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Vertical Lift Models Substantiated by Statfjord Field Data

Øivind Fevang*, Marthe Gilje Fossmark, Kari Nordaas Kulkarni, Håvard Thomassen Lauritsen, Statoil, Svein M. Skjaeveland*, UIS
*SPE member

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Abstract
The Statfjord field entered into the blow down phase after 30 years of production. Production of injection gas and gas liberated from residual oil is the main production target in this phase. In some areas, the gas cap has been produced and the wells are producing mainly water until the solution gas is mobilized. These wells have gone through large changes in gas-liquid-ratio (GLR) and water-cut (WCT). Production tests from wells located in such areas have been used when analyzing the ability of multiphase-flow correlations to model vertical lift performance (VLP). Accurate modeling of the VLP is critical to predict a realistic production rate during the blow down phase.

Measured wellhead (THP) and downhole pressures from about 80 production tests, from four wells, were used to analyze the accuracy of VLP correlations at widely varying flow conditions (GLR, WCT, and THP). Altogether 17 multiphase pressure drop correlations incorporated in the program Prosper were tested by comparing observed and calculated downhole pressures.

Based on the production tests the ability of the different correlations to predict the VLP varies with the following top 4: Hagedorn Brown, Petroleum Experts, Petroleum Experts 2, and Petroleum Experts 3. These correlations are recommended if no measured data is available.

In general a somewhat low pressure drop is predicted at low gas-liquid ratio (GLR), and a somewhat high pressure drop is predicted at high GLR. After tuning, accurate predictability was observed for the different correlations for limited ranges in GLR e.g. 50-300 Sm3/Sm3. However, for larger ranges in GLR it was not possible to achieve an accurate VLP correlation, even after tuning. Hagedorn Brown and Petroleum experts seem to be the most accurate correlations for a wide range of producing GLR.

The error in the predicted production performance when a single VLP correlation is used can be substantial for highly productive wells with large variations in producing GLR. It is recommended to shift the tuning following the GLR development.

Introduction
Background
Calculating the pressure drop in the production tubing is important for well design, production optimization, and for generation of production prognosis. Many multiphase flow correlations are proposed. Still, none of them are proven to give good results for all conditions that may occur when producing hydrocarbons (Pucknell et al. 1993). Analysis of available correlations is often the best way to determine which one to use (Brill and Mukherjee 1999). Some will be good for liquid wells, whereas others for gas. Most of the correlations are to some degree empirical and will thereby be limited to conditions of which the correlations are based on (Pucknell et al. 1993).

The main objective of this paper is to evaluate which vertical lift models are recommended used for wells producing at greatly varying flow conditions, from typical oil well mixtures to typical gas well mixtures. In particular, it is evaluated if a single correlation can be used for all flowing conditions. Furthermore, different matching techniques are evaluated when tuning correlations to measured data, as well as the accuracy of the correlations to predict the pressure loss for different flowing wellbore mixtures (GOR, GLR).

The Statfjord field is the largest oil field in the North Sea, in terms of reserves. The in-place oil volume is slightly more than 1 billion Sm3. The field is located on the Norway-United Kingdom sector boundary. Production started in November 1979. The two main reservoirs are the Brent Gp. and the Statfjord Fm. Most of the in-place volume is located in formations with permeability in the Darcy range. A schematic picture of the surface facilities is shown in Figure 1.

The main drainage strategy for the Statfjord Fm. was up dip, miscible gas injection. From 1997, gas injection was partly replaced with up dip water injection. In the Brent reservoir the main drainage strategy was down dip water injection. WAG injection began in the Brent Gp in 1997. In 2007-2008, the Statfjord Late Life project (SFLL) started. Since then, both the main reservoirs have been depleted in order to liberate gas from remaining oil. The SFLL wells are placed in shallow locations with high productivity. When the Statfjord late life project started, a gas cap was established in the Statfjord Fm, while in the Brent Gp. only small volumes of WAG gas was remaining, however large volumes of solution gas was associated with the remaining oil. A conceptual cross section of the reservoir and the saturation distribution at the start of the Statfjord late life is shown in Figure 2.

In the period from 2007 until now, the gas cap in the Statfjord Fm. has been produced out in areas of the field. In the Brent Gp. the pressure has been depleted below the bubble point pressure, but there has not been any significant increase in gas-liquid ratio yet. The gas reserves coming from solution gas in the Brent Gp. are strongly dependent on the expected pressure development. The pressure development is a function of the liquid production. One of the important factors for predicting the liquid production rate is the lift performance.

Production tests from selective wells located in the Statfjord Fm. have been used as basis when investigating the different correlations. Calculations are performed using Prosper, a well performance, design and optimization program developed by Petroleum Experts (2010). Wells in the Statfjord Formation have been producing from a gas cap (created from gas injection). Initially, the gas production wells produced with a very high GLR, lately several of the wells have had water and oil breakthrough. These wells have therefore been producing with greatly varying gas-liquid ratios (GLR), one of the main parameters influencing vertical lift performance. Wells in the Brent Gp. are currently producing with low GLR, but with depressurization, GLR will increase. The correlation's accuracy when predicting bottomhole pressures with varying GLR is studied. Furthermore, tuning of the of correlations to measured data and the effect on simulation results are investigated.

Pressure-Drop Calculation in Oil and Gas Wells

Total pressure drop in a well may be expressed as the sum of a hydrostatic, a frictional and an acceleration term. Pressure drop caused by the hydrostatic term is normally the largest contribution to the total pressure drop. For gas wells producing with very high gas velocities, the frictional pressure drop may exceed the contribution from the hydrostatic term. The acceleration pressure drop is negligible, it is considered mainly for cases of high fluctuating flow velocities (Brill and Mukherjee 1999). Test data used in this study are defined as liquid wells in Prosper, and the flow correlations listed in Table 1 are used to calculate pressure drop. The pressures are calculated from top to bottom, and the correlations are used as they are implemented in Prosper.

The proportion of the pipe cross-section or volume that is occupied by the liquid phase is defined as the liquid holdup (H_L) (Brill and Mukherjee 1999). The mixture density of flowing fluids is calculated based on liquid holdup. Estimating the liquid holdup is very important as the main pressure drop is the hydrostatic pressure drop. In most cases, there is a difference in the velocity between the phases (oil, gas, and water). The difference in phase velocity is called slip. Slip is important for the mixture density, and thereby the hydrostatic pressure drop. All correlation except the Fancher & Brown correlation considers slip, see Table 1.

The flow correlations are often divided into empirical correlations and mechanistic models. Empirical correlations are based on experimental data and dimensional analysis, while mechanistic models are based on simplified physical considerations like conservation of mass and energy. It can be quite difficult to discriminate between empirical and mechanistic correlations. Often a combination is used to develop multiphase correlations (Yahaya and Gahtani 2010). A commonly used division of the flow correlations are shown in Table 1.

Pressure-drop Calculations for a Typical Well

Conceptual test data describing liquid and gas wells are generated in order to study the variance in calculated pressure drop for the different multiphase-flow correlations. The generated data are representative for a typical Statfjord well. Test data given to Prosper is; tubing head pressure (THP) and temperature (THT), water cut (WCT), liquid rate (q_L) and gas-oil ratio (GOR). Table 2 defines typical flow rates for a typical liquid well and Table 3 for a typical gas well. For liquid wells, the main contribution to total pressure drop comes from the hydrostatic term, ~85 to 98 % of the total pressure drop, depending on water cut and liquid rate. The remaining percentage comes from friction. Pressure drop due to acceleration is negligible. Even for gas wells with a gas-rate of $8x10^6$ Sm^3/day, only 3% of the total pressure drop is due to acceleration. Contribution from the acceleration term was thereby found negligible for all realistic cases.

The flow correlations in Prosper give similar pressure drops for a liquid well as shown in Figure 3. The lack of variation between the correlations is probably due to similar estimations of liquid holdup. In addition, Petroleum Experts (PE), Petroleum Experts 2 (PE2), Petroleum Experts 3 (PE3) and Duns and Ros modified (DRm) use the same flow regime map. Liquid holdup estimation from Beggs and Brill (BB) are used in Hagedorn and Brown (HB) and DRm. The small variations between the correlations are believed to originate from the friction term.

Larger variation in predicted pressure drops were observed for the gas-condensate wells, as shown in Figure 4. Both the hydrostatic and the frictional pressure loss vary amongst the correlations. The different correlations predicted different flow regimes along the well. Flow regime impacts both liquid holdup and friction calculations. Even within the same flow regime the correlations predict various pressures. Persad (2005) observed that the differences between the correlations disappeared for high GLR's.

PE, PE2 and PE3 give similar results both for liquid and condensate wells, the same observation was done by Persad (2005). This was expected, since there is only small difference in the correlations. The Orkiszewski correlation seems to perform in line for liquid wells, but deviates for the gas-condensate wells. The same observations for Orkiszewski were made by Pucknell et.al (1993). DRo and PE4 predicts low frictional pressure drop for gas-condensate wells compared to the other correlations. BB is mainly a pipeline correlation, and is not recommended to be used for near vertical flow conditions. FB is a no-slip correlation and will thereby under predict the pressure drop in most of the cases. Gray is mainly a correlation developed for gas and gas condensate wells (Gray 1974). Persad (2005) found Gray to be the most accurate correlation for gas wells.

Comparison of Measured and Calculated Pressure Losses

Selection of Well & Data

We have included production test data from four Statfjord wells. The well path to the downhole pressure gauge is illustrated in Figure 5. The wells are generally completed with 7" tubing, with some 50-100 meter sections of 5" tubing. B-1 has a longer 5" section, approximately the lower half part of the well. The fluid properties are given in Table 4.

Figure 6 shows error in calculated bottomhole pressure for all tests using the Hagedorn & Brown (HB) correlation. Error is calculated using eq. 1.

$$Error = \frac{calculated\ BHP - Measured\ BHP}{Measured\ BHP - Measured\ THP} * 100 \quad \text{......} 1$$

We observe that the error is large at low gas rates and moderate liquid rates. We believe that this is due to unstable flow. Consequenlty we have removed tests with gas rates less than 100 kSm^3/d.

Analysis of the Prosper calculations shows that the pressure drop increases with decreasing oil rates (at constant water and gas rates) for some of the calculations. This behavior seems too occur at GOR's higher than 4000 - 10000 Sm^3/Sm^3. Based on this analysis we have excluded tests with GOR larger than 10000 Sm^3/Sm^3, even though we believe that the test data is of good quality.

After applying these two criteria, the selected test data fall within a ± 10% error band, as shown in Figure 7. The number of well tests used for further analysis is 57. The data range covered by the valid production tests is presented in Table 5. Even though the number of tests has been reduced, the experimental data cover a wide range in rates and rate-ratios.

Discussion of Results

A comparison of the error in the calculated bottomhole pressures for all of the verified tests is shown in Figure 8. Both the average error and the absolute average error for 17 flow correlations are shown. Figure 8 show that HB, FB, PE, PE2, PE3, and the Olga correlations (O2P, O3P and O3PE) have the lowest percentage error and the smallest standard deviation. Orkiszewski, BB and M give the highest percentage error. This is consistent with earlier work (Persad 2005; Pucknell et al. 1993; Trick 2003). BB is primarily a pipeline correlation. It is developed based on gas-water data in horizontal and slanted pipes.

As expected, FB gives the lowest pressure drops for all the tests, resulting in negative percentage error in Figure 8. This is due to FB being a no-slip correlation. It is stated by Petroleum Experts (2010) that predicted pressures from FB always should be less than measured. This is not the case here. Results show that FB predicts both too high and too low pressure drops compared to the measured values, but it is always low compared to the other correlations. FB is not recommended in general for use in quantitative work, even if it gives a good match to measured data (Petroleum Experts 2010; Brill and Mukherjee 1999).

It was attempted to find a correlation between the error in the calculated pressure drops and the flow conditions. The error in the calculated pressure drop for all valid tests from well A-2 are shown in Figure 9-Figure 13. The error is plotted as a function of WCT, GOR, liquid rate, gas rate and GLR. There appears to be a correlation between the calculated error and the GLR as shown in Figure 13.

It is believed that the apparent correlation between calculated error and WCT (Figure 9) is coming from the correlation between the error and GLR, as there is no clear correlation between the error and liquid rate. An alternative explanation is that the error correlates with the gas rates as shown in Figure 12. However, the gas rate is closely connected to GLR in the Statfjord Fm. and a correlation between error and gas rate has not been observed by others e.g. Persad, Pucknell et al.

The calculated hydrostatic pressure drop seems to be very similar for all correlations independent of GLR (Figure 14). The calculated pressure loss due to friction is only 2-4 bars in all of the production tests (Figure 15). It seems like the explanation for the correlation between gas rate and error in GLR is that the liquid hold-up as a function of GLR and friction loss at these relatively low gas velocities (q_g <1.4 MSm^3/day, in 7" tubing) is somewhat over predicted. The calculated errors based on the HB correlation are shown in Figure 7, as a function of GLR. Although there is a spread in the calculated error there is a trend of increasing error with increasing GLR. The calculated error based on PE, PE2 and PE3 are shown in Figure 16. The trend is the same as for the HB correlation.

A comparison of the error in the calculated pressure drop from all of the verified tests is shown in Figure 17. The tests are split into low and high GLR. The correlations with the smallest error are HB FB, PE, PE2, and PE3. Others (Persard, Pucknell) have found Gray (modified) to be the most accurate correlation for gas wells (high GLR). Based on our data Gray modified over predicted the pressure drop for almost all tests. The reason might be that our data range is different, mainly due to lower gas velocities.

Tuning of the Flow Correlations

It is common to modify (tune) the flow correlations to match the observed pressure(s) in the well. In our case we have only one pressure gauge in each well. In this section we try to tune the flow correlations to the measured data. Different tuning methods are tried; 1) tuning to the low GLR data, 2) tuning to the high GLR data, and 3) tuning to all the test data. These three scenarios represent three different possible production scenarios where case 1 and 2 are the most common. Prosper is used in this paper for tuning of the flow correlations. Prosper has a non-linear regression routine with two variables. One variable is a multiplier to the gravity term. The other variable is a multiplier to the frictional term.

To study the effect tuning has on the flow correlations, the test data from well A-2 is used. The tuning is performed for the following flow correlations HB, FB, PE, PE2 and PE3. These correlations were found to give the most accurate pressure predictions. Pressure from one set of test data was tuned to match the measured bottomhole pressure. The modified correlations, with respective tuning parameters, were then used to predict pressures for all tests as shown for PE2 in Figure 18. The change in pressure drops caused by tuning is shown with circles with an arrow in-between. Tuning to measured pressure results in a close to linear shift (in %) for the calculated pressure loss as shown in Figure 18. An attempt was made to tune all of the measured data simultaneously. This did not result in a general improvement in the behaviour of the pressure correlation as the tuning still results in a "linear shift". However, the average error was reduced. The same tuning was tried on the other flow correlations with the same result as for PE2, as shown in Figure 19. The current tuning method increases the accuracy of the flow correlation within the GLR range it is tuned to. However, it does not necessarily improve the accuracy outside the data range it is tuned to, as shown in Figure 19. Furthermore, it is not possible to achieve an unbiased match with a single set of tuning parameters for a wide range of GLR. In fact, the smallest error is in many cases achieved without any tuning.

Production Prediction

Adequate modeling of vertical lift performance is important at many production stages of a field. Production rates are given by the intersection of VLP and inflow performance relationship (IPR) curves as shown in Figure 20. As described earlier, the Statfjord Field has changed drainage strategy from pressure maintenance to depletion. The gas comes from the gas cap in the Statfjord Fm. (created from gas injection) and gas liberated from the remaining oil (Brent Gr. and Statfjord Fm.). Most of the gas is expected to come from the Brent Gp. The estimated reservoir pressure and GLR development for a typical well producing from the Brent Gp is shown in Figure 21. VLP curves are calculated based on multiphase flow correlations. For this analysis, PE2 will be used when creating lift curves. In previous sections it was found that PE2 in general calculates the pressure drop accurately for low GLR's, but overestimates the pressure drop at high GLR(s). The impact tuning has on the liquid production rate for typical Brent wells are shown in Figure 22 and Figure 23. The impact tuning has on the production performance is relatively moderate (<5%) mainly because the expected variation in flowing GLR is only 70-300 Sm3/Sm3. Please note that variation in calculated error for many of the tests is (-5 to +7%) which is much larger than the "average" error corrected by tuning (within this GLR range). Consequently, tuning to a single production test might lead to significant error in predicted production.

An alternative case with a much larger variation in production GLR (Figure 24) has also been simulated. The simulated production profile from this case is shown in
Figure 25 and Figure 26. In this case we compare results from a single set of tuning parameters versus using different tuning parameters dependent on the GLR. In all cases default tuning from Prosper has been used. The line with 5% error bars is the "correct" production rate (using GLR dependent tuning parameters). The green line represents the production using the tuning parameters obtained by matching high GLR tests. The red line represents the production using the tuning parameters obtained by matching low GLR tests. No tuning (purple) is very close to low GLR tuning. This demonstrates that using a single set of tuning parameters may result in inaccurate rate prediction for a well with large variation in producing GLR.

Conclusions

1. HB, FB, PE, PE2 and PE3 are the most accurate flow correlations based on the Statfjord data. However, FB is not recommended used as it generally under predicts the pressure drop. The recommended flow correlations are the most accurate, independent of rates and rate-ratios.
2. The accuracy of the flow correlations seems to be dependent on the flowing GLR. The flow correlations tend to over predict the pressure loss at high GLR and under predict the pressure loss at low GLR. PE3 and HB tend to be most accurate at high GLR's, while PE tend to be most accurate at lower GLR's for pure predictions
3. With non-linear tuning it is possible to tune the flow correlations to the measured data for a limited range in GLR. However, it is not possible to find a single set of tuning parameters to match the data if there is large variation in GLR (100-3000 Sm^3/Sm^3)
4. For the Brent Gp. at the Statfjord Field, it might be possible to use a single flow correlation as the expected range in flowing GLR is relatively low.
5. If the range in flowing GLR is large the error in the predicted production performance can be significant when a single set of tuning parameters is used.

Acknowledgements

The Statfjord license is acknowledged for permission to publish this paper.

Nomenclature

HL = liquid holdup
p = pressure
q = volumetric flow rate
Δ = difference
μ = viscosity
ρ = density

Subscripts

G = gas
L = liquid
o = oil
t = total
w = water

Abbreviations

BB = Beggs and Brill
DRm = Duns and Ros Modified
DRo = Duns and Ros Original
FB = Fancher and Brown
Fm = Formation
GLR = Gas-liquid ratio
Gm = Gray Modified
GOR = Gas-oil ratio
Hydr = Hydro-3 Phase

HB =	Hagedorn and Brown
M =	Mukherjee and Brill
O =	Orkiszewski
O2P =	OLGAS 2.phase
O3P =	OLGAS 3-phase
O3Pe =	OLGAS 3-phase Extended
P1 =	Parameter 1, tuning parameter for hydrostatic gradient
P2 =	Parameter 2, tuning parameter for the frictional gradient
PE =	Petroleum Experts
PE2 =	Petroleum Experts 2
PE3 =	Petroleum Experts 3
PE4 =	Petroleum Experts 4
PE5 =	Petroleum Experts 5
PI =	Productivity index
BHP =	Bottomhole pressure
THP =	Tubing-head pressure
THT =	Tubing-head temperature
VLP =	Vertical lift performance
WCT =	Water cut

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Tables

Table 1: Classification of correlations

Correlation	Abbrevation	Category	Slip considered?	Flow regime considered?
Fancher Brown (1963)	FB	Empirical	No	No
Gray Modified (Gray 1974, Petroleum Experts 2010)	Gm	Empirical	Yes	Yes
Hagedorn Brown (1965)	HB	Empirical	Yes	No
Duns & Ros Original (1963)	DRo	Empirical	Yes	Yes
Duns & Ros Modified (Petroleum Experts 2010)	DRm	Empirical	Yes	Yes
Orkiszewski (1967)	O	Empirical	Yes	Yes
Beggs & Brill (1973)	BB	Empirical	Yes	Yes
Mukerjee Brill (1999)	M	Empirical	Yes	Yes
Petroleum Experts (1,2,3) (2010)	PE (1,2,3)	Empirical	Yes	Yes
Petroleum Experts (4,5) (2010)	PE (4,5)	Mechanistic	Yes	Yes
Hydro 3-Phase	Hydr	Mechanistic	Yes	Yes
OLGAS 2P	O2P	Mechanistic	Yes	Yes
OLGAS 3P	O3P	Mechanistic	Yes	Yes
OLGAS 3P EXT	O3Pe	Mechanistic	Yes	Yes

Table 2: Data for typical liquid wells

Liquid well	q_L [Sm^3/day]	q_G [Sm^3/day]	GOR [Sm^3/Sm^3]	GLR [Sm^3/Sm^3]	THP [Bar]	THT [°C]	WCT [%]
A	4000	640000	160	160	100	60	0
B	4000	320000	160	80	100	60	50
C	4000	64000	160	16	100	60	90
D	2000	320000	160	160	100	60	0
E	2000	32000	160	16	100	60	90

Table 3: Data for typical gas-condensate wells

Gas-condensate well	q_L [Sm^3/day]	q_G [Sm^3/day]	GOR [Sm^3/Sm^3]	GLR [Sm^3/Sm^3]	THP [Bar]	THT [°C]	WCT [%]
A	500	500000	1000	1000	100	60	0
B	500	1000000	2000	2000	100	60	0
C	500	2000000	4000	4000	100	60	0
D	500	4000000	8000	8000	100	60	0
E	500	8000000	16000	16000	100	60	0

Table 4 Black oil PVT properties for the fluids

Black Oil PVT			
Bubble Point	Solution GOR	Oil FVF	Oil Vicosity
Bara	Sm3/Sm3	m3/Sm3	Cp
45.8	36.9	1.277	0.580
78.9	61.57	1.340	0.463
112.7	84.4	1.404	0.401
156.1	118.9	1.503	0.335
196.1*	154.7	1.600	0.287
276.7	154.7	1.577	0.324
448	154.7	1.525	0.402
* Bubble point pressure of original oil			
STO Density 837.7 kg/m3			
Gas Gravity 0.8483			
Water Salinity 20023 ppm			
Temperature 99.4 C			
Tuned to Glasø (Pb,Rs, Bo) & Beggs et al (Oil viscosity)			

Table 5 Range in production test data and well configuration

Property	Range	Units
Gas-liquid ratio	145 – 5393	Sm3/Sm3
Water cut	0 – 96.8	%
Liquid rate	146 – 2552	Sm3/day
Gas rate	160 – 1251	kSm3/day
Tubing head pressure	54 – 221	Barg
Gauge pressure	122 – 290	Barg
Depth DHPG TVD	1702 – 2581	Meters
Depth DHPG md	1908 – 3628	Meters
Tubing size	7” (parts of 5”)	Inches
Deviation inclination at gauge	47.5 – 85.0	Degrees

Figures

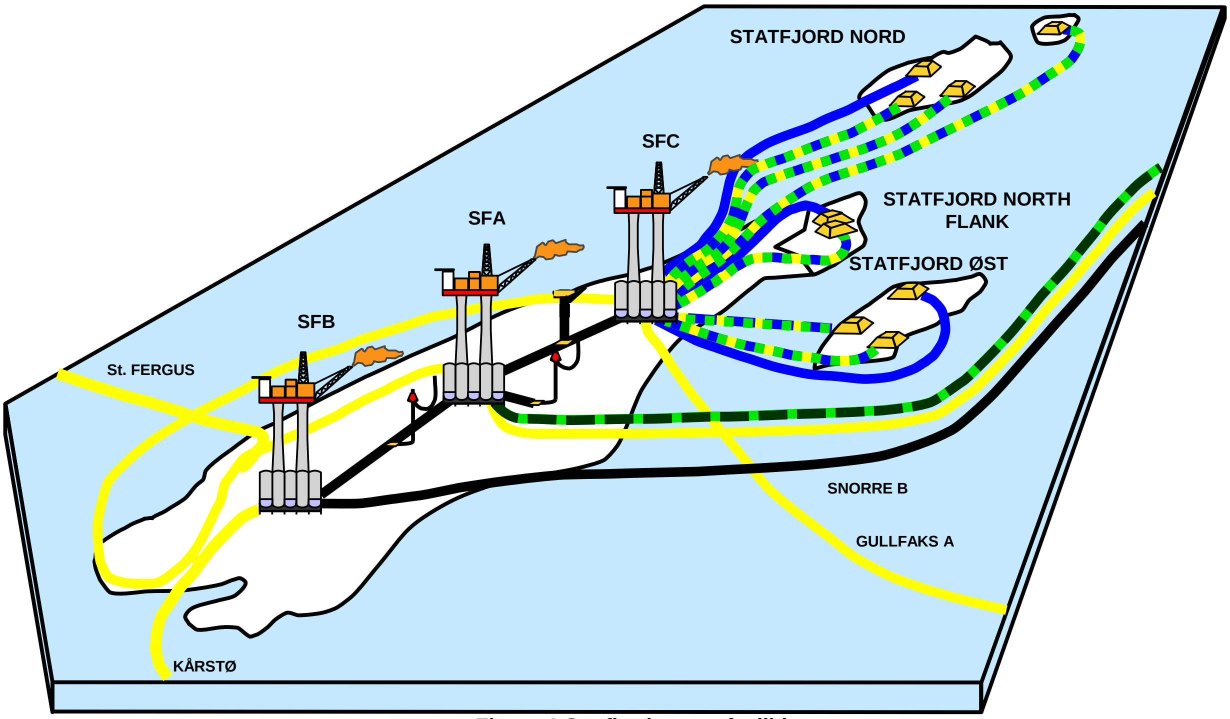

Figure 1 Statfjord area – facilities

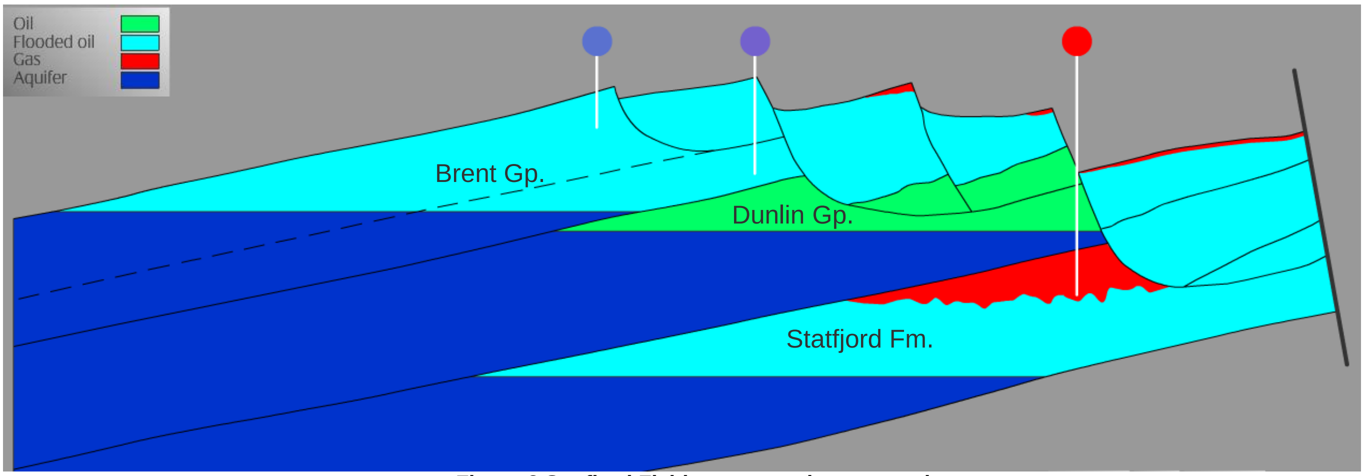

Figure 2 Statfjord Field, conceptual cross section

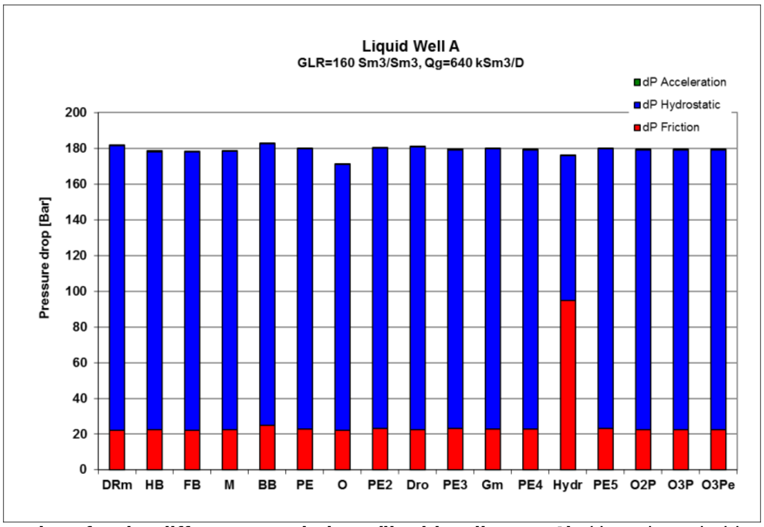

Figure 3 Calculated pressure drop for the different correlations (liquid well, case A). (there is probably an error in the estimated split between gravity and frictional pressure loss for the Hydr correlation)

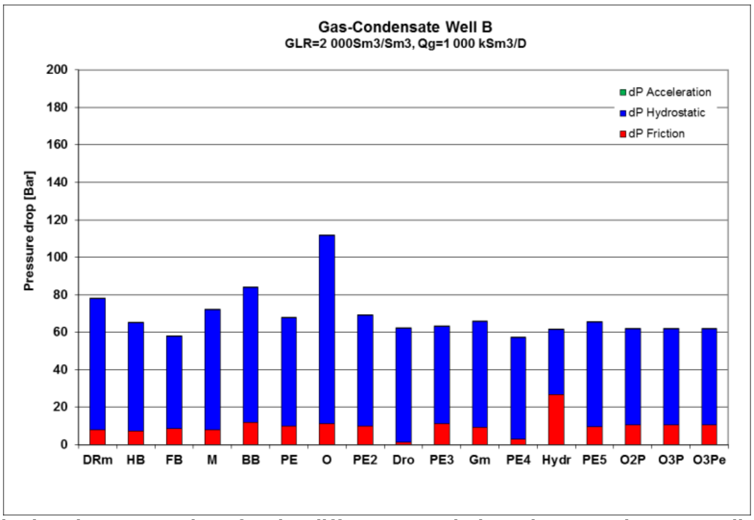

Figure 4 Calculated pressure drop for the different correlations (gas-condensate well, case B)

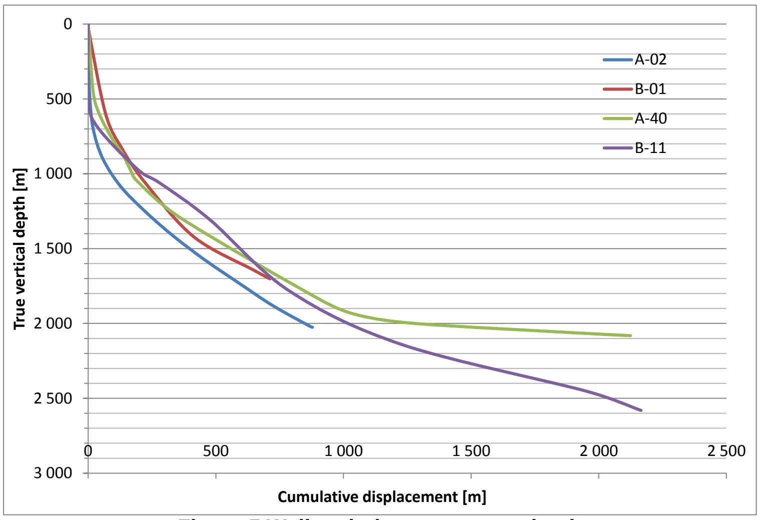

Figure 5 Well path down to gauge depth

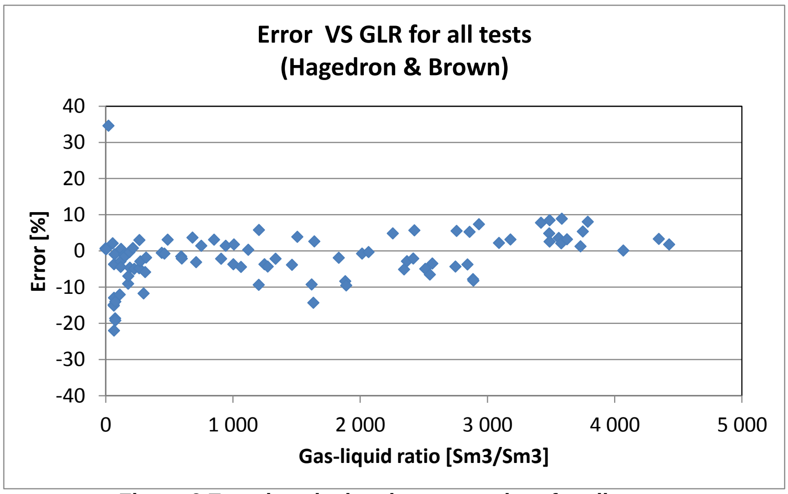

Figure 6 Error in calculated pressure drop for all tests.

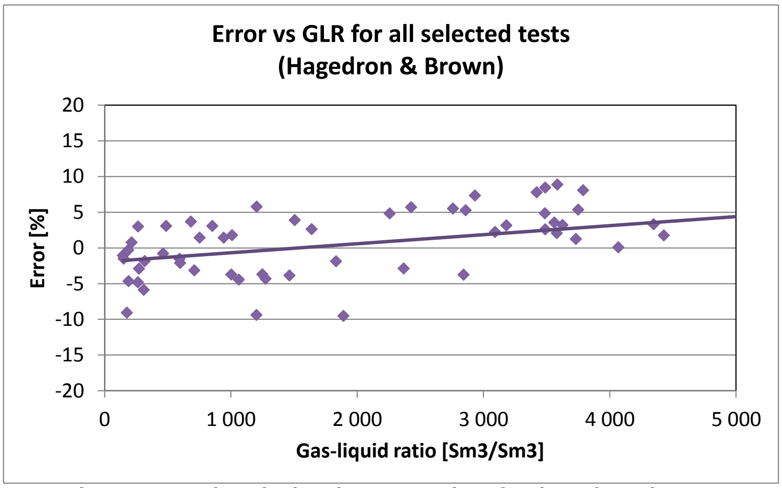

Figure 7 Error in calculated pressure drop for the selected tests.

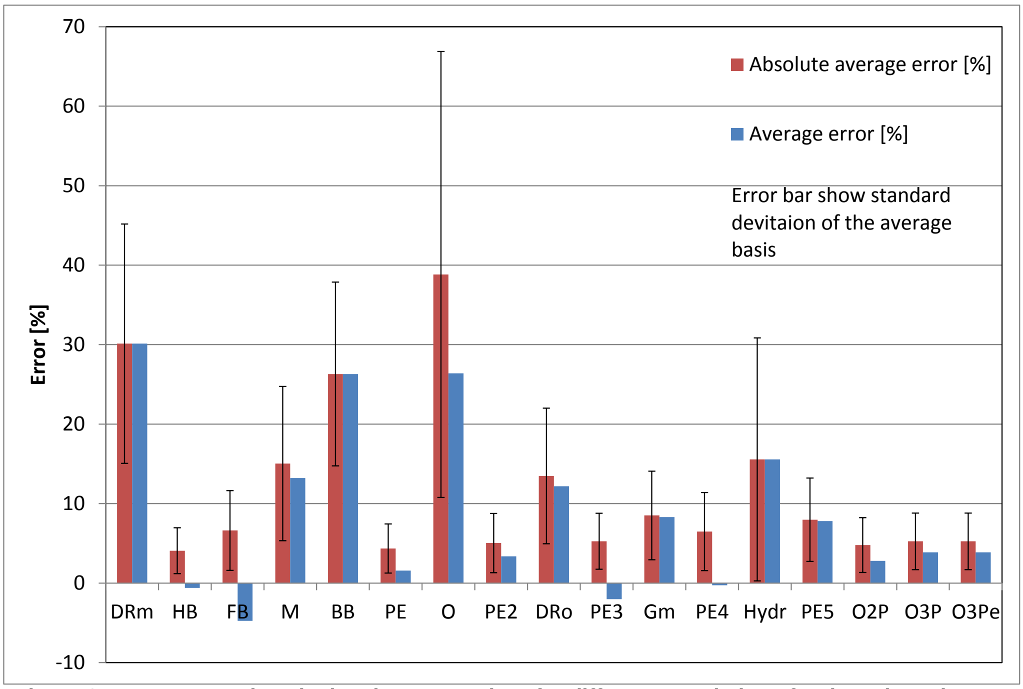

Figure 8 Average error in calculated pressure drop for different correlations for the selected tests.

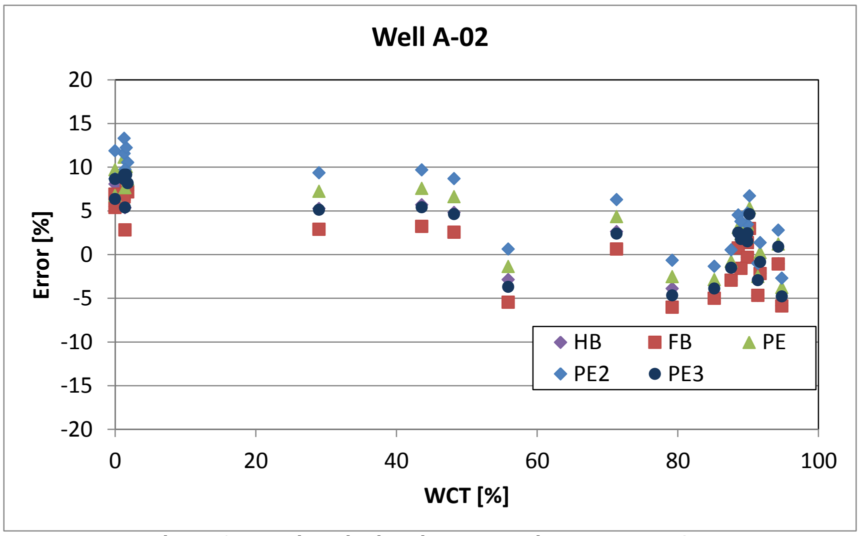

Figure 9 Error in calculated pressure drop versus WCT.

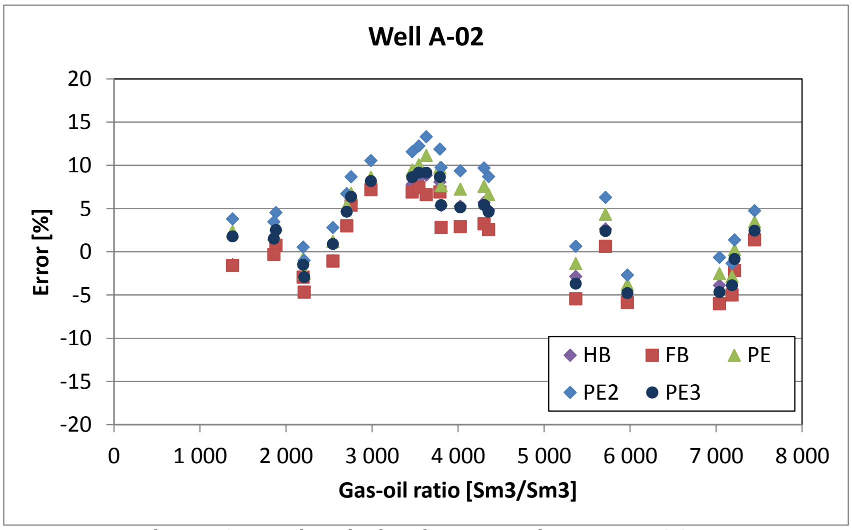

Figure 10 Error in calculated pressure drop versus GOR.

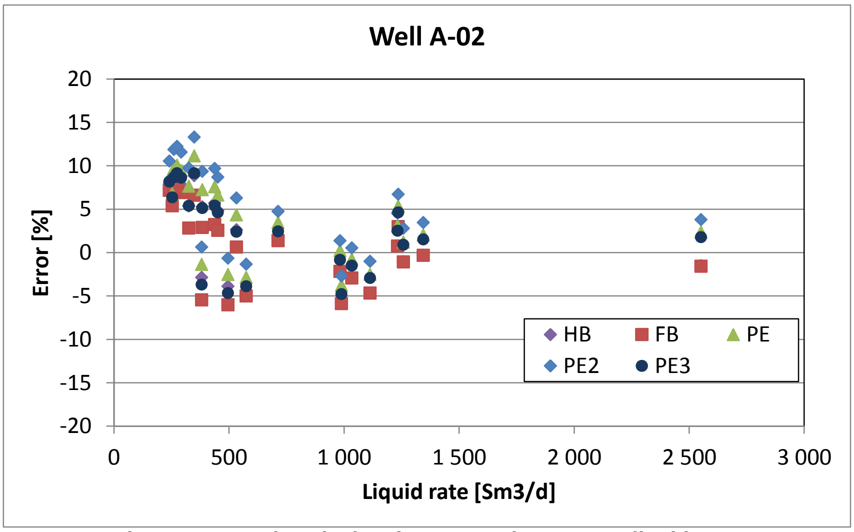

Figure 11 Error in calculated pressure drop versus liquid rate.

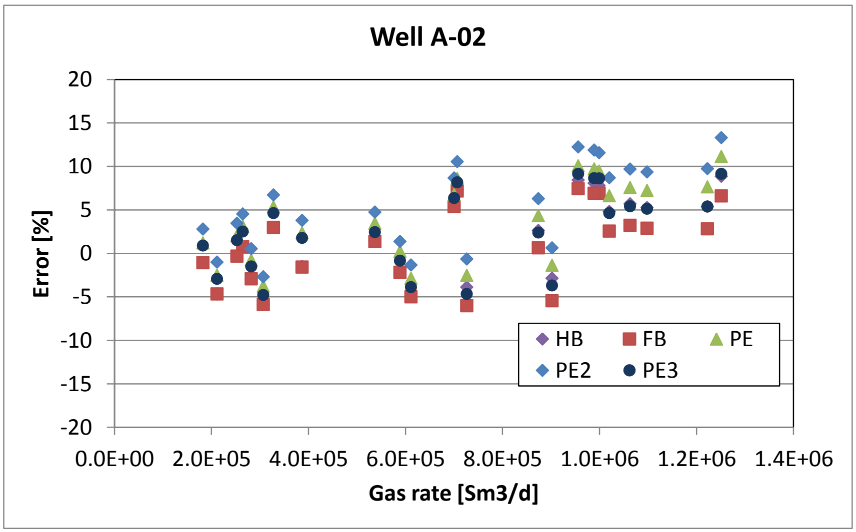

Figure 12 Error in calculated pressure drop versus gas rate.

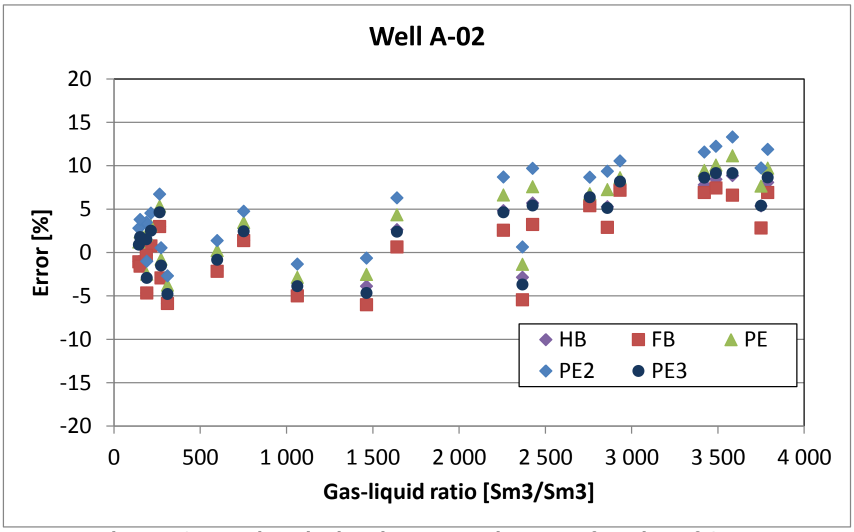

Figure 13 Error in calculated pressure drop as a function of GLR.

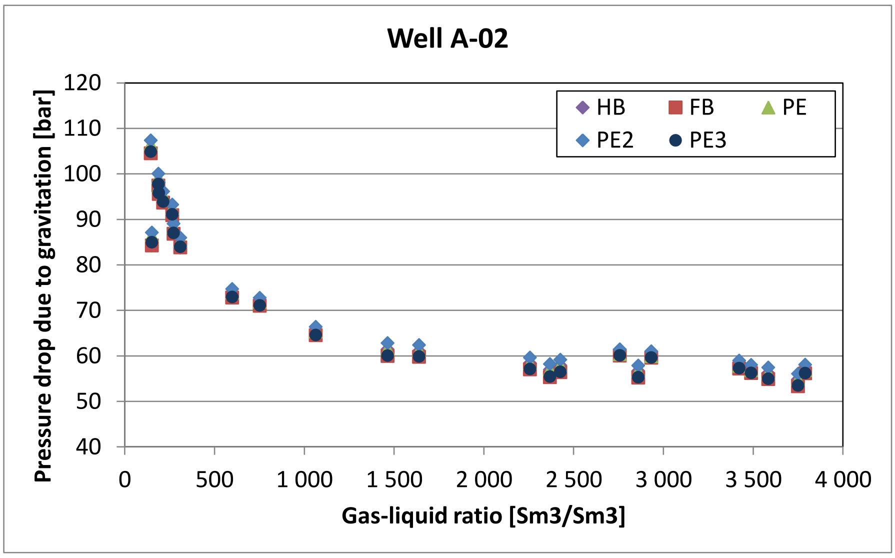

Figure 14 Calculated hydrostatic pressure drop versus GLR.

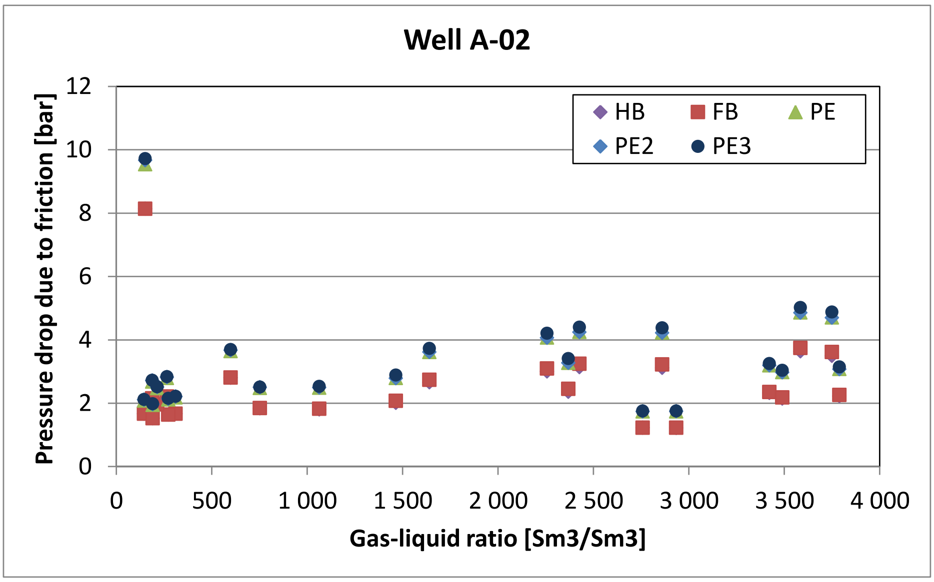

Figure 15 Calculated frictional pressure drop versus GLR.

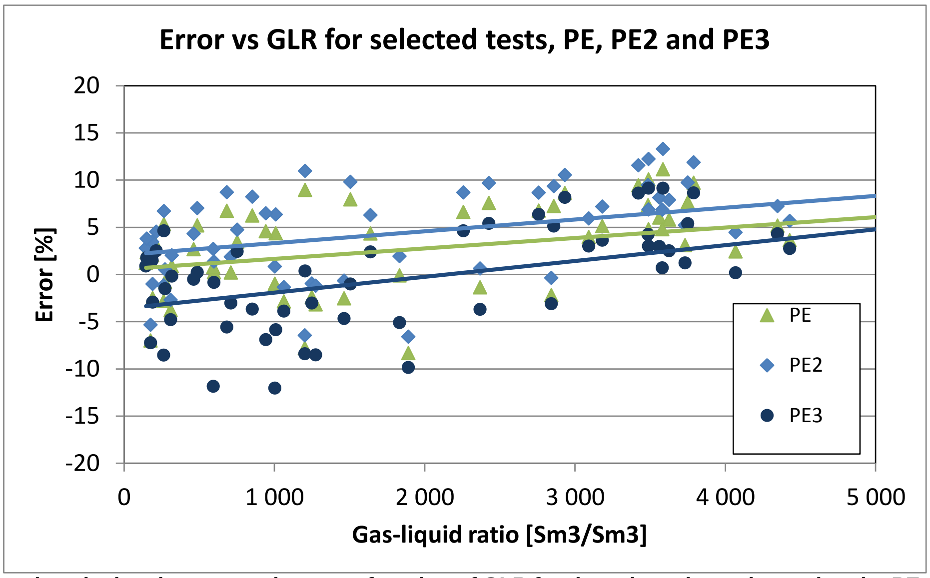

Figure 16 Error in calculated pressure drop as a function of GLR for the selected test data using the PE correlations.

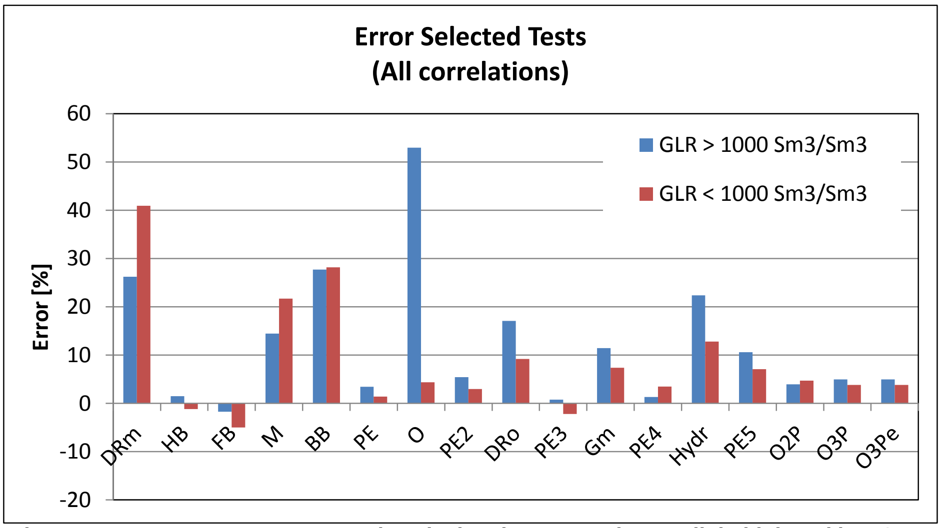

Figure 17 Average percentage error in calculated pressure drop, split in high and low GLR.

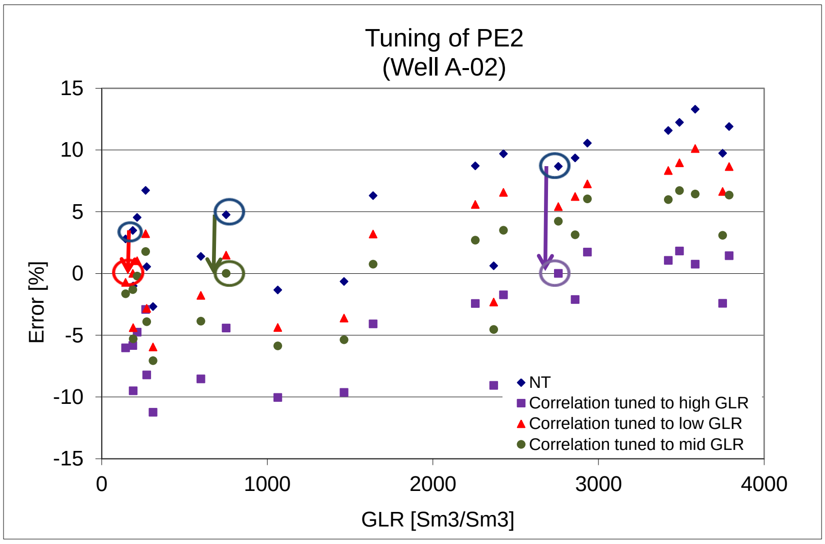

Figure 18 Tuning of PE2, low GLR=190 Sm^3/Sm^3, middle GLR=750 Sm^3/Sm^3, and high GLR=2800 Sm^3/Sm^3

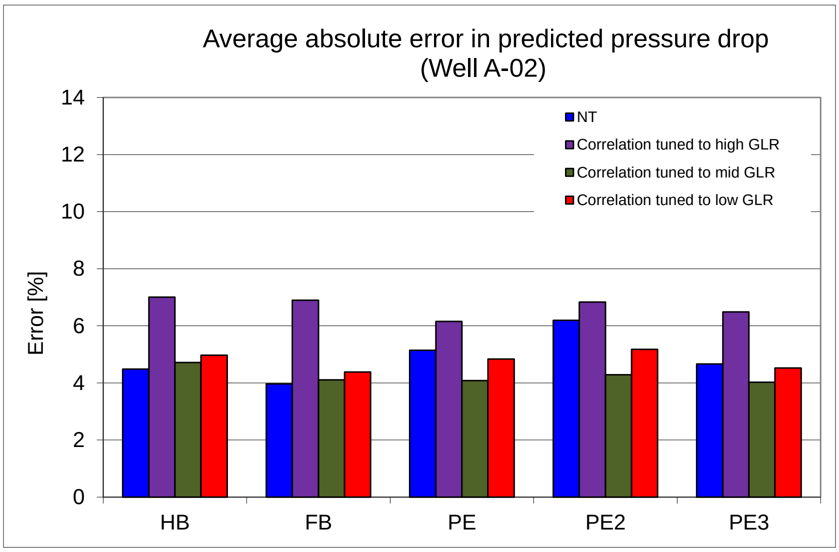

Figure 19 Summary of tuning of the different correlations to various GLRs.

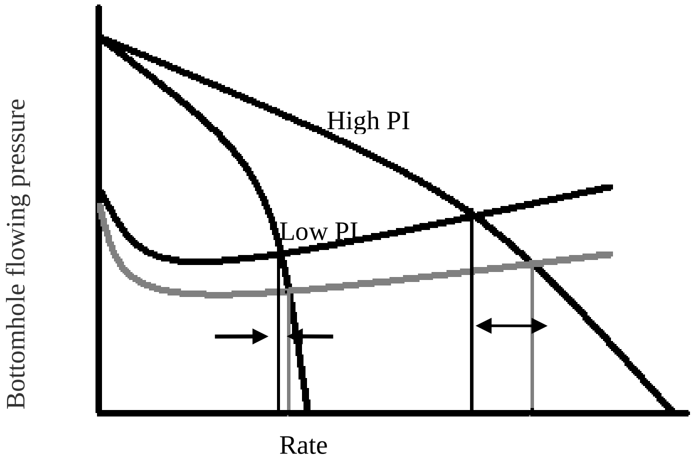

Figure 20 Sketch of VLP and IPR curves

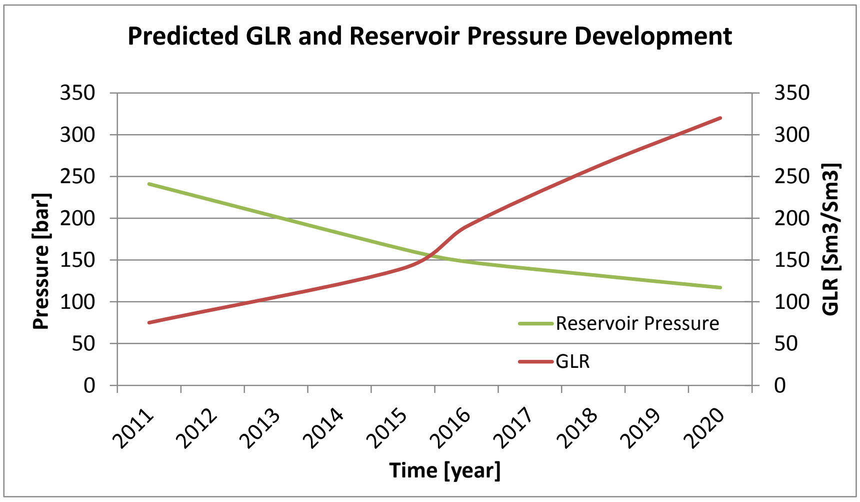

Figure 21 Reservoir pressure and expected GLR development for a typical well producing from the Brent Gp.

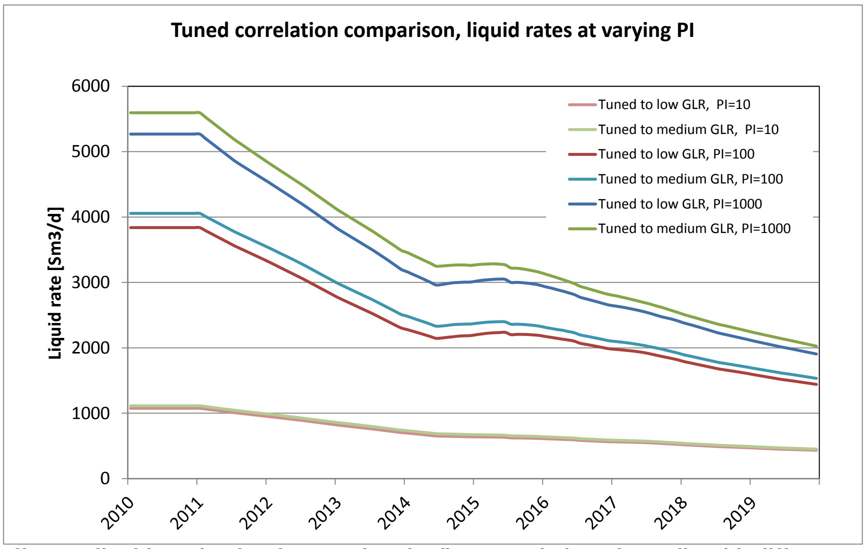

Figure 22 Effect on liquid production from tuning the flow correlations for wells with different productivity

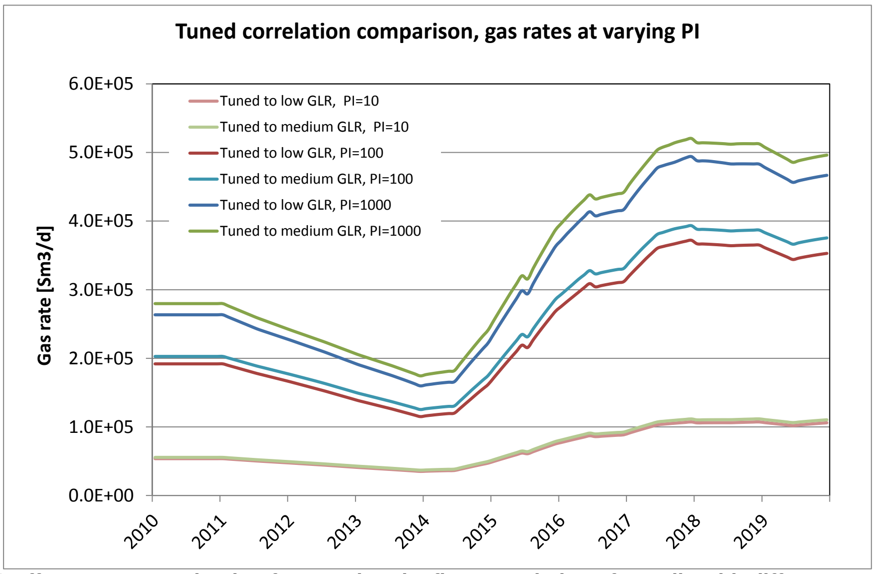

Figure 23 Effect on gas production from tuning the flow correlations for wells with different productivity

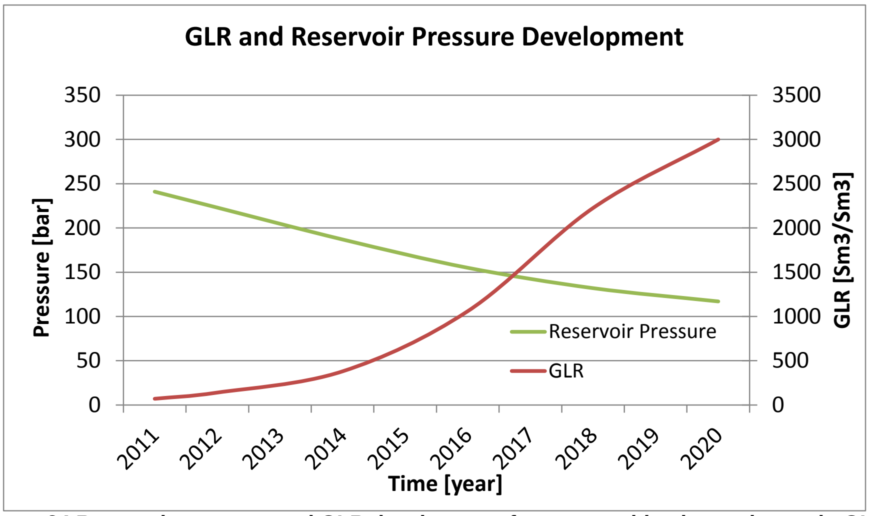

Figure 24 Reservoir pressure and GLR development for a case with a large change in GLR.

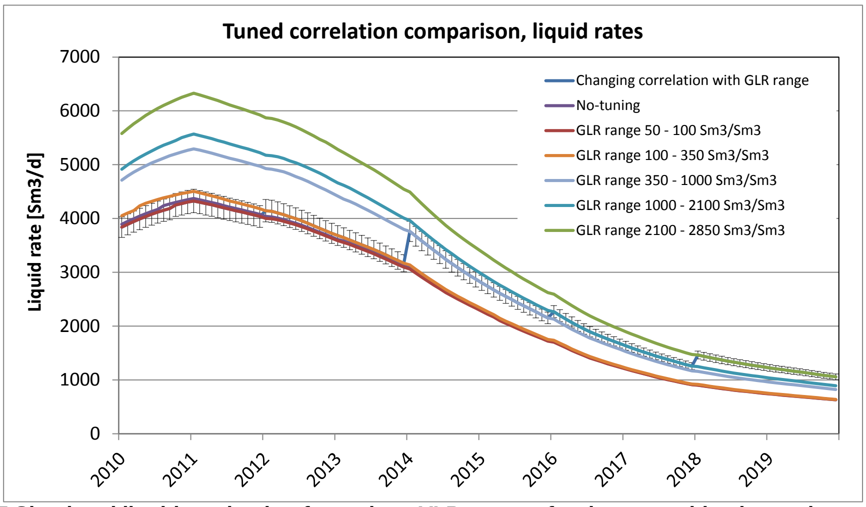

Figure 25 Simulated liquid production for various VLP curves, for the case with a large change in GLR.

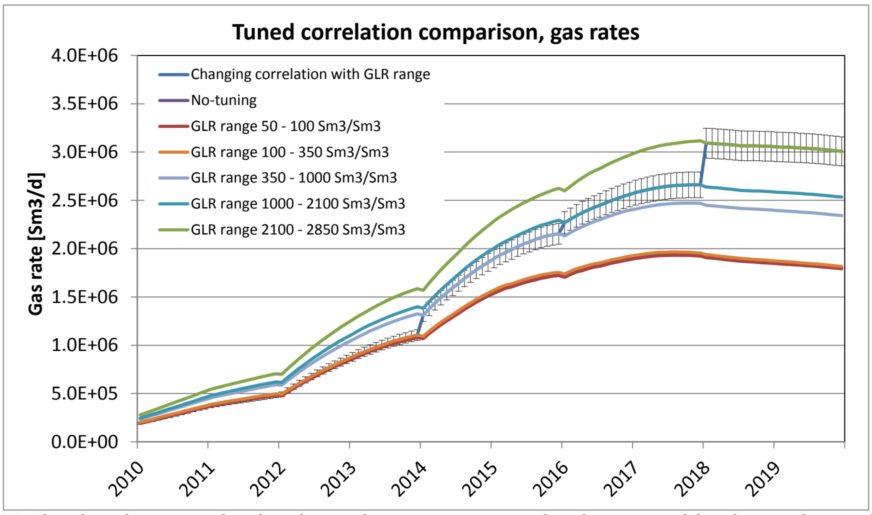

Figure 26 Simulated gas production for various VLP curves, for the case with a large change in GLR.