Title	:	An Improved Method for the Monitoring of the Productivity of Natural Gas Wells
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Nomenclature

k	= permeability	[mD]
h	= height of the producing gas column	[m]
kh	= average permeability times height of the producing gas column	[mDm or mDft]
S	= rate independent skin	
F	= rate dependent skin	
A	= area [Sm2]	
PI	= productivity index in pseudo pressure units	[(Pa.s*Sm^3/d)/bar^2]
IPR	= inflow performance relationship	
IPR(A)	= IPR derived from analytical inflow equation and models	
IPR(F)	= IPR derived using production data and Forchheimer correlation	
IPR(M)	= true IPR as it could be measured, no correlation	
A	= Darcy coefficient = 1/PI	[bar^2/(Pa.s*Sm^3/d)]
B	= non-Darcy coefficient	[bar^2/(Pa.s*(Sm^3/d)^2)]
L	= length	[m]
p	= pressure	[bar]
$\bar{p}$	= average pressure in the reservoir	[bar]
ρ	= density of the fluid	[kg/m^3]
β	= turbulence	[1/m]
M	= real gas pseudo pressure	[bar^2/Pa.s]
Z	= compressibility	[-]
r	= radius	[m]
t	= time	[s, days]
T	= temperature °Celtigrade]	[°Rankine,
μ	= viscosity	[Pa.s]
$\bar{\mu}$	= average viscosity over range of pressures or space	[Pa.s]
θ	= porosity	[-]
Ca	= Dietz shape factor	[-]
PSS	= pseudo steady state	
$Q = Q_{sc}$	= flow rate at surface conditions	[Sm3/d]
FBHP	= flowing bottom hole pressure	[bar]
FTHP	= flowing tubing head pressure	[bar]
SIBHP	= shut in bottom hole pressure	[bar]
WHP	= well head pressure	[bar]
X_f	= fracture half-length	[m]
PLT	= production logging test	
VBA	= visual basic for applications	
CVD/CVE	= constant volume depletion experiment/ constant volume extractor experiment	
HUD	= hold-up depth	[m/TH]

Subscripts

a = analytical
cz = crushed zone
d = damaged zone, drainage
dev = deviation
e = experimental, external
h = horizontal
w = water
p = perforation
nDS = non-Darcy behavior in the near well bore area
r, res = reservoir
wt = well test
wf = well flowing
f = fracture
pp = partial penetration
D = dimensionless
frac = fracture
g = gas
i = initial
nD = non-Darcy
nDR = non-Darcy behavior in the reservoir
w = well bore

Abstract

Up to now the well performance department within Total Exploration and Production Netherlands (TEPNL) base the assessment of well inflow performance on experiences in the field. No tools are available to systematically monitor and assess the reservoir-completion-tubing performance in the longer term (years). This makes that normal production decline cannot be discriminated from abnormal production decline and productivity decline over long periods of time cannot be observed. The well management process is complicated by the large number of small reservoirs operating in different circumstances. As a result well performance interventions have largely become a remedial activity rather than a pro-active way of increasing production.

In this thesis we will discuss the development of two tools that will allow the performance engineers to monitor all 52 TEPNL productivities over the entire period of time digital production data is available. Problematic wells are selected based on their initial productivity and their current productivity. Productivities are determined using Forchheimers correlation. Tagged well are coupled to an appropriate analytical skin model, depending on the well configuration. Evolution of certain parameters that are identified as being impactful on the PI of the specific are calculated. Certain mechanisms have been proposed which cause well performance deterioration. The root cause for the decline is interpreted based on well historics, surface measurements of salinity and the evolution of PI. Finally, when a cause has been established and it appears to be skin related an intervention can be proposed and potential production gains can be estimated.

The new tools can also be used to review past interventions in a systematic and simple manner. At this moment well interventions are not or hardly reviewed on their impact. The tool can now help to quantify the problem, as well as give an objective measure of the success of past interventions.

The approach proposed in this thesis is new, and only limited data is available to validate the approach. Some promising results are observed based on the 4 interventions done in the past as well as well historics currently available. At this stage, the method tags an additional 9 wells as declining faster as expected. 4 of which are suspected to be related to skin buildup, 1 to water invasion, 1 to interference with another well and 1 due to tubing damage. The remaining 2 wells could not be linked to a single specific cause, 1 well is either suffering from salt deposition or water advancement, while the other either salt deposition or tubing damage.

1. Preface

To follow up the deliverability of a reservoir and its wells, regular multi-rate production testing needs to be performed. Well interventions may have to be planned and designed to increase deliverability and minimize production costs. Although the Dutch Government stimulates the development and production of the small gas fields off the coast by making it financially more attractive with its ‘small fields policy’, the fields still remain economically marginal. Both multi-rate production testing and well interventions are costly operations, especially on North Sea offshore facilities. TOTAL EPNL operates some of these relatively small gas fields in the K and L block. Cost savings result in uncertainty on both production and reservoir data, which leads to estimate the productivity of the wells using general models, mainly the Forchheimer model. Well interventions are scheduled based on the intuition and past experience of the well performance team members. TEPNL wishes to investigate whether decision making in well intervention strategy can be improved, based on the data currently available. Since gathering more detailed data is not budgeted, the proposed method should take into account this constraint.

Total EPNL initiated this master thesis project in order to:

1) Develop a method to monitor the productivity of the individual wells and trace abnormal production decline.
2) Provide an improved theoretical foundation for the approach to systematically monitor the main production impairing factors causing an abnormal production decline.

Total EPNL has a preference to use the routines available in PROSPER since this software is commonly used in the company. The outcome of the proposed approach can become the base for not only a better planning of the well interventions, but also for an improved well intervention design. The discussed approach aims to become a suitable and cost efficient tool for a decision maker who wants to quantitatively assess and compare different decisions, and aims to progress the decision making from a qualified guess to more exact knowledge.

Robust qualitative evaluation of the production impairing factors proved to be not possible, and even exact quantitative evaluation proved not to be straight forward. This is not surprising since production impairing factors are known to be hard to diagnose, even in much better documented situations. Only a more extensive data gathering program than used in today by TEPNL can eventually bring a better solution. But comparative evaluation showed possible and could to be a good base for improved decision making. The tool can be a frame for better and more systematic follow up of the wells and for a more focused evaluation of well interventions and intervention design.

I wish to thank Total EPNL for this experience in a professional environment. My special thanks go to Hubert Blandamour who gave me the freedom to explore and learn from my mistakes, and Pauline Benazet for giving me access to their data and knowledge as well as for patiently helping me with my questions. Last but not least I wish to express my sincere appreciation for the guidance and valuable suggestions provided by Prof. Pacelli Zitha from TU Delft.

2. Introduction

The true inflow performance relation (IPR) of a well is the result of the unique well penetrating a unique reservoir. Its IPR curve contains all the influences of reservoir characteristics, and the so-called near wellbore skin effects. A true IPR can be measured in the field by an extensive multi-rate test program. Several empirical methods which produce an IPR based on just a few measured points have been proposed in literature to bypass this costly operation. One of the most widely accepted empirical, also called experimental methods; applicable on gas fields is the multi rate Forchheimer method.

Big advantage of an empirical model is its simplicity and cost-effectiveness in the field. One of the main disadvantages is that these models do not offer insight, since they miss detailed and explanatory analytical formulas showing at least the sensitivities to certain parameters and their relation to the overall phenomenon. The advantage of a well developed analytical model is that it does give the insight that interests the well intervention designer. The reverse side to the medal is that an analytical model needs a very detailed set of input data which are costly and sometimes even impossible to gather accurately from the reservoir and its wells.

The TOTAL EPNL data base supplies for all individual wells continuously measured production flow rates (Q) and the corresponding flowing tubing head pressures (FTHP). Production tests are rare and just on a few wells bottom hole gauges are installed. It will be investigated if it can be assumed that the experimental IPR produced by entering very limited input from the field in the multi rate Forchheimer PROSPER routine has a direct correlation with the true IPR of the well. If so, it will be a cost efficient way to monitor the productivity of the well. Does the limited input from the field; reservoir pressure (P_{res}) and one single measured operating point (FBHP;Q), combined with the Forchheimer model hold enough information about production impairing factors to be relevant for well intervention design? And can this information be extracted from it? These are the questions this study seeks to answer.

An analytical IPR, derived from an analytical inflow equation coupled to an adequate skin model, can be altered by varying its input parameters. These parameters can be used to 'fit' the analytical IPR on the empirical IPR. Would this deliver relevant parameter values for the well intervention designer? In this way the advantages of the empirical IPR and the analytical IPR, i.e. cost-effectiveness and analytical insight are combined. A direct correlation between the real, measured IPR, the experimental IPR produced by the PROSPER routine and based on the average reservoir pressure and the monthly averaged flowing bottom hole pressure of the individual wells, and the analytical IPR produced by a semi analytical inflow equation is the backbone of the idea. How parameters relevant to the well designer influence the analytical IPR, and what the evolution of this IPR can tell about the evolution of these parameters is the core of this study.

3. Background

The goal of this study is to explore the possibility to produce an IPR based on an empirical inflow correlation and very limited field input data available in the historical data base of TEPNL. It will be investigated if combining this experimental IPR with a corresponding analytical IPR model can extract more information concerning production impairing phenomena down hole.

To frame this study a description of the situation in the field is given below. The reservoir and its wells are briefly described as well as the current TEPNL data acquisition program since these historical data will be the source to evaluate the proposed method. No extra data acquisition in the field is done for this study.

After an overview of the field and its data gathering program, this chapter will address essential questions: which is a suitable experimental method in determining a well's IPR and how can this experimental value be coupled to analytical equations describing the same IPR. For both the experimental IPR and the analytical equations several options will be proposed and discussed. Additionally, we found that the data gathering is even insufficient in providing data for the experimental method. Namely the knowledge of the FBHP is absent. To counter this appropriate correlation will be used chosen based on a comparison of 17 correlation available in literature.

The experimental IPR will be based of simple production data; flow rate, FTHP and reservoir pressure. The analytical equations are based on a diffusivity equation linking time, flow rate, drawdown pressure and reservoir parameters. The solution of this diffusivity equation is performed for an ideal reservoir. To make the equations suitable for the reservoirs and well setups found in the field skin factors are introduced.

Based on the knowledge found in this chapter we can progress to coding the final working tools presented in the conclusion. The building blocks; the empirical IPR, the analytical IPR and the link between both will allow us to estimate production gains from an intervention identify damaged wells as well as estimate the evolution of several pre-defined reservoir parameters.

As stated, the model needs to work based on the available data. As such the situation will often be simplified. Heterogeneity in the reservoir is not taken into account; it is assumed the whole reservoir has the same average properties. Often a well is perforated over several distinct intervals, sometimes zones are within the same formations, but occasionally also in different geological formations. In literature it is abundantly clear that separate layers cannot be interpreted based on even good multi-rate tests. In this study it is assumed that all production comes from 1 layer with height equal to the total producing height of the different reservoirs and average properties as interpreted from a well test.

3.1. Field description and field data acquisition program

A description of the situation in the K and L block is relevant to the choices made in the data acquisition phase of this study. It will also clarify and justify the assumptions made to select the appropriate correlation, for instance, to translate FTHP to FBHP. Note that when the fields or fluids differ significantly from the ones found in this study the assumptions should be revised and if needed adjusted.

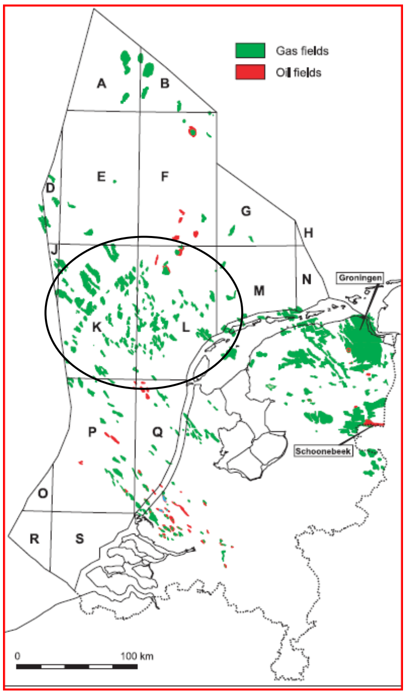


Figure 1 Hydrocarbon map of the Netherlands

The assets operated by TEPNL consist exclusively of gas fields situated in the North Sea K and L blocks (see fig.1). The individual fields in these blocks have small Gas Initially In Place (GIIP) volumes, ranging from 0.5 to 20 GSm^3. They have little or no communication with each other and their lifetimes range from 5 to 30 years.

The source rocks of most of these gas fields are the Westphalian coals. Volumetrically the Upper Rotliegendes reservoir rock contains most of the gas. Smaller quantities are found in the Westphalian Tubbergen. In the K and L block area both formations are hydrocarbon bearing. Both reservoir formations are loaded by Westphalian source rocks and sealed by the Silverpit shales. Traps are generally provided in the form of fault-dip structures.

Westphalian Tubbergen sand rock often has a good porosity ranging from 9 to 20% and permeabilities from 0 to above 100 mD with an average of 1-2 mD. Initially most wells can achieve good production rates, however poor connectivity between panels causes these rates to fall off rapidly. Upper Rotliegendes formations have porosities of 15% and up to 20% at 4000 m. (de Jager, 2007)

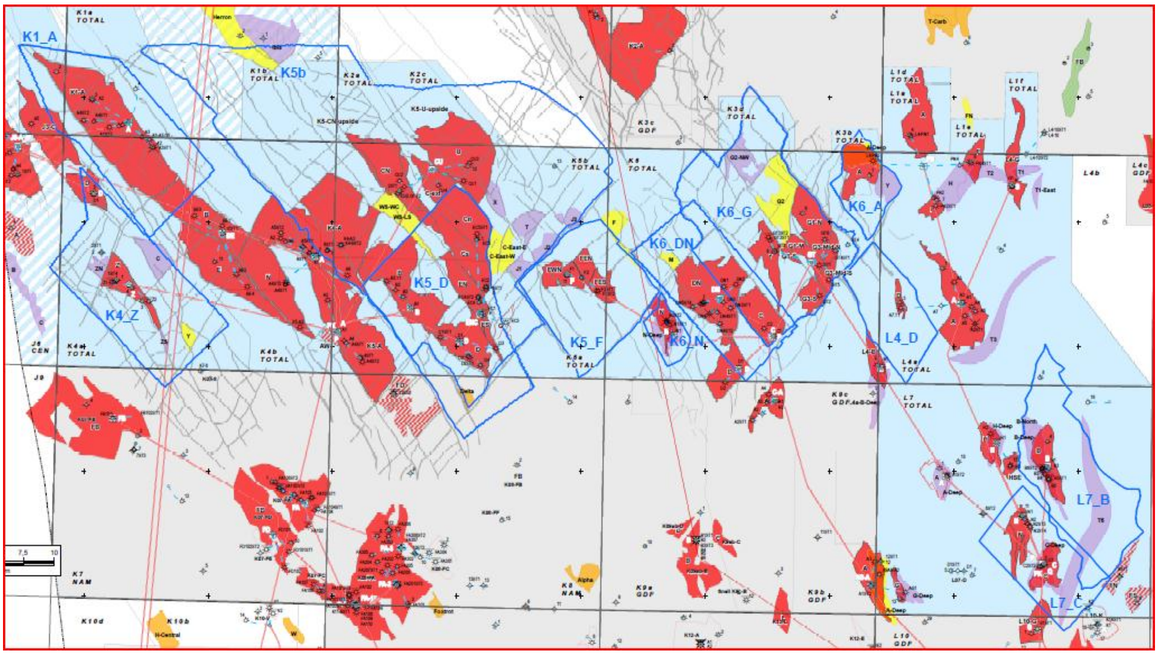


Figure 2 Detail of reservoirs in K and L block

The reservoirs in the K and L blocks vary considerably in size. Due the geological setting, the reservoirs tend to be larger towards the West. The large reservoirs are heavily compartmentalized by internal fracturing, requiring multiple platforms to drain the whole area. TEPNL tries to drain adjacent compartments simultaneously, letting the water front advance uniformly to avoid pressure differences to build up.

Depending on the geology a most appropriate well architecture is chosen. Commonly the wells are completed with perforated casing or a slotted liner. Some wells are fractured. For each completion type the inclination can range from vertical to horizontal.

The gas is composed of mainly methane, ethane and inert gases. Methane fraction usually lies between 80 and 90 mol%, about 5 mol% is ethane. The remainders are varying fractions of CO_2 and N_2. H_2S is not present in any of the reservoirs. Condensate fractions are around 30-40 Sm³/MSm³ gas, before water breakthrough the water fractions depend on the reservoir pressure, but ranges from 3 to 40 Sm³/MSm³ gas (Elewout, 2008). After water breakthrough the water fractions can increase to above 200 Sm³/MSm³ gas.

TEPNL field data acquisition is lean. Digital record of the flowing tubing head pressure (FTHP) and gas flow rate (Q) at the tubing head are continuously measured since January-June of 2007 depending on the well. Per separator the CGR and WGR are continuously monitored. The liquid fractions have to be back allocated per well by manual interpretation based on the flow rates of the individual wells. At the end of the drilling operations the formations are logged using neutron and gamma ray logs to identify potential reservoir layers and their porosity. Usually wells are only tested once or at very long time intervals. At the occurrence of an unexpected event well testing may be done as well. Production logging tests or PLT are done occasionally when very obvious issues occur , however it is not the rule. Formation heights to interpret well test results origin from the initial logging before casing the hole or, when available, from a PLT. Drainage radius is estimated using well test results, and by cross checking with the known geological environment in the vicinity of the well.

3.2. Real Gas Pseudo Pressure, M

In the paragraph treating the analytical inflow models we will require to linearize the diffusivity equation in the pressure domain. For liquid wells (dead oil) this is easily and accurately achieved by assuming pressure independence of viscosity and viscosity of the fluid. For gas well this issue is somewhat more complicated because this assumption is no longer valid. In literature, two linearization methods are proposed for real gasses. The pseudo-pressure method proposed by (Al-Hussainy et al., 1965) and the pressure-squared method proposed by (Russell et al., 1966).

Both methods require at least a simple PVT analysis to determine the relation between pressure and viscosity and pressure and gas compressibility in the pressure range of interest.

Russell's pressure-squared method is based on averaging the pressure-dependent variables over a given pressure range. Due to this pressure averaging the pressure terms become squared in the final formulation. This method of working implies that either the working pressures need to be known a priori, or the solution of the diffusivity equation needs to be derived iteratively.

Al-Hussainy's method counters this issue by introducing a new quantity; the real gas pseudo pressure. This quantity will include all the variables that are pressure dependent, making it the only pressure dependent term in the diffusivity equation. By integrating this quantity over any given pressure range the pseudo pressure can be calculated explicitly, eliminating the need for several iterations. Although in mathematical terms this method is more convenient and elegant it requires the used to get accustomed to the values, units and meaning.

In essence what both methods do for an IPR in either of the quantities (p-squared or pseudo pressure) do is eliminate the pressure dependency. When an IPR is plotted in a conventional P-Q space the PI (dP/dQ) is decreasing due to changing of the fluid properties, not so much due to changing of reservoir characteristics. When an IPR is plotted in M-Q or p^2-Q space the PI remains constant over the whole range of pressures.

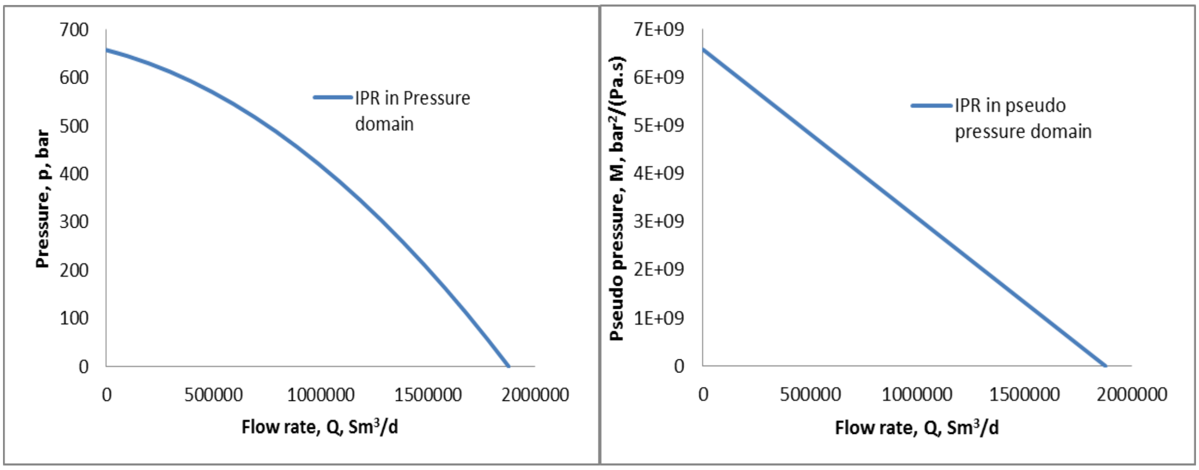


Figure 3 (a) IPR in pressure domain shows a variable PI over the given drawdown range, (b) when the same IPR is expressed in pseudo pressures the PI remains constant over the given pressure

It is recommended to always use pseudo-pressures for the highest accuracy (comparing with p and p^2). Pressure-squared values can be used without loss of accuracy at low pressures (<140 bar) when the μZ-product is roughly constant, or at high pressures (>210 bar) when the gas behaves similarly to oil (pseudo pressure varies linearly and marginaly with pressure) (Bourdarot, 1996). TEPNL wells have pressures below, between and above 140 and 210 bar. Apart from intuition in the pressure values, pseudo pressures do not have any downside (Dake, 1998) (Aziz et al., 1976) and are accurate in all circumstances.

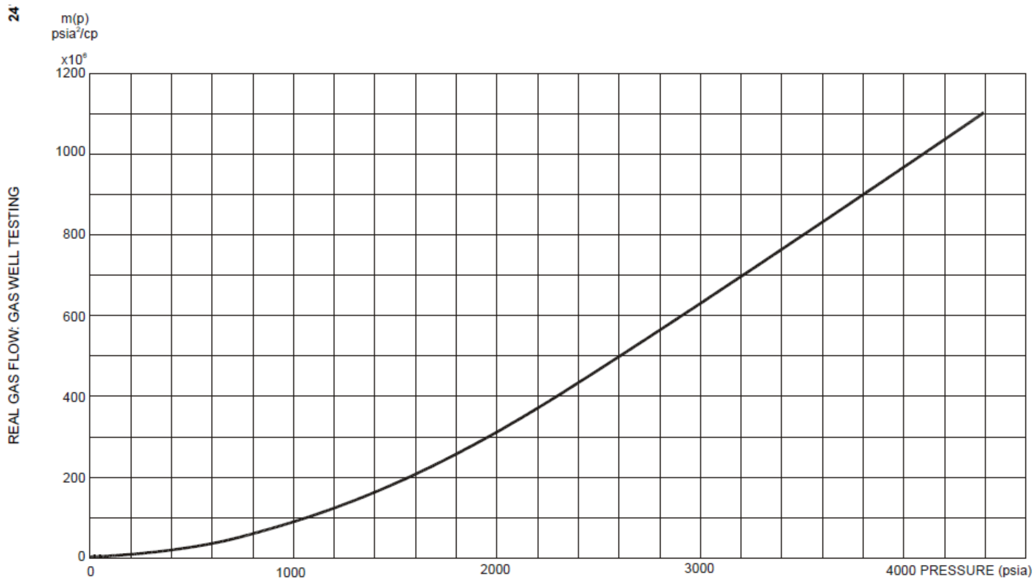


Figure 4 Relation between pseudo pressure and pressure, not the linear relation above 210 bars

In future IPR curves still the PI is observed to be rate dependent. The rate dependency is coupled to turbulence occuring in the reservoir or condensate banking around the well. This will be discussed in more detail in the paragraph about non-Darcy skin.

3.3. Analytical Inflow Models

An Inflow Performance Relationship (IPR) is constructed from an inflow relationship derived from the diffusivity equation. The Petroleum Expert software PROSPER allows to generate an IPR starting from both an experimental or empirical correlation and a semi analytical inflow equation (Petroleum Experts, 2012). As stated earlier, the first option is more attractive to use in the field for its cost efficiency, the latter option is the most interesting if one wishes to get insight into the possible causes of a decrease in well productivity. Deviations in the field from the theoretically calculated inflow values based on these semi analytical inflow equations are accounted for by a skin factor, S. This S value quantifies the production impairing phenomena which are not accounted for by the formation model. Only the formation models that describe the reservoir and which are completed with an analytical skin model are eligible candidates for this study. For gas and condensate wells 4 analytical formation models are available in the PROSPER software. Each of them describes the reservoir in a different way, however the skin model used they have in common. The analytical formation models are:

Table 1 Available analytical PI correlations in PROSPER.

Jones formation correlation (Jones, 1976)	$Q_{sc} = \dfrac{703 \cdot 10^{-6} kh\left(M_{res} - M_{wf}\right)}{T \cdot \left(\ln\left(\frac{A_d}{C_A r_w^2}\right) - 0.75 + S + FQ_{sc}\right)}$
Back pressure correlation (Fetkovich, 1973)	$Q = C\left(P_r^2 - P_{wf}^2\right)^n$
Petroleum Experts correlation (Petroleum Experts, 2013)	*Proprietary*
Horizontal well (Goode, 1991)	$PI = 7.0810^3 k_h h / \mu B_o (p_{wD} + S_m)$

In this table k stand permeability, h for gas column height, T for temperature in degrees Rankine, A_d for the area drained by the well, C_A for the Dietz drainage factor, r_w for the well's radius, S for mechanical skin and F for rate dependent skin.

Each of these four models, combined with the skin model available in PROSPER, can produce a pseudo-analytical IPR. Unfortunately the use of the skin model proposed in PROSPER is limited to vertical, deviated or horizontal well trajectories completed with perforations. Since completions with a slotted liner and fractured wells are present as well in the field the use of only this skin model cannot be justified. The inflow correlations available in PROSPER can prove valuable within their range of applicability, but for the types of wells that are not covered by these correlations, an analytical inflow model based on literature review will be proposed and presented in this chapter. The proposed alternative is based on a model similar to the Jones formation model mentioned above and is completed with an analytical skin model based on correlations found in literature

For wells that can be analyzed using a PROSPER routine (i.e. perforated) it is recommended to use Jones' correlation for vertical and deviated wells and the Horizontal well correlation for horizontal wells. This recommendation is based on the underlying theory. Both the Jones' correlation and the Horizontal well correlation are derived from the Darcy inflow equation and take into account a rate dependent skin. The Petroleum Expert correlation likely (based on input requirements) has a similar form as the Jones' equation. It is designed to account for variations in liquid saturations near the well bore by adjusting the permeability values according to the relative permeability curves. However, mathematical formulations of the inflow equation and relative permeability curves are lacking. The Back pressure equation is an empirical equation based on experimental observations made by Vogel (Vogel, 1968). It is treated in this chapter because the skin definition is analytical. It is not recommended to use this method because the assumption that C and n are independent of flow rate and pressure is not valid for gas flow (Aminian et al, 2007). Therefore the quadratic form of the Jones equation is a more appropriate choice. Even after consulting literature it remained unclear how the skin model is incorporated into this experimental Back pressure formulation. The Jones' correlation was derived for an ideal well and reservoir (meaning vertical, full penetration, homogeneous formation, radial flow…). For a slanted well it is the effect of the deviation of the well trajectory from the vertical that is represented by skin, rather than by adjusting the boundary conditions of the diffusivity equation.

3.4. Alternative Analytical Inflow Model and Skin Models

The back-pressure and Jones-correlations presented by PROSPER allow both the incorporation of skin effects into their inflow model. As stated earlier the analytical skin model used in PROSPER to complete is only applicable to a limited set of field conditions. Certain well architectures are not covered by the PROSPER. Because we want to develop a flexible tool, applicable in all circumstances an alternative inflow equation and skin models are proposed.

In this section analytical skin models available in literature will be reviewed. The purpose is to have an analytical skin model for the different well architectures found in the TEPNL fields. The equation is based on the radial diffusivity equation linking pressure drawdown, time, reservoir parameters and flow rate to one another for an ideal well and reservoir.

$$\frac{1}{r}\frac{\partial}{\partial r}\left(\frac{k\rho}{\mu}r\frac{\partial p}{\partial r}\right) = \phi c \rho \frac{\partial p}{\partial t}$$

Substituting the pressure by the pseudo pressure, the diffusivity equation becomes:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial m(p)}{\partial r}\right) = \frac{\phi \mu c}{k}\frac{\partial m(p)}{\partial t}$$

The radial inflow equation is solved assuming that the reservoir and completion are ideal (Dake, 1998). The solution is derived for a closed vessel, where pressure declines are related to flow rate alone (no inflow).

- the reservoir or drained area is homogeneous and isotropic,
- has an infinite radius,
- has a constant thickness,
- is bound by impermeable boundaries,
- the well perforates the whole reservoir thickness,
- the fluid's compressibility is small and constant

The solution of the diffusivity equation for pseudo steady state flow regime then becomes (Al-Shawaf, 2012; Dake, 1998):

$$M_{res} - M_{wf} = \frac{1422 Q_{sc} T}{kh}\left[\ln\left(\frac{A_d}{C_A r_w^2}\right) - 0.75 + S + FQ\right]$$

In this formula the skin, S is inserted by convention to describe non-ideal reservoir and reservoir-well bore connection. Similarly the non-Darcy skin, F, relates to a pressure drop not occurring in the ideal reservoir. Typical skin effects include influences from drilling and completion activities such as drilling mud invasion or perforation tunnels, however more trivial well parameters are also included in this factor, for instance the well's deviation. Where the skin's origin is often in mechanical properties, the non-Darcy skin is by definition not related to the mechanical state of the reservoir. This pressure drop is a function of the flow rate and is most prominently a function of the turbulence occurring in the reservoir, in some cases non-Darcy skins have been observed in wells developing condensate banks (only for retrograde fluids, not applicable here).

The input data for this study are all taken during normal production. Note that this equation is no longer a function of time because pseudo steady state is assumed. Usually production is at steady flow rate for long periods of time. A well reaches a pseudo steady state flow regime when the radius of investigation has reached a series of impermeable outer boundaries and flow lines have stabilized (Bourdarot, 1996). Depending on the author the velocity with which the compressible zone propagates changes slightly, all of them however relate to (Jones P. , 1962; Van Poolen, 1964; Chaudhry, 2003):

$$r_i = constant\sqrt{\frac{k\bar{p}_r t}{\emptyset\bar{\mu}}}$$

Given common parameter values for the reservoirs in question, the outer radius should be reached by the compressible zone after 1 day of flow for small drainage areas (re = 200m), and after about 10 days for larger reservoirs (re = 1500 m). Also for the horizontal wells this should not be a problematic assumption as reservoirs are generally quite thin (< 40m). The transient wave will reach the shoulder beds almost immediately, from then it behaves as a well perforated over the entire reservoir thickness with horizontal flow lines (Bourdarot, 1996).

Some deviations have a positive effect on production (S<0), others have a negative impact (S>0). The resulting pressure deviation compared to the ideal case is easily calculated by:

$$\Delta M_{res-wf} = \frac{1422 QT}{kh}(S + FQ_{sc})$$

The above expression indicates that low quality reservoir (kh) are more sensitive to skin development, larger reservoirs are less sensitive to skin than small ones. This should be taken into consideration when selecting wells for intervention.

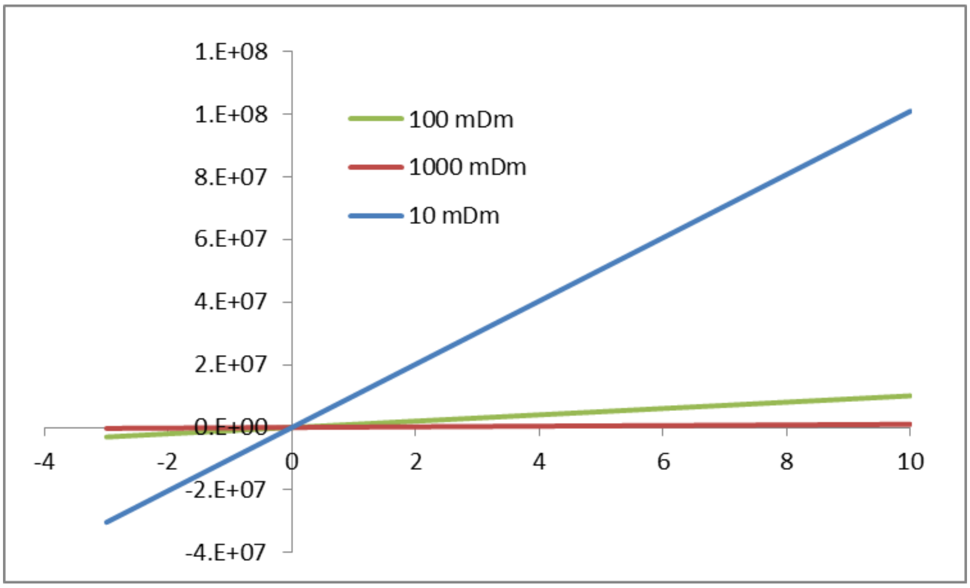


Figure 5 Pressure loss due to skin for 3 different reservoir qualities. Good kh minimizes the impact of skin on the drawdown

Table 2 below illustrates which skin models were reviewed in literature for this study, and which authors performed research on the topic. An appropriate skin model will be selected from the models listed below for further use in this study.

Table 2 Skin models and their authors

Partial penetration skin (S_{pp})	Odeh, 1980; Brons, 1961
Perforation skin (S_{cz}, S_p)	Karakas, M., Tariq, S.M., 1991; Locke, 1981; McLeod, 1983; K. Ferui, 2002
Deviation skin (S_{dev})<75 deg	Rogers, 1996; Cinco, 1975
Deviation skin (S_{dev})> 75 deg	Daviau, 1988
Fracture skin (S_{frac})	Cinco-Ley, 1978; Mahdiyarm, 2007
Damaged zone skin (S_d)	Van Everdingen, 1953
Deviated + fracture skin ($S_{frac,d}$)	Welling, 1998; Ehlig-Economides, 2008
Non-Darcy skin (F_{nD})	Aminian, 2007

In cases where multiple skin phenomena coexist, an appropriate summation method for the describing models should be used. Mutual interference can be expected and several methods are presented in literature. The linear summation method as proposed by Vrbik and as shown below was chosen (Vrbik, 1991). This method has the advantage of simplicity while other methods are more complex and often sensitive to input data which are not available in this study. The other methods (Papatzacos, 1987;

Odeh, 1980) do not produce more accurate results (Yildiz, 2003). Although Yildiz’ research on the summation methods was limited to (partially) perforated wells, the Vbrik method is adopted since more information regarding the subject was not found.

$$S_{tot} = S_{pp} + S_{cz} + S_p + S_{dev} + S_{frac} + (F_{nDR} + F_{nDS})Q_{sc}$$

Perforation skin as defined by Tariq and Karakas for vertical wells (Karakas, M., Tariq, S.M., 1991) was reviewed by Sun (Sun et al, 2013). The authors concluded that the model delivers good estimates under the condition of an isotropic formation with no damage, under the condition of single-effect drilling damage, crushed zone or permeability anisotropy, and under the condition of two simultaneous effects of drilling damage and crushed zone damage or drilling damage and permeability anisotropy. Based on work performed by Sun et al. can be concluded that compared to McLeod and Locke the Tariq and Karakas model predicts skin factors larger by a factor 2 when perforation depth is larger than drilling damage. Perforation skin for horizontal wells is much less described in literature. Ferui developed a finite element model for predicting the skin in horizontal taking into account the effect of the perforation tunnels and anisotropy of the permeability. However he did not consider damaged areas around the well or the perforations. For this reason the model underestimates the skin. The finite element method used by Ferui is able to describe complex flow geometry problems. The accuracy of the model depends on the precision of the numerical simulations. In literature, a discontinuity in perforation skin is observed when damaged zone radius approaches the perforation depth. However, in TEPNL wells fluid losses are often limited and perforations are deep. In fields where this would not be the case, the Tariq and Karakas model has been adjusted to offer more continuous results as proposed by (Akim et al., 2009). In the original perforation model there was a discontinuity in skin when the damaged zone radius was equal to perforation radius. This problem has been solved by adjusting the skin factor based on the flow through either perforation or damaged zone. Skin values are lower for every perforation length. In this study the damaged zone radius is unknown and has been given an arbitrary geometry related to the well architecture (open hole exposure time). Good quality, deep perforation, methods are used and little mud losses are observed. We assume the adjustment on the Tariq-Karakas correction is not applicable in the analytical model as we will be using it. Below a schematic of the physical model that is being used by Tariq-Karakas:

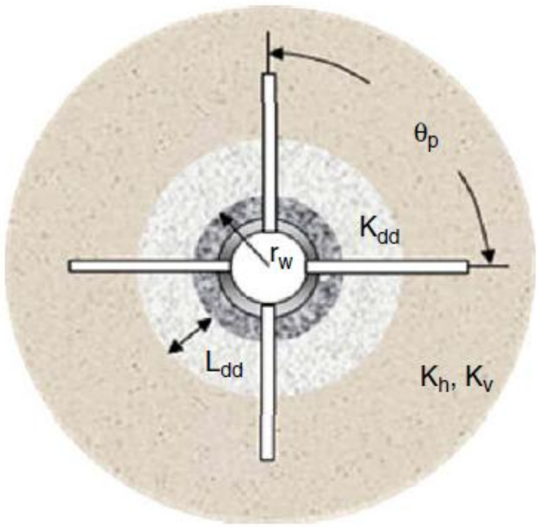


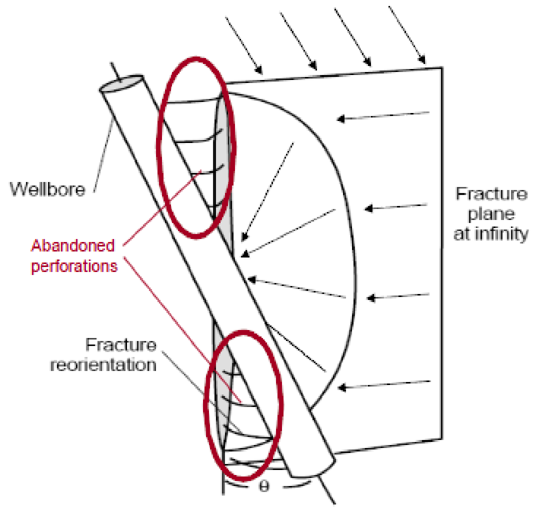
Figure 6 Top view of the physical model proposed by Tariq-Karakas. Note that the perforations are not in the same horizontal section

Damaged zone skin is to be accounted for in wells completed with a slotted liner. The type of skin is defined in an analytic manner by (Van Everdingen, 1953). The model assumes a cylindrical damaged zone around the wellbore, with a uniform permeability and radius of the altered zone.

Deviation skin was also described by several authors. Comparison of several correlations reported in literature revealed very little difference between the evaluated correlations below 75 degrees of inclination to the vertical (Choi et al. 2008). Above this threshold correlations give very different results. A skin factor specifically tailored for horizontal gas wells was developed by assuming infinite conductivity in the center of the reservoir (Daviau, 1988). However errors are small when the horizontal well is within 37,5% off the center (half of the reservoir height) of the reservoir. When the off-centered well is outside this limit the results should be regarded as indication only.

A fracture skin factor correlation for vertical wells was derived assuming linear inflow into the fracture and incorporating a term quantifying the pressure deviation due to non-radial inflow (Mahdiyarm, 2007). A FEM simulator was developed by the authors to generate a large data bank for different conditions of the well. Based on these data different fracture skin formulations are derived. Based on their observations a fitting curvewas derived to account for relative conductivity of the fracture and the formation. At high fracture conductivities (10 times matrix conductivity) this fit function value remains constant. For all fractured TEPNL wells the relative conductivity of the fractures are larger than 10 with respect to matrix permeability (Leblanc, 2011). Which analytical fracture skin factor to use depends mainly on the ratio between drainage radius and fracture half length. (Cinco-Ley, 1978) already described fracture skin, and Mahdiyarm et al. continued their work. (Mahdiyarm, 2007) was benchmarked versus a finite element simulator on many different aspects giving good results. Strong variations are seen between Cinco-Ley and Mahdeyarm et al. when comparing fracture surface damage. Cinco-Ley's fracture skin was derived for linear streamlines in the reservoir, opposed to the pseudo-radial flow used for Mahdeyarm's derivation. TEPNL fractures are small (30-50 m) compared to the drainage radius (100-1000+ m), the pseudo-radial skin facture should thus be more suitable here.

In low permeable reservoirs it was observed that for deviated and fractured wells almost 100% of the flow is through the fractures (Zhang et al., 2009). But when the fracture and the well path are not alligned well-fracture connectivity is limited. The authors developed 2 models; one in which perforations are connected to the fracture in 1 point, and another that considers inflow from both disaligned perforations and fracture. It was found that fracture to well connectivity can have a great impact on fracture skin. Differences with the regular skin model for a vertical well are large, even at small disalignment and large perforation densities. However, not one author of the mentioned papers published a formulation for skin that can be used for engineering purposes. All studies were done using finite element simulations. In this study the fracture skin in deviated wells will be approximated using the vertical fracture skin model (Mahdiyarm, 2007), keeping in mind that this is likely to be a too optimistic approach. Below a schematic of the described problem:



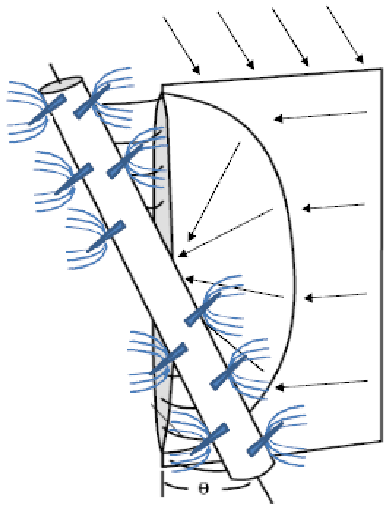


Figure 7 In slanted well fracture-well bore connectivity is not optimal, Zhang et al. described a new numerical model, where different results are observed. There is no access to this model so linear summation was used.

Non-Darcy pseudo-skin factors differ from all the others by nature. While other skin factors find their origin in deviations from the ideal reservoir, the non-Darcy skin finds its root in the fluid being non ideal. At high rates internal friction in the fluid starts to play an important role. The pseudo skin, calculated by multiplying the non-Darcy coefficient, F, by flow rate, depends on both the reservoir matrix and fluid characteristics (Zeng, 2008). Below a relation between flow rate and turbulence and porosity and pressure drop due to turbulence.

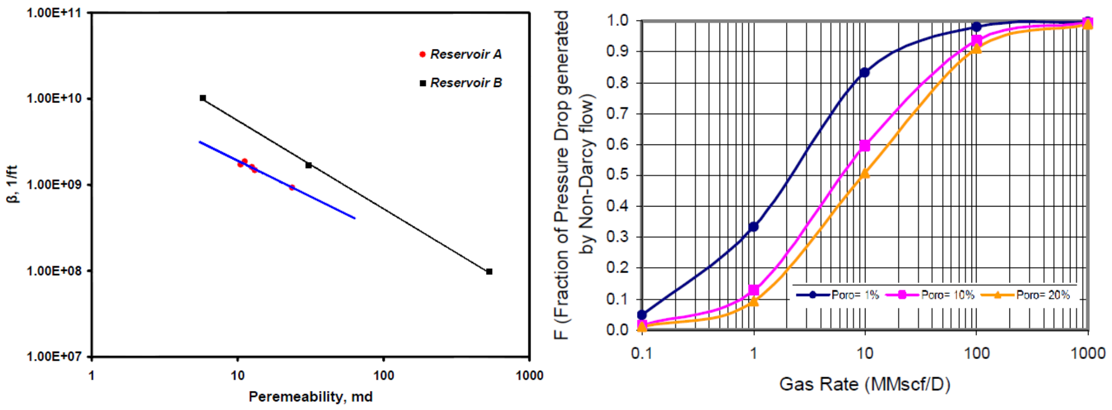


Figure 8 Dependency of turbulence on permeability, on porosity and on flow rate. Note that for a well with 100 mD permeability almost 100% of the total pressure drop is related to turbulence at 1000 MMscf/d

Analytical models are available to describe turbulence. Controling factors are considered to be permeability, porosity and tortuosity of the pores. However also rock type and liquid saturation are found to be important (Armenta, 2003). Experimental models are often reduced to simplified forms, based on fitting turbulence-rate data with a power law fit using permeability, sometimes also taking into account porosity (Geertsma, 1959; Pascal, 1980; Coles, 1998). Later we will observe that non-Darcy flow behavior cannot be derived based on production measurements through the empirical model. The analytical non-Darcy skin was benchmarked by plotting analytical IPR curves on an IPR made up from good multirate well test data. None of the models discussed above managed to fit the curvature in a satisfactory manner. The same issue was observed when 18 correlations were benchmarked against well test data of 9 wells (D. Martinez, 2012). Martinez concluded that the best performing correlation predicted the pressure drop 71% too high.

Because neither the analytical model, nor the empirical model can estimate non-Darcy behavior in a satisfactory manner it was decided to use the PI instead of the IPR as an indicator in this study. The PI is defined as the derivative of the IPR at zero flow rate. Given the inflow equation the PI is equal to the inverse of the Darcy coefficient. By using only the PI as an indication for the productivity we loose information about the formation. In the chapter "Discussion" is discussed what some of the possibilities are when good estimates of B would be available. In appendix A all skin models are discussed, including the formulas and the assumptions made.

3.5. Empirical Inflow Models

PROSPER offers several routines to determine well productivity. They are related in form to their analytical counter parts discussed above. These productivity estimations should be able to function within the constraints of the available data discussed in 3.1. The most commonly used correlations are:

Table 3 Experimental IPR correlation usable using available data

Multirate Forchheimer	$P_r^2 - P_{wf}^2 = AQ^2 + BQ$
C and n method	$Q = C(P_r^2 - P_{wf}^2)^n$

The coefficients in the Forchheimer relationship are referred to as Darcy coefficient (A) and non-Darcy coefficient (B). The Darcy coefficient is theoretically related to the PI of the well as defined by its rock characteristics. The non-Darcy coefficient incorporates pressure losses related to turbulence in the fluid. Similarly the C and n, express the PI and the “loss” related to turbulence.

Equating the Forchheimer equation to the analytical inflow equation presented before gives:

$$A = \frac{1422T}{kh}\left(\ln\left(\frac{A_d}{C_A r_w^2}\right) - 0.75 + S\right)$$

$$B = \frac{1422T}{kh}(F)$$

Ideally we would like to have a productivity indicator (PI) which is independent of pressure and flow rate. In literature it has been described that the C coefficient of the C and n method is not a good indicator because it is a function of the pressure. Theoretically speaking the multirate Forchheimer correlation would be independent off pressure (thanks to the use of pseudo pressures) and independent of rate (thanks to the second order term describing turbulence). In this study the Forchheimer regression will be used. The form of the empirical correlation is conveniently similar to the one derived from for the analytical inflow equation. This makes fitting both function a trivial matter.

The Forchheimer correlation requires input of a minimum of 2 operating points, the reservoir pressure and condensate and water to gas ratios (CGR, WGR). The data gathering that is done does not reach these requirements. Only flowing tubing head pressure (FTHP) and flow rate (Q) are continuously measured for all the wells. Reservoir pressure is approximated at different times by the shut in bottom hole pressure (SIBHP). Between shut in periods the reservoir pressure is assumed to fall linearly with production. The liquid ratios are back calculated from total liquid rates measured in the separator.

The Forchheimer equation contains 2 parameters to fully describe the IPR. The Darcy coefficient (A) indicates the productivity of the well while the non-Darcy coefficient describes the rate dependent pressure loss. These parameters are equivalent to the rate dependent skin and rate independent skin. Because there are 2 unique parameters describing the IPR, at least 2 operating points are required to determine them correctly. Not having a second operating point forces us to use a Gauss-Newton regression to determine both (Heithorst, 2013). Because the IPR is now based on a simple regression rather than physical meaning it was decided to only use the Darcy coefficient as a PI, rather than the whole IPR. In the analytical description it was already apparent that we are not able to correctly predict non-Darcy effects theoretically, but now there is also not enough data to determine its effect experimentally. What this means is that the Darcy coefficient is not corrected properly for the rate dependence of the PI. This brings the usability of this Darcy coefficient into question. Generating the Darcy coefficient is a time consuming matter. If the Darcy coefficient is not correctly adjusted for its rate dependence we should consider using the classical PI used in liquid wells (Q/ΔM). To determine whether the Darcy coefficient in fact does a better job than a simpler method such as PI = Q/ΔM trends were analyzed in Q/dP(Q) and A(Q) plots. Darcy coefficients are observed to remain closer to constant than simply using Q/dP. For small flow rates however, Q/dP could be used in the interest of time.

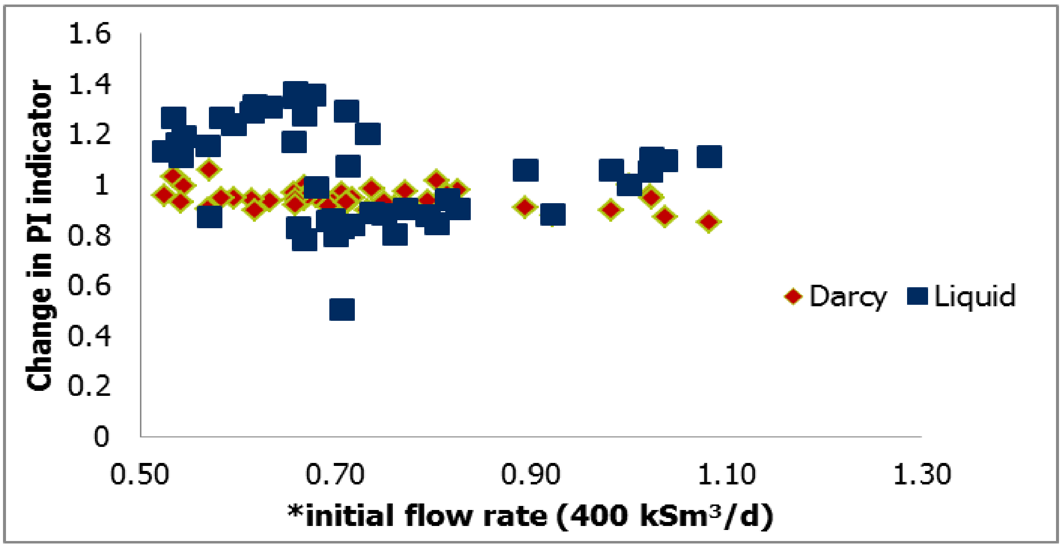


Figure 9 Normalized dependence of the productivity indicator in function of rate. The Darcy coefficient in red remains close to its normalized value than the simple liquid PIµ

In the chapter "Discussion" some remarks will be made what potential advantages are from using a full IPR. Data quality is such that introducing multiple operating points with marginal differences measured during normal production is not an option. Due to various uncertainties the regression occasionally generates unphysical results when the operating points are too close in P, Q-space. What the impact is of these uncertainties and of using only 1 operating point to produce an IPR will be discussed in chapter 4.

3.6. Estimation of flowing bottom hole pressure

The PI determination requires the input of (FBHP, Q)-couples. In the studied situation only FTHP is recorded and thus will have to be converted into FBHP. Conversion is a complex matter since pressure and temperature changes along the path to the wellhead: liquid fractions, viscosities, densities and velocities will change accordingly. Modern models split up the flow regime that occurs on a flow regime map. Boundaries between flow regimes vary according to the author of the model. In the studied dry gas fields the flow regimes range from single phase gas in the early life of the wells to slug flow with increasing LGR's and decreasing flow rates. The model providing the most accurate predictions of the flow regime and pressure should be determined for each field separately. In this study 16 correlations for accomplishing such conversion were benchmarked. Fig.4 compares the relative error between the FBHP obtained by conversion with and the FBHP measured directly using the down hole sensors. The benchmarking is based on measurements listed in table 4. The wells mentioned in Table 4 above all produce at low LGR's and at moderate flow rates. Only K5F2 has flow rates above 1000 kSm³/d this implies that calculated errors above 1000 kSm³/d are all derived from K5F2 measurements, which we know are not completely reliable. The set of data that could be gathered was not complete for the full range of field situations, but it is assumed that the result of the above benchmark is representative for all the wells in the K and L block. The wells are all similar in the composition of produced fluids and depth. All measurements are taken before water breakthrough. The correlations have shown to be sensitive to LGR; however there were no data available to verify the impact on the error. The relative error is calculated as:

$$Relative\ Error = \frac{P_{calculated} - P_{measured}}{P_{measured}}$$

Table 4 Overview of the available FBHP data to benchmark 16 tubing pressure loss correlations

Wells	**Date gathering device/duration**
K4A5, K5CU1, K5CU3	Temporary bottom hole gauges (several months, several flow rates)
K5F2	Temporary bottom hole gauges, only one flow meter on a combined flow line of K5F1 and K5F2, no periods of isolation
K4A4, K4A5, K4A6, F15A1, F15A3, F15A6, K6GT1, K6GT2	When well tests are performed bottom hole gauges are hung in the well, for a short time, single flow rate measurements were used to check the error (several weeks, often only 1 flow rate)

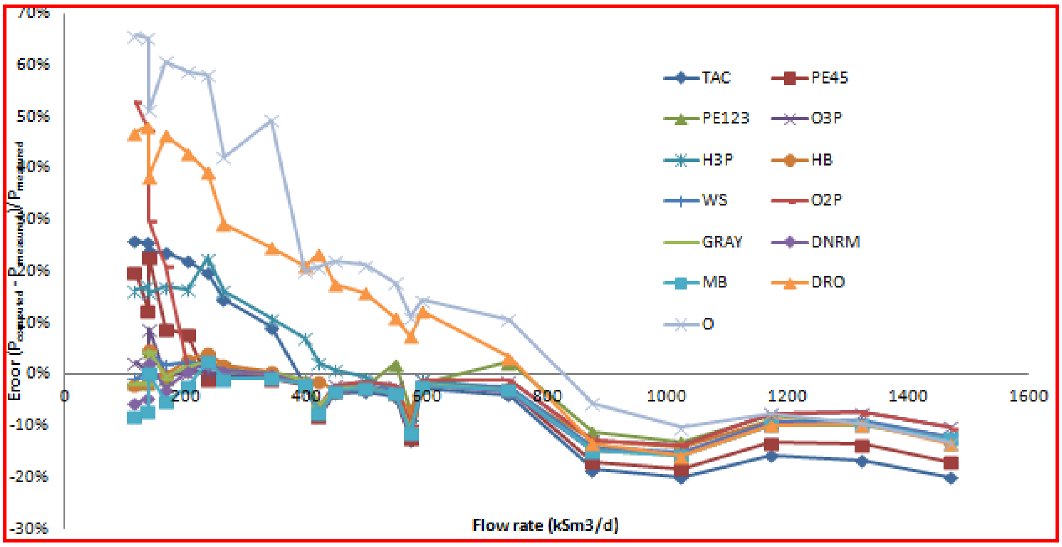


Figure 10 Relative error of the available FTHP-FBHP conversion correlations versus flow rate

At the lower flow rates many correlations give good results, at the higher flow rates (for K5F2 data points) the error increases. Note that K5F2 data points carry an uncertainty in the flow rate estimation.

Criteria to judge the correlations are the relative error and the standard deviation on the error. Olga 3P (Bendiksen, 1991) scored the best, followed by Petroleum Experts proprietary correlation and (Hagedorn and Brown, 1965). Olga 3P has a mean error of -3%, and has with a standard deviation of 0.0533 the smallest P90 interval. To verify the use in other LGR conditions further literature was reviewed. The Hagedorn and Brown correlation was benchmarked at high water cuts by (Reinicke, Remer, Hueni, 1987). Reinicke et al. observed that the error of the H&B correlation remained constant in the range of 10-700 m3 water per million m³ gas produced. Another study by (Persad, 2005) found that the error increases with LGR (0-400 m³ water per million Sm³ gas) for the most correlations available in Prosper and decreases for the PE correlations. Olga 3P was not benchmarked in his paper.

Because the mentioned publications are contradictory it was decided to proceed with the Olga 3P correlation, which is also the recommended correlation within TOTAL organisation (Blandamour, 2012) (Irfansyah et al., 2005).

Based on the fluid composition mist flow is expected in the early life of the TEPNL wells when pressures are high and LGR are low. When pressures drop and LGR's increase (water breakthrough or more dissolved water) the flow can become either stratified or slug, Olga 3P is what is called a mechanistic model (Bendiksen, 1991). These models offer general, physical expressions to describe the flow. This gives more confidence in the applicability of the results for flow regimes outside of the domain reviewed above. This as opposed to empirical correlations like the H&B correlation, which are based on curve fittings based on experiments done in specific conditions (Yahaya, 2010; Pucknell, 1993). In appendix B a full description of all correlations is given as well as well as numerical data on which the benchmarking is based.

3.7. Summary

The goal of this study is to create a tool to monitor productivity of wells operated by TEPNL, and estimate the behavior of some key skin inducing parameters.

A method to do so is proposed. It combines the advantages of the experimentally determined Forchheimer IPR with the ability of deriving specific reservoir characteristics as presented in the analytical inflow model. The proposed methodology is to produce time series of PI values based on production data. When this methodology is applied in an environment where two operating points are available per time step the complete IPR can be utilized. The Darcy coefficient from is chosen to be the indicator of choice for the well's PI. Both the empirical as the analytical equations can derive this Darcy coefficient. Reservoir parameters and/or skin inducing parameters will be derived based on the evolution of the Darcy factor and linked to complementary knowledge available of the reservoir and its surroundings. An analytical model has been adapted with appropriate skin factors to make it applicable to all TEPNL well configurations. This model will be used on all wells, even when a routine is available in Prosper.

Table 5 Overview of skin models to be used in specific well setups

Vertical, perforated well	Tariq and Karakas (perforation) + Odeh (partial pen.)
Vertical, slotted liner/open hole	Van Everdingen (damaged zone) + Odeh (partial pen.)
Vertical, fractured	Mahdiyam (fracture) + Cinco (damaged zone) + Odeh (partial pen.)
Deviated, perforated	Tariq and Karakas (perforation) + Rogers (slant) + Odeh (partial pen.)
Deviated, slotted liner/open hole	Van Everdingen (damaged zone) + Rogers (slant) + Odeh (partial pen.)
Deviated, fractured	Mahdiyam (fracture) + Rogers (slant) + Cinco (damaged zone) + Odeh (partial pen.)
Horizontal, perforated	Ferui (perforation) + Daviau (slant) + Odeh (partial pen.)
Horizontal, slotted liner	Van Everdingen (damaged zone) + Daviau (slant) + Odeh (partial pen.)

Although the method in itself is simple and elegant, it carries with it many uncertainties. The experimental IPR is based on a single operating point with an uncertain reservoir pressure and a calculated bottom-hole pressure. The analytical model needs to be completed using values obtained from a well test interpretation. Some parameters can be estimated, others, mainly in the detailed skin description are too detailed to measure or observe in normal well tests.

4. Uncertainties and sensitivity analysis

In the previous chapter a methodology was proposed that allows us to analyze the productivity of all wells. The method is based on the fitting of a PI obtained from a pseudo analytical inflow equation to an empirical counterpart. The analytically derived inflow equation includes a flexible skin model adaptable to the different well architectures. For different well architectures different skin models are used and added up linearly. Detailed skin models often introduce many unknown variables. Before moving on to the full application on all TEPNL wells, this chapter will determine the uncertainties and analyze the sensitivity to the main physical parameters. To finalize a test run will be done and discussed.

All wells are divided into groups of type wells according to the skin model to be used.

Table 6 Overview and division into type wells

Well architecture	Well numbers
I. Vertical, perforated	F15A1, K4A1, K4D1, K5A1, K5B1, K5ENC1, K5F1, K6C1, K6D1
II. Vertical, slotted liner	L4B1
III. Vertical, fractured	K5ENC2, L4A1&2&3&4&6
IV. Deviated, perforated	F15A3&4, K1A1&4, K4A4&5&6, K4BE1&2&4, K5B2, K5ENC3, K6DN1&5, K6GT1&2, K6N2, L4PN2
V. Deviated, slotted liner	K6DN4
VI. Deviated, fractured	F15A5, K4A2&3, K4BE3, K5A3, K5CU1, K6GT4&6, L4PN1&4
VII. Horizontal, perforated	F15A6, K1A2, K5CU3, K5D1&3, K5ENC5, K5F2, K6GT3&5, K6N1
VIII. Horizontal, slotted liner	F15A3, K1A3, K5A2, K5D2, K5ENC4, K6C2, K6D2, K6DN2&3, L4PN3

The performed work in this chapter leads to test and automate the proposed method and to preliminary validate it in the field. Validation has to be understood in the sense of what can be the usefulness for the well intervention designer since results are open for interpretation and no exact predictions of the parameters can be made.

4.1. Uncertainties in the empirical and analytical inflow model

The inflow models that were proposed carry uncertainty with them. In this section the uncertainties on various input parameters will be discussed and quantified. The empirical model contains production data as input, their uncertainty is mostly due to measurement error and conversion error on the FBHP. The input data used for the analytical model are derived from well test interpretations. For this study it is assumed that these derived data are correct. Uncertainties are more related to lack of precise knowledge of the geological properties.

4.1.1. Uncertainties Empirical Forchheimer IPR

The experimental PI derived from the Forchheimer correlation is normally based on the input of reservoir pressure, and at least 2 operating points defined by flow rate and corresponding flowing bottom hole pressures. For this study the reservoir pressure is derived by linear interpolation of Shut In Bottom Hole Pressures (SIBHP) readings as close as possible in time to the production readings. The SIBHP measurements need to be quality checked since shut in time has a large impact on them in some cases. Linear interpolation should be correct if we assume that the well drainage area behaves as a tank (i.e. depletion by expansion). When the BHP measurement follows a linear trend on a cumulative production- P/Z plot the assumption of a tank model is satisfied. Also for the few cases where the well does not show this linear decline the linear interpolation method is still used to approximate reservoir pressure. Note that these SIBHP measurements are usually done while other wells in the field are still producing. Some influence could be expected, especially for those wells that are not behaving like an expansion drive.

The buildup equation shows that pressure builds up faster when reservoir conductivity (kh/μ) is low. If the well was operating with a large drawdown the buildup will naturally take longer. For a good conductive well (K4A4), which was operating at 20% drawdown the reservoir needs 6 days to build up to 99% of the reservoir pressure. Later in field life, when pressure falls and viscosity decreases, the buildup will take longer (viscosity can decrease by factor 3 through time). The error on the reservoir pressure will be related to measurement error and interpolation error when the well has built up for more than 6 days. It is assumed that the SIBHP is equal to the reservoir pressure when the well has been building up for more than 6 days. If the buildup is shorter the error increases rapidly (logarithmic scale). In the analysis an error of +/- 3 bars is taken on the reservoir pressure readings (Blandamour, 2013).

The single operating point that is available in the TEPNL data base carries uncertainties on both flow rate and flowing bottom hole pressure. The error on the flow rate has been estimated at +/- 5% (Blandamour, 2013). The error on the FBHP was investigated based on some wells equipped with bottom hole pressure gauges. For those wells investigated Olga 3P gives an error between -5 and 20%. The relative error on the bottom hole pressure was taken at +/- 5% on the calculated value. To verify this range the Darcy coefficient was calculated based on calculated bottom hole pressures, and plotted against the Darcy coefficient calculated using measured bottom hole pressure. At low Darcy coefficients (high PI) the range might be slightly too small, at Darcy coefficients of 1000 $bar^2/(m^3/d)$ most values fall within the proposed range.

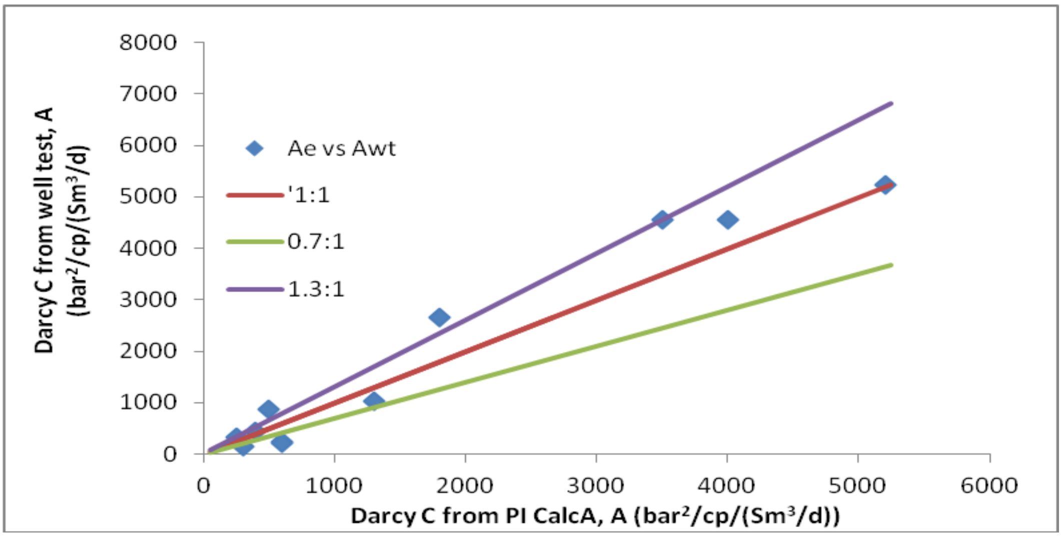


Figure 11 Analytically determined Darcy coefficient (Awt) based on well test interpretation vs. Experimentally determined Darcy coefficient using production gauges averaged over 1 month (Ae)

The multi rate Forchheimer correlation requires 2 operating points as an input but only 1 is available in continuous production scenarios. This of course limits the proposed methodology refer to 3.3.where we change from IPR to PI as indication for productivity.. It was set out to create the tool so that the 2 independent variables A and B would be retrievable through the empirical IPR. In the case of only 1 operating point available only 1 independent variable is retrieved, with the other one being directly linked. The question then becomes if value for PI (= $dQ/dP(Q = 0) \sim 1/A$) obtained in this way really links to the productivity of the wells as would be measured in a well test. To verify this the Darcy coefficient obtained from single operating point measurements is correlated to the PI as can be calculated using the results of an available well test interpretation. 14 well tests have been performed in the time frame for which the tool can be applied (from January 2007 on). Bearing in mind the uncertainties on the input of the empirical correlation a rather good match was obtained between the well test interpretation and PI estimates from production data. Most values fall within the range of +/- 30%. From this it is concluded that for the purpose of the method presented in this study the performance of the Forchheimer model to estimate the PI is acceptable, even when introducing one single operating point. The consequence however is that we have to continue with PI values, the Forchheimer A coefficient, instead of the Forchheimer IPR curves.

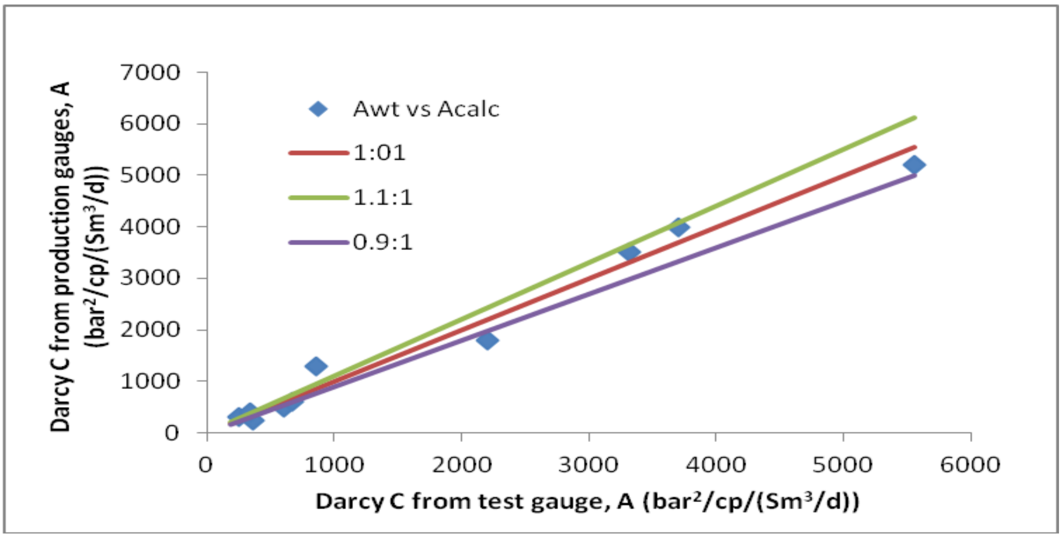


Figure 12 Experimentally determined Darcy coefficient based on two operating points measured in a multi rate well test (Awt) vs. experimentally determined Darcy coefficient based on a single production point averaged over 1 month (Acalc)

Additional investigation was done to get insight into potential evolution of B. The results of the multirate Forchheimer method were compared with just 1 operating point and with multiple operating points as input. In general the Gauss-Newton regression over-estimates the rate dependent pressure loss. In some low rate wells, the IPR even closely resemble a straight line as found for dead liquid wells. Appendix C contains the well test interpretation results and the correlation shown above.

4.1.2. Uncertainties Analytical IPR

The uncertainties of the analytical IPR were harder to quantify. In the paragraph above it was assumed that the PI calculated from the well test interpretation was the correct value. However, it is clear that this PI value is also an interpretation and it is not uncommon that interpretations of kh and skin vary by margins of more than 50% depending on the quality of the well test, interpretation of the well logs and knowledge of the drainage area of the well. In the thesis we are most interested in near well bore effects. The pressure response can only be interpreted after the well bore storage effects have ended, by which time the pulse is already deeper in the reservoir. This implies that arguably the most important part of the reservoir is not ‘seen’. Related to this, in well tests often different ‘zones’ are identified, each with its own kh-value. Picking 1 average value is in practice difficult to realize. In this thesis, the kh value when the pressure derivative first stabilizes was used.

4.2. Sensitivity analysis of the analytical inflow model

The skin inducing formation parameters, introduced in the detailed skin factors, as presented in section 3.3., will be used to equate the analytical PI to the empirical PI. Many variables are involved, but not all of them are equally relevant or influential in the determination of skin. To simplify the routine and to gain insight in which parameters are potentially causing productivity decline a sensitivity analysis is performed for each type of well architecture. In Chapter 3 it was mentioned that the impact of skin is depends also on kh, T and the Dietz drainage area. For each type of well architecture, one representative well is selected whose characteristics are used as input values. The sensitivity analyses for the vertical and deviated versions have been illustrated on the same graph since sensitivities are found to be the same except for the permeability anisotropy. Anisotropy has a more pronounced effect the more the well bore is deviated. However its role in the skin or productivity determination remains marginal.

4.2.1. Vertical or deviated, perforated wells (K5B1)

K5B1 has an interpreted kh-value of 140 mDm and a drainage area around 100 kSm².The skin can be completely described using the Tariq and Karakas model. They concluded that perforation skin depends on:

Table 7 Influencing parameters for vertical and deviated perforated wells

parameter	symbol	value	units
Crushed zone perm ratio	kc/k	0.85	-
Permeability anisotropy	kv/k	1/9	-
Crushed zone thickness	Rcz	0.02	meter
Damaged zone radius	Rd	0.35	meter
Perforation density	SPF	6	shots/foot
Perforation depth	Lp	0.4	meter
Perforation radius	Rp	0.0048	meter

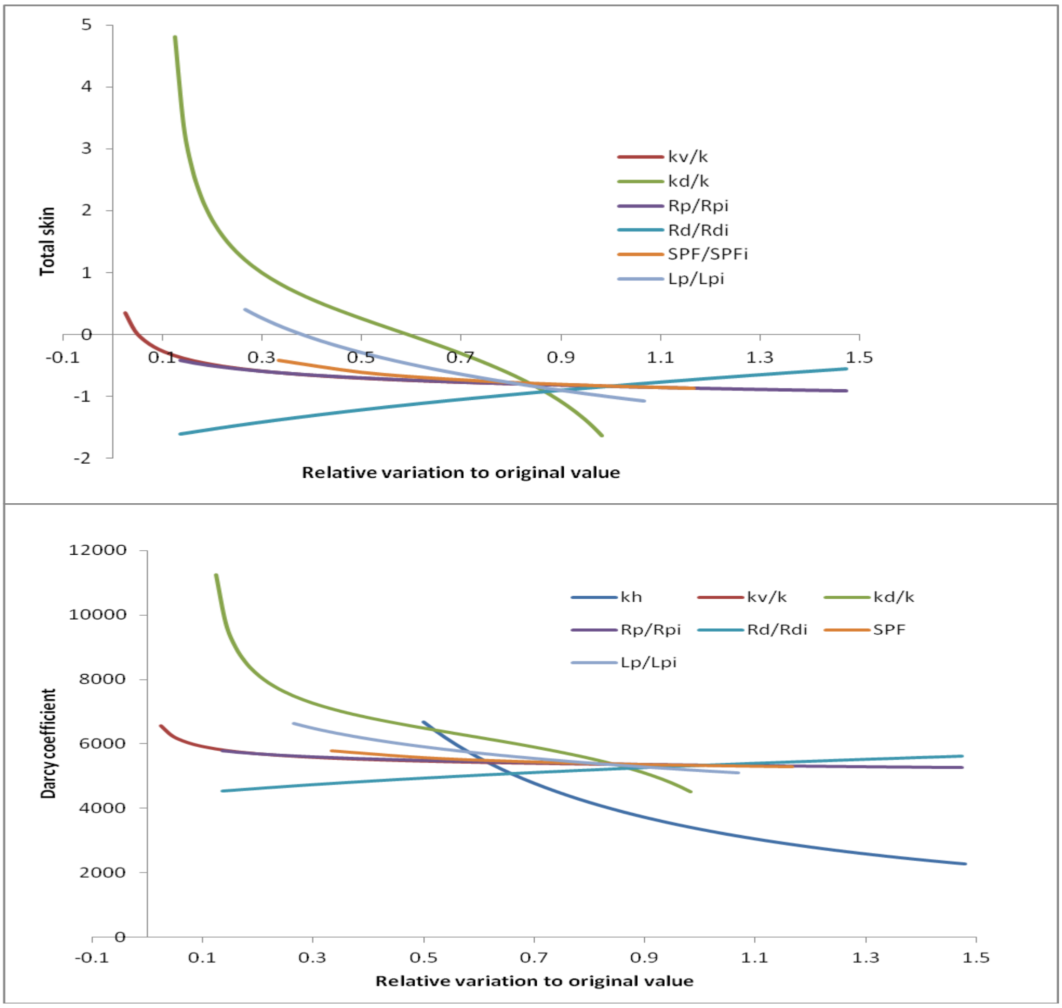


Figure 13 Sensitivity of the analytical skin model (top), showing impact of mainly k_d/k on the bottom the sensitivity of the analytically determined production indicator is displayed using input from well K5B1. Note that it is not only skin impacting performance but also the reservoir itself

From the graphs above can be observed that for vertical or deviated perforated wells the damaged or crushed zone permeability have the largest impact on skin. Especially at high damage ratios Kd/k the skin is very sensitive. Also the radius of damaged zone is important, however to a lesser extent. On the lower graph we identify the kh-value being the most important determinant for productivity, followed by the same parameters influencing skin.

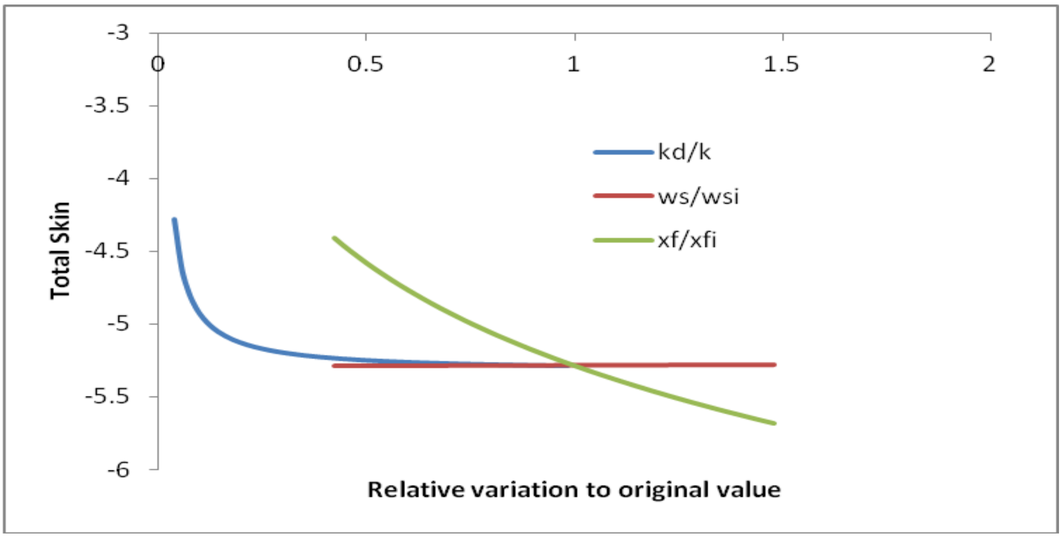
4.2.2. Vertical or deviated fractured wells (L4A1)

The second type of well is described by the Mahdiyam's skin model (Mahdiyarm, 2007). The sensitivity analysis on the analytical model is applied on well L4A1 with a kh-value of 500 mDm and a Dietz drainage area of 200 kSm². The involved parameters are:

Table 8 Influencing Parameters for vertical and deviated fractured wells

parameter	symbol	value	unit
Fracture half length	Xf	40	meter
Damaged zone permeability ratio	Kd/k	0.5	-
Fracture damaged zone thickness	Ws	1.0	meter
Relative fracture conductivity	Cr	10	-

The relative fracture conductivity was not investigated as the fractures are always of very high conductivity compared to the reservoir matrix (Leblanc, 2011).



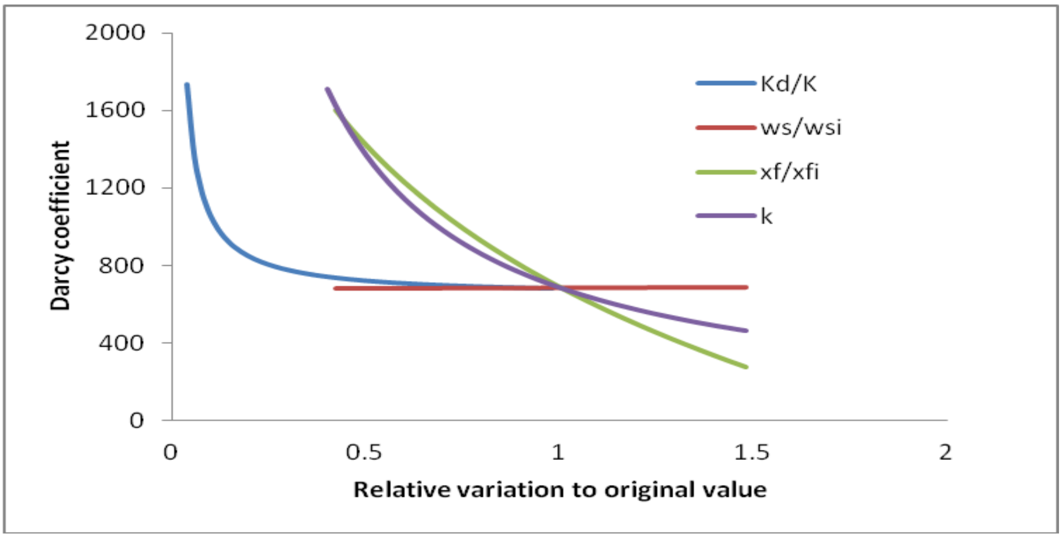


Figure 14 Sensitivity of the skin factor describing the combination of a vertical fractured well (top), only the near fractured permeability ratio and the fracture geometry impact the skin in these types of wells. The bottom graph illustrates the impact on the well's performance. Note that the permeability of the reservoir has the same relative influence as the fracture geometry.

The skin effect of a fractured well is primarily function of the fracture length, with a very weak relation to the damaged zone permeability. The kh-value and the fracture length's influence are of the same order of magnitude on the productivity.

4.2.3. Horizontal, perforated wells (K1A2)

K1A2 has a kh-value of 1170 mDm and drains approximately 300 kSm². The skin is described by Tariq and Karakas, modified for horizontal wells. The inflow model is as defined by Kuchuk and Goode and the perforation skin by Ferui (Goode, 1991; K. Ferui, 2002). Parameters involved are:

Table 9 Influencing parameters for horizontal perforated well

parameter	symbol	value	unit
Horizontal drain length	Lh	150	meter
Permeability anisotropy	kv/k	1/9	-
Perforation depth	Lp	0.9	meter
Formation height	h	18	meter
Formation permeability	k	60	mDarcy

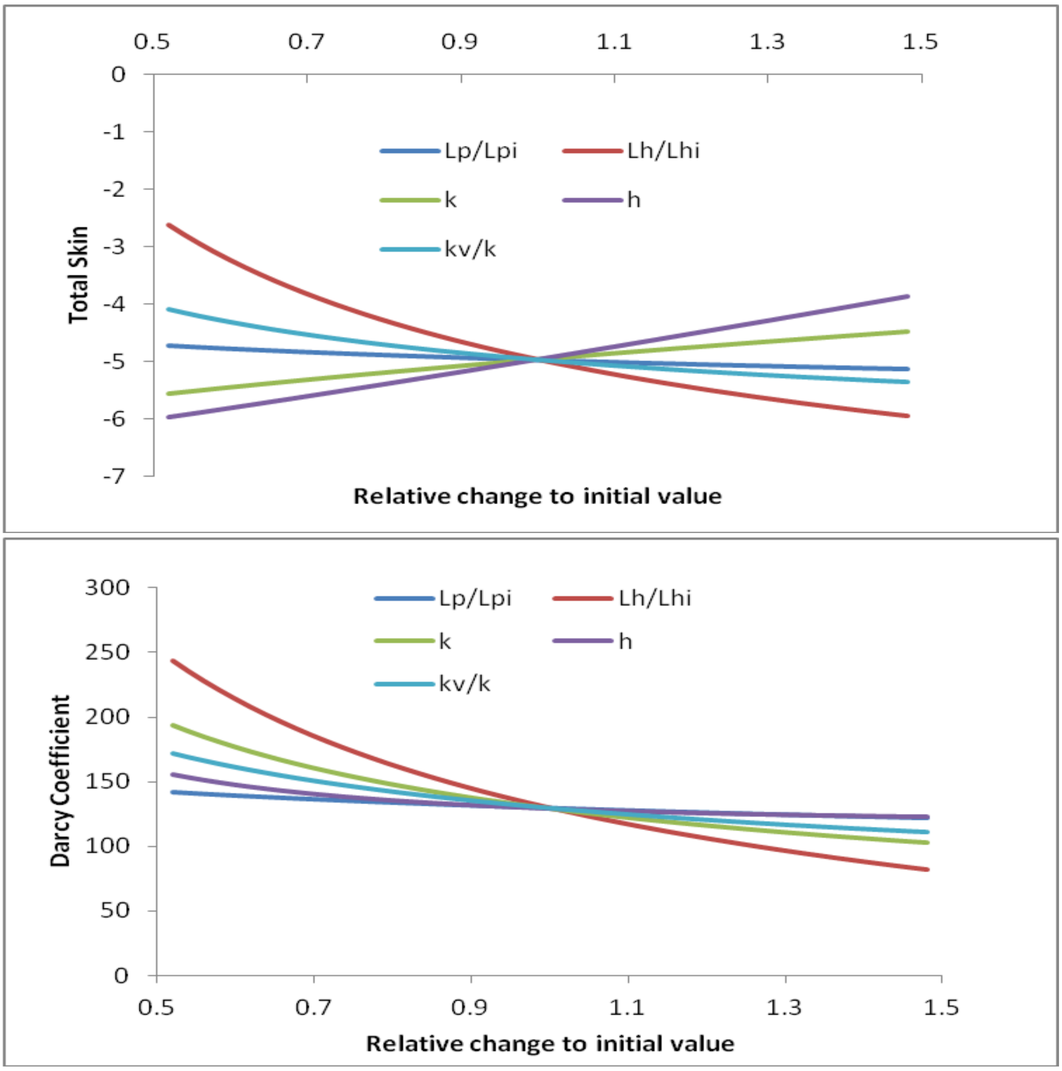


Figure 15 Top graph illustrates the sensitivity of the analytical skin model for horizontally perforated wells. The height of the formation as well as the length of the drain plays a prominent role in the total skin. The productivity of a horizontal well is mostly dependent on the length of the horizontal drain and the permeability of the formation.

The skin in horizontal depends primarily on the length of the horizontal drain and the height of the formation, and less on the depth of the perforations, permeability anisotropy and matrix permeability. The sensitivities for the productivity are most prominent drain length, followed by permeability and permeability anisotropy. The perforations and height of the formation play a much smaller role.

4.2.4. Horizontal wells with slotted liner (K1A3)

K1A3 has a short horizontal section of 100 m, the kh-value is 1100 mDm, with a drainage area of 400 kSm2. According to the Daviau's geometry skin and Van Everdingen's damaged zone skin the following parameters are relevant:

Table 10 Influencing parameters for open hole horizontal wells with slotted liner

parameter	symbol	value	unit
Damaged zone permeability ratio	Kd/k	0.2	-
Dimensionless damaged zone radius	Rd/Rw	10	-
Horizontal drain	Lh	100	meter
Permeability anisotropy	kv/k	1/9	-
Dimensionless well position	zw/H	0.25	-

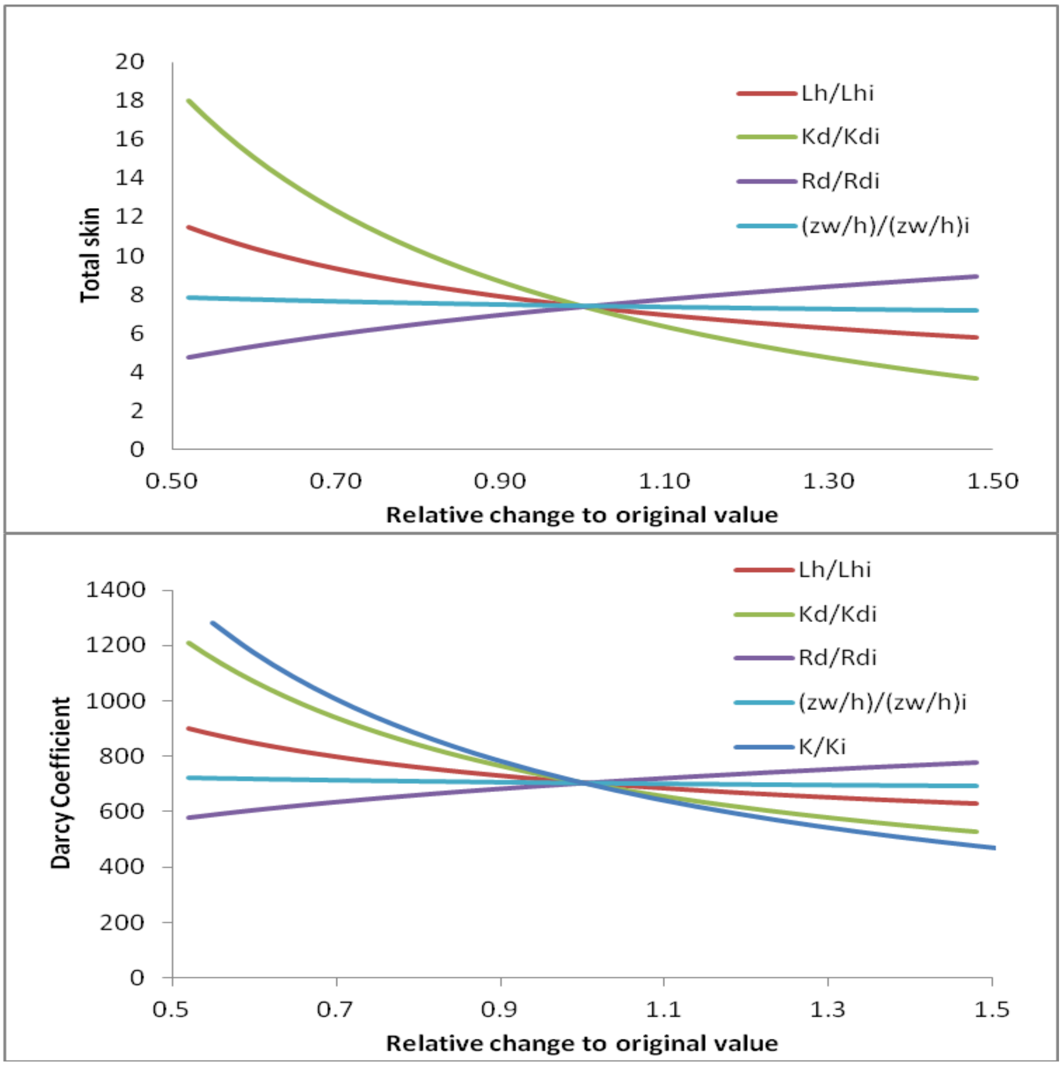


Figure 16 Illustration of the sensitivity to various parameters of the skin model describing a horizontal well surrounded by a slotted liner. The permeability ratio of the damaged zone is the only meaningful factor.

The slotted liner completion has most sensitivity of course to damaged zone permeability. The skin is hardly depending on the vertical positioning of the wellbore in the reservoir at the given permeability anisotropy.

4.3. Physical meaning and selection of the dominating parameters

The sensitivity analysis indicates that for cemented casing completions the altered permeability zone ratios are always important in skin calculation, regardless of the deviation. For perforated wells only permeability ratio, damaged zone radii and perforation depth are the skin inducing parameters able to explain significant changes in skin.

In vertical and deviated fractured wells only the fracture length has large influence on the skin. The damaged zone only becomes important at very low permeability ratios.

Horizontally perforated wells are mainly sensitive to the depth of the perforations, the length of the horizontal drain, the height-permeability anisotropy product and the permeability itself.

For wells completed with a slotted liner the PI depends mainly on damaged zone permeability and radius, as well as the horizontal drain length. In non horizontal well setups it is only the kh-value that influences the productivity, both in equal measure. For horizontal wells, the height of the formation is of much less importance.

In this study we are particularly interested to know which parameters can explain the evolution of the PI. Therefore, from the above parameters those likely to vary over time were selected as indicators of the development of certain type of skin. This was done to not unnecessarily complicate the model and to not describe the same physical process in 2 different variables. In total 8 parameters were identified as being able to alter skin or productivity in a meaningful way.

4.3.1. Reduction of effective reservoir permeability due to condensate drop-out

Reservoir matrix permeability is one of the major properties driving the PI of all wells. Only a reservoir pressure dropping below dew point is identified as a flow impeding mechanism which could potentially lower this parameter. No relative permeability term is present in the inflow equation to account for this phenomenon, but the condensate drop-out in the reservoir could be traced or monitored by this matrix permeability k. A decrease of its value would indicate the pressure dropping below dew point pressure Pd. In the conditions described for TEPNL it is not likely that the average reservoir pressure drops below the dew point. When it appears often liquid condensation occurs as a condensate bank around the well bore. The phenomenon can thus be treated in the sense of additional skin as defined by (Al-Shawaf, 2012). However calculation of this skin factor requires specific data, such as saturation profiles, permeability-stress relations… (all from CVD or CVE experiments), that have not been gathered by TEPNL. When interpreting which of the parameters is at the root of a given PI reduction, the permeability can be ruled out by plotting the reservoir pressure and temperature on the phase diagram for the given fluids.

4.3.2. Reduction of height of producing zone due to rise of gas-water contact

The next most important parameter influencing the PI is the height of the producing zone. The analytical parameter describes the height of the gas column from which is produced. Change in this parameter would indicate a change in average GWC level. Invasion of formation water can lower the gas producing height of the formation as well as one layer depleting or watering out when the well is producing in a multilayer setup. When the water reaches the perforations it can be measured at the surface through salinity readings on the flow line. Often salt readings are only available at the separator receiving the production from several wells, which can make interpretation difficult when another well on the separator already has formation water breakthrough. From liquid wells it could be assumed that salt is produced before the average water level reaches the lower perforations due to coning. Gas well coning differs from oil wells in the fact that the gas cones downward instead of the water upwards. (Armenta, 2002) described this phenomenon and concluded that the first water is produced when the water front has already advanced significantly. The numerical value of salinity might thus not be an accurate indicator of the advancement of the water front, but it should be decent indicator of whether or not the front is advancing above the perforations or not.

4.3.3. Reduction of partial penetration ratio

Partial penetration skin occurs when the producing formation height is only partially perforated, or when the inflow into part of the perforations is restricted. In several wells wireline operations have identified settling/precipitation of solids/salt in the perforations. Salt precipitation can be an issue especially late in the life of the field when pressures have declined (Kleinitz et al., 2001). The perforations could be blocked by salt precipitating from the water coning from the bottom. In gas wells the coning would occur differently than in oil wells (Kabir, 1983). Kabir showed that in gas reservoirs water only breaks through after most of the reservoir has already been flooded. At first the gas moreover tends to cone downwards while the water invades between the wells, while the gas production still largely benefits from the lower perforations (Armenta, 2002). Perforation blockage by debris cannot be monitored at the surface, but variation in time of hp/h can be explained by it. Indications of salt precipitation can be found by analyzing water samples also described by (Kleinitz et al., 2001). These types of analysis however are not part of the regular TEPNL data gathering program.

4.3.4. Damaged and crushed zone permeability

The damaged zone and crushed zone permeability and the perforation depth are of significant importance in all types of wells except for fractured wells. These parameters are discussed together since the physical phenomena affecting them are the same.

Permeability as well as the geometry of the perforations can change due to salt precipitation and the migration of fines or reservoir particles. The salt can precipitate at this location because the pressure is low and changes rapidly. Fines are settling in this environment because the crushed zone and/or precipitated salt act as a physical barrier to these particles. (Suman, 1972) showed that perforations can be partially filled with migrating fines. None of these processes can be measured at surface, but can eventually be monitored by the evolution of these parameters.

4.3.5. Horizontal drain length

The horizontal drainage length is the determinant for a horizontal wells performance. Variability of the drain can occur when parts of the lengths are shut off by for instance stagnant water in a dip in the trajectory. Alternatively it can be that the well trajectory was drilled outside of the reservoir unit, limiting the potential compared to its design value. Drilling outside the reservoir not only limits the producing length, when the lower layer is water bearing this could plug off the more downstream parts of the completion with a liquid plug (King, 2009). It is unlikely that condensation water would accumulate in the dip considering the fluid’s composition. Debris settling in the flow line is a possibility when fluid velocities are low. Although horizontal wells usually operate at limited drawdowns, solid particles could migrate into the well bore. Especially open hole and slotted liner wells are at risk of inflow of solids into the well. Again, when the carrying capacity of the fluid is too low the debris settles, leading to (partial) blockage of the flow line and thus additional pressure loss. The mechanisms behind perforation plugging are the same ones acting in vertical wells. In this case the performance of the well-reservoir connection is lowered, not so much the length in itself. In the sensitivity analysis we observed that a horizontal well is insensitive to perforation density and this mechanism is thus unlikely to affect these types of wells.

4.3.6. Fracture half length (xf):

The fracture opening is key to a fractured well's productivity. The fracture opening is governed by principally the mechanical properties of the rock, reservoir pressure and pressure drawdown. High drawdowns and high reservoir pressure will close the fracture leading to conductivity loss (Du, 2004).

Paradoxically the effective fracture length can also increase with time due to long-term cleanup effects of production. The effects of cleanup are usually smaller than the effects of the increased closure stress as production advances. Stress cycling, the cycle of applying drawdown and shutting the well in could cause fines to dislodge and migrate into the fracture dimishing conductivity. Precipitation of minerals when formation water comes in contact with fracturing fluids have been reported to also play a role in the conductivity of the fracture (Lehman et al., 1999). Combined usually the conductivity and fracture length decrease with time.

In the TEPNL case, right after the completion good fracture conductivities have been measured. Additionally the conductivity only has minor influence on the productivity, save for extreme cases. In literature no mention has been made of fracture becoming smaller. However, it is assumed that fracture closure not only affects width (conductivity) but also the length of the fracture. Overall it seems that fractured wells are very rubust, only when conductivity values get very small the fracture skin increases significantly.

4.4. Summary

Uncertainties of the analytical and empirical IPR relations were discussed together with their sensitivity to various parameters. It was found that the empirical approach provides a good estimate of the PI, also when compared with a PI based on well test results. We started out with the intention to use the whole IPR (described by an A and B coefficients). With the current data gathering program no reliable values of B can be generated. This means only 1 coefficient can be used to estimate the PI of a well. The Darcy coefficient (A) will be used in the rest of the report to estimate the PI of a well. The Darcy coefficient is the slope of the IPR at flow rate equal to zero. This value is not related to turbulence in the well, and only takes into account the mechanical damage. Losing the second coefficient (B) implies that it is not possible to solve for kh and skin, but only for 1 of them while fixing the other. Opportunities related to having a full IPR are discussed in chapter 6.

Parameters key to the productivity of a well differ between well types. Perforation performance is mainly linked to crushed and damaged zone permeability ratio, and to lesser extent to other perforation properties such as depth and radius. Fractured wells are sometimes called 'fool proof' completions. In the sensitivity analysis we saw that the productivity of a well is not sensitive to any kind of damage build up, only fracture closure could potentially decrease the wells production. Horizontal wells are mainly linked to horizontal drainage length and the height of the formation. The performance of the perforations is of secondary importance. Some of these parameters can be monitored or inferred from surface measurements, but many of them cannot. The key parameters were linked to their physical meaning and physical processes that could have an influence on them. This chapter results in a list of parameters will be used to track the evolution of PI.

5. Analysis for the wells in blocks K and L

In the first two chapters a methodology was proposed to monitor the main production impairing parameters near the wellbore. All necessary models, correlations and input data were discussed. Next an analysis of the uncertainties of the selected models and their sensitivities to the main physical parameters was examined. In the previous chapter the most important parameters for quantitatively estimating the productivity of a well were identified and physical mechanisms that could alter productivity were described. In this chapter a Visual Basic Application (VBA) tool is built to automate the conceptual model. After completion and optimization the VBA tool will be used to screen all wells and analyze the selected wells listed in Table 11.The pre-selection or screening of the wells is done using the empirical IPR. The wells displaying abnormal productivity decline are analyzed further using the analytical model. Further interpretation is based on surface measurements other than the flow rate and pressure drawdown. The available data differ per well and cannot be generalized. Surface measurements of interest are those which could be realistically linked to the physical processes mentioned in chapter 4.

5.1. Presentation of the tools: PI Calc and PI Calc A

The methodology for monitoring and analyzing the productivity of wells contains two parts: PICalc and PICalcA. The first part uses the empirical inflow model. The empirical IPR bases its PI evolution with time on production measurements. In chapter 4 we saw that based on the Darcy coefficient is a good estimation for the real PI of a well. PICalc calculates the PI evolution with time of all wells. Besides a series of estimated parameter values appearing in the analytical model, the output of PICalc will be taken as input for PICalcA. PICalcA will alter the key parameters of the analytical inflow model to follow the evolution with time as calculated by PICalc. For each type of well architecture a set of analytical parameters was defined which can be linked to the production impairing phenomena TEPNL wishes to evaluate. Since both tools are relatively new there is no experience built up yet about which ranges of results PICalcA can produce in the field. Gaining experience with the PICalcA tool, and getting a better idea of what variability of the different analytical parameters is calculated by it, can prove useful in future well performance activities. In this chapter 5 only a quick outline of the algorithm behind the tools is given. A complete manual for both tools is attached in Appendix D.

5.1.1. PI Calc

PICalc works with the empirical inflow model, creates a link to Petroleum Experts PROSPER software, and gathers all relevant production data from the various data bases available within TEPNL. The data are read for the whole production history as far as digitally available. TEPNL started digital data recording since the first half of 2007, the exact date varying per well. The script calculates the Darcy coefficient on a monthly basis. It makes a best and worst case scenario according to the uncertainties defined in chapter 4. The flow chart of the process and an example of the output is shown below:

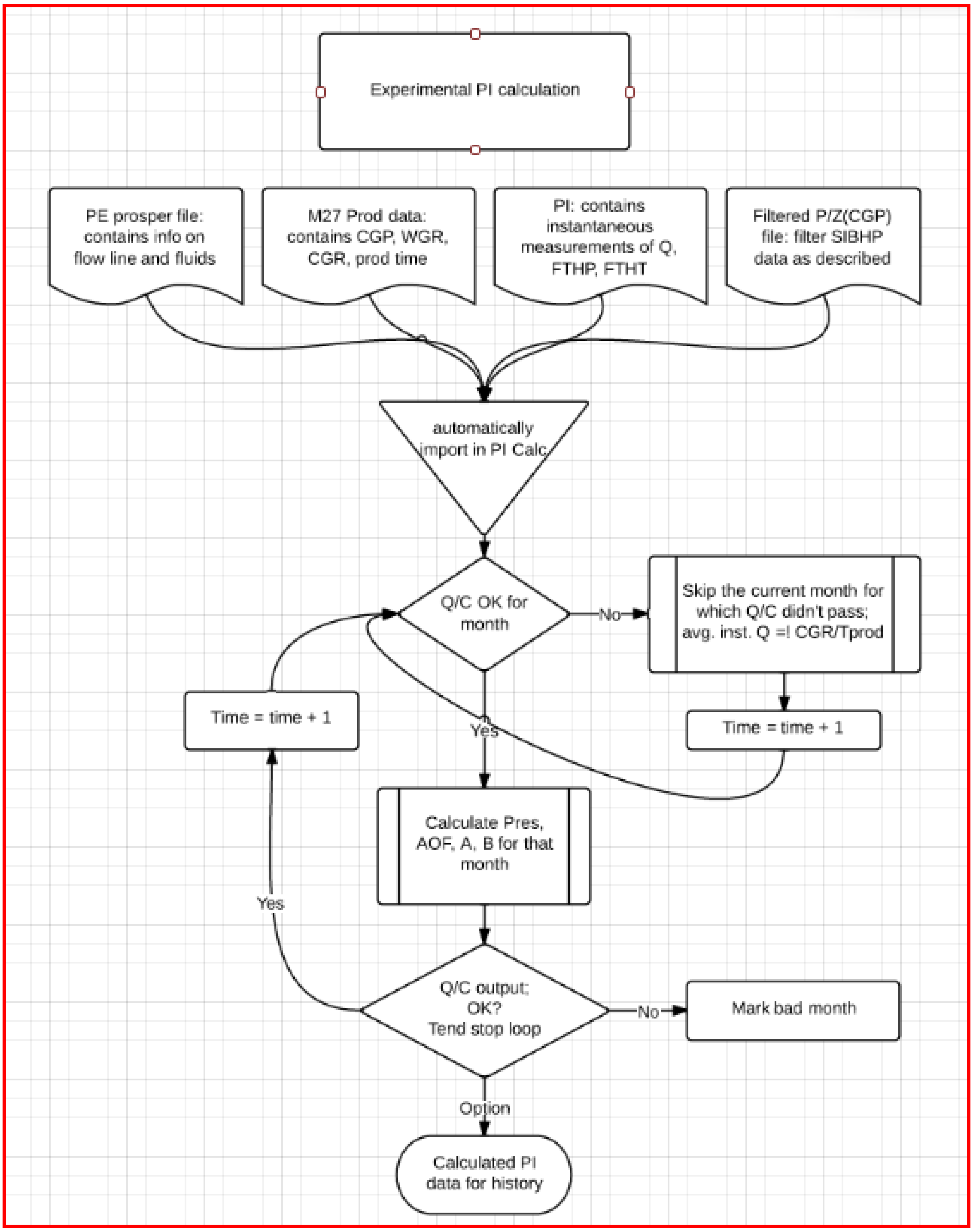


Figure 17 Flow chart of the input stream and requirements of the experimental PI determination.

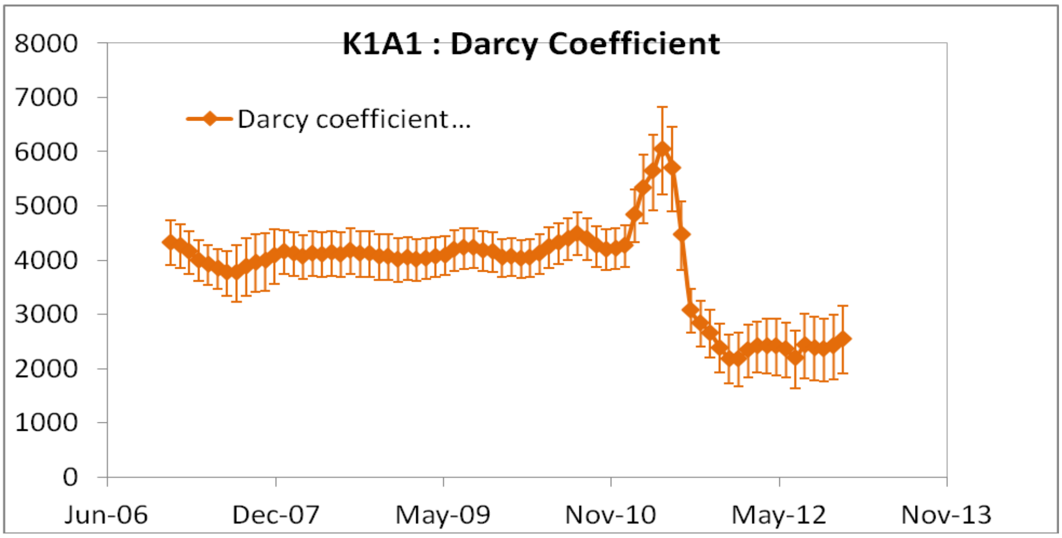


Figure 18 Output PI Calc for K1A1 with error bars calculated as discussed above. Note that the output is as predicted, before the spike the well was producing steadily after an intervention the productivity increased i.e. the Darcy coefficient decreases. This is clearly illustrated in the picture.

5.1.2. PI Calc A

PICalcA are the automated calculations of the second part of the method, based on the analytical inflow model. The tool takes the base case output of PI Calc as shown in fig. 10. The PICalcA tool is split into 2 functionalities. On one hand there is the fitting algorithm, at the other hand there is the calculation of a potential gain in production. The first starts from initial analytical parameters values, to be specified by the user. The fitting algorithm will change one of the predetermined variables within a specified range. For each monthly period the script will determine which value of the running parameter most closely matches the PI determined by the experimental correlation. The method results in errors on the fit usually smaller than 5% of the experimental value. When the user judges the error is too large, the accuracy of the fitting can be increased by adjusting the resolution of the method. This can either be performed by narrowing the range of possible value, or by decreasing the step size between subsequent parameter values.

Initial parameter values are chosen from well test data and may have to be adjusted while doing a first manual fitting. All except the analytical parameter under investigation or running parameter should remain fixed for the complete analysis. Test runs show that indeed it is possible to fit the analytical PI to the experimental PI in this way. Adjusting the selected so-called dominant analytical parameters within reasonable ranges allows not only to fit the analytical PI value to the empirical PI value, but also to follow its evolution with time. At the end of this chapter guidelines are proposed how to do the procedure in practice. For reasons discussed before, the tool only uses the Darcy coefficient A, neglecting the non-Darcy coefficient B. If the method is applied in an environment with more extensive data collection strategies the method should be reviewed. Remarks regarding this will be formulated in the last chapter “Discussion”.

The second functionality PICalcA is estimating under productivity or potential gain. In some cases the PI evolution shows a period of constant PI, followed by a sudden or gradual decrease. The second functionality of PICalcA calculates an indication of what the potential gain is when an intervention would prevent the productivity decrease. This is done by calculating the Darcy and Non-Darcy coefficients for a date before the PI decline has been observed. It is recommendable to use averaged values taken over a sufficiently long time to flatten out short term variations which are likely unrelated to the real reservoir characteristics. Short term variations could be caused by measurement error or FBHP conversion error. Potential gain is defined as the difference between the observed flow rate minus the flow rate obtained with Darcy and Non-Darcy coefficients at a preset value and at current reservoir conditions.

Below the PICalcA routine is presented. The user needs to put in common reservoir characteristics, and select the skin model to be used according to well architecture. The interface, flow chart and example of the output are shown below:

Import - Potential - Fit	Import data	Potential calc	Fit A

RESERVOIR INPUT						
k	1.20	md		Rdamaged	1.00	m
kv	0.13	md		Kdamaged	0.12	md
h	2.30	m		Rcz	0.02	m
drainage area	20000.00	m2		Kcz	0.12	md
Dietz factor	31.00	-		Hp/Hmin	0.90	
T	715.00	Rankine		hmin/hi	0.50	
COMPLETION INPUT				xfmin/xf	0.60	
well radius	0.10	m		Shot phasing	60.00	deg
perforation interval	2.30	m		xf	40.00	m
shot density	6.00	spf				
shot diameter	0.00	m				
shot depth	0.90	m				
deviation	50.00	deg				
Partial penetration	1.00	fract				

Case:	2.00	
Case 1: vertical/dev + perf		K1A1, K4A1, K4A4, K4A5, K4A6, K4BE1, K4BE2, K4BE4, K5A1, K5A3, K5B1, K5B2, K5D3, K5E
Case 2: vertical/dev + frac		K4A2, K4A3, K4BE3, K5CU1, K5ENC2, L6GT4, L4A1, L4A3,
Case 3: hori + frac		K6GT6
Case 4: hori + SL		K6C2, K6D2, K5A2, K5D2, K5ENC4, K5ENC5, K6DN3, K6DN2, K6DN3, L4PN3
Case 5: hori + perf		K5D1, K6GT3, K6GT5, K1A4, K1A2

Import - Potential - Fit	Import data	Potential calc	Fit A

Figure 19 Input screen for PICalc A, note all input that is required for the solution of the diffusivity equation is shown top left. Additional information for the skin description is done by the remainder of parameters.

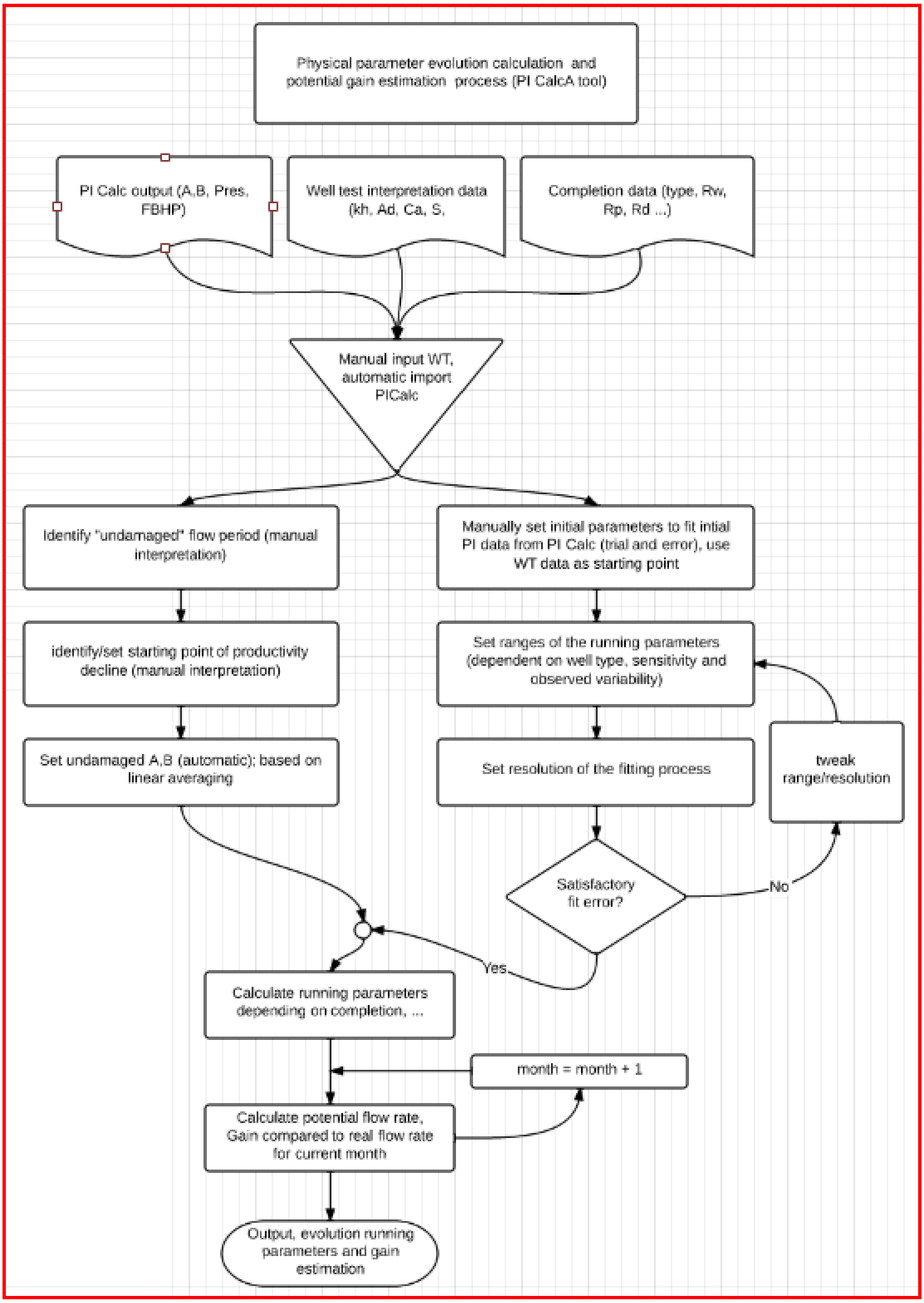


Figure 20 Overview of workings of PICalc A. 2 paths are available, the left calculated the production that is lost due to skin, the right path calculated physical parameters related to this decline

Output of the PICalcA routine is the evolution of skin, its relevant physical parameters, and the potential production gain related to a chosen start date:

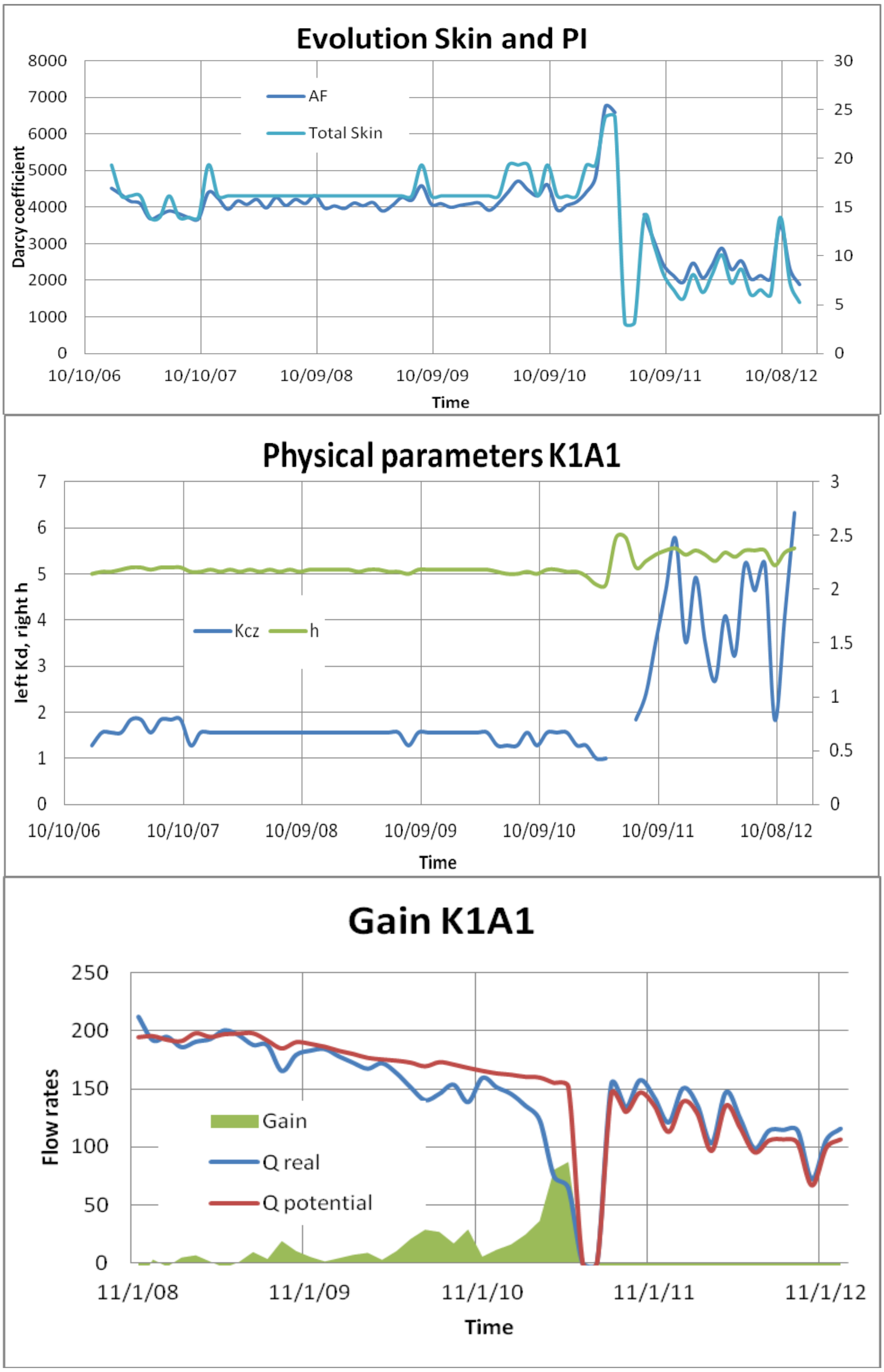


Figure 21 Example of output from PICalc A. Top picture shows the evolution of the Darcy coefficient (PI) over time, with the evolution of the skin superimposed on the curve. The related physical parameters

identified in Chapter 4 are printed below. The bottom picture illustrates the problem in terms of production loss

At this stage, the functionality of the PICalcA routine is only useful to estimate variations in the production impeding parameters when an interpretation of the problem has been made (the problem is known). After some time, when more knowledge and experience is available of what kind of variations are to be expected, maybe the tool could be used for interpretation purposes itself.

The second functionality to estimate potential production gain is an easy way to visualize the potential of a well intervention. However, the procedure is susceptible to human error, since the reference point needs to be selected manually and not objective. In the above case, it is obvious from what date productivity starts to go down, but this is not always so. The accuracy of the gain estimation was verified on wells where obvious jumps in productivity were observed. Although often data quality is such that even obvious and sharp changes in PI are much more difficult to see, it was observed that the tool gives a good estimation of the potential production gains of a well.

5.2. Wells with production decline

In the previous sections it was explained how the empirical PI is generated, and how subsequently the analytical PI can be adjusted to it. In this section a procedure is proposed to identify the wells that have lower productivity than expected. Since only a single production point and reservoir pressure are put in the PROSPER multi rate Forchheimer routine, the screening of the wells is solely based on the evolution over time of the Darcy coefficient A. An increasing A value, an IPR becoming steeper over time, indicates a deteriorating productivity. This information of the evolution of A with time is the output of the first algorithm PICalc discussed above. All wells in the K and L blocks (52) are screened with the multi rate Forchheimer correlation for the period digital historical data are available. Detailed completion, geological and geophysical data are collected for those wells showing a degrading productivity pattern. This PI evolution for all the wells is given in Appendix E.

In total all 52 wells were screened of which 4 had insufficient data quality (incomplete, very erratic) and 9 wells showed a steadily increasing Darcy coefficient over time. The 9 wells with decreasing productivity are: K4A1, K4BE3, K4BE4, K6D2, K6DN1, L4A4, L4A6, L4PN1 and L4PN3. They are selected for further study. Other wells have shown substantial improvement over short times. This decline is sudden, and not continuous. Likely it is coupled to variations in FWHP and not due to the reservoir. As discussed before, an increasing A value can indicate increasing skin factors, but also a lowering kh-value. For this reason an accompanying WGR/NaCl plot is relevant. In some cases a clear correlation between WGR and A is visible at first glance. For other cases a deeper study needs to be done to form an opinion of what might cause the declining productivity. The 9 wells in question are: K4A1, K4BE3, K4BE4, K6D2, K6DN1, L4A4, L4A6, L4PN1 and L4PN3. A strong link with the WGR is observed for K6DN1, L4PN1 and to lesser extend for L4PN3.

To get a first clue of the magnitude of the problem, the potential production gains are estimated. The optimal production is estimated by fixing the coefficient A at a time before the increasing trend starts. The skin is back calculated from the production data. The production gains that can be calculated by lowering the skin factor to a reasonable value are shown in the table below. As mentioned before not all the problem wells will suffer from skin build up, and it is unrealistic to think all skin can be removed.

Production decline can often be clearly identified. The production gains showed below are the result of resetting A and B parameters to their initial value, before the productivity decrease starts. In theory A and B values should remain constant, independent of pressure or production history. It is assumed that the initial A and B factors describe the reservoir in its undamaged state. Other parameters such as WGR, CGR, and Pres are the most up to date data available. Note that the non-Darcy coefficient, previously neglected, is used only here to estimate the potential of the well, not to derive any formation properties.

Table 11 Overview of wells with suspected skin issues

WELL	GAIN (kSm^3/d)	h PERF (m)	H PLT (yr) (m)	DEV (deg)	COMPL (-)
K4A1	70	120	N/A	10	PERF
K4A3	50	51.5	18 (07)	44	FRAC
K4BE3	-	23	N/A	50	FRAC
K4BE4	150	100	N/A	60	PERF
K6D2	130	490	N/A	93	PERF
K6DN1	40	64	33 (07)	30	PERF
K6DN3	30-140	320	N/A	90	SlotdLiner
K6GT4	40	29 m (F), 27m (P)		55	PERF/FRAC
L4A4	20	41	N/A	0	FRAC

5.3. Application of the analytical model and interpretation

Now that the wells showing productivity decline have been identified, each of them will be analyzed in more detail with the PICalcA tool. Because PICalcA is currently not able to give a cause of the problem, the declines are checked for correlation with measured data. These data are taken from wireline surveys as well as production data and are used to identify mechanisms discussed in chapter 4.3. A final report per well should indicate the referential potential (based on empirical formulation), variation in the relevant parameter as calculated by PICalcA , a diagnosis or possible cause, evidence for the diagnosis, and history of interventions regarding this and other parameters on that particular field.

The most interesting result would be if a clear link could be shown between falling PI and a given measurement like salt production or WGR. Based on the rate of decline, some scenarios can be more or less likely.

Many different forms of PI degradation can occur. Some wells gradually and continuously lose productivity, others continuously and gradually lose productivity down to a certain level where the PI stabilizes. In other wells changes in PI are sudden, over short periods of time are observed.

Each of these 3 aspects of PI evolution are coupled to a physical mechanism discussed above. It is assumed that water invasion goes gradual, over long periods of time until the reservoir completely waters out. When debris buildup in the tubing is at the root of the problem it is assumed that the buildup is gradual over a long time, stabilizing at a new productivity level when erosion becomes equal to precipitation. Significant decline over a short period of time could be explained by either damaging of the flow line, or salt precipitation. The two latter mechanisms work over period of hours to days, near instantaneous over the time intervals discussed here (Aquilina, 2012). Ideally these aspects would be matched statistically based on previous observations. Knowing that the set of wells is limited, as well as the time duration for which they are observed this proved to be impossible. The aspects discussed above were in fact matched to previous observations, but they are too small in number to give statistical certainty.

Therefore, when no correlation can be made between PI degradation and surface observations, this can be due to absence of measurement data or because no correlation exists, the interpretation will be based on the shape of the PI evolution and the rate of decline of the particular well.

In the past, a well with a stable PI history showing a sudden drop in PI followed by a persistent and gradual decrease, was linked to mechanical damage to the tubing (observed collapse with bailer run). A well producing at stable PI, suddenly dropping to another, lower and constant PI level was linked to salt deposition (observed PI increase after fresh water wash). In some cases similarly to salt depositions the sudden drop in PI could be linked to interference with other wells. More gradual and continuous declining rates are likely due to slow moving processes such as water invasion, fracture closure and debris build up. In some cases the long decline stops, reaching a new equilibrium state at a lower PI. The decline can occur over the course of several years before a new equilibrium is reached. Our physical interpretation of this phenomenon is the buildup of debris, gradually covering more and more the lower perforations. Equilibrium is reached when the flow velocities reach the critical point where erosion equals deposition. Of course, the purpose is to detect “damaged”, i.e. underperforming wells in the sense that there is potential for improvement. Even though these wells are damaged, in a limited time frame they do not show any variation in PI over time. For example, K1A1 showed salt deposition and a clear and sudden decrease in PI. After the problem was remedied with a water/acid wash it was observed that the PI was higher than before the salt deposition. This indicated that the well was already under producing before the salt deposition started, which would not have been picked up in the first screening of the wells.

In the interpretation process, surface measurements will be used where available to indicate certain processes, all the other processes cannot be monitored by readings and require wireline operations to verify:

Table 12 surface measurements related to damaging mechanisms

Surface indicator	**Indicated process**	**Remark**
Salinity readings	Water invasion	Can only be observed when the waterfront reaches the perforations. Potentially delayed observation in wells only partially completed or horizontal wells. Could also indicate salt precipitation in/around perforations.
Geological map and cross linked PI evolution	Interference	Wells completed within the same reservoir could lead to a reduced drainage area, leading to lower productivity. Both the geological map and the PI curves could indicate interference.

K4A1

The Darcy coefficient shows a sudden increase May 2011, before this date the PI stable at A = 450 $bar^2/Pa.s/(Sm^3/d)$. After a long shut in period end 2012, the PI improved for a short time. Currently it is again at the trend defined by the undamaged reservoir, as seen between end of 2011 and mid-2012.

An intervention was scheduled immediately after the PI decrease in June 2011. The bailer showed signs of collapsed tubing. Very likely this is the root of the problem, with additional resistance building up in the tubing ever since. The additional PI loss after the collapse could be due to salt deposition at this imperfection in the tubing. Salt deposition is most intense where local and large pressure drops occur as demonstrated by (Duc, 2011). Precipitation is caused by oversaturation of the water holding the salt. Lowering the pressure and thus evaporating the liquid phase could eventually lead to precipitation. It is assumed that the collapse of the tubing results in a reduced area open to flow thus increasing the flow velocity. At this position in the well bore the fluid runs an increased risk of over saturating and depositing the salt in the fluid. In this case the instantaneous production loss after damaging the tubing is estimated at 100 kSm^3/d, while the secondary production loss due to salt deposition is estimated at another 75 kSm^3/d.

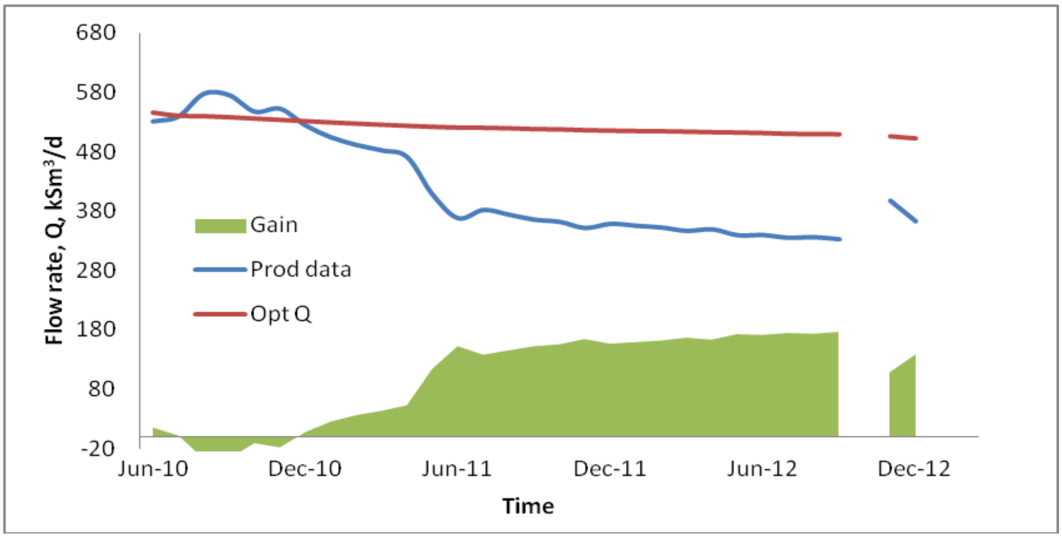


Figure 22 Potential flow rates and gain over time for K4A1, note the sudden increase in potential gain when the tubing collapses followed by steady a steady increase likely caused by precipitants in the tubing

K4A3

In this well the decline was initiated mid-2011. Although dates coincide with K4A1 discussed above, there appears to be no correlation between the failing K4A1 tubing and the decline in K4A3. K4A6 was put on stream at the same date. Based on the geologic map, there is no reason to believe there is interference between these wells. The wells have a large spacing (2 km) and they are separated by a fault known to be sealing. Plotting flow rates and pressures of both wells also does not reveal any correlation. Shut in late 2012 briefly increased production afterwards, however it fell back quickly. Applying the interpretation logic for vertical wells, a slow and gradual decline is either linked to debris build slowly blocking perforations or water invasion. In past wireline operations no debris buildup has been observed, and there is no reason why debris accumulation would start now (often it is a recurring problem in TEPNL wells showing signs from the start of production). Also considering the correlation between the salinity of the produced water and the Darcy coefficient, the root cause of the decline is water invasion. According to the analytical model the formation water advances at a rate of 0.8m per year. Late-2012 the PI briefly increases again after a shut in. In oil wells this could be explained by previously coning water returning back to its static equilibrium position. However, as indicated by Armenta (2012), coning in gas wells is actually beneficial compared to static rise of water. No explanation is available for the increase that is observed here. According to PICalcA the reservoir has lost 4 m of the initial 16 m of gas column to water rise. According to a PLT performed in 2007 most production stems from the from (lower) UWest C3 and to lesser extent from upper Westphalian C5b. Considering most production comes from the bottom formation, plugging back the lowest formation to cut off water production would not be beneficial. If the interpretation is wrong, and the loss is not due to water invasion, a potential increase of 50 kSm^3/d could be found.

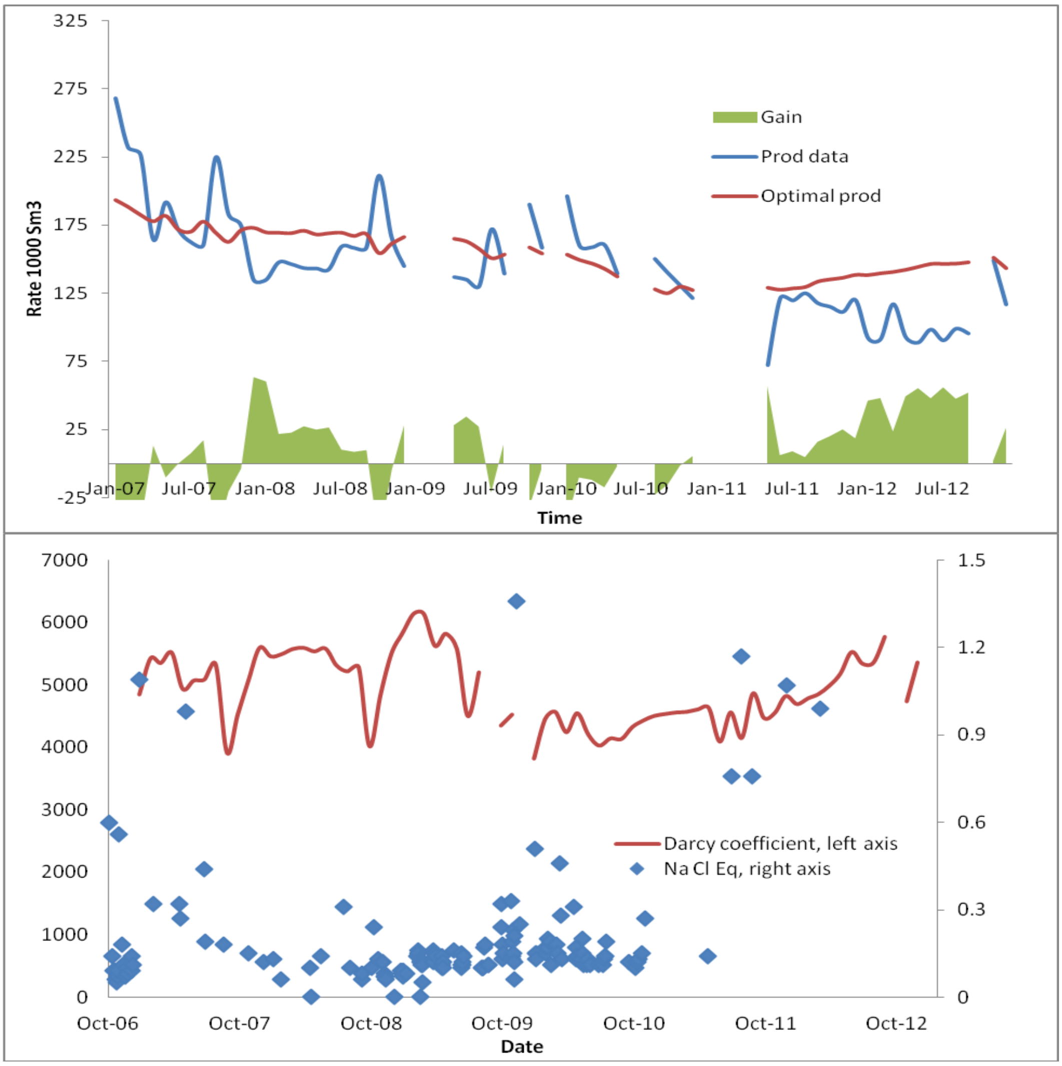


Figure 23 PI and salinity evolution for K4A3. Note that the PI increases after a long shut in period late 09, after which the PI falls steadily until now

Table 13 Overview of possible variations of the relevant skin related parameters

	Δh/hi	ΔKcz/Kczi	ΔPP/PPi
K4A3	4/16	0.08/0.15	0.05/1

K4BE3

K4BE3 has a history of flow string blockage due to debris buildup. The well was initially producing water from one of the reservoir layers. In May 2007 however the layer producing the formation water was plugged. The effect of this is clearly visible with a steadily increasing PI after the shut in. In April 2008 the well was mini-fractured (test fracture to determine rock characteristics for full fracture prediction modeling) and fractured after which again salt is produced. The tubing was cleaned out and the formation acidized in July 2012, restoring the HUD back to 2008 levels and likely removing any formation damage that might have been built up. From this it is expected that the productivity would return back to 2008 levels, which would mean a flow rate gain of 25 kSm^3/d. In practice a gain of 15 kSm^3/d was observed. This number can still increase in the coming months, as the flow still needs to stabilize.

These types of interventions are very common. Remedial operations are bulked together because rig time is so expensive. Bulking offers gains in likelihood the issue will be solved, however we lose knowledge about which factor was actually influencing the productivity (salt, or debris?). Combined with poor follow up it is difficult to know which of the stimulations actually drives the gain. In this case it is impossible to know if the acid increased permeability near the fracture surface, or the cleaning of the tubing improved the performance of the tubing and perforations.

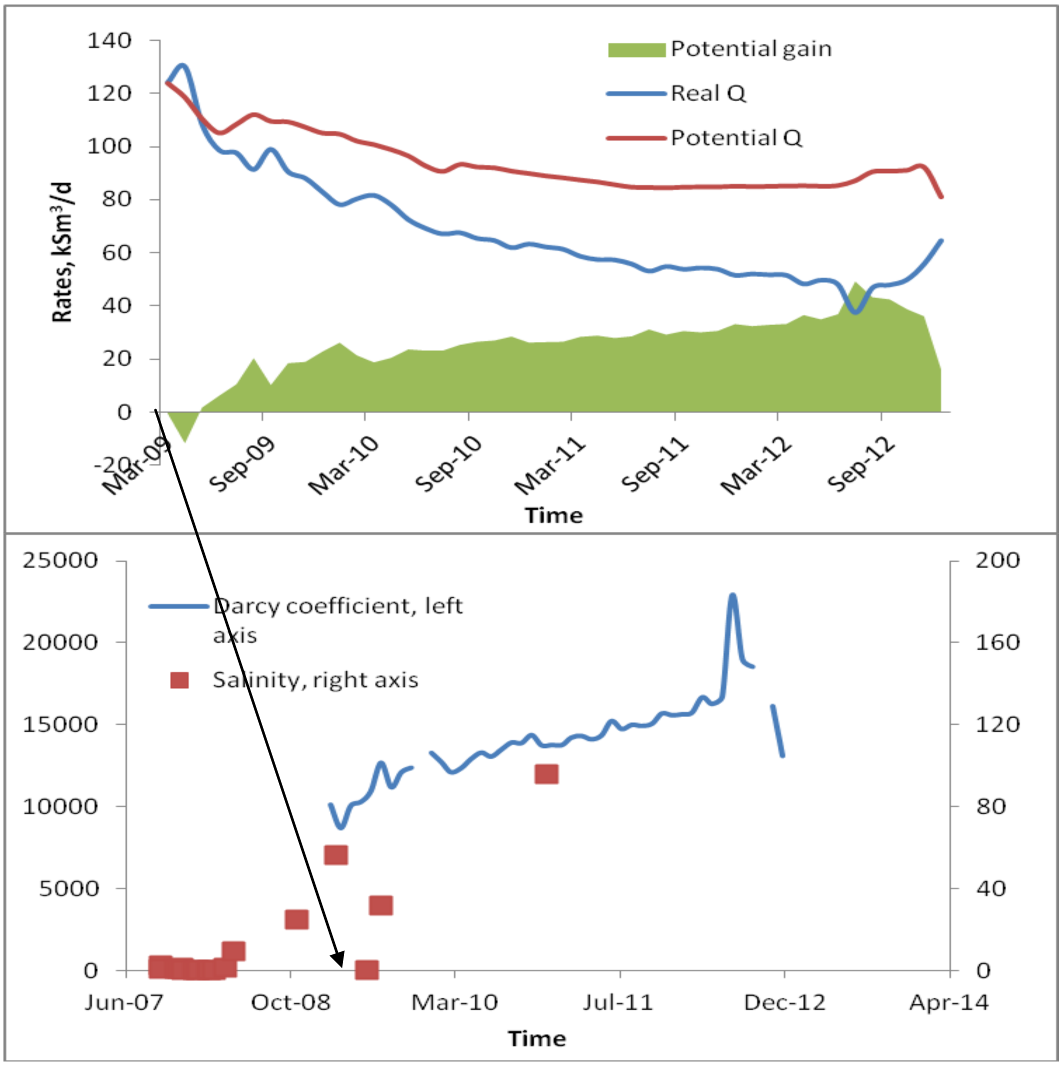


Figure 24 Potential, Productivity and Salinity over time of K4BE3

Table 14 Overview of possible variations of the relevant skin related parameters

	Δh/hi	ΔKd/Kdi	ΔPP/PPi
K4BE3	0.5/2.3	0.032/0.034	0.2/0.9

<u>K4BE4</u>

K4BE4 was completed in February 2006 with initial gas production in March 2006. One wireline operation was done in March 2007, where the HUD was observed at the top of the perforations, and cleaned out to restore production. Since the cleanout the productivity has been declining steadily from A = 440 $bar^2/(Pa.s(Sm^3/d))$ in September 2007 to A = 795 $bar^2/(Pa.s(Sm^3/d))$ in July 2011. The potential production gain by restoring the reservoir to its undamaged state is considerable, 150 kSm^3/d. Because of the aspect of the PI evolution, and its well historics we are inclined to attribute the current problem again to debris accumulation. The recommended course of action would be a bailer run followed by a fresh water and acid wash. History shows that the last cleanout also had a potential gain of 150 kSm^3/d, which was later also realized with the cleanout. Some saline water was observed in the production stream. Salinities remain low between 0-2 g/l. These low salinity numbers are not in line with the height reduction estimated by PICalC (3 meters). The PICalcA tool predicts that 25% of the height of the perforated interval is completely blocked by debris. Here, it is observed that blockages due to debris are not 100% impermeable. Instead of completely blocking the perforations and flow line they oppose an additional barrier to flow.

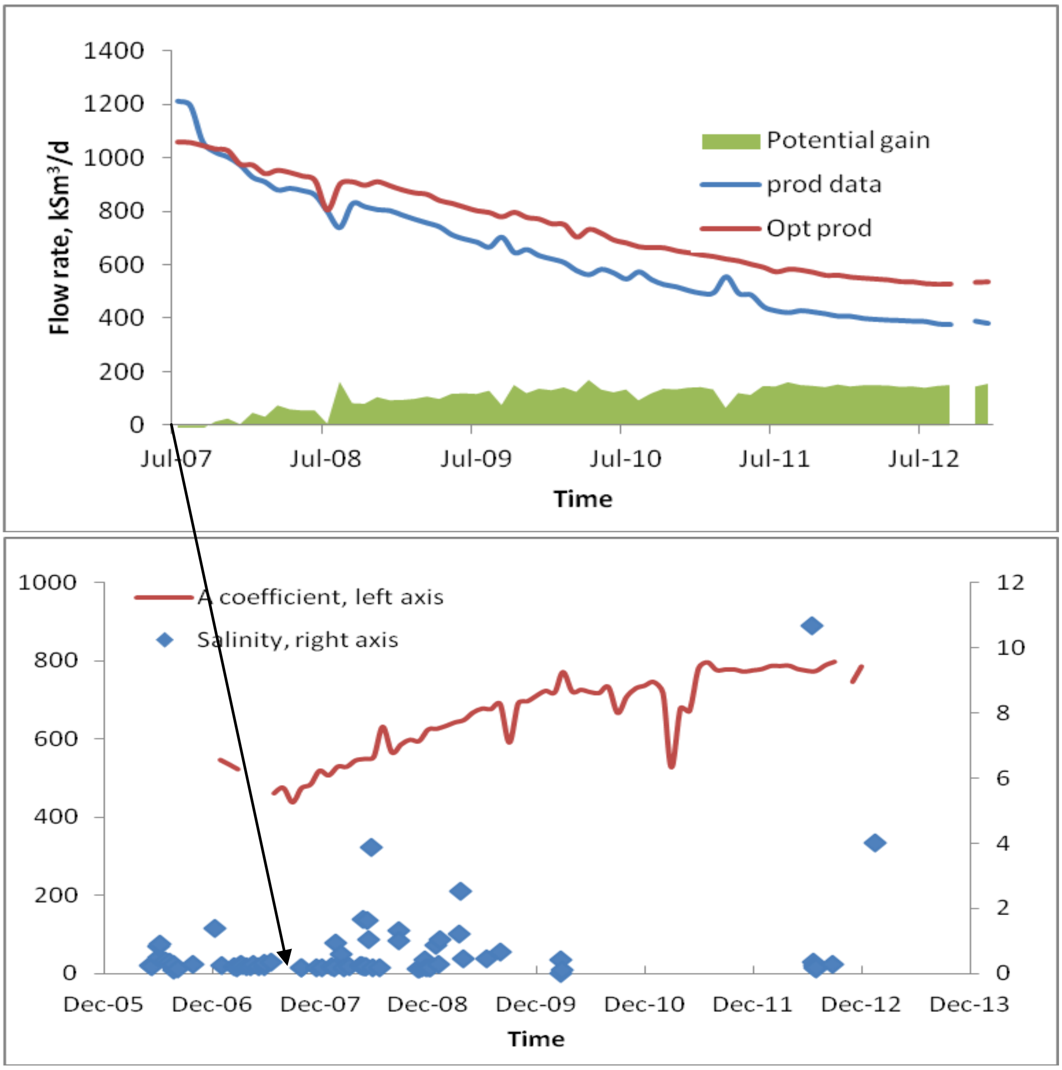


Figure 25 Potential, Productivity and Salinity over time of K4BE4

Table 15 Overview of possible variations of the relevant skin related parameters

	Δh/hi	ΔKcz/Kczi	ΔPP/PPi
K4BE4	3/13	5.5/7	0.25/1

K6D2

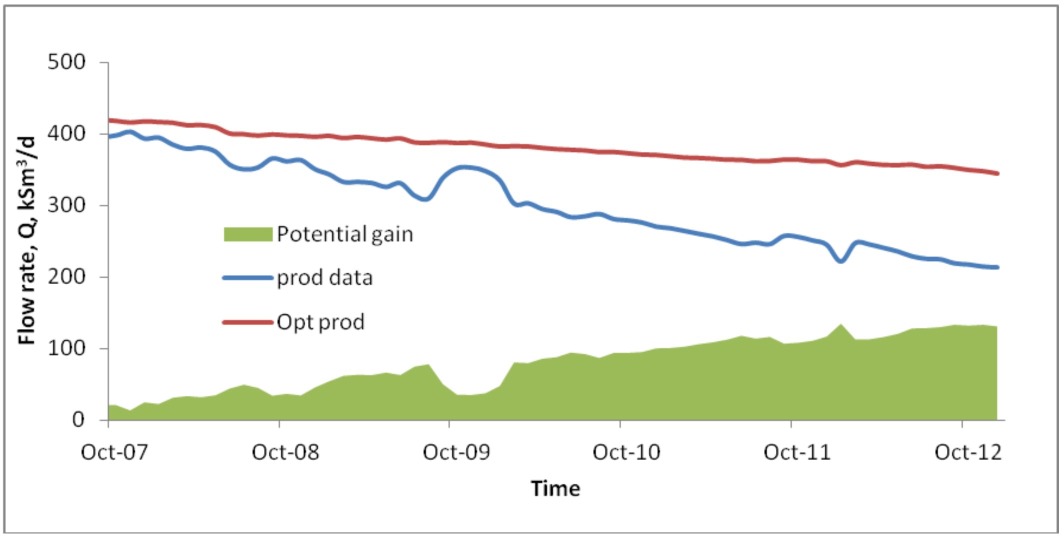
K6D2 is a horizontal well, with a horizontal drain of 391 m in a formation of 40 m thick. The well is completed with a slotted liner. No wireline surveys were done, nor were there any interventions.

For these types of wells we have discussed that the damaged zone permeability, the length of the drain, the reservoir permeability and the reservoir height are able to cause significant changes in PI. The well is not producing any saline water. In this case that does not necessarily exclude water advancement as the well is placed 30 meters above the initial water level. FBHP and reservoir pressure are both above dew point, so relative permeability effects are also excluded.

Partial shutoff of the drain is not likely because the trajectory is continuously downward. Formations of liquid plugs in a slotted liner are less likely because the there is no container to hold the plug in place, or if needed, the fluid can bypass the plug. The formation of a liquid plug also does not stroke with the observed aspect of the PI evolution (this would be a sudden event), and no formation water was observed at surface. Liquid plugs cannot be formed out of gas condensate as pressure and temperature do not allow gas to condense down hole.

A gradual and continuous decrease of PI is seen. In this case the only parameter that gas not been ruled out is damaged zone permeability around the well. The permeability ratio should have decreased from an initial 1.1 mD to currently 0.7 mD. Potential production gain is 130 kSm^3/d. Suggested prognosis is an acid job. Good acid jobs are difficult to achieve in horizontal wells, even more so for slotted liner completions.

Given that no well historics are available, the interpretation is solely based on salt readings, the aspect of the PI evolution and the sensitivity analysis. While the final goal of the thesis is to do just that, not enough statistical information is available to draw conclusions regarding the accuracy of the interpretations based on this method.



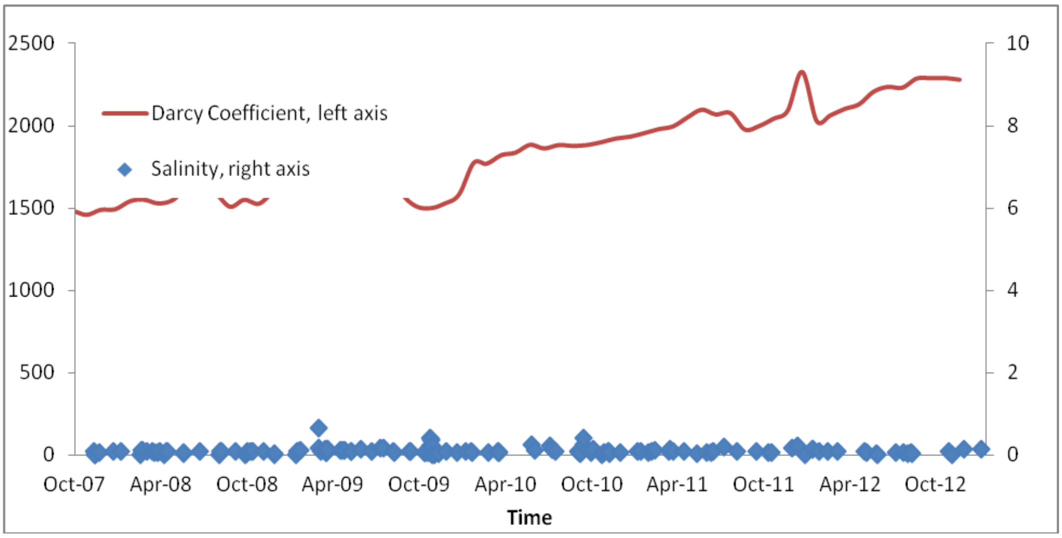


Figure 19 Potential, Productivity and Salinity over time of K6D2

Table 16 Overview of possible variations of the relevant skin related parameters

	ΔL/Li	ΔKd/Kdi	ΔPP/PPI
K6D2	120/391	0.4/1.1	-

<u>K6DN1</u>

K6DN1 is a deviated well perforated in the Lower Slochteren formation. HUD was confirmed at 90m above the top perforations. Sampling revealed the debris was soluble in fresh water, after which the well was cleaned with a fresh water wash, returning the HUD back to normal (4054 m/TH). In March 2007 a velocity string was installed, perforated and a PLT was performed. The revealed that production comes from the bottom 33 m (LS-S1-2).The PI of the undamaged reservoir is considered to be observed in January 2007, at the closest time to the cleanout and the installment of the VS. The VS was installed because the well was self-killing. At this time the Darcy coefficient is 277 $bar^2/(Pa.s(Sm^3/d))$, from here the productivity decline at an increasing pace until its current Darcy coefficient of 2630 $bar^2/(Pa.s(Sm^3/d))$.

Perforated wells have been indicated to be sensitive to perforation damage and debris buildup in the tubing. Currently we observe that WGR and salinity are increasing together with the Darcy coefficient, possibly indicating further water front advancement (6m over 5 years). Alternatively previous wireline operations have confirmed that salt is precipitating in the tubing and possibly also the formation. This issue is potentially solved by the installation of the VS. The VS makes that bottom hole operating conditions are at higher pressure, limiting dehydration of the fluid and limiting salt precipitation.

In this case, none of the potential damaging mechanisms can be excluded based on measurements. Based on PICalcA 6m of the gas column is replaced by water, or the tubing is blocked over 80% of its height. Based on WGR measurements, salinity measurements and well historics I would conclude that both mechanisms are occurring simultaneously. Consequently the proposed course of action would be another fresh water wash coupled to tagging the GWC to see its advancement compared to the last PLT run.

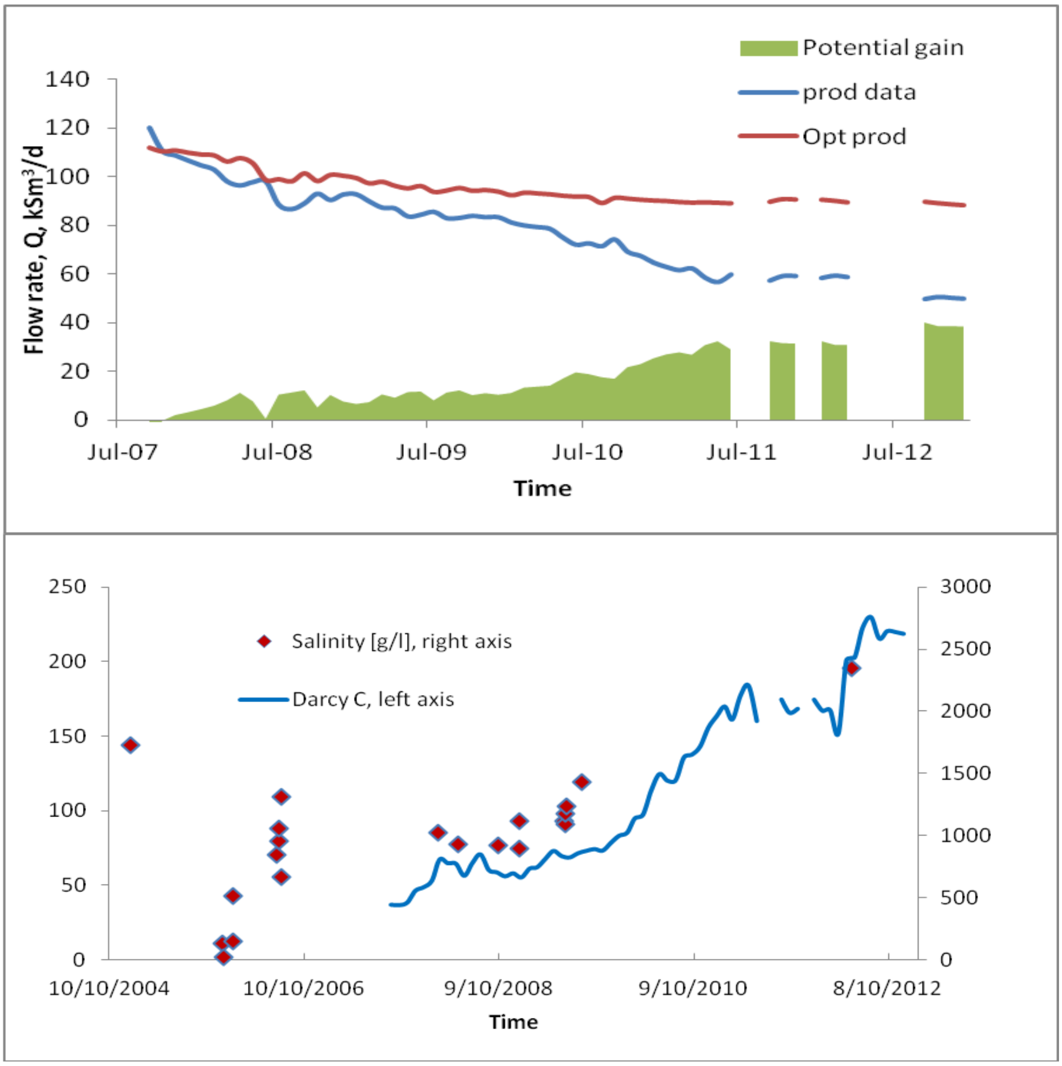


Figure 20 Potential, Productivity and Salinity over time of K6DN1

Table 17 Overview of possible variations of the relevant skin related parameters

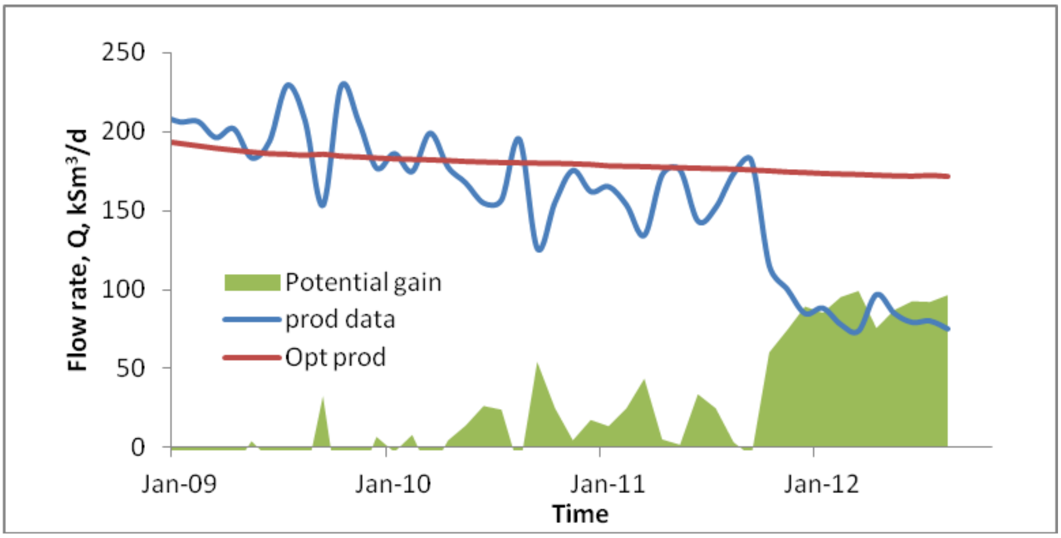
	Δh/hi	ΔKd/Kdi	ΔPP/PPi
K6DN1	6/33	1.7/2	0.8/1

K6DN3

K6DN3 is a horizontal well completed with a slotted liner. This well had water breakthrough in 2002. The salt production has increased steadily, while the PI has flat at A = 950 $bar^2/(Pa.s(Sm^3/d))$. A spike is observed August 2011. After the spike the Darcy coefficient stabilizes at A = 2100 $bar^2/(Pa.s(Sm^3/d))$. In February 2008 a wireline run (carrying a camera) confirmed a deformation of the tubing. The deformation did not appear to impede flow at that time. The deformation did prevent the wire to go down to the perforations and tag the HUD as well as the condition of the perforations.

A spike like this possibly indicates a problem in the tubing or plugging by salt deposition. Gains could be 140 kSm^3/d.

Alternatively, to salt deposition blocking the flow line, this abrupt change in PI could be explained by suddenly shutting off part of the production string due to a liquid plug in the horizontal section. The PICalcA tool estimates the losses in drain length to be 170 m out of 175m, or the damaged zone permeability to lose 97% of its initial permeability. Both scenarios look unrealistic, but again should be confirmed to build up experience with the tool. It is more likely that the deformation was aggravated further increasing the flow impedance. Compared to the undamaged well setup, the well is currently under producing 100 kSm^3/d. For this well there is no proposed course of action as the tubing is damaged. In this case no stimulation operations are possible.



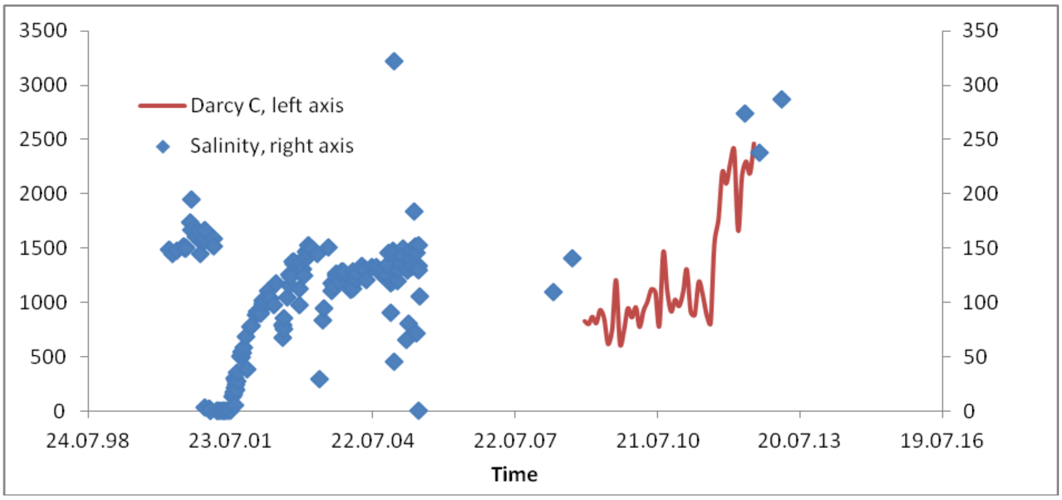


Figure 21 Potential, Productivity and Salinity over time of K6DN3

Table 18 Overview of possible variations of the relevant skin related parameters

	ΔL/Li	ΔKd/Kdi	ΔPP/PPi
K6DN3	160/190	1.70/1.75	-

<u>K6GT4</u>

K6GT4 is a deviated and fractured well. The Darcy coefficient evolution remains flat at 2040 $bar^2/(Pa.s(Sm^3/d))$ from the start of the measurements to May 2010. In June 2010, the Darcy coefficient increased to 5080 $bar^2/(Pa.s(Sm^3/d))$ for 1 month, afterwards falling back to 4000 $bar^2/(Pa.s(Sm^3/d))$. The well is producing from 2 layers spaced 100 m apart. A PLT run performed in April 2007 observed cross flow from the lower formation into the top formation. In February 2010 a wireline run tagged the HUD 100 m above its previous level. The debris was identified as being salt. After a fresh water wash the HUD returned back to normal, with minimal effects on flow or productivity. In September 2010 the well was cleaned out. Sand and salt were recovered in minimal quantities. After the cleanout the well was filled with brine (salt water) of which 1100 Sm^3 was lost into the formation. The lost water was produced back out with the aid of N_2 injection. A new well was put on stream in October 2010, on the geological map both wells were assumed to be in isolation of each other.

From the sensitivity analysis performed in Chapter 3 we remember that fractured wells are robust against any type of mechanical skin buildup. The only processes realistically affecting a fracture's performance would cause gradual decline. In this case, an abrupt decrease in productivity should be linked to issues in the tubing or due to interference with other wells. In this particular case, the initial spike of A to 5000 $bar^2/(Pa.s(Sm^3/d))$ is assumed to be caused by the fluid loss into the formation, causing relative permeability effects as well as an unfavorable flow regime in the tubing. Later on, when K6GT6 was taken on stream the drainage area of K6GT4 was limited. This is observed in the plot comparing Darcy coefficients of both K6GT4 and K6GT6. A production stop of K6GT6 could verify if interference is the problem in this well.

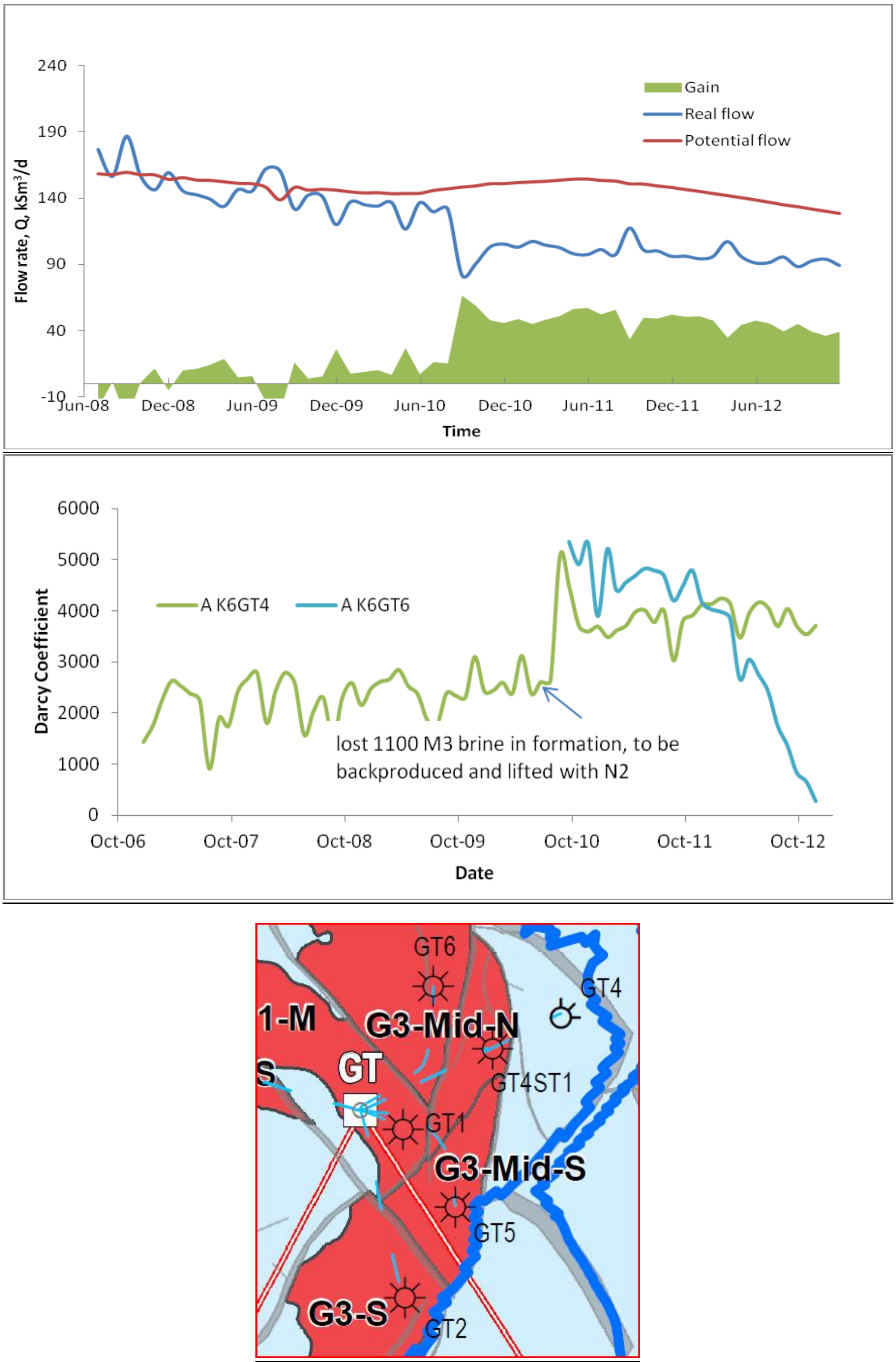


Figure 22 Potential gain and PI evolution of GT4 and GT6 plotted together demonstrating interference and a detail of the geological map of the area with positions of the wells. Note that the loss of brine occurs at almost the same time as the startup of K6GT6

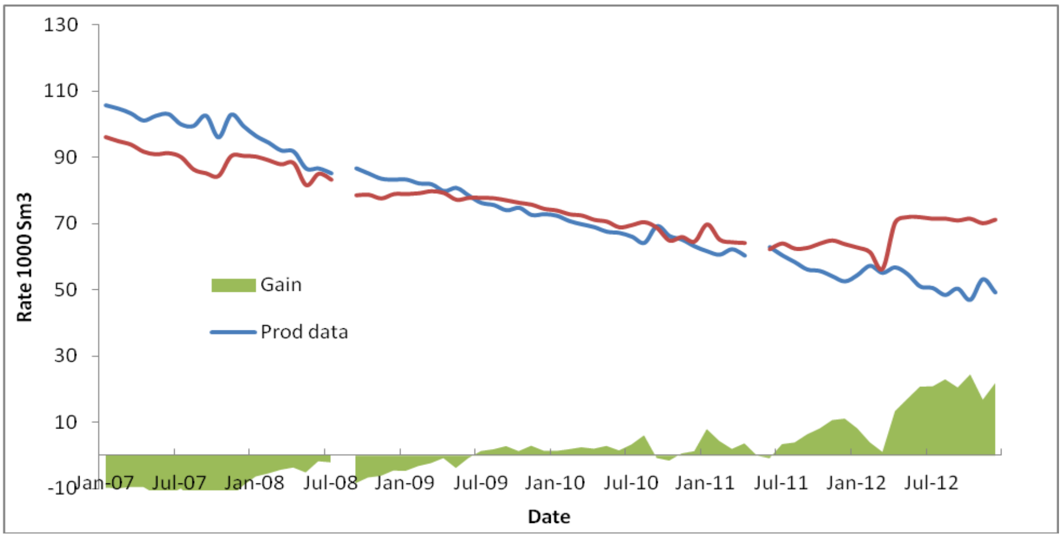
Table 19 Overview of possible variations of the relevant skin related parameters

	Δh/hi	ΔKd/Kd	ΔPP/PPi
K6GT4	6/15	0.1/0.15	0.09/1

L4A4

A vertical, fractured well. All wells on the separator have been producing since July 1984, and was fractured in April 1997. Production started declining abnormally starting June 2010. Wireline runs in 2001, 2003 and 2009 indicate that the HUD remains constant over time. The Darcy coefficients declines from 185 bar^2/(Pa.s(Sm^3/d)) June 2010 to 383 bar^2/(Pa.s(Sm^3/d)) in December 2012. In February 2012 sudden jumps in productivity are observed in both L4A4 and L4A6. At this point the inlet pressure of the separator was reduced, lowering the FTHP by 2 bar. This reservoir is near its field life with a reservoir pressure of 25 bar and FTHP of 6 bar. On this platform no individual sampling points are fitted on the flow lines. Salinity readings are available on the separator, connected to 6 wells. It is unknown which of the wells are producing formation water and which are not. In L4A6, which has many similarities to L4A4 (identical pressures and very similar completion) the same jump in productivity is observed when the separator pressure was lowered. Other L4A wells seem unaffected by the change in working pressure.

Wireline has that debris buildup is very limited in this well. Water advancement cannot be ruled out because there are no separate salinity measurements per well. It is observed that both L4A4 and L4A6 are operating at FBHP of 10 bar, whereas other L4A wells are still at 12-13 bar. It is possible that at these pressures salt is precipitating and causing damage. Alternatively, it has been discussed that fractures' closure stress increases with production. It is thus also possible that the fractures are closing, with production impairment as a consequence.



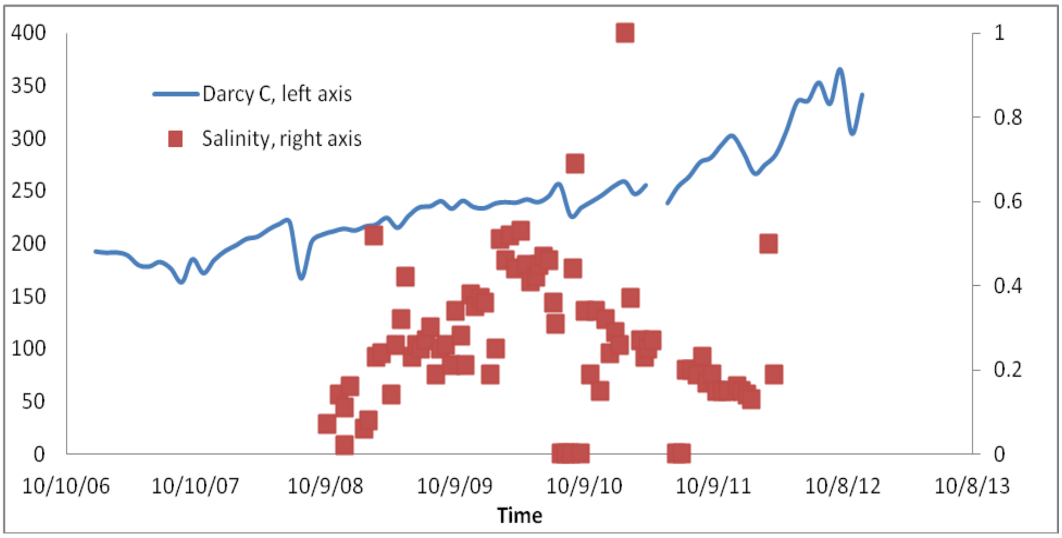


Figure 23 Potential, Productivity and Salinity over time of L4A4

	Δh/hi	ΔKd/Kd	ΔPP/PPi
L4A4	11/33	0.6/1	0.13/1

5.4. Summary

In this chapter the problematic wells were discussed and interpreted. Grouping these 9 wells in any way (architectures, reservoir, problem) did not result in a clearer picture of the issues playing in these fields. The wells have no common denominator to group them by. The problems are common for different well architectures and reservoirs. The same reservoir shows different problems and so on. From the numbers we can conclude that wells that 10% of wells using perforations has some issue, this percentage rises to 21% of wells that are not perforated (fracture, slotted liner). It would seem that while fracture and slotted liner completions are robust against skin development, they offer disadvantages in terms of debris migration into the flow line.

In chapter 5 all wells tagged as problematic by the experimental routine were ran through the analytical routine. When all wells would be treated the calculated gain would be around 700 kSm^3/d or 6% of a actual total daily production of 11.400 kSm^3/d. From the few wells that showed some sign of decline some observations were made concerning the link to the proposed physical mechanisms driving the decline as discussed in chapter 4. The aspect of the PI evolution can be one of monotonous, slow decrease. These types have been linked to water invasion. The same aspect is observed for wells where the tubing slowly plugs with scale or salt. Two wells, with a known history of salt precipitation, have shown that the decline stops at a certain point. This point is reached presumably when erosion and precipitation balance each other out. When decline is sudden, time range of 1 – 2 months, the evolution is too quick to be related to water invasion or debris build up in the tubing or perforations. In 1 well the sudden change was linked to damage in the tubing. A second well shows this behaviour and could be used to verify that these sudden changes are inherently linked to tubing damage. An intervention on one well had good results, even though no decrease in productivity was observed by the empirical routine. It needs to be realized that the time horizon of the routine is only 5 years, while some wells have been producing for more than 20 years. It is thus imaginable that damage has been incurred in the past, and has stabilized now. These wells will need to be identified by trial and error. The proposed routine does not offer a solution to this problem.

6. Discussion

In this study a tool is proposed and implemented to track the evolution of the productivity of all the wells currently producing in the K and L block. The tool is providing this information based on data within the constraints of the TEPNL data gathering strategy. The well performance engineer gets a notification only when a well's productivity drops below a certain level. For the wells that are tagged by the experimental routine PICalc, a set of steps has been discussed to further diagnose the well and to estimate the production gains that can be expected from an intervention.

This management by exception method is based on the monthly calculation of an experimental PI, provided by the multi rate Forchheimer correlation. The actual diagnosis of the well remains predominantly a well history exercise, although the analytical model is able to add estimations of certain physical parameters as well as, in some cases, rule out physical damage mechanisms when the correct data is available.

In the progress towards creating this tool the experimental routine was checked on its uncertainties. Total uncertainty of the experimental routine was evaluated by introducing error margins on the input data. Reservoir pressure was assumed to be measured to an accuracy of 3 bars. This is an acceptable assumption in cases where a well shows a linear P/Z-decline. For wells that do not show this ideal decline, it is difficult to say if this error is realistic. In those cases 3 bars is likely a conservative value. The true gas flow rate was considered to be within 5% of the measured value. While these measurements can be very accurate in ideal conditions, the error can be very large outside the orifice design measuring range. Given that orifices on some wells are not changed for many years, an error of 5% is a safe estimate. For wells just starting production, at flow rates close to the optimum measuring rate, the error could be lowered to 1-2%. When the flow rate drops to less than 20% of the orifice design rate, the measurements become very unreliable with errors between 5-20% depending on the deviation from design rate. Originally, within the TEPNL organization the FBHP was calculated using the Gray correlation having an average error of 10%. Resulting from the introduction of all these error margins mentioned above, is the uncertainty range on the PI of the experimental routine. In many cases the change in calculated PI, which is assumed to be linked to well degradation, is in the order of magnitude of the uncertainty. To get more reliable output it is advisable to reduce the error on the FTHP-FBHP conversion to a minimum, since results are most sensitive to this input. The conversion to FBHP was analyzed, essentially trying to reduce the error. The FTHP-FBHP conversion correlations showed that the Gray correlation mismatches the observations considerably for the TEPNL field conditions. In the method the range of uncertainty on the PI is between an acceptable 5% for low flow low pressure wells, but up to 50% for high flow high pressure wells.

Based on benchmarking 18 correlations on 12 wells, this study recommends using Olga 3P instead, which displays the smallest average error (5%) and standard deviation on the error. Although Olga 3P performed best, it still introduces a large uncertainty in the method. The range of uncertainty on the final result is so large that the results almost become irrelevant, especially for high productivity wells. Further research could prove useful when venturing into other conditions than the ones encountered in the studied wells, more specifically wet gas wells or wells producing at high LGR's.

This conclusion has had more impact on the TEPNL well performance department than solely its utilization in the presented routines. Daily practice showed that Gray was unable to predict self-killing wells adequately. Now, with the new insights the life time of a well can be more accurately predicted, and interventions like for instance installing a velocity string can be designed with more confidence.

The analytically formulated PI is used when a well is diagnosed as having productivity issues. The analytical PI is equated to the PI found by the experimental routine. In this study a detailed skin model is used, to derive certain physical parameters related to skin build up. Skin models were selected for all types of wells operated by TEPNL. Although these models are often used in the industry, it is difficult to predict its errors in field conditions. Passed experiences within TEPNL of the perforation model of Tariq and Karakas as well as the horizontal well model have shown good results. In this thesis, different skin models are linearly summed up. Although this is widely used practice, it is unknown how accurate the summation method really is. Here, the Vrbik summation method brings in large and not quantified uncertainties. Extra research could be done to verify the accuracy of the models separately, as well as combined. To the author's knowledge, no papers have been presented on this topic. Until further investigation, it is assumed that the analytical inflow model coupled to the skin models give results acceptable for the purpose of this study.

The estimate of the PI by the experimental routine based on the field data was correlated to PI estimates from good well testing data. It was found that they give a good match with results from well tests. The error between both is within the range of uncertainty on the experimental PI. The good match was encouraging given all the uncertainty on the well test interpretations as well as on the input data of the empirical model. Good matches were observed over the whole range of PI's of the TEPNL wells. This gives a good foundation for further use of the tool. In this same analysis of the experimental model it was found that increasing the amount of operating points as input for the experimental correlation increased the performance of the method somewhat, but not dramatically. Although the estimate of PI does vary too much with the amount of available operating point, an independent evolution of the non-Darcy coefficient would offer great opportunities discussed later.

Finally the presented methodology was applied to all 52 wells operated by TEPNL. For 9 wells the diagnosis was that they had productivity issues. Following the interpretation guidelines, 2 were diagnosed having a damaged tubing, 2 with water invasion, 2 with debris build up in the production string, 1 with mechanical skin build up around the wellbore, 1 showed interference with another well and in a fractured well the fracture is potentially closing. 2 interpretations are "unsure" in that sense that 2 options could be present. Unfortunately the interpretation could not be verified in cases where skin build up is at the root of the productivity decline. In 1 case the damaged tubing was confirmed, while water invasion in another well was also confirmed by the geosciences department. Although promising results were obtained, the method is still in its infancy. Validation of interpretations as well as experience with the tool needs to be gained. Validation was done to an extent possible at this date. 4 interventions aiming at restoring productivity were done in the period 2007-2012. Comparing the interpretations that would have been made before the intervention with the actual result of the intervention shows some weaknesses as well as confirmation of the method. 2 wells were treated in 2008; productivity history is only available for a period of 6 to 12 months. This period proved to be too short to predict problems. In one of the 2 wells no trend was observed, in the other a clear trend is observed, but too short to be tagged by the method as problematic. In 2011 three wells were treated, 1 well showed a very good result however no decline in PI was observed beforehand. Considering the nature of the intervention (clean out) and the physical mechanism behind it, it could be that this well had already reached its equilibrium state prior to data gathering in 2007. The other intervention showed some improvement (not much), also within the range of uncertainty of the experimental PI calculation. The program did not tag the well as problematic.

The above paragraphs show some weaknesses; namely that the uncertainty is very large compared to expected gains in PI. Only very long productivity decline periods can be observed, where short decreases fall within the variation induced by changing surface conditions and uncertainty. Another weakness is the available history. Especially in cases where the PI reaches a new equilibrium it is possible that the equilibrium has been reached prior to 2007-2008 when digital data gathering started. This is a missed opportunity, as in these cases gains can be expected to be large considering the skin factors related to partial penetration. From this we take away that uncertainty of the experimental model, as well as the variability induced by surface variations in FTHP are enough to mask average sized productivity decline, or productivity decline built up prior to 2007. Digitizing the archived production data could potentially lead to more insight for older wells.

In the course of the study some important limitations and/or uncertainties were exposed, mostly related to the experimental PI determination. Several methods were identified to improve the accuracy and reliability. The largest improvement to the routine could be found when systematically all wells are produced at a minimum of two rates per month until stabilization has been reached. Secondly the use of direct bottom hole pressure readings also reduces the range of uncertainty considerably.

The first recommendation counters the issues found when only 1 operating point is available. Although lowering the production for obtaining the second flow rate would be economically ill-advised, the knowledge that is gained is considerable. Also note that in the discussed reservoirs the stabilization period would be in the range of a few days, limiting the production loss. Based on comparison of both multi rate Forchheimer PI and single rate Forchheimer PI (Gauss-Newton) values with PI found in well testing circumstances, it was found that the difference was lower when multiple rates were used. Additionally, multiple operating points allow the routine to derive a unique non-Darcy coefficient. A unique and independent non-Darcy coefficient would offer the analytical model with a secondary equation. In most well setups the degradation of the well is either due to near well bore permeability reduction, water invasion or reduction of penetration. We know that the non-Darcy coefficient is primarily function of the near well bore permeability. Near wellbore permeability evolution could be excluded using this secondary equation, giving the well performance team tools to exclude two out of 3 possible impairment mechanisms: salinity measurements for water advancement, non-Darcy coefficient for permeability reduction.

The recommendation of fitting bottom hole measuring equipment stems from the observation that the range of uncertainty determined in chapter 4 is mainly driven by the fact that the current method does not directly represent the true PI of the well. The Darcy coefficient as it is used now represents the performance of the reservoir and tubing system. In case scale builds up in the tubing or the tubing is damaged the conversion is too optimistic; the FBHP is lower than it is in reality resulting in a pessimistic interpretation of the PI while in fact the tubing is underperforming. In essence the measurement of FBHP would allow decoupling the tubing's performance from the formation inflow performance. At this stage, the PI is a performance indicator describing the tubing-formation system rather than the formation on its own. The well performance engineer would have a tool to evaluate the performance of the tubing compared to the ideal case as well as input for the PI Calc routine that is independent of the tubing's performance. Although this equipment comes at additional cost, the new insights and the new application of the data might sway management in reconsidering their strategy.

7. Conclusions

A new method to evaluate to productivity of large amounts of wells over long time intervals developed. The new method is based on the empirical Forchheimer correlation and takes into account. The experimentally determined PI is linked to an analytical skin model. Skin models are available for the different well types operated by TEPNL. Through comparison of the experimental PI and the Pi derived using the analytical model, changes in parameters upon which the well productivity depends. Which parameters are important for each well setup was determined from the sensitivity analysis on the theoretical model. The experimental PI determination was validated using 14 well tests on a variety of well architectures and completions giving good results.

The propose methodology and tool was applied to analyze 52 wells: 9 wells showed a decline productivity over the period of the lifecycle considered. On these 9 wells a gain of 700 kSm^3/d (which is 6% of current production) could be found by remediating the incurred damage. On this limited data set, several degradation patterns were recognized. Specific PI evolutions were found for water invasion, debris build up in the production string and damaged tubing. Due to the limited set of data, these specific evolutions should be further evaluated when more data become available. The parameters derived using the analytical skin model could not be validated using the available data. At this moment they should be seen as an indication of the order of magnitude of the problem. They indicate how sensitive a certain well is to specific changes in the well or near well bore area. It is up to the well performance engineer to judge if the relative changes are realistic or not, also taking into account the physical background of the parameters and their time dependency.

Additional to the ability of the methodology to tag those wells that are under-performing (management by exception), it gives also an indication of what the change in physical parameters could be. It estimates the potential gain and potential source of the problem. The output of the routine gives an easy to understand tool for the review of well interventions. The proposed method gives a brief and quantified review of any intervention, understandable for anyone that is interested.

Weaknesses in the routine have been exposed, all of which are related to the data gathering program within TEPNL. Improvement on these fronts could further benefit the accuracy of the methodology and data it can provide.

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