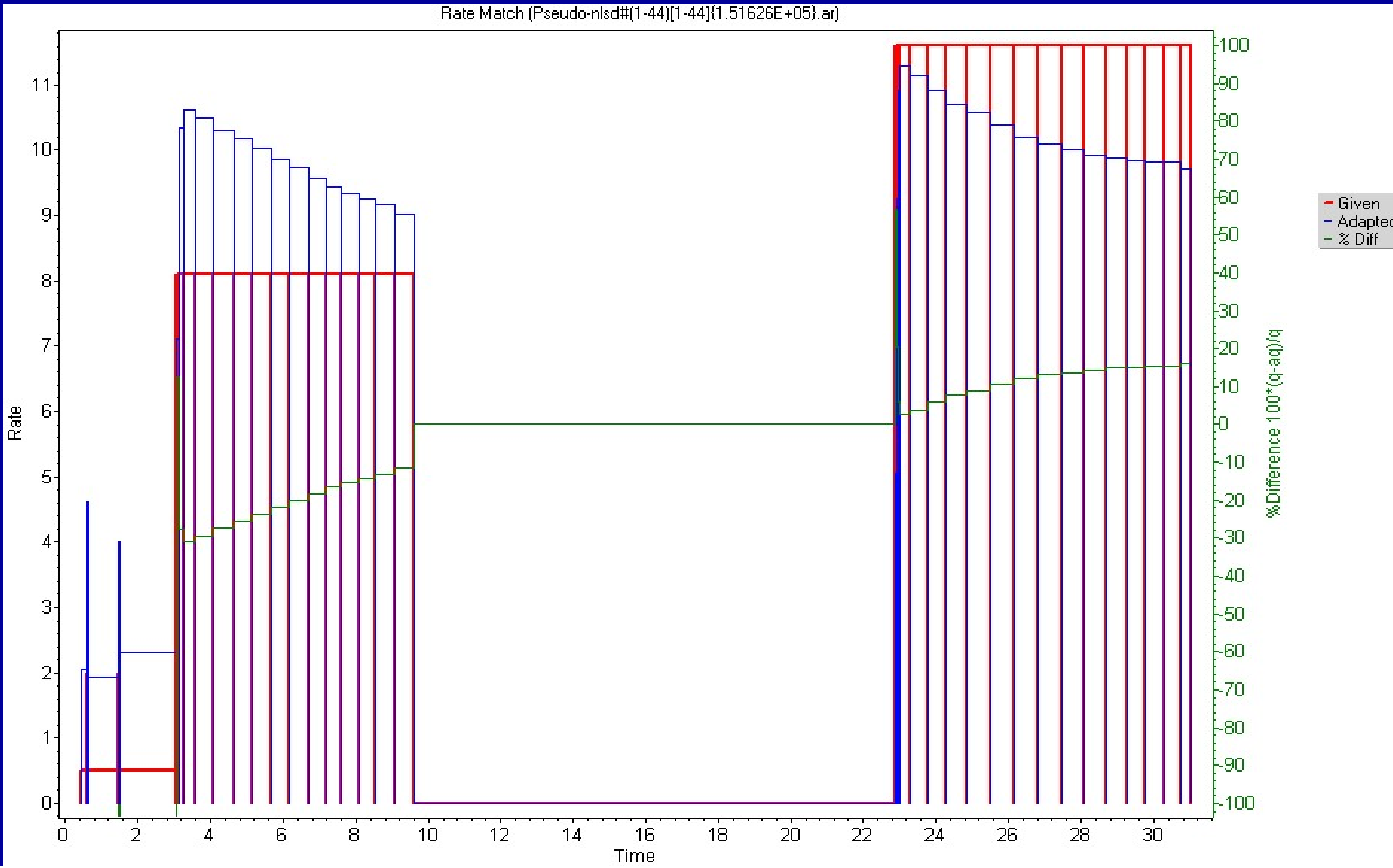

Log-Log Match - Flow Period 8
Pressure Change and Derivative (psi)
Elapsed time (hrs)
10000
1000
100
10
1
0.0001
0.001
0.01
0.1
1
10
100


Horner Match - Flow Period 8
Pressure (psia)
1800
1700
1600
1500
1400
1300
1200
1100
1000
0
100
200
300
400
500
600
Superposition Function (STB/D)

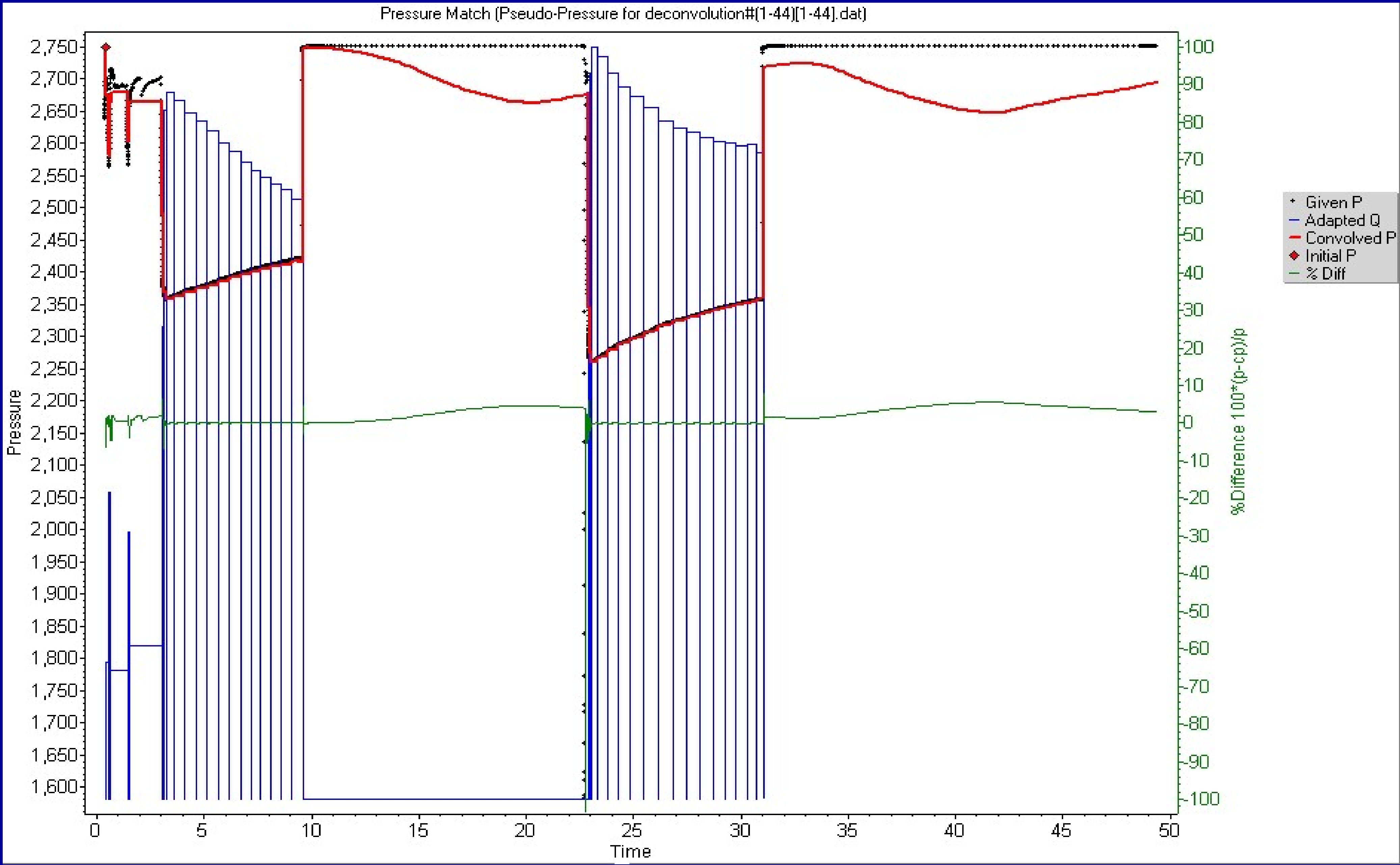
Rates from deconvolution (2)



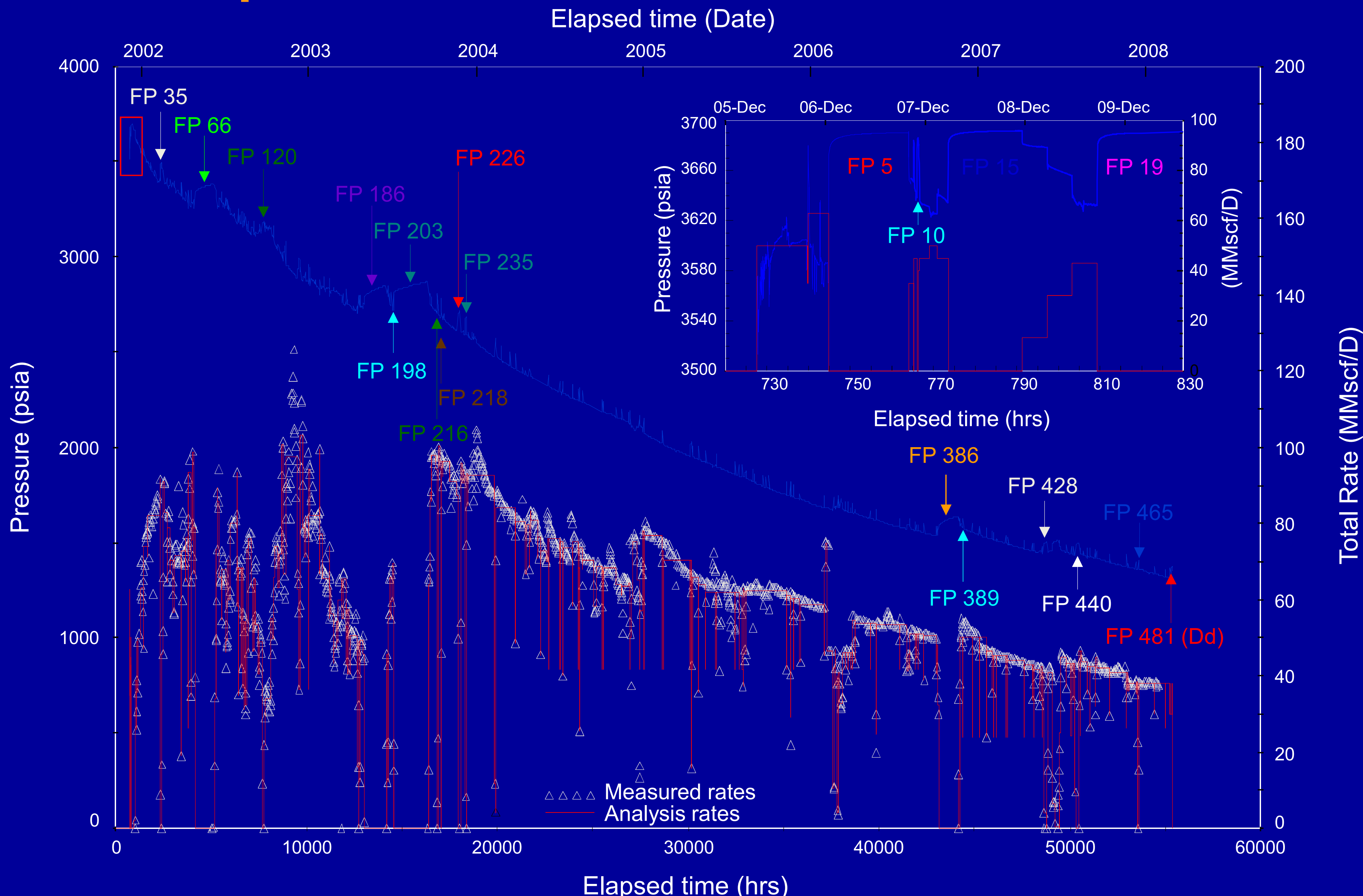
Rates from deconvolution (2)



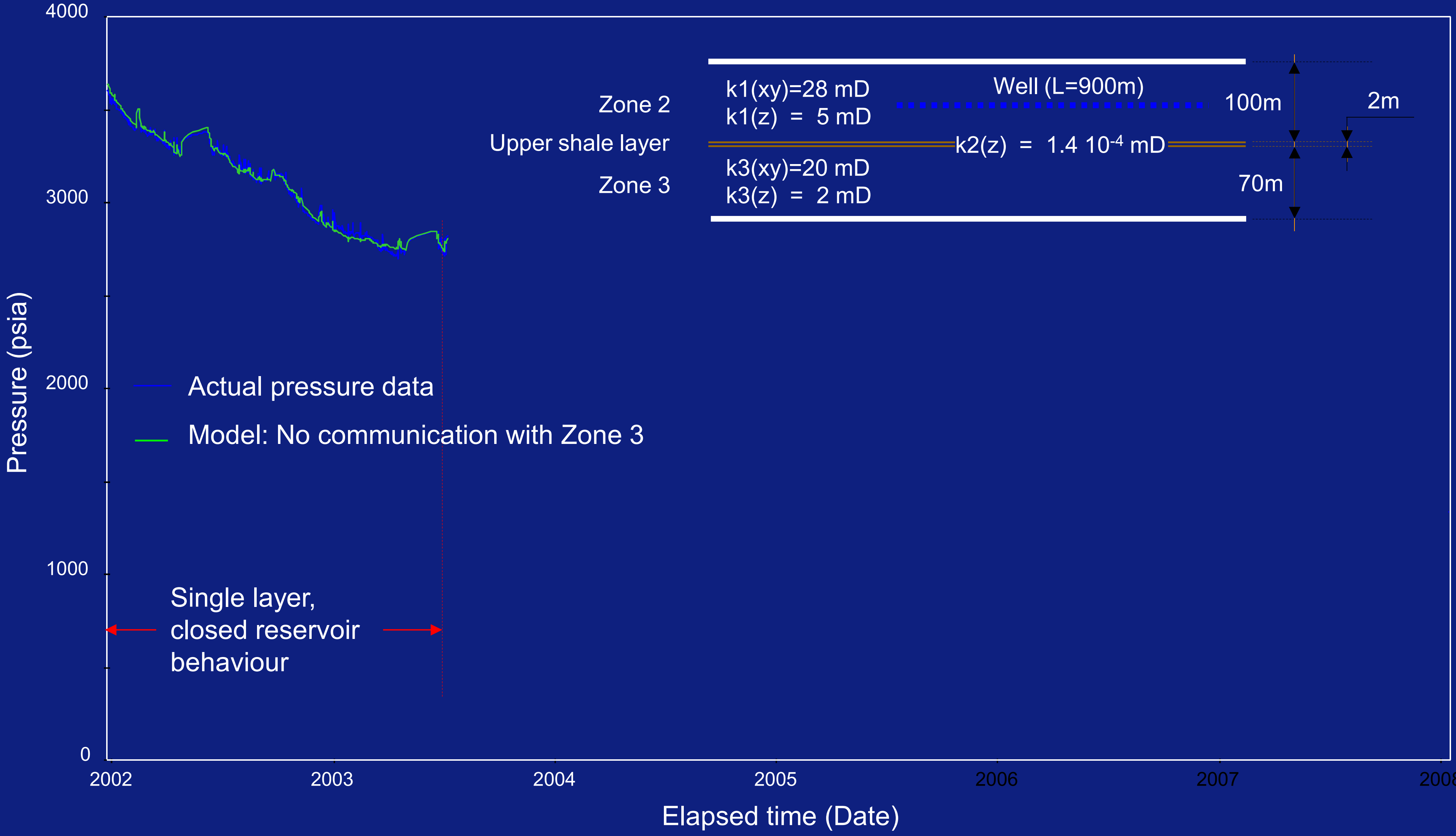
Rates from deconvolution (2)



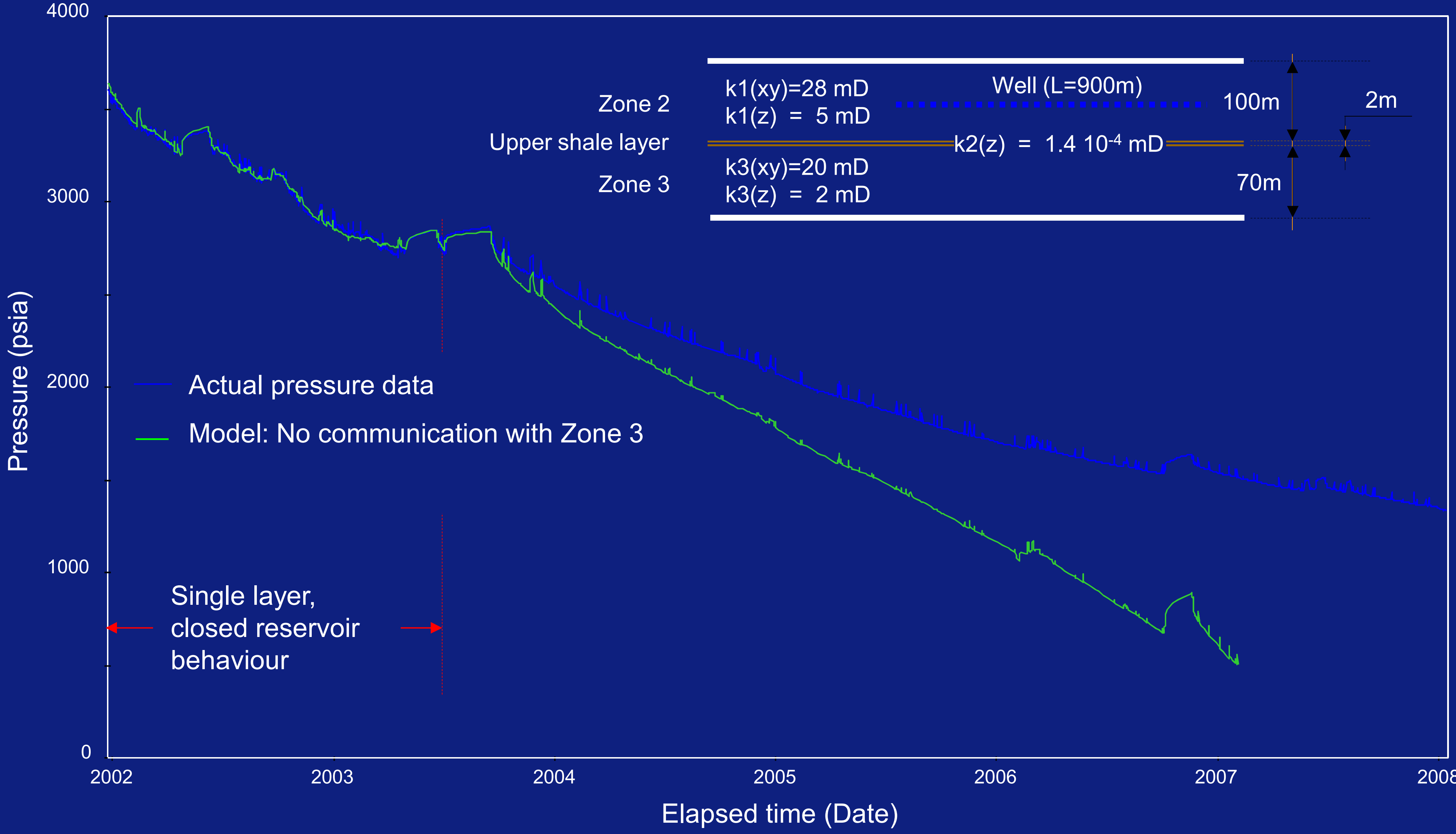
Time-dependent behaviour



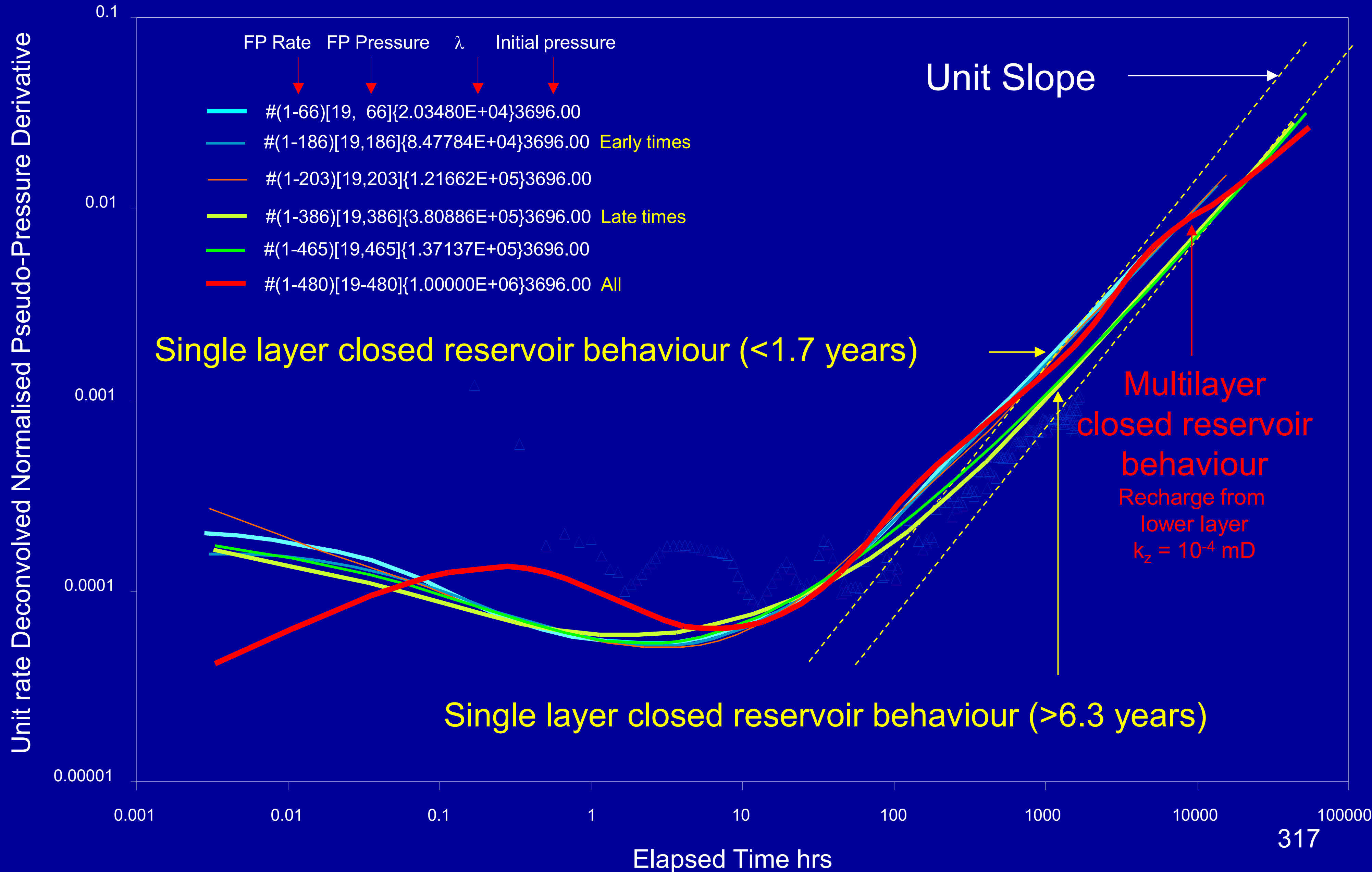
Simulation of pressure history



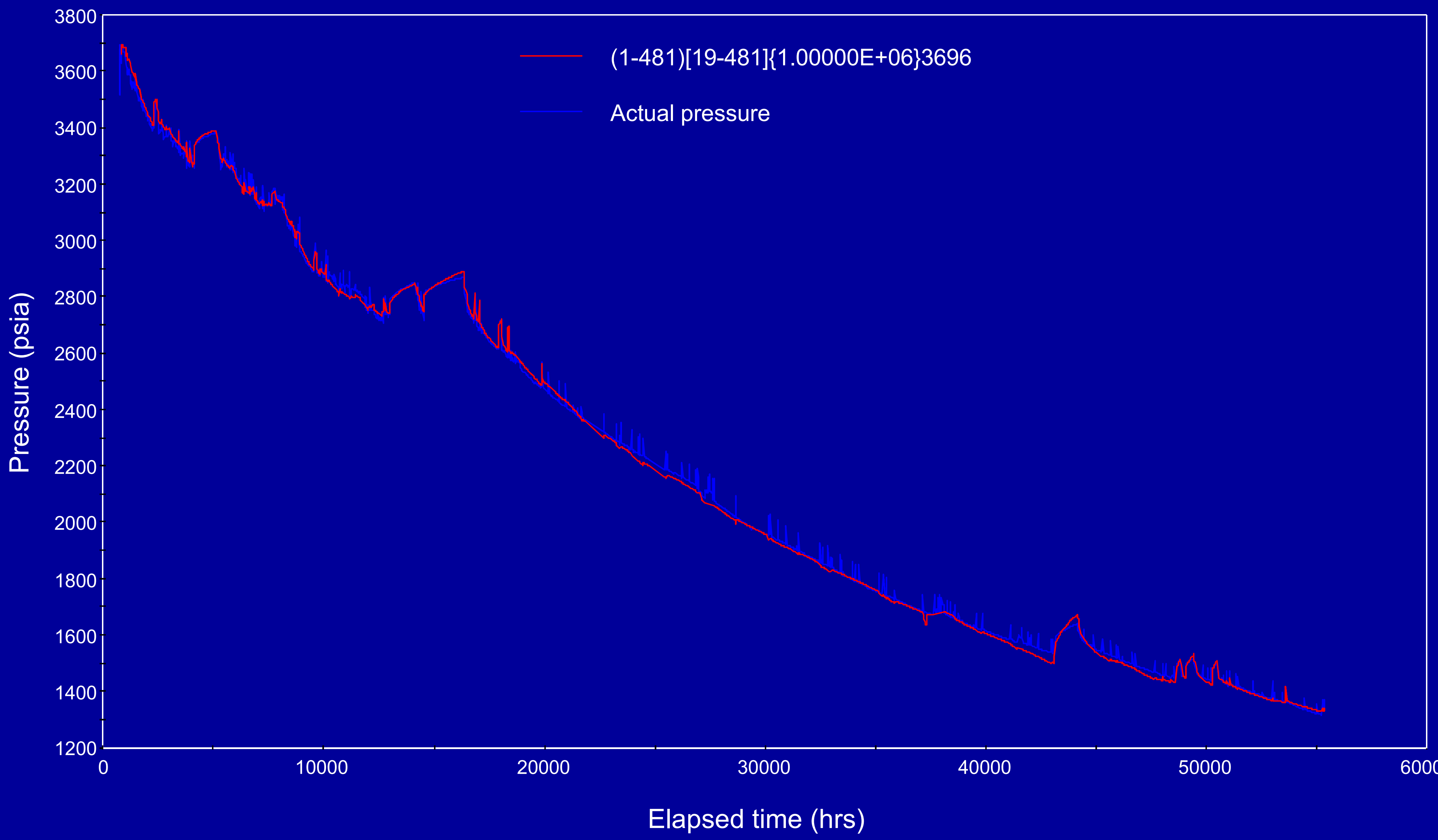
Simulation of pressure history



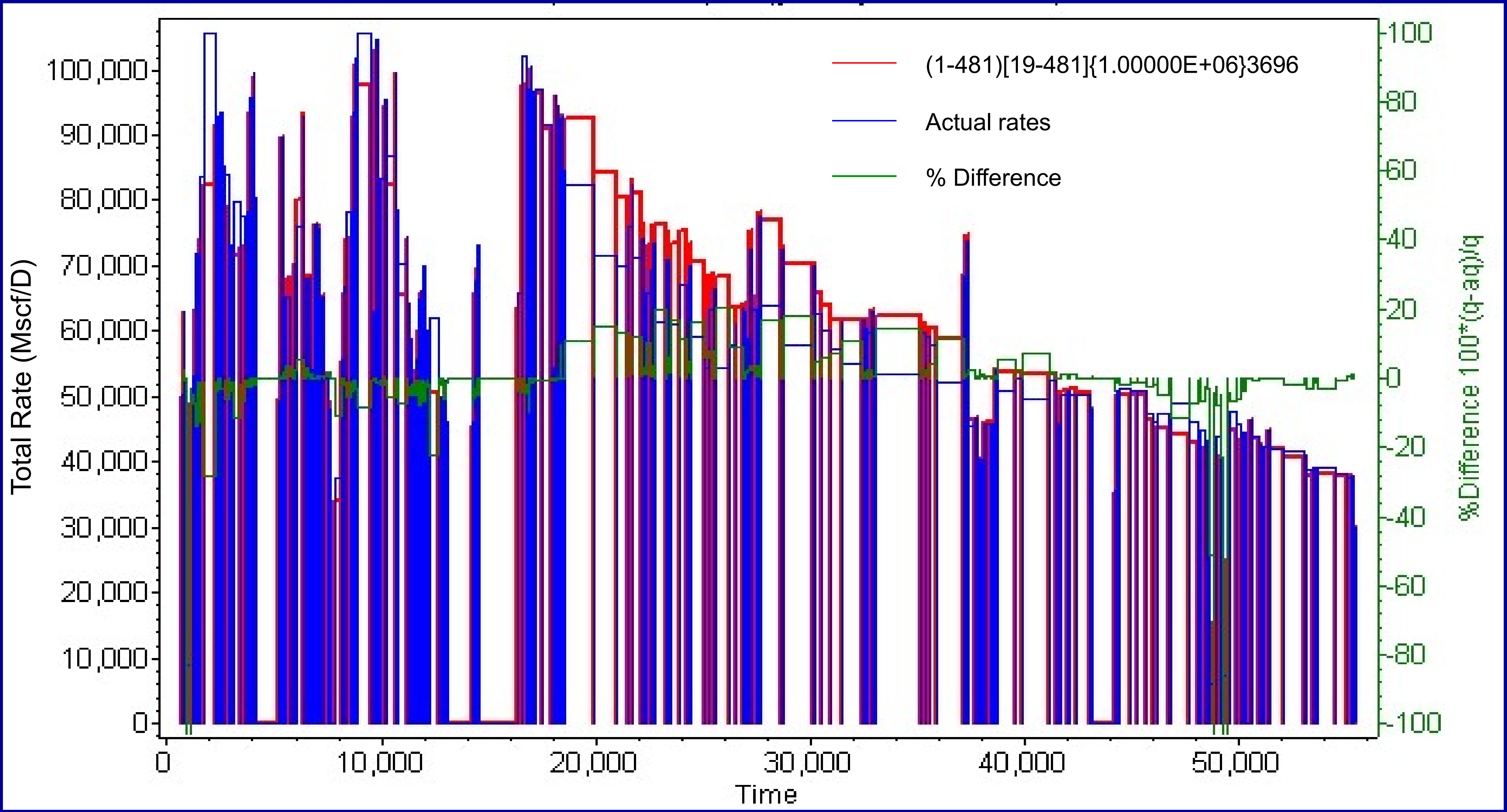
Deconvolved multilayer behaviours



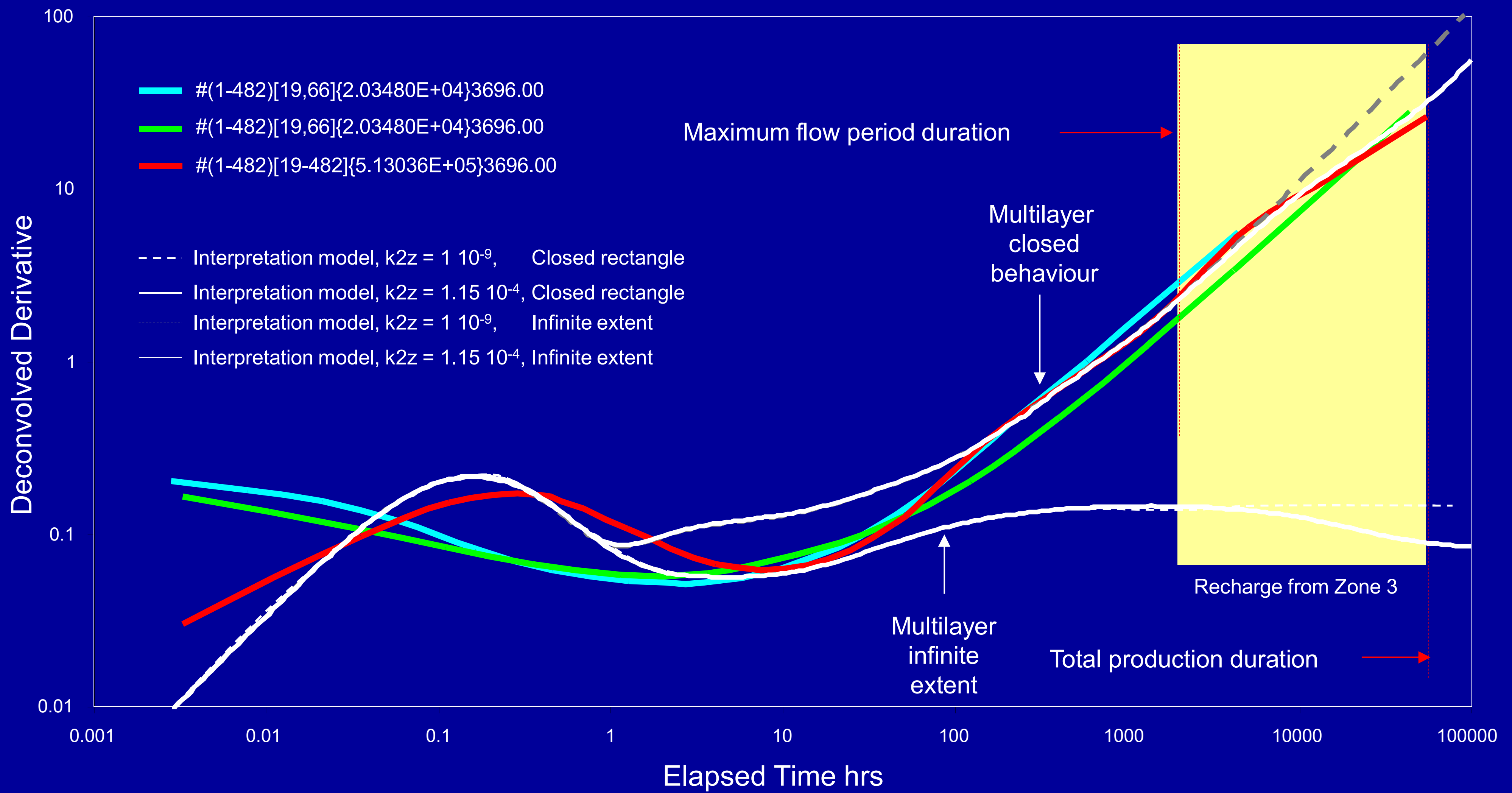
Reconvolved pressure history vs. actual



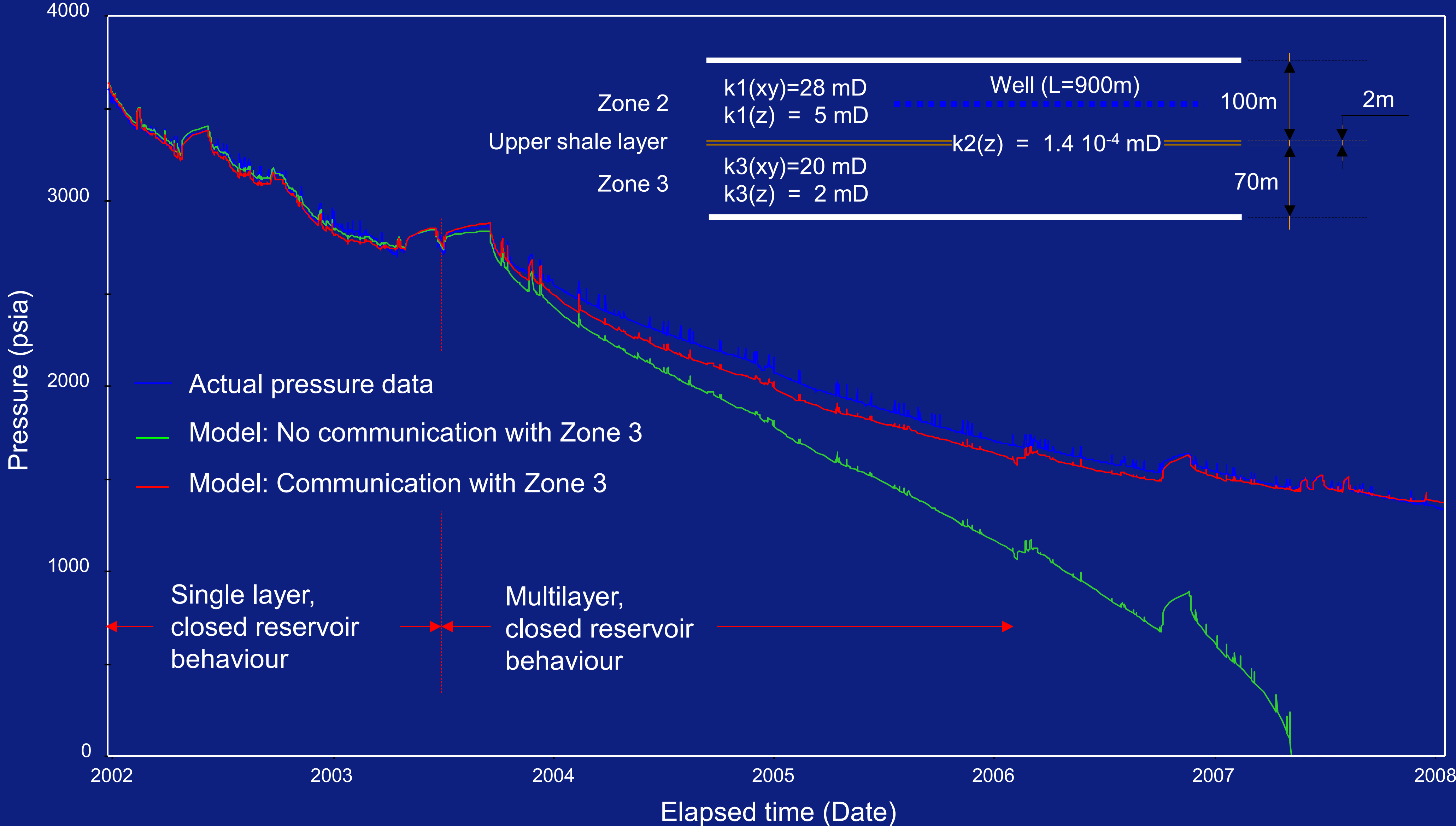
Adapted rates vs. actual



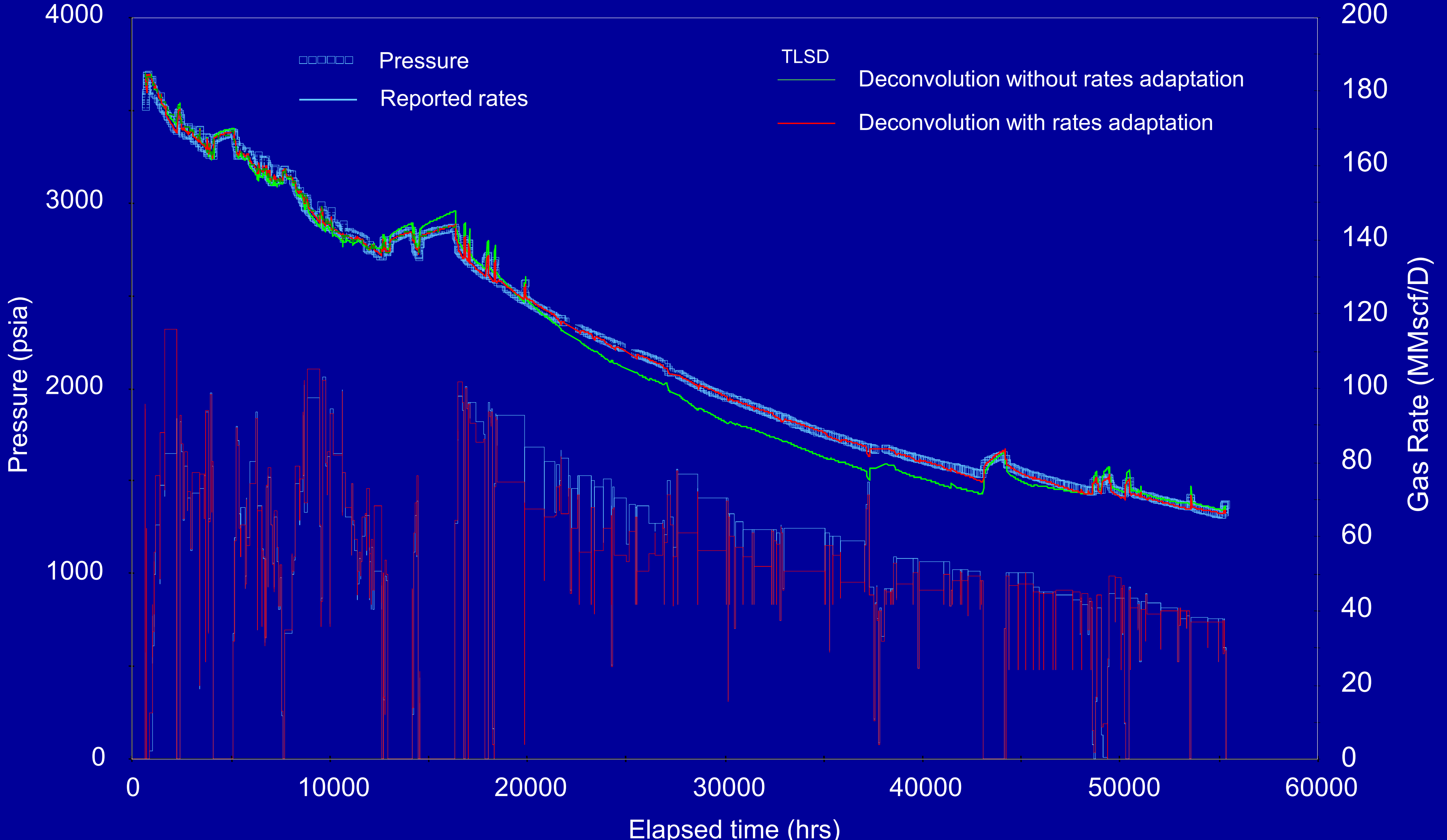
Deconvolution multilayer analysis



Simulation of pressure history



Example 2: Verification of deconvolution: Pressure history match and Reported vs. adapted rates



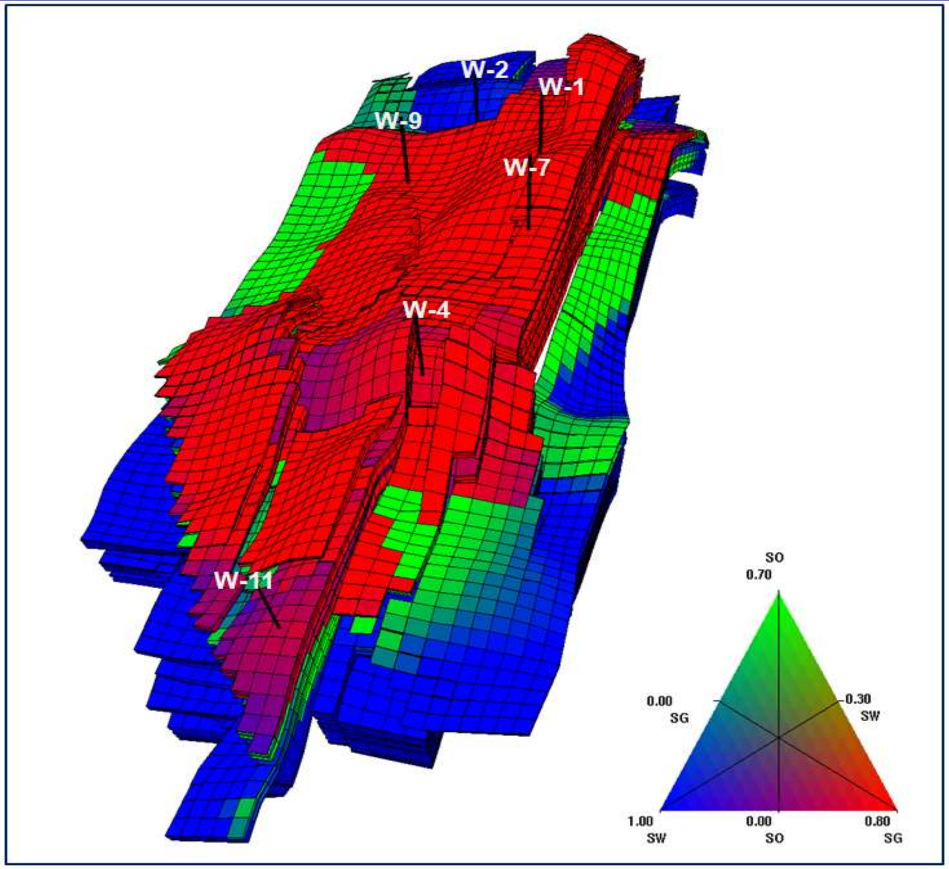
Field Example

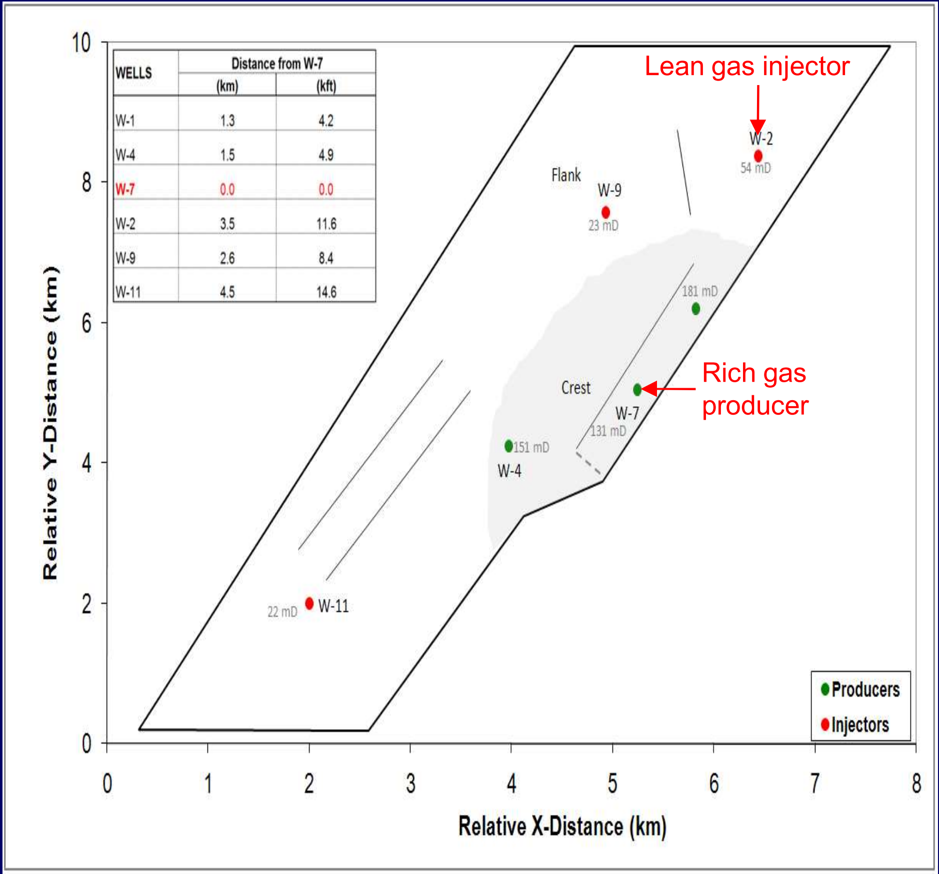
MTGc Reservoir – Algeria

Rich Gas Condensate

MTGc Rich Gas Condensate Reservoir

North Africa

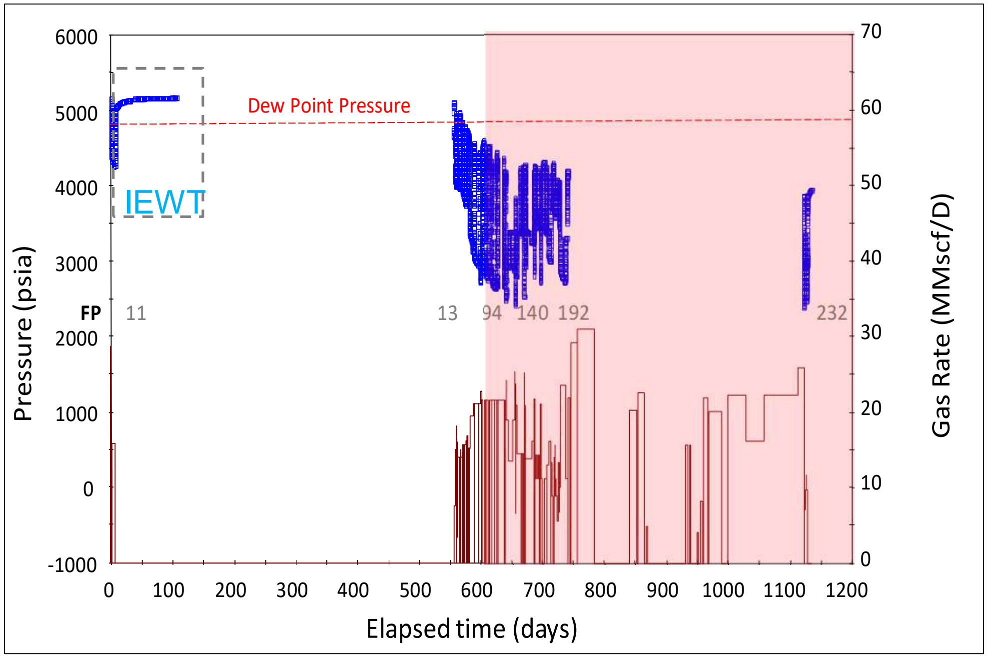




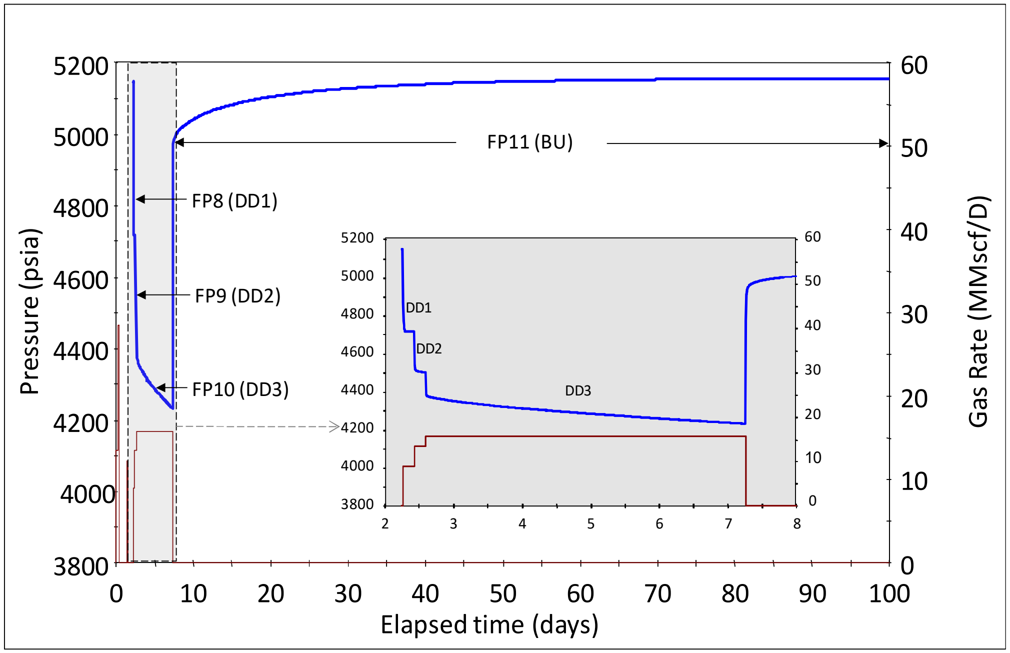
WELLS	Distance from W-7	
	(km)	(kft)
W-1	1.3	4.2
W-4	1.5	4.9
W-7	0.0	0.0
W-2	3.5	11.6
W-9	2.6	8.4
W-11	4.5	14.6

Well W-7 Pressure Rate History

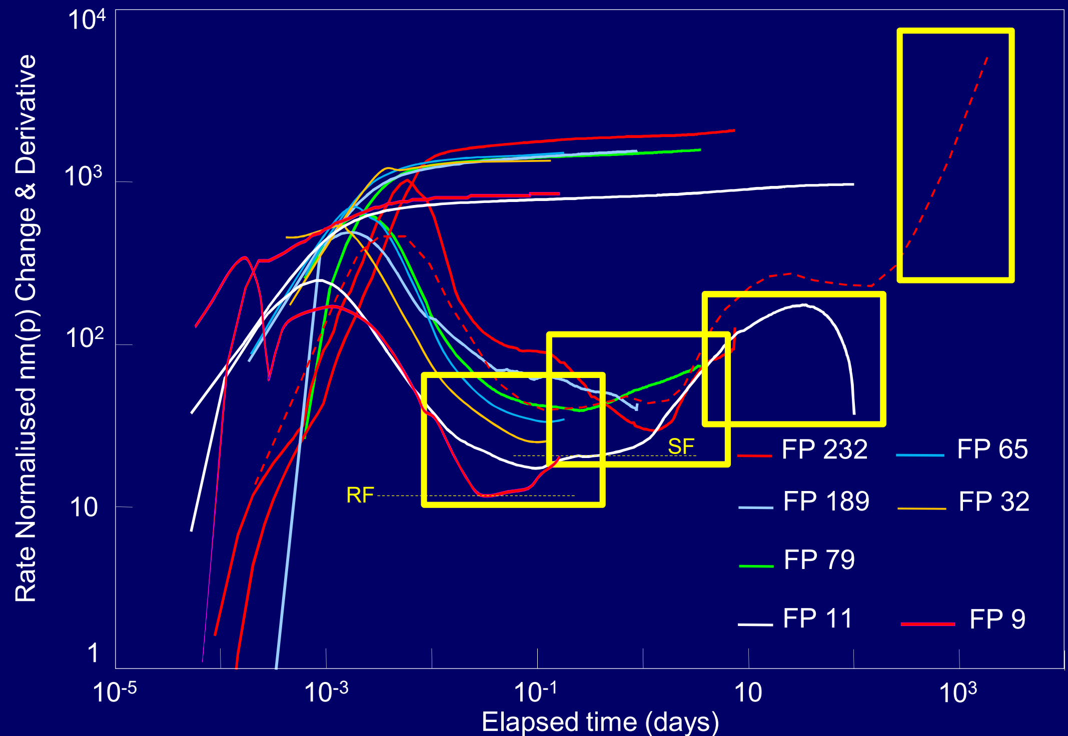
Entire Rate & Pressure History

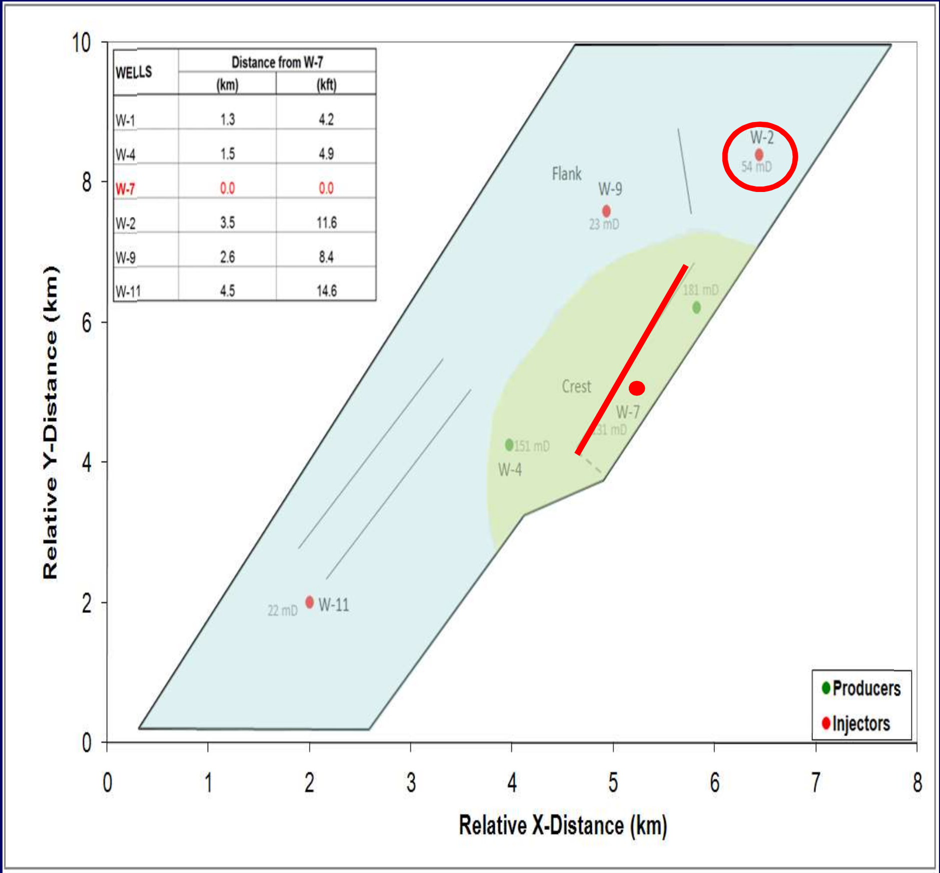


Initial Extended Well Test – IEWT



Pressure Change & Derivative Diagnosis





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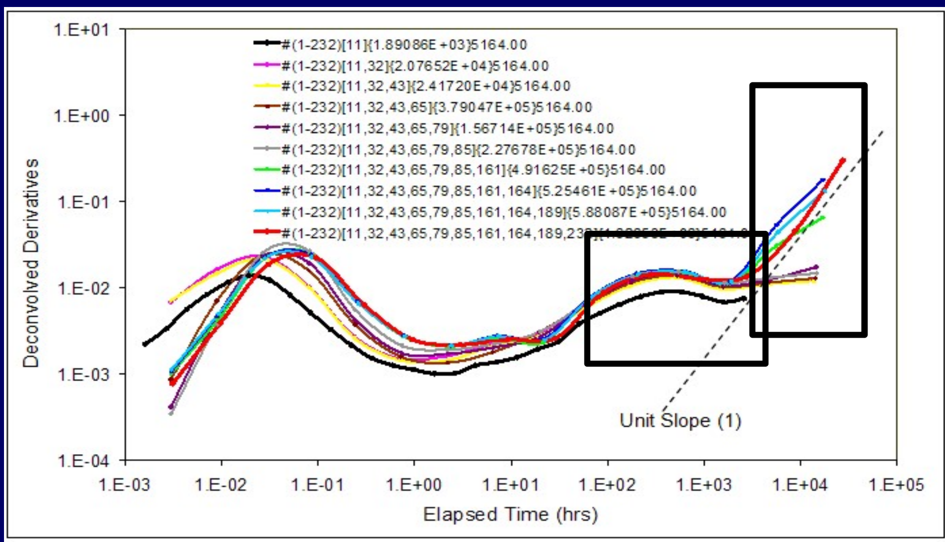
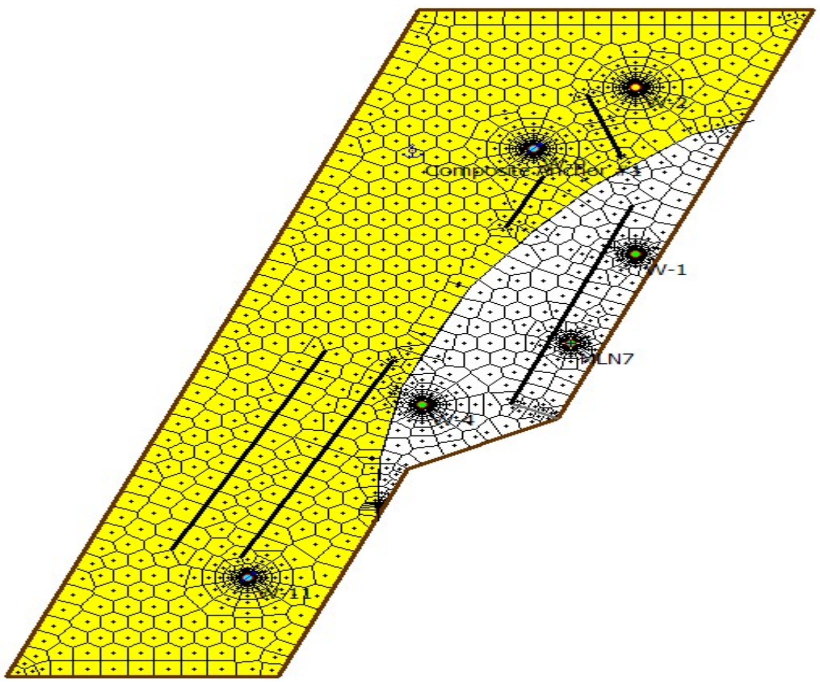
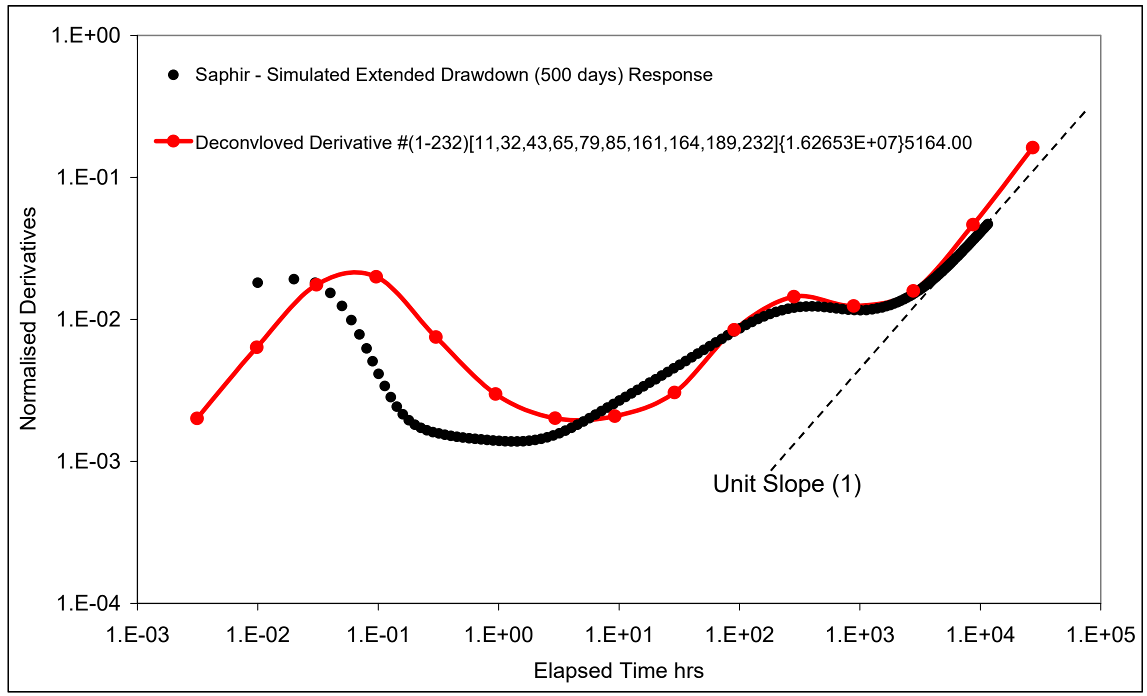


Comparison of Deconvolved Derivative and Simulated DD Saphir (Voronoi) Response





Saphir DD derivative matches the deconvolved derivative &confirms the composite behaviour due to reduced K away from the well, followed by a closed system response

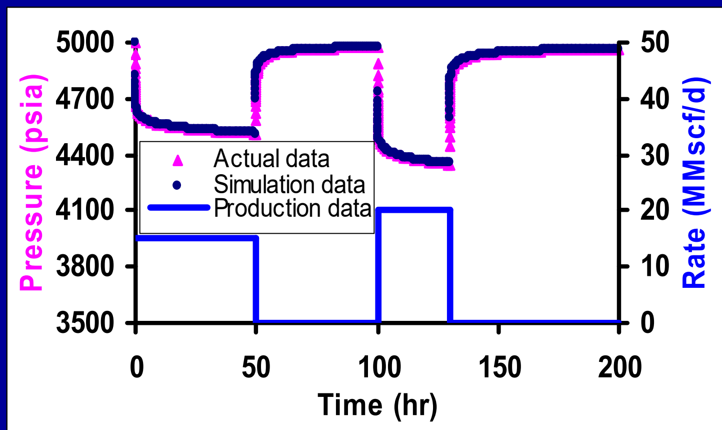
Summary of deconvolution practical use

- **Powerful well test interpretation tool**
  - Increase of radius of investigation (well vs. flow period)
  - Identification of most probable behaviours
  - Correction of rates

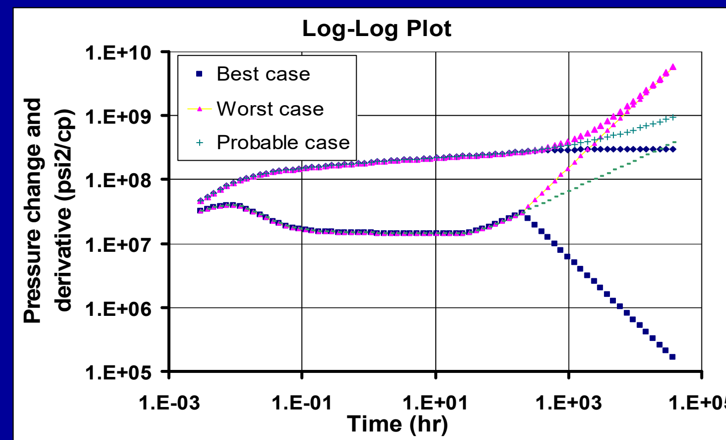
- **Requires user's know how, like any other interpretation method**

SPE 122299
Well Production Forecasting
by Extrapolation of the Deconvolution of Well Test Pressure Transients

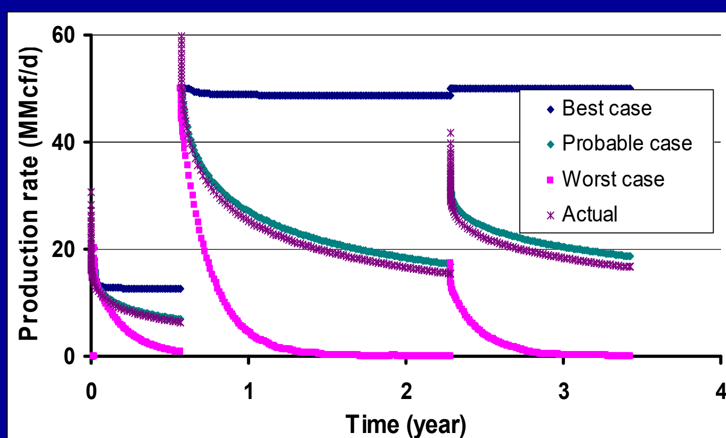
Tim M Whittle, Hui Jiang, Stuart Robert Young and Alain C. Gringarten



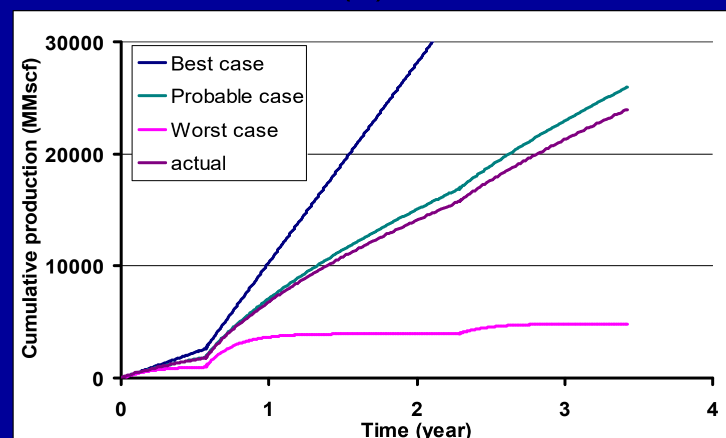
(a)



(b)

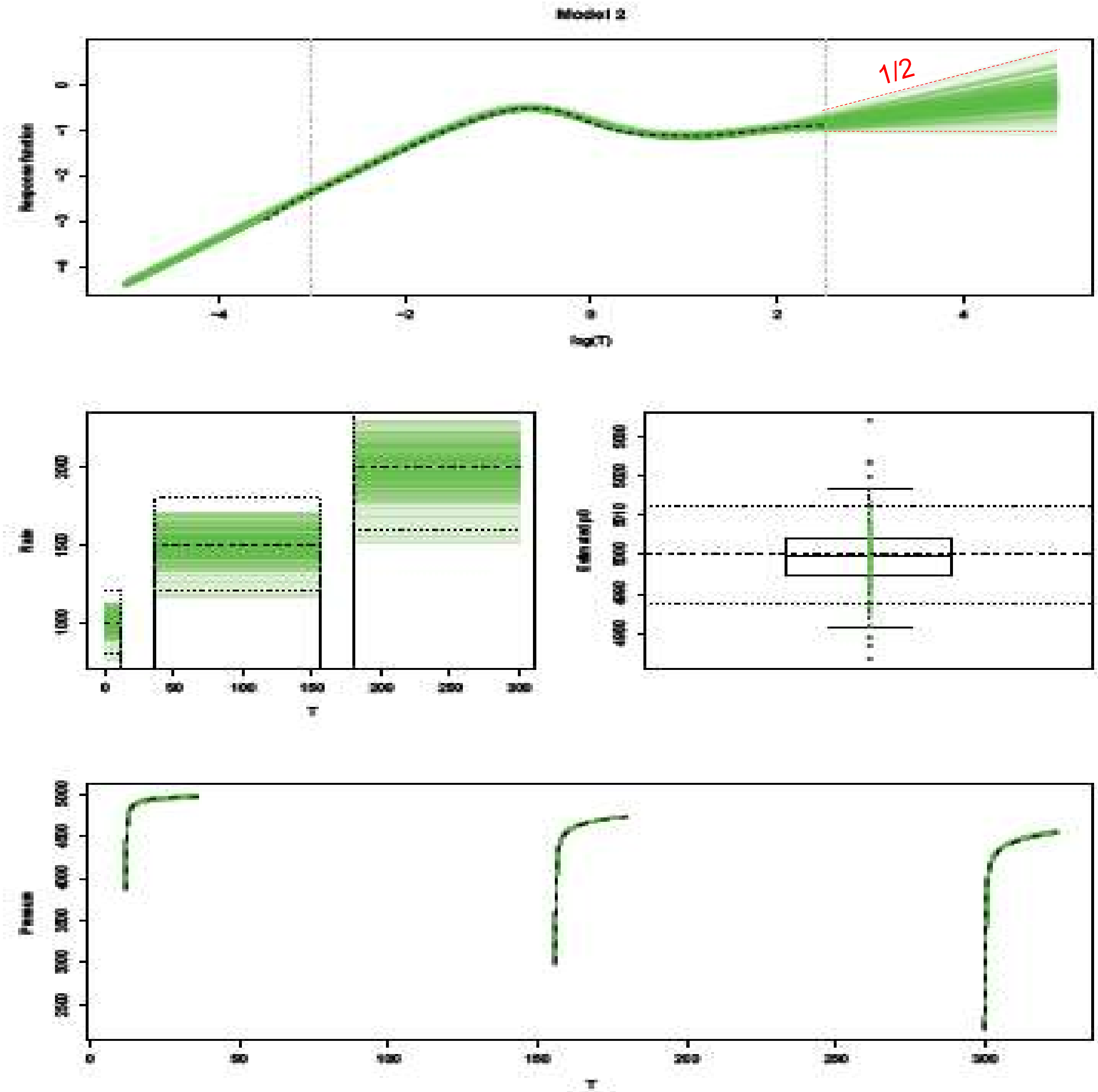


(c)

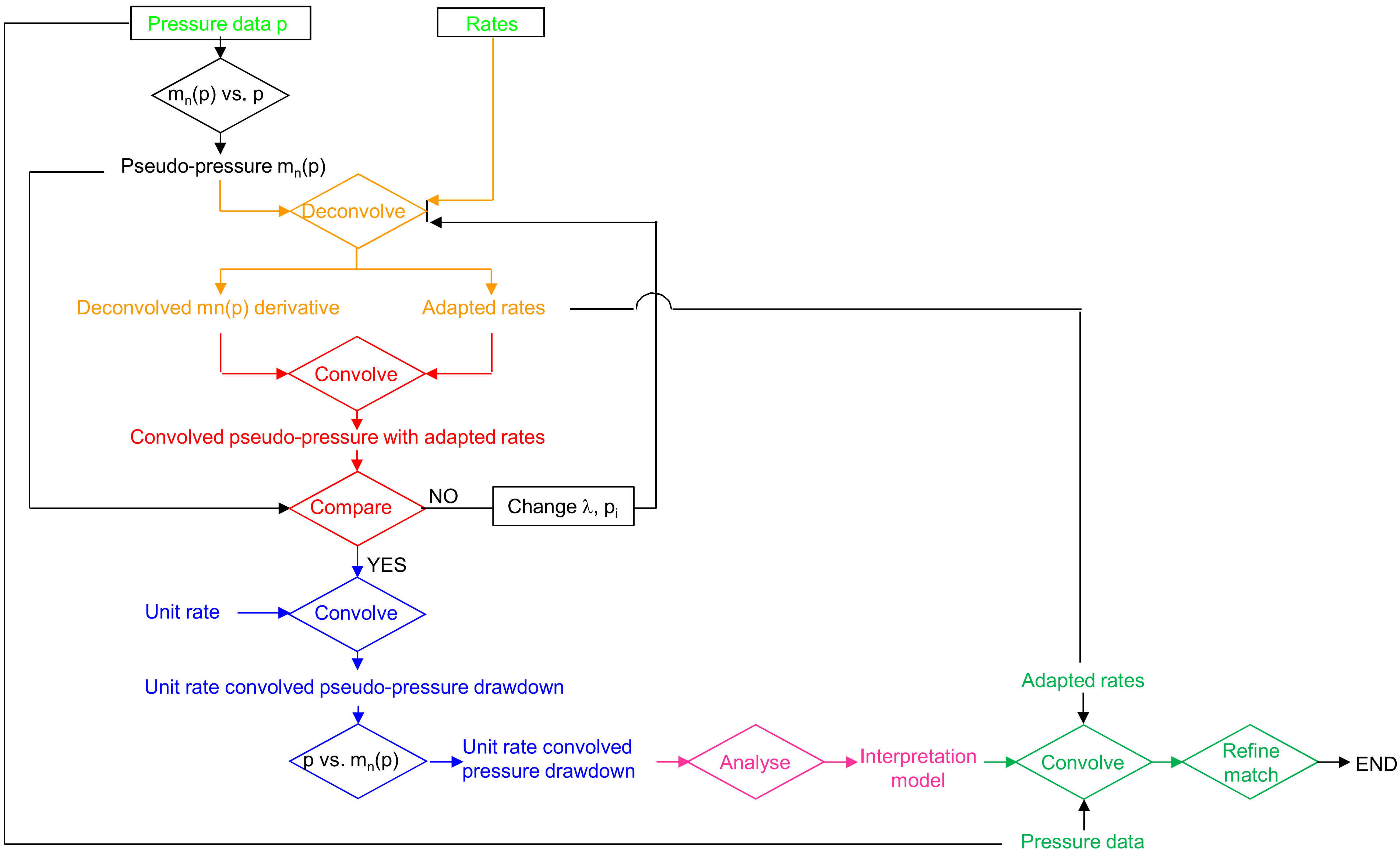


(d)

Uncertainties in deconvolution



INTERPRETATION METHODOLOGY USING DECONVOLUTION



DECONVOLUTION IN PREVAILING COMMERCIAL SOFTWARES

	TLSD Imperial Restricted to MSc, WTA PhD and JIP sponsors	Interpret Paradigm	Saphir Kappa	PIE Well Test Solutions	PanSystems EPS Weatherford	FAST Fekete IHS
Algorithm	von Schroeter, Hollaender and Gringarten, SPE 71574, ATCE, New Orleans, Sept 2001					
Implementation	Unit slope at early times	TLSD	?	No unit slope at early times	TLSD	?
Parameters	ν, λ	TLSD	?	Pressure gauge resolution	TLSD	ω, ν, λ
Methods As labelled in Saphir	*Von Schroeter*: Any or all FP	TLSD	*Kappa*: One BU and last points of other BUs	*Levitan*: p_i from deconvolving individual BUs No Q adaptation	TLSD	TLSD

Well test analysis: what's next

Value tied to power in Identification and Verification

	ANALYSIS METHOD	IDENTIFICATION	VERIFICATION
50's	Straight lines	Poor	None
70's	Pressure Type Curves	Fair (limited)	Fair to Good
80's	Pressure Derivative	Very Good	Very Good
00's	Deconvolution	Much better	Same as derivative
Next	?	>>>	>>>

Well test analysis: what's next

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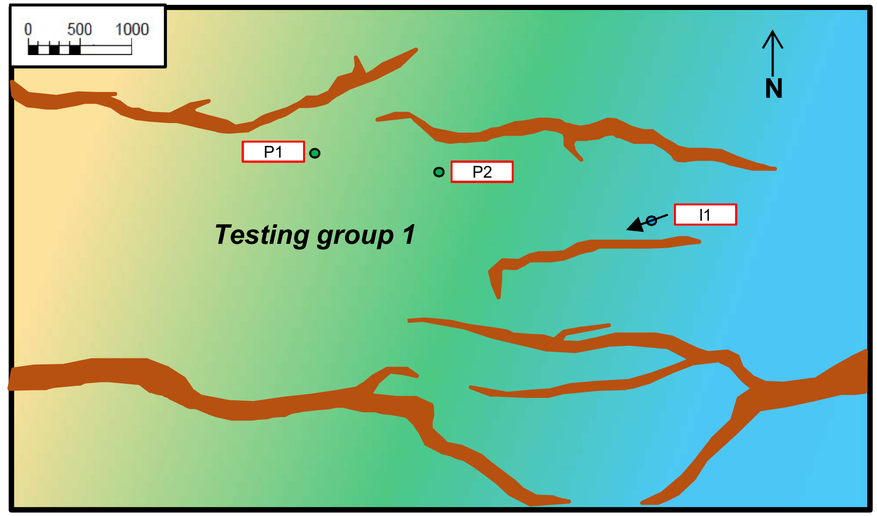
80's	Pressure Derivative	Very Good	Very Good
00's	Deconvolution	Much better	Same as derivative
Next	Multiwell deconvolution	>>>	>>>

EXAMPLE OF MULTIWELL DECONVOLUTION

nexen
A CNOOC LIMITED COMPANY

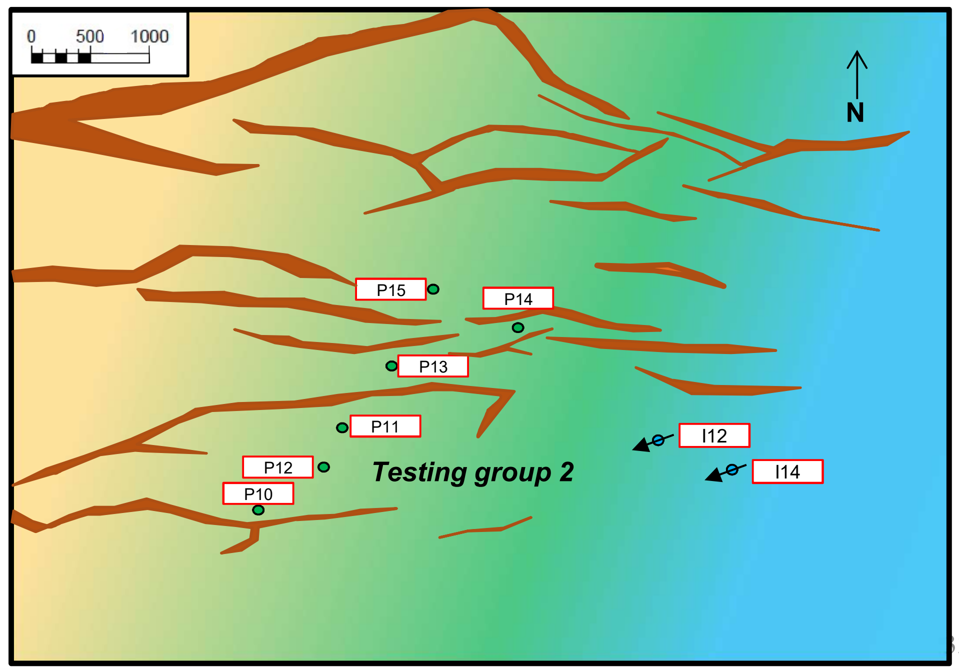
DATA

- North Sea oilfield which has just completed a long initial drilling campaign.
- Regular well test analysis has been affected by:
  - Interference
  - Short buildups



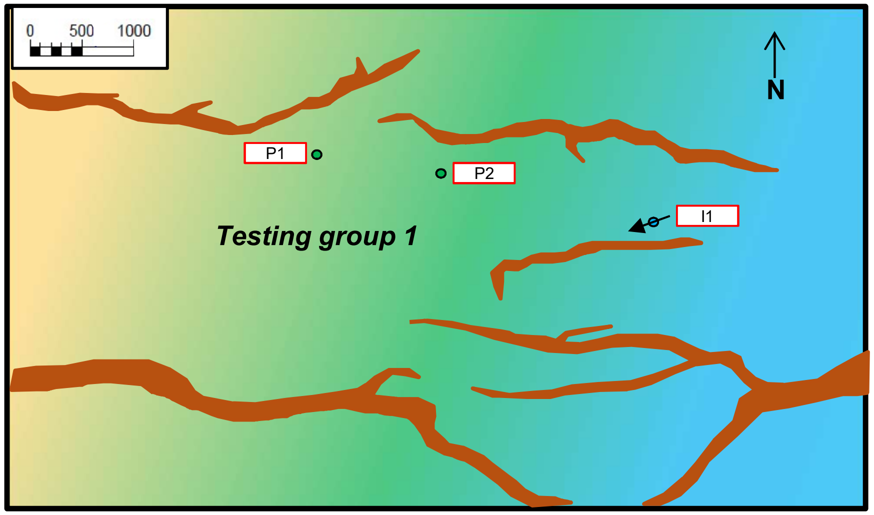
AIMS

1. Perform multiwell deconvolution on two groups of interfering wells within the field.
2. Use the results from multiwell deconvolution to understand the location of faults in the field.
3. Assess the reliability and practicality of the algorithm.
4. Suggest a methodology to apply multi-well deconvolution to interfering wells.

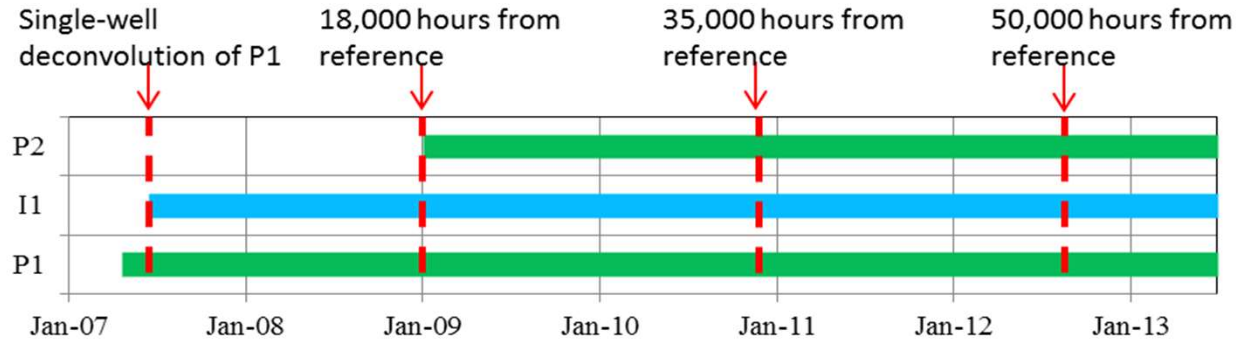


GROUP 1

- Two producers and one injector
- Deconvolutions run on various sections of the dataset:
  - 0 to 4700 hours
  - 0 to 18000 hours
  - 0 to 35000 hours
  - 0 to 50000 hours

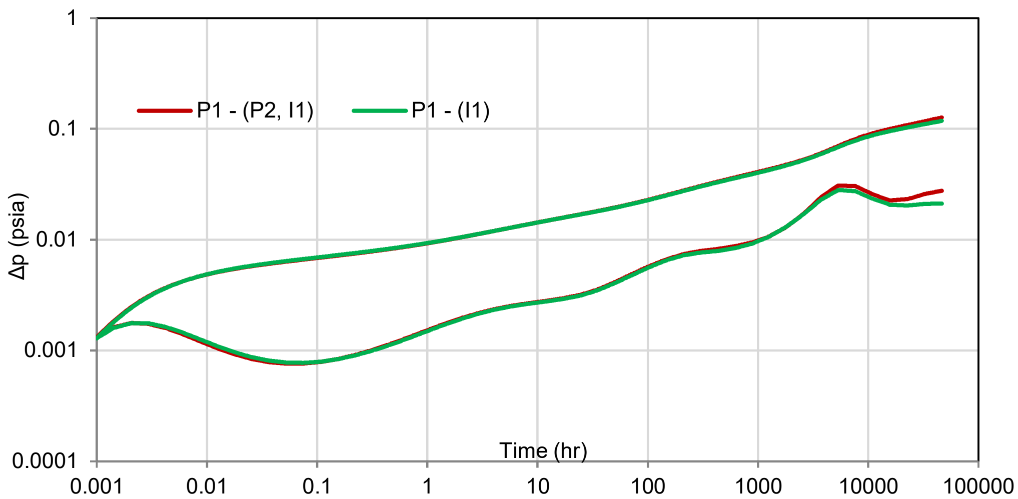


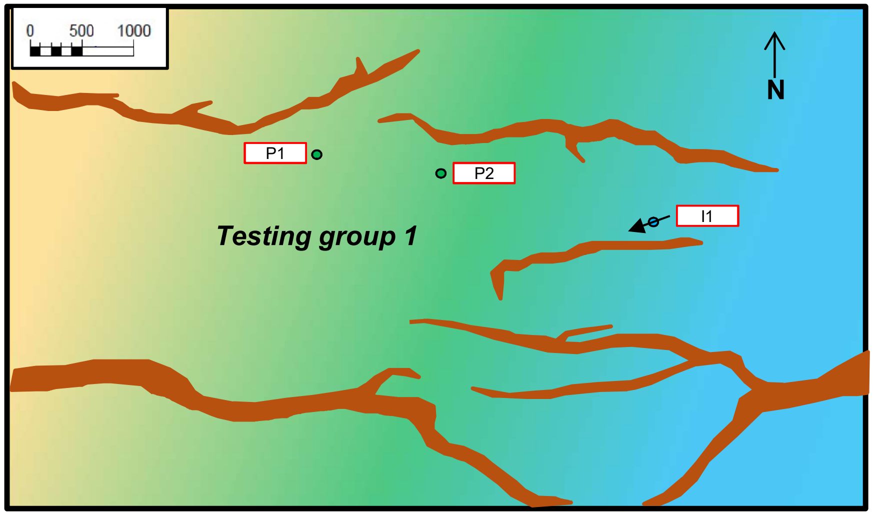
- Multiwell deconvolutions were run with all 3 wells included in the algorithm.
- Secondary deconvolutions were run with 1 well at a time excluded from the algorithm.



MULTIWELL DECONVOLUTION RESULTS FOR GROUP 1

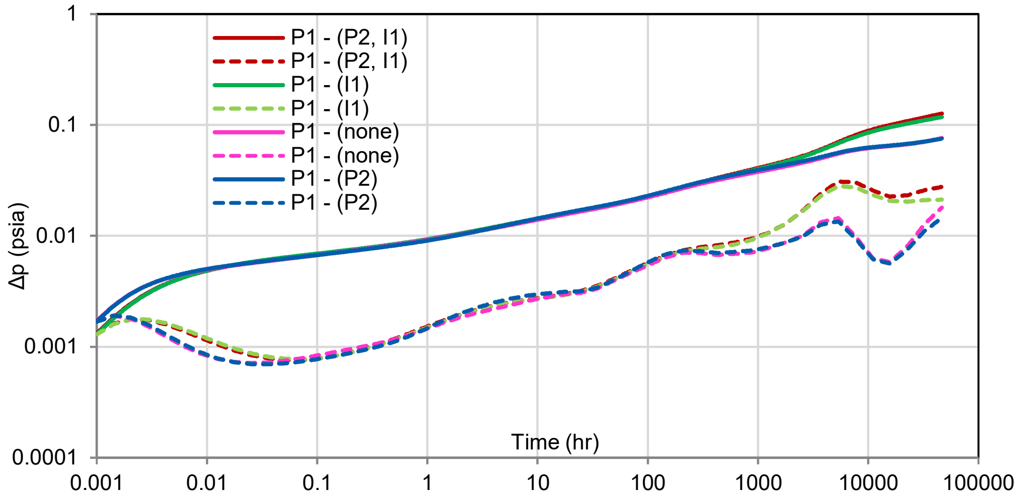
1. The P1 deconvolution with only I1 interference removed is very similar to the deconvolution with I1 and P2 interference removed

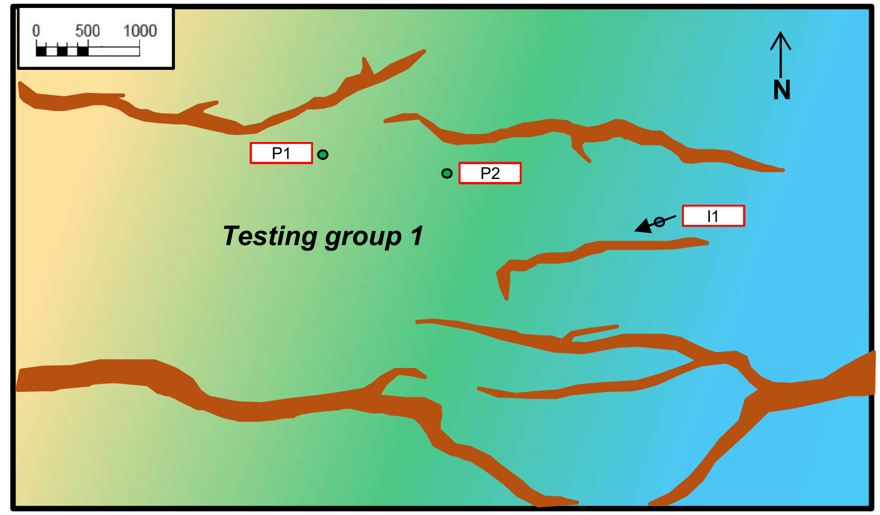




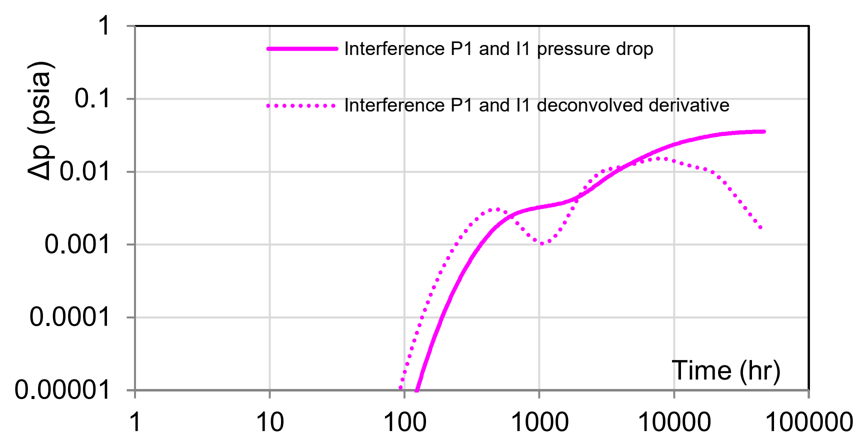
MULTIWELL DECONVOLUTION RESULTS FOR GROUP 1

1. The P1 deconvolution with only I1 interference removed is very similar to the deconvolution with I1 and P2 interference removed
2. The P1 deconvolution with no interference removed is similar to the deconvolution with only P2 interference removed.



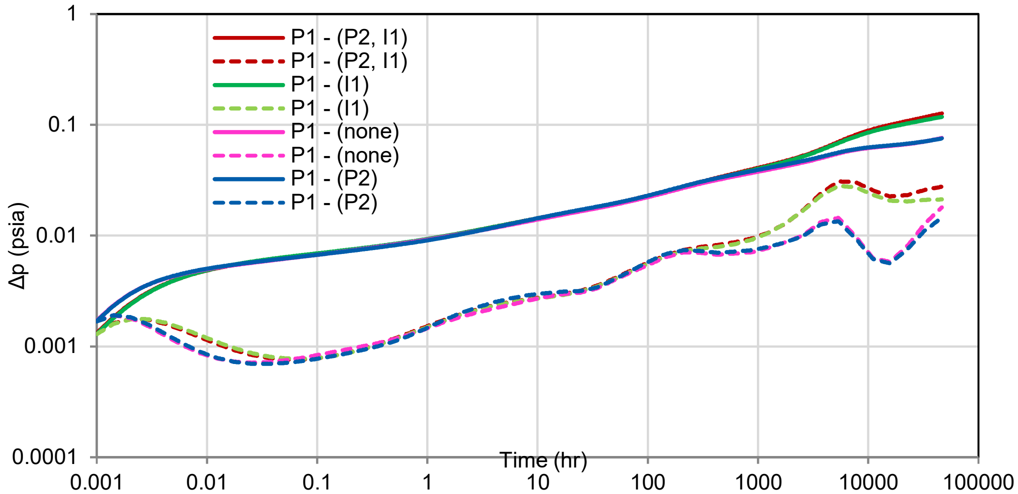


3. Interference of P2 on P1 occurs much later than interference of I1 on P1.



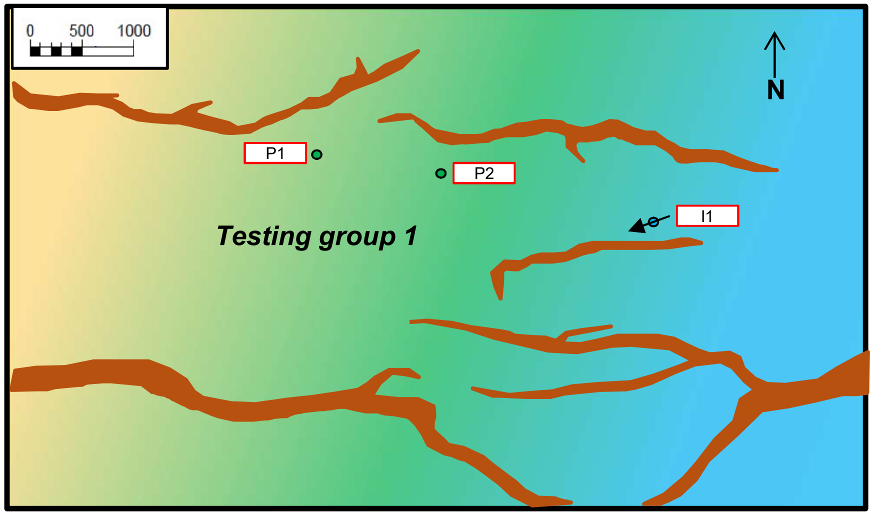
MULTIWELL DECONVOLUTION RESULTS FOR GROUP 1

1. The P1 deconvolution with only I1 interference removed is very similar to the deconvolution with I1 and P2 interference removed
2. The P1 deconvolution with no interference removed is similar to the deconvolution with only P2 interference removed.



- Conclusion: Limited communication between P1/P2.

(This is consistent with current reservoir simulation models have included a semi-sealing baffle to flow between P1/P2)



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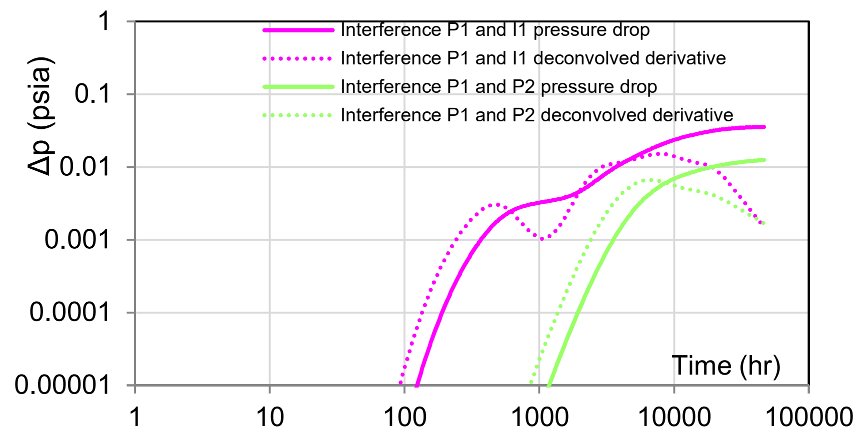
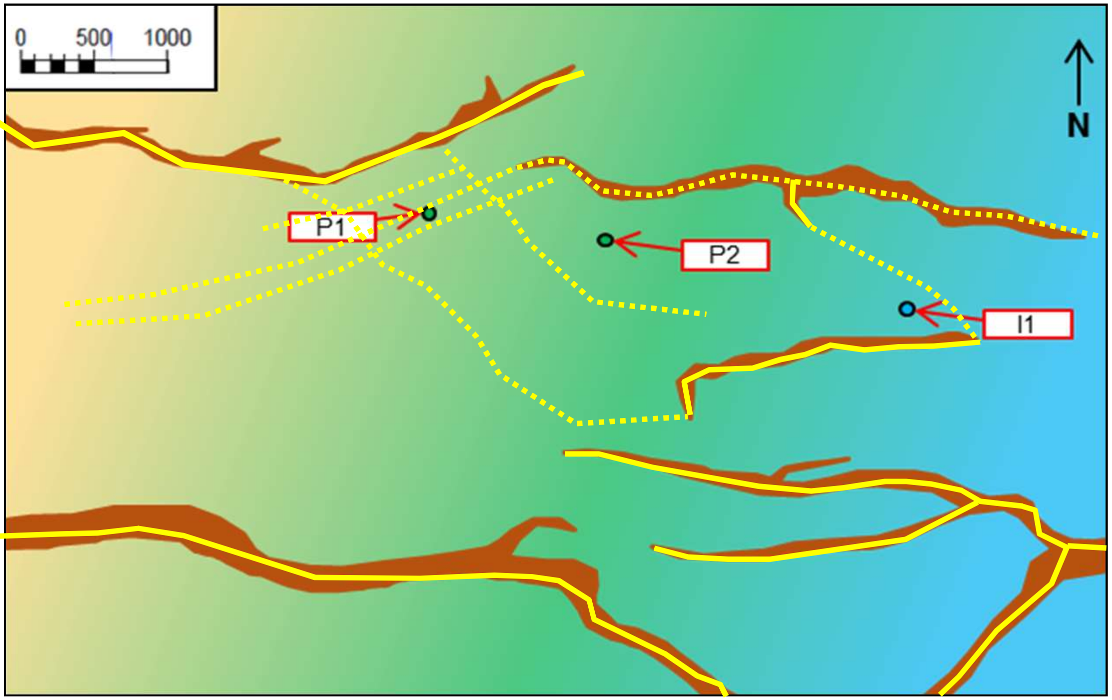
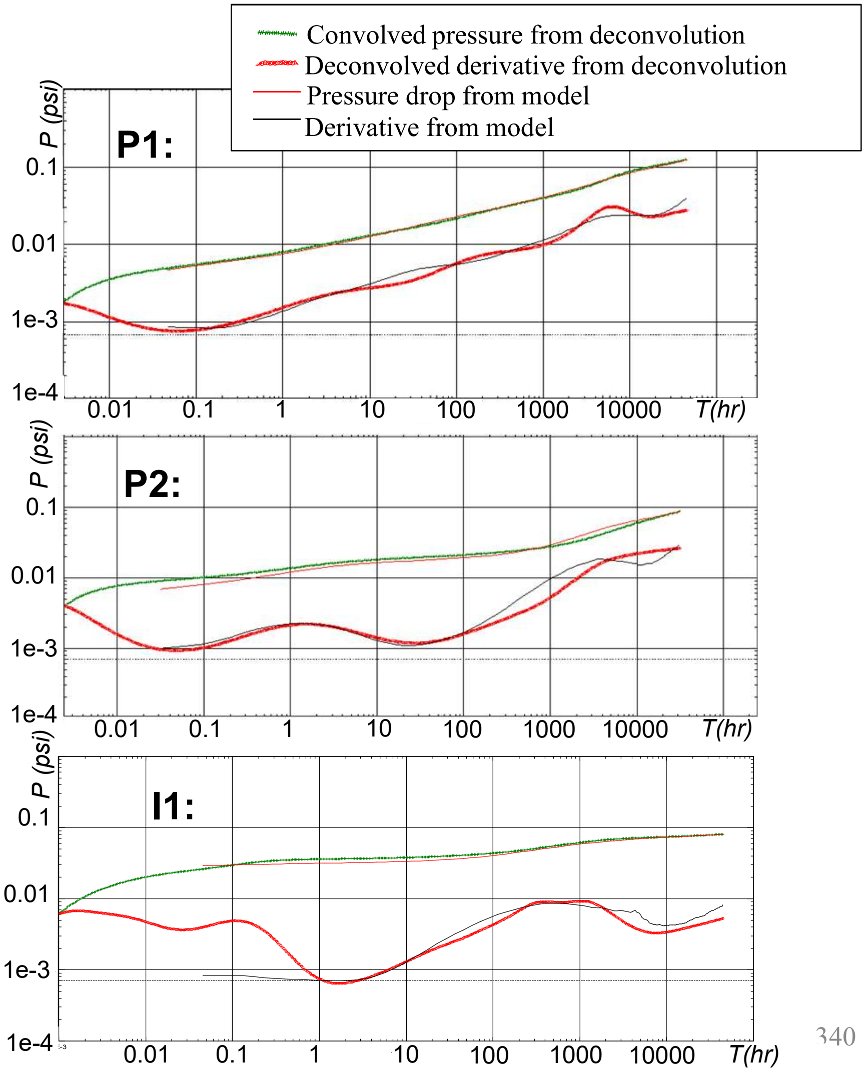


ANALYSIS OF GROUP 1 MULTIWELL DECONVOLUTION RESULTS

The final deconvolved data for wells P1, P2 and I1 were modelled numerically.

- The boundaries of the system were initially from faults observed in seismic.
- Leakage of faults was adjusted.
- Extra baffles to flow added.





Matching yields k and skin values.

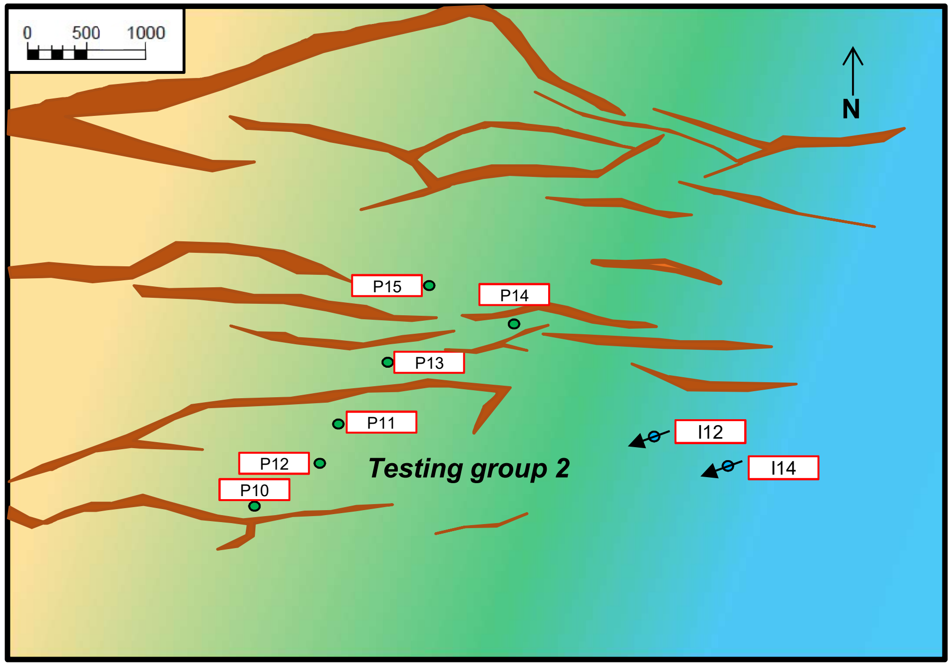
GROUP 2

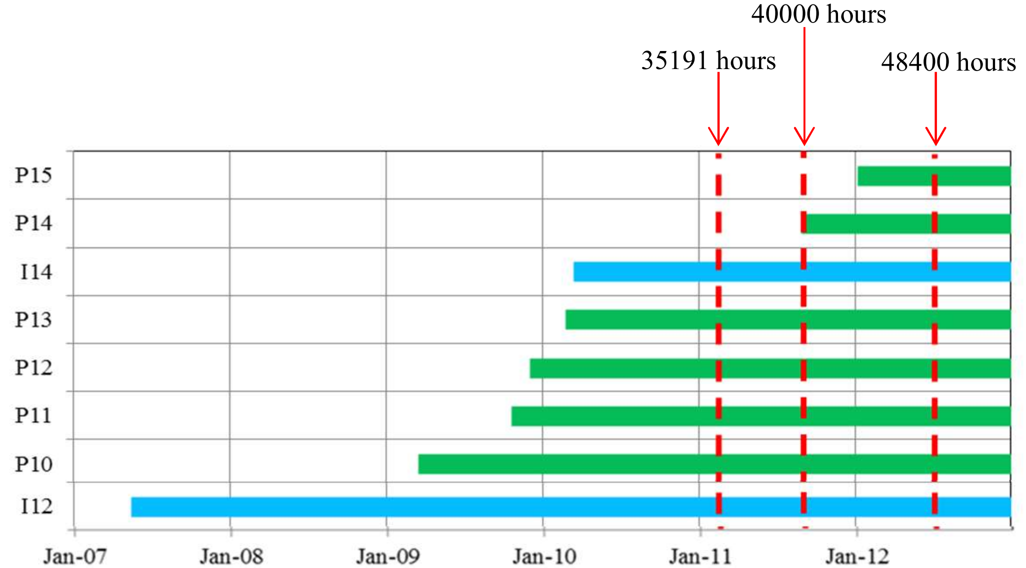
Six interfering producers and two injectors.

- Multiwell deconvolution was performed on every well
- Other wells were added to the deconvolution one-by-one
- P13 example:

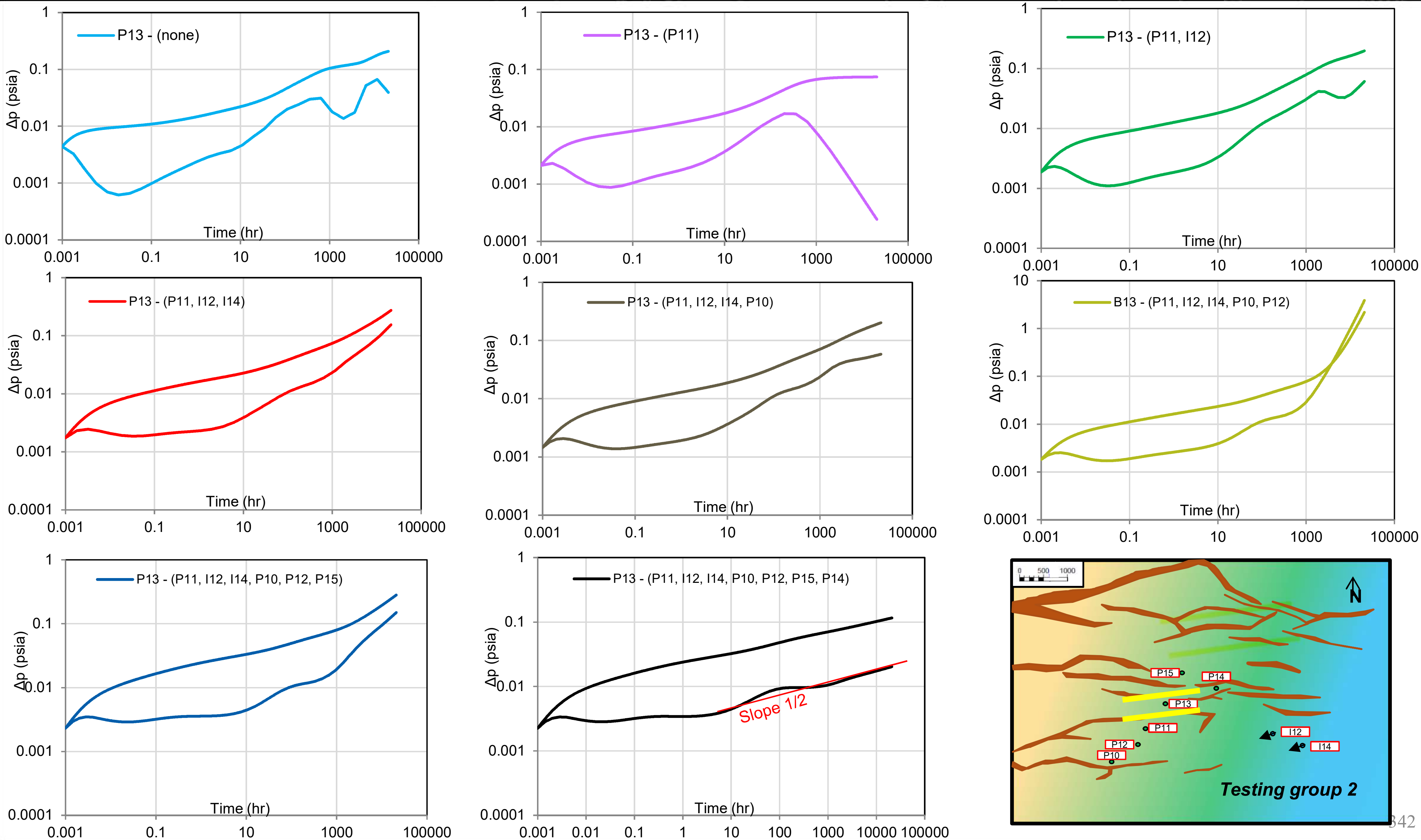
Various sections of dataset were deconvolved:

- 0 to 35191 hours
- 0 to 40000 hours
- 0 to 48400 hours





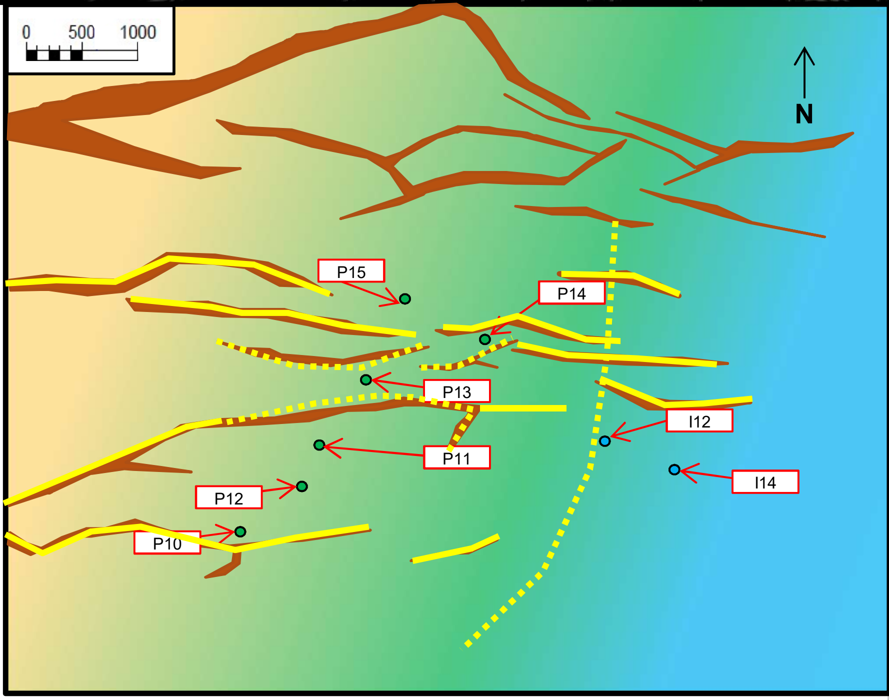
MULTIWELL DECONVOLUTION RESULTS FOR GROUP 2



ANALYSIS OF GROUP 2 MULTIWELL DECONVOLUTION RESULTS

The final deconvolved data for Group 2 wells were modelled numerically.

- The boundaries of the system were initially from faults observed in seismic.
- Leakage of faults was adjusted.
- Extra fault and baffles added.



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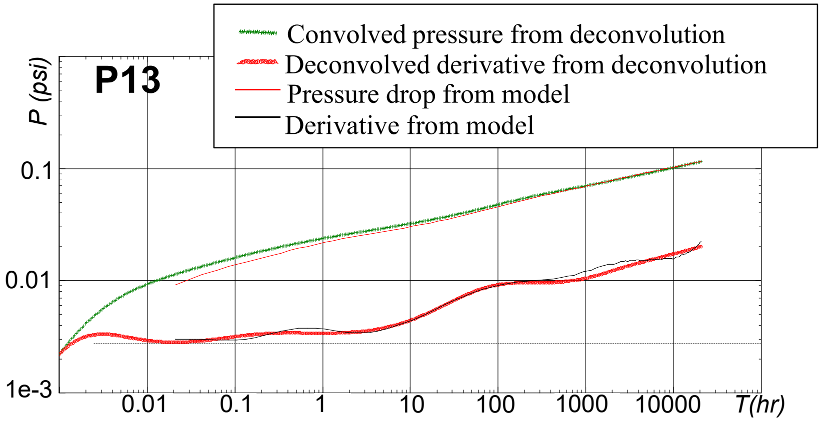
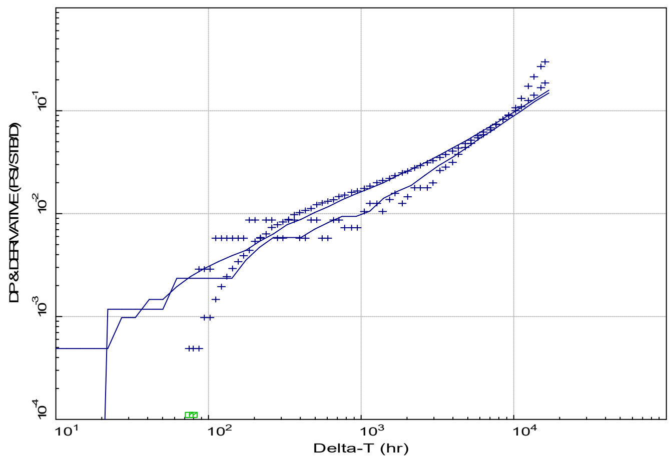
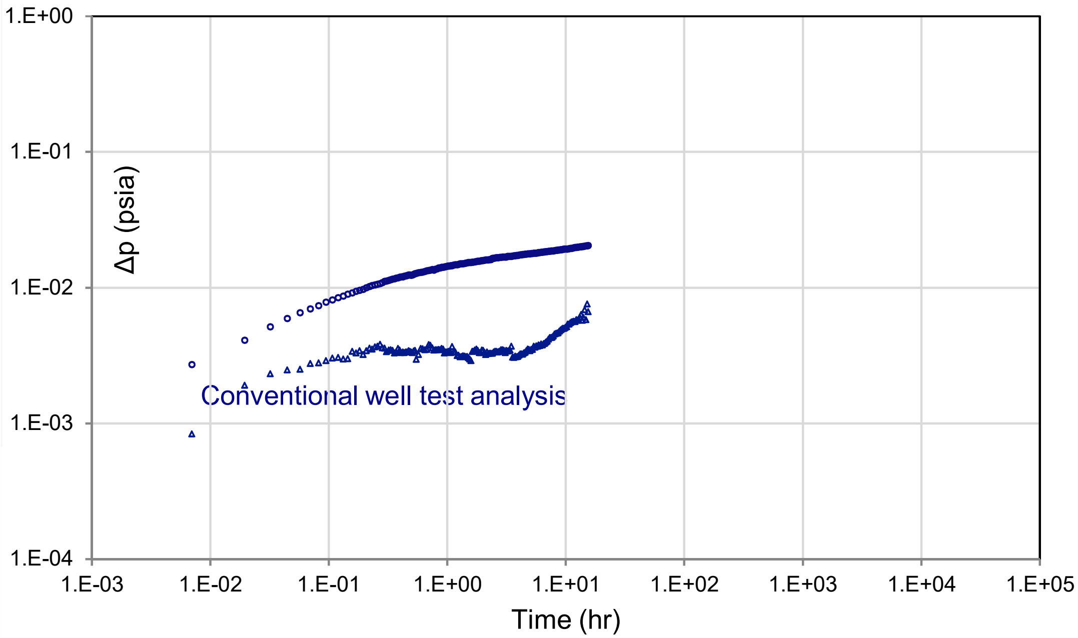


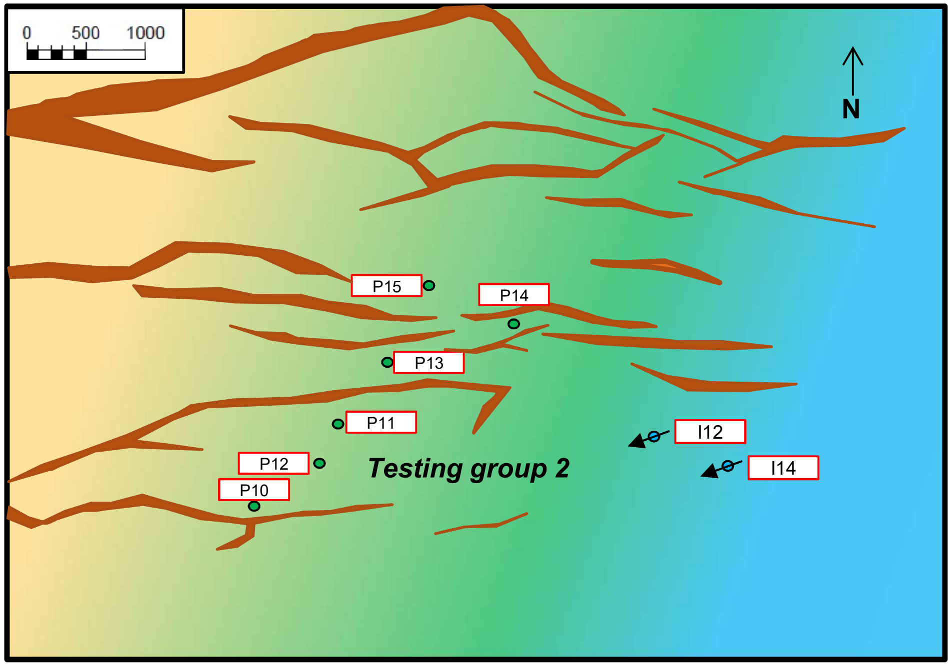


Interference of P10 on P13 yields storativity $\phi c_t h$ between P13 and P10

SPE 174353 Thornton *et al.*, Europec Madrid June 2015

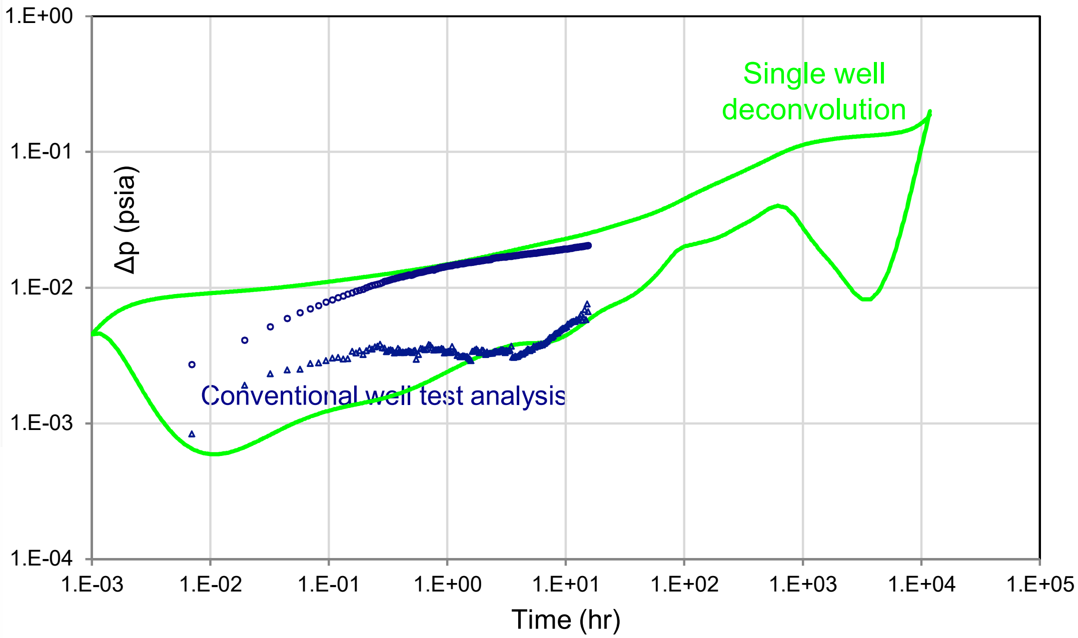
BENEFITS OF MULTIWELL DECONVOLUTION

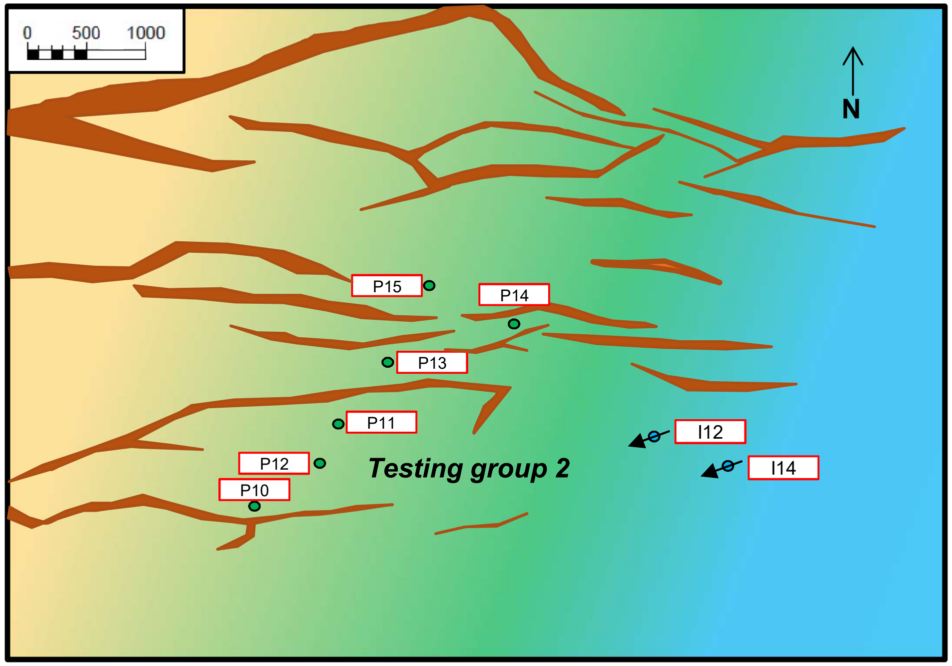




- Conventional well test analysis provides limited information

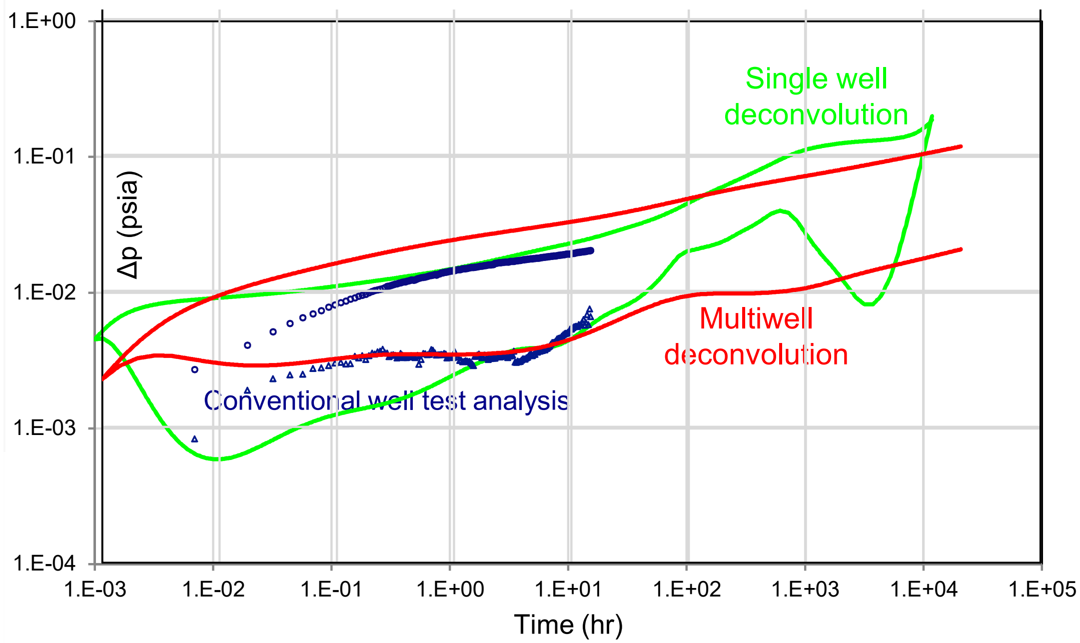
BENEFITS OF MULTIWELL DECONVOLUTION

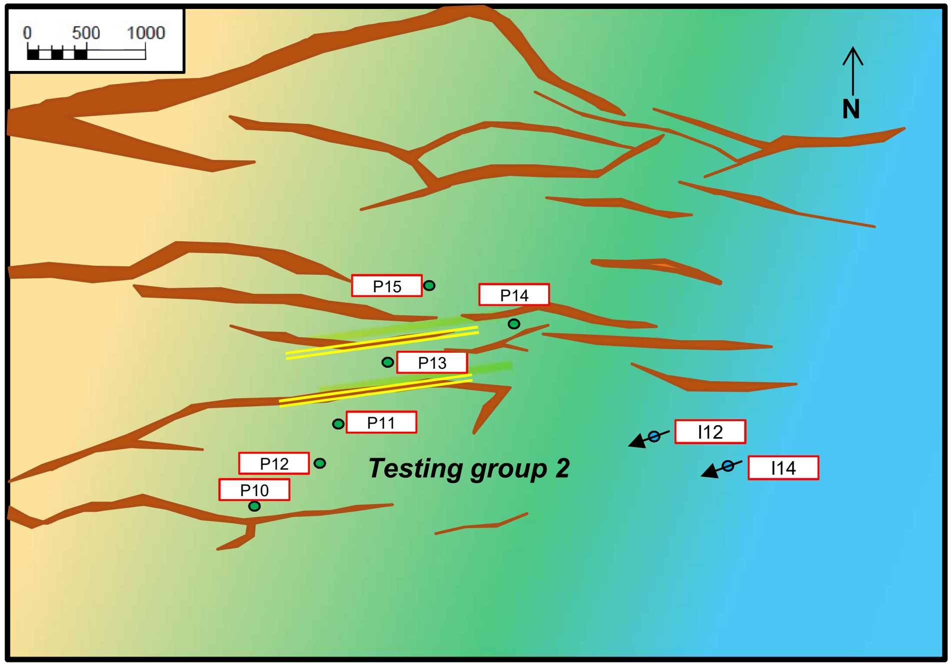




- Conventional well test analysis provides limited information
- Deconvolution accesses the true zone of investigation
- Single-well deconvolution can be distorted by interference

BENEFITS OF MULTIWELL DECONVOLUTION





- Conventional well test analysis provides limited information
- Deconvolution accesses the true zone of investigation
- Single-well deconvolution can be distorted by interference
- Only multiwell deconvolution provides a reliable derivative representing the geology

PRINCIPLES OF WELL TEST ANALYSIS

WELL TEST ANALYSIS CONSISTS OF:

- WELL TEST INTERPRETATION MODEL **IDENTIFICATION**
- WELL TEST INTERPRETATION MODEL **VERIFICATION**

PRINCIPLES OF WELL TEST ANALYSIS

MODEL IDENTIFICATION

- ❑ is a pattern recognition, inverse problem:
  - ❑ given the data (well test and others),
  - ❑ knowing characteristic shapes created by well defined flow regimes,
  - ❑ identify which flow regimes could create this type of test data

PRINCIPLES OF WELL TEST ANALYSIS

MODEL IDENTIFICATION

- **pattern recognition does not involve calculations, only shape recognition**

- **Shape recognition is based on characteristic shapes representing the various flow regimes.**

  These shapes are usually available in the literature. They are determined by calculating the behaviour of well defined flow regimes, analytically or numerically (numerical models may be more flexible, but numerical dispersion may hide key flow regime characteristics).

- **test data can only see significant contrasts in mobility and storativity**

PRINCIPLES OF WELL TEST ANALYSIS

MODEL VERIFICATION

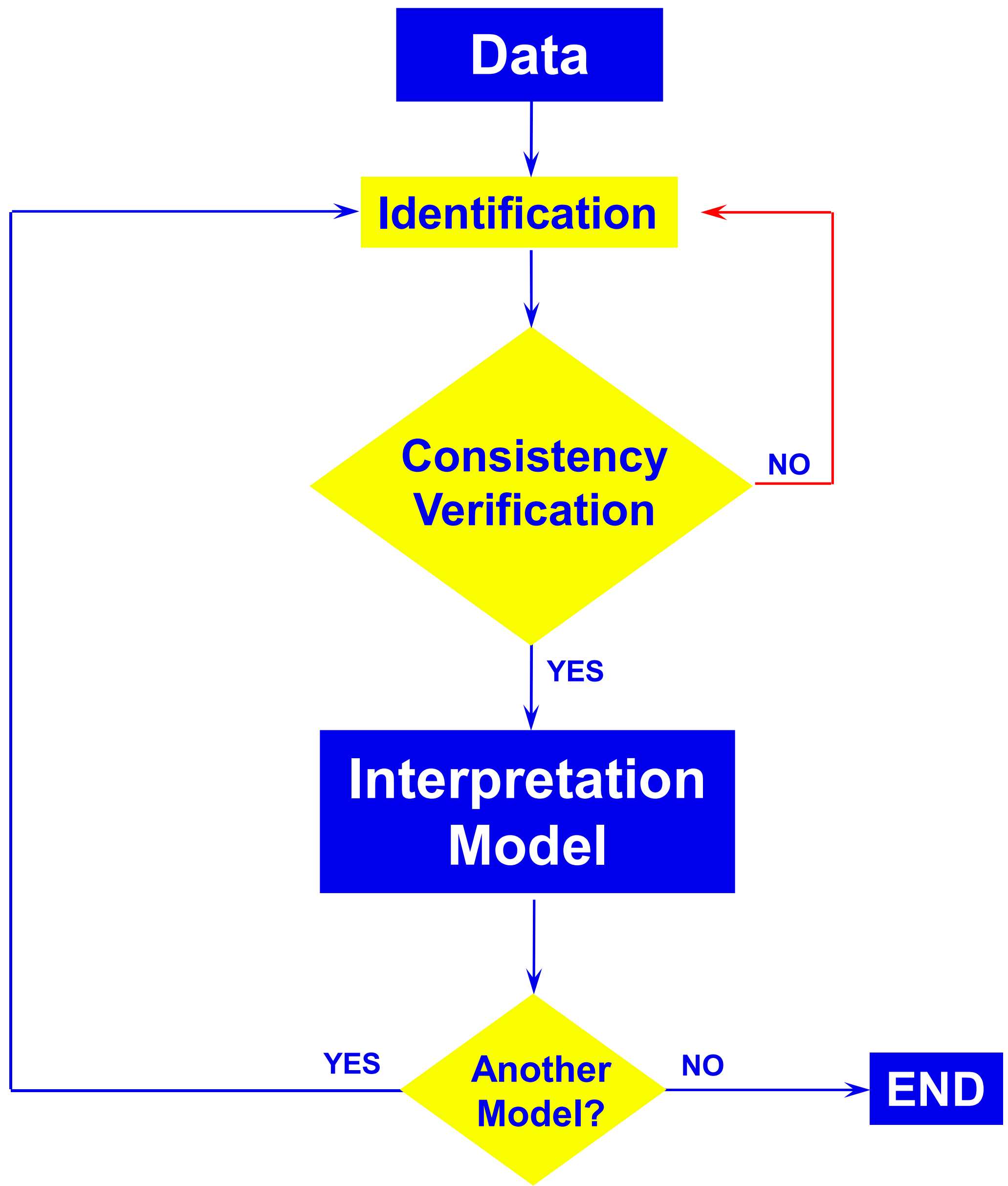
- is a direct problem:
  - given the data (well test and others),
  - given a well test interpretation model,
  - verify that the well test interpretation model is consistent with the data

PRINCIPLES OF WELL TEST ANALYSIS

MODEL VERIFICATION

- **the BEHAVIOUR of the diagnosed interpretation model is compared with the data.**
- **the BEHAVIOUR of the diagnosed interpretation model can be calculated analytically or numerically.**
- **Analytical solutions are usually more practical for simple reservoir shapes.**

INTERPRETATION PROCESS



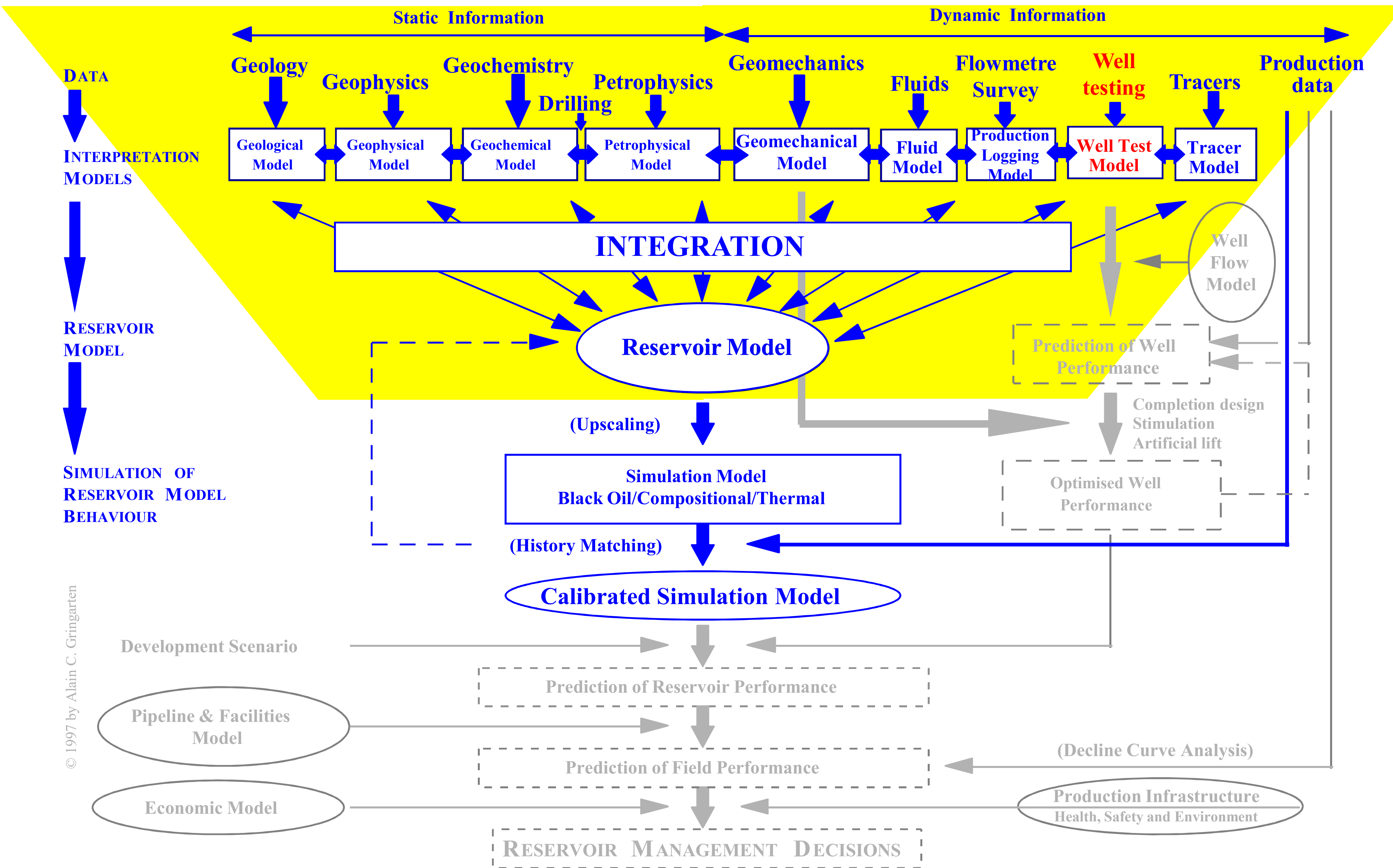
NUMERICAL WELL TEST ANALYSIS

- **Setting-up a numerical model and adjusting property distributions by matching with test data is NOT well test analysis.**

  IT IS SIMULATION

- **It requires the knowledge of the reservoir model, which is obtained through reservoir characterisation.**

RESERVOIR CHARACTERISATION



RESERVOIR CHARACTERISATION

- Once the reservoir model is constructed, one must verify that this reservoir model is consistent with all available information and interpretation models.

  This means that the reservoir model must reproduce:

  - the seismic,
  - logs, etc...,
  - and well tests.

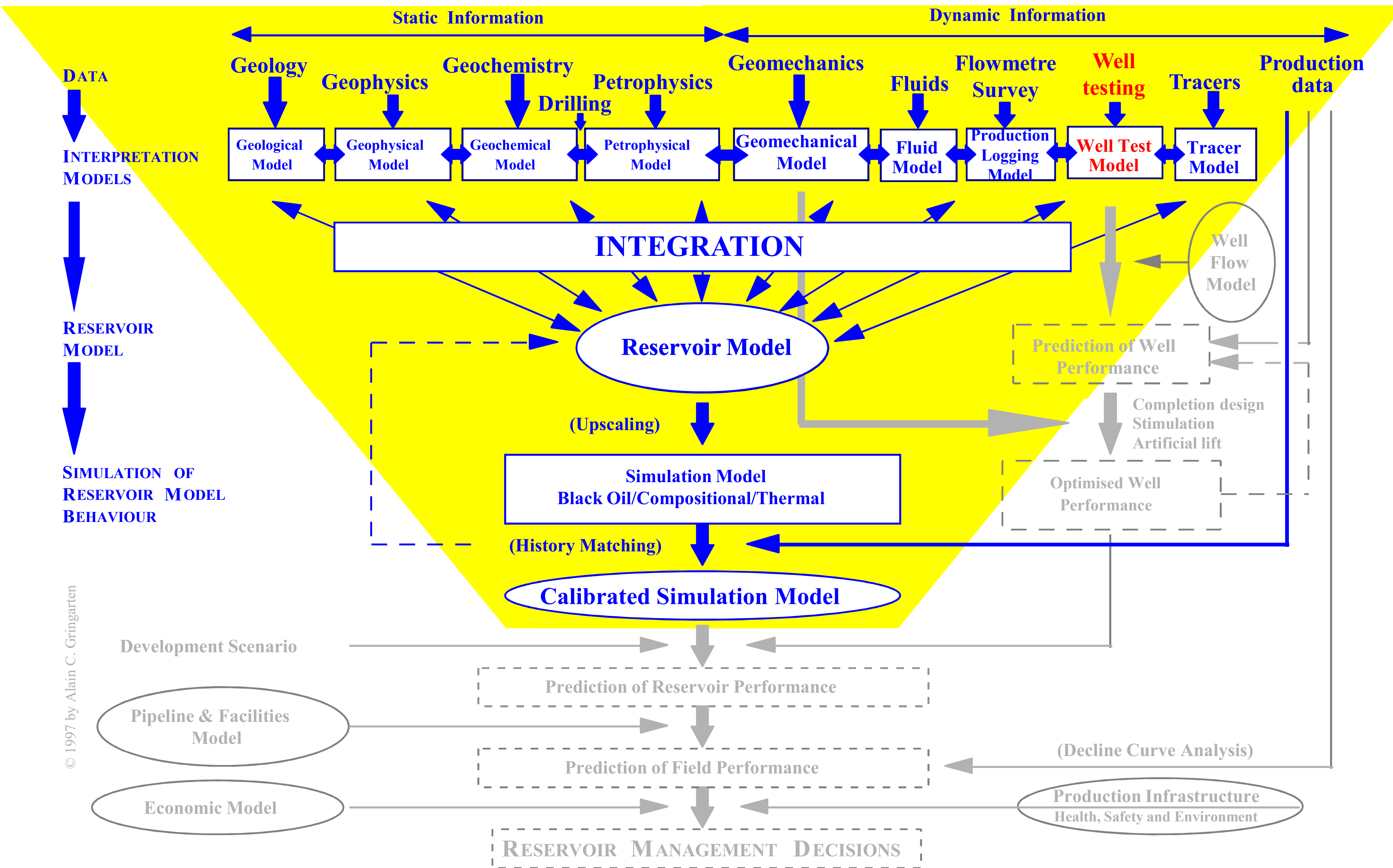
VERIFICATION OF THE RESERVOIR MODEL

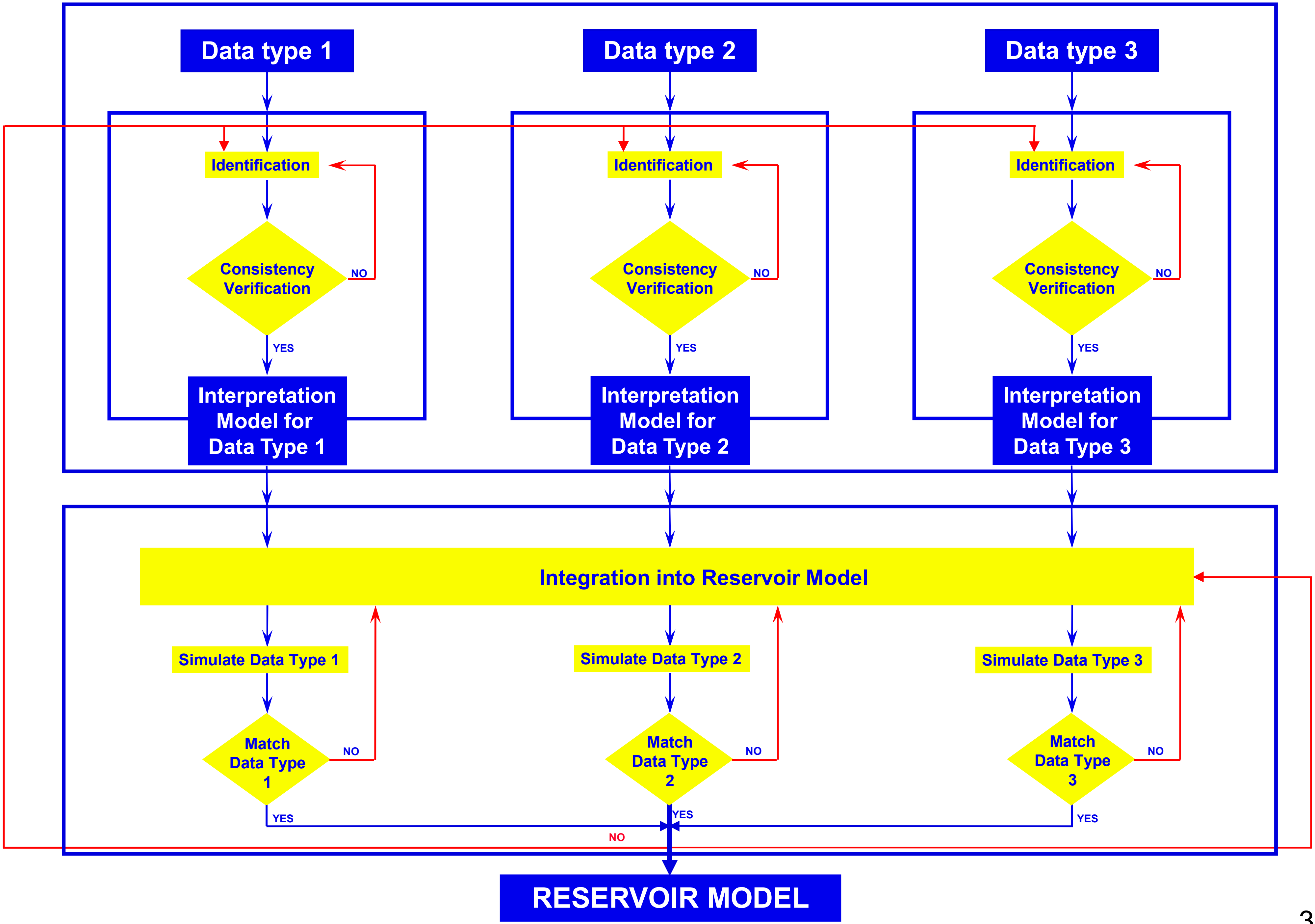
- The response of the reservoir model must therefore calculated with:

  - a seismic simulator to verify that it can reproduce the seismic data;
  - a log simulator to verify that it can reproduce the log data; and
  - a flow simulator to verify it can reproduce the well test data.

The latter usually would require switching to a type of grids more suitable to modeling near-wellbore effects and heterogeneities than the grids typically used for full field simulation.

RESERVOIR CHARACTERISATION




Data type 1
Data type 2
Data type 3
Identification
Identification
Identification
Consistency Verification
NO
YES
Consistency Verification
NO
YES
Consistency Verification
NO
YES
Interpretation Model for Data Type 1
Interpretation Model for Data Type 2
Interpretation Model for Data Type 3
Integration into Reservoir Model
Simulate Data Type 1
Simulate Data Type 2
Simulate Data Type 3
Match Data Type 1
NO
YES
Match Data Type 2
NO
YES
Match Data Type 3
NO
YES
NO
RESERVOIR MODEL

NUMERICAL WELL TEST ~~ANALYSIS~~ SIMULATOR

THERE IS NO SUCH THING AS NUMERICAL WELL TEST ANALYSIS

BUT THERE IS A PLACE FOR A NUMERICAL WELL TEST SIMULATOR

- **It is not in model identification (*defining a well test interpretation model from well test data*)**
- **It can be in simulating possible flow regime behaviours when analytical solutions are not adequate (*forward modelling*)**
- **It can be in verifying the consistency of the well test interpretation model (*forward modelling*)**
- **IT IS MAINLY IN VERIFYING THAT THE RESERVOIR MODEL IS CONDITIONED BY THE WELL TEST INTERPRETATION MODEL**

VERIFICATION OF THE RESERVOIR MODEL

WITH WELL TEST DATA