IMPERIAL COLLEGE LONDON

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CANDIDATE SELECTION AND ASSESSMENT OF THE BENEFITS OF VELOCITY STRINGS ON THE DUNBAR FIELD

By

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A report submitted in partial fulfilment of the requirements for the MSc and/or the DIC.

September 2012

DECLARATION OF OWN WORK

I declare that this thesis

"Candidate Selection and Assessment of the Benefits of Velocity Strings on the Dunbar Field"

is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and/or with appropriate acknowledgement given.

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Candidate Selection and Assessment of the Benefits of Velocity Strings on the Dunbar Field

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Imperial College supervisor – **Professor Olivier Gosselin**

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Abstract

The Dunbar field is located in the North Sea. The reservoir contains critical fluid and is currently being produced via water injection and natural depletion. For the parts of the field that are produced via natural depletion, velocity strings or tail pipes can be installed in wells to extend their producing lifetime and stabilise production. Velocity strings are normally used in gas wells. The Dunbar case is different as it is mainly an oil field, but contains high gas-oil ratio (GOR) wells. Gas production increases as the reservoir pressure declines, thus making velocity strings suited to wells under natural depletion, where they help to increase the gas velocity above the critical velocity, enabling the well to continuously unload liquids. The design must be optimised and the timing must be correct, otherwise a velocity string can act as a choke and prevent the well from producing at its potential rate. A well screening process was developed in order to identify suitable candidates for well intervention. Vertical Lift Performance (VLP) curves were generated for successful candidates and the completion design (type, i.e. velocity string or tail pipe, internal diameter, setting depth and length) was optimised. The impact on reserves was then evaluated in order to determine the gain from installing a velocity string or tail pipe.

The objective of this study is to discuss the methodology used in screening the wells that are in the part of the reservoir under natural depletion for candidacy for the installation of a velocity string or tail pipe, and to evaluate the impact on reserves for successful wells. The study shows that the installation of a velocity string can lower the abandonment pressure, and therefore extend the producing lifetime and increase reserves for a well. It also shows that several factors influence the suitability of a well for the installation of a velocity string or tail pipe, and so individual well by well screening is required. The aim of suggested further work is to evaluate whether it is actually feasible to develop a standardised well selection process that can be applied directly to neighbouring fields with similar fluid characteristics, where problems relating to liquid loading will remain in focus as North Sea fields continue to mature.

Introduction

The Dunbar field was discovered in 1973 and is located 420 km north east of Aberdeen in the Northern North Sea. The reservoir contains over 1 billion barrels of oil equivalent (boe) and has been produced since 1994. The reservoir is complex and compartmentalised, with a critical fluid that behaves like a light oil in some parts of the reservoir, and like a gas condensate in other parts. It is located 3650 mTVDss, and initial pressures of 575 bars and fluid temperatures of 120°C have been encountered. The main layer of the reservoir (Brent) contains over 80% of the hydrocarbons in place, and half of the hydrocarbons in place are in rocks with a permeability less than 10mD. The current production strategy consists of pressure maintenance via water injection in some parts of the field, and natural reservoir pressure depletion in others.

For the parts of the reservoir under natural depletion, an economic option for stabilising and extending production lifetime when the reservoir pressure has dropped is to install a velocity string or a tail pipe. They are tubing with a smaller diameter, whose function is to provide a reduced flow area, increasing the gas velocity above the critical velocity (Turner *et al*., 1969), and allowing the continuous removal of wellbore liquids (condensed water, condensate) from the well. Tail pipes are usually shorter in length and are set deeper in the well completion than velocity strings. Other methods of gas well liquid loading remediation exist, such as plunger lift, gas lift, surfactant injection and electrical submersible pumps (ESPs), and their use has been well documented (Lea *et al*., 2008). Other, more radical methods such as microwave heating (Kamal *et al*., 2011) are being developed, but velocity strings have proven to be a low cost tool.

Although the use of velocity strings and tail pipes is somewhat routine onshore, their application offshore is more complex. North Sea regulations state that offshore wells need to be fitted with a Sub Surface Safety Valve (SSSV) that is operational at all times. Coupled with harsh offshore environments this provides technical challenges in terms of the installation of smaller tubing while keeping a SSSV fully operational.

Previous studies (Hutlas and Granberry, 1972; Adams and Marsili, 1992; Lea and Nickens, 2004; Arachman et al., 2004; Oudeman, 2007; de Jonge and Tousis, 2007; Goedemoed et al., 2010) have looked at the installation of velocity strings in order to remediate liquid loading in gas wells. The Dunbar case is different as some of the wells in concern produce as much gas as they do oil, so the focus is on wells being produced via natural depletion. In addition, more operationally defined criteria must be used in order to determine well candidacy for remediation as opposed to liquid production and gas velocities below the critical velocity only.

Liquid Loading and its Remediation

Liquid loading occurs when gas wells are unable to lift liquids from the wellbore to the surface. Liquid loading and its associated phenomena are not obvious, as wells suffering from liquid loading may still produce for a long time. Symptoms of liquid loading may include sharp drops in a production rate decline curve, liquid slugs produced to surface, increasing pressure differential between the tubing and casing with time (without packers present) and sharp changes in gradient on a flowing pressure survey (Lea and Nickens, 2004).

The issues regarding liquid loading in gas wells have been well documented in the literature with case studies. One of the more well known criteria for determining the gas velocity above which a gas well will continuously unload liquids was developed by Turner *et al.* in 1969. They deduced that the prevailing mechanism for liquid removal in a gas well could be modelled using liquid drops entrained in a vertically flowing high velocity gas core, and concluded that the minimum velocity required to unload a gas well is that which will move the largest liquid droplet that can exist in the gas stream. This critical velocity can be calculated using equation 1, and the critical gas rate can be calculated using equation 2:

$$v_t = 1.912\frac{\sigma^{1/4}(\rho_l - \rho_g)^{1/4}}{\rho_g^{1/2}} \quad \text{....................(1)}$$

$$q_{gc} = 3.06\,\frac{p v_t A}{Tz} \quad \text{.................... (2)}$$

Coleman *et al.* (1991) later found that the 20% correction added to equation 1 to make the numerical factor 1.912 was unnecessary, and so 1.59 is more commonly used.

Liquid loading is detrimental to well performance because it causes a drop in production rates, liquid slugging at the surface and can eventually lead to a well dying if left untreated. The technologies available to remediate liquid loading have also been well documented, and include strategies such as wellhead compression, plunger lift, surfactant injection, gas lift, ESPs and progressive cavity pumps (Lea *et al.*, 2008). The installation of a velocity string can be advantageous compared to the other available forms of gas well deliquification because it is low cost, can be performed without killing the well and requires no further maintenance after installation (Oudeman, 2007). Installation without the requirement to kill a well protects low pressure reservoirs from damage which can occur due to the use of kill fluids, or by entrained solids (Poppenhagen *et al.*, 2010). However, further installations of smaller and smaller tubing will be required for effective liquid unloading if the reservoir pressure continues to drop (Schinagl and Denny, 2007). The associated drop in production rates when velocity strings or tail pipes are installed (caused by increased frictional pressure losses in the well) are also potential drawbacks. Tail pipes use shorter lengths of pipe and are only installed in the lower part of the completion where the fluid velocity is below the critical velocity, and so the frictional losses and drop in production rates are lower.

Velocity strings and tail pipes tend to come in standardised sizes. 2”, 2⅜” and 2⅞” diameter installations were analysed. The requirement for a fully operational SSSV means that velocity strings must be set below the SSSV. This can be achieved using new packers. Tail pipes however, can be hung off existing no-go nipples present in the current completion. No-go nipples are placed deep in the production tubing and provide a reduced diameter, preventing tools of a certain size falling within the tubing. Figure 1 shows the difference between a current completion, velocity string and tail pipe installation.

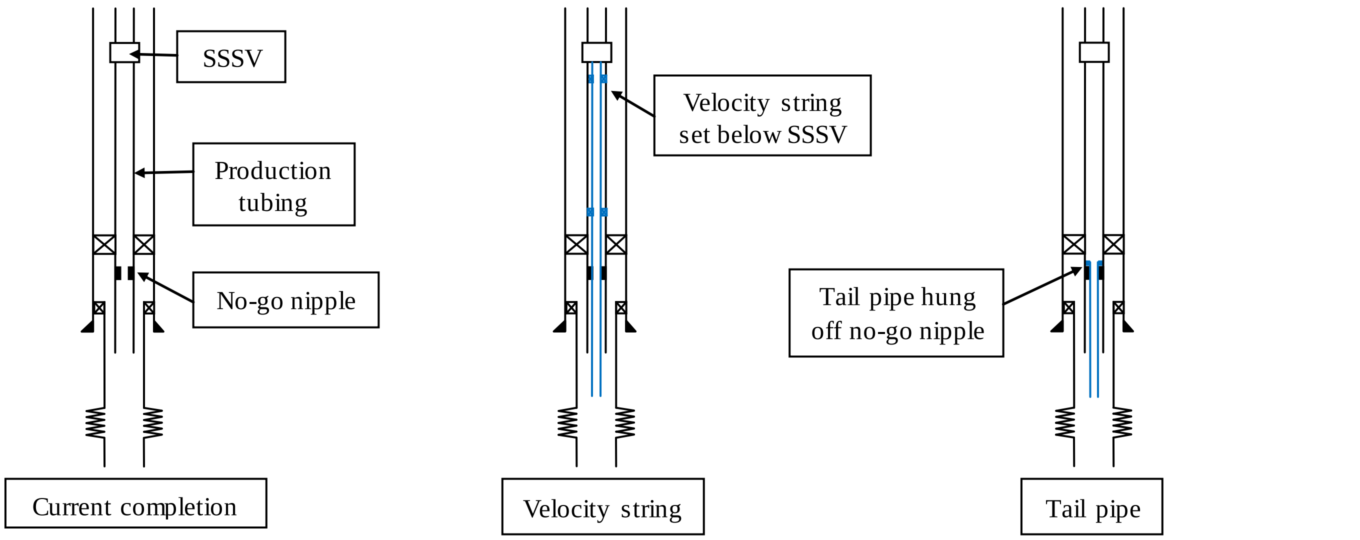


Figure 1 – Diagram showing an example current completion, velocity string and tail pipe installation

The application of velocity strings is far more common for gas wells than oils wells (or high GOR wells compared to low GOR wells). This is because ESPs have proved to be a very effective method for adding pressure to oil wells with low erruptivity. Their application to gassy wells is less popular due to their inability to handle large volumes of gas. Even though new pumps capable of handling high GOR flows are being developed (Schinagl and Denny, 2007), there is a need for lots of power and rig space, which is unavailable on the Dunbar platform.

With respect to the North Sea, regulations state that SSSVs must be fully operational at all times, providing a technical challenge in the use of technologies such as velocity strings or plunger lift, though new systems allowing the use of plungers below the SSSV have been developed (Hearn, 2010). Chemical injection using surfactant via capillary tubes can also be used, but surfactants need rigorous testing before they can be approved. Velocity strings therefore provide a simple, quick and relatively low cost solution to problems regarding liquid loading.

Candidate Well Selection

The well selection and velocity string design process plays an incredibly important part in remediating liquid loading. If installed too early, velocity strings can act as a choke for a well, reducing its production rate, as frictional pressure losses will dominate the pressure drop in the well. Installation too late may mean a reduction in a well's cumulative production because the well may die before the installation, causing a loss in production. With these factors in consideration, developing adequate selection criteria is necessary for project success.

A well screening process was developed in order to identify candidates for velocity string or tail pipe installation. These forms of well intervention are suited to wells in reservoirs under natural depletion, as they help to raise the gas velocity above the critical velocity, enabling the well to continuously unload liquids. Wells in reservoirs supported by water injection will eventually suffer from water breakthrough, and the contrast in density between injection water and reservoir gas will compound any liquid loading symptoms further. For this reason the study focused on the 11 still producing wells in the part of the Dunbar field under natural depletion.

The well screening process encompassed three different sources of data; information from the Dynamic Synthesis for each well (source: TOTAL E&P UK), well test data, and production and wellhead parameter data. It can be summarised in the workflow shown in Figure 2.

Dynamic Synthesis

- Score the 11 wells based on criteria such as production mechanism, GOR, water cut, well understanding, presence of scale.
- Eliminate wells with operational issues, such as the need for initial well intervention before a velocity string can even be installed.

Well Test Data

- 4 wells remain after the analysis of data from the Dynamic Synthesis.
- Use well test data to analyse trends in GOR and water cut for these wells.

Daily Production Data

- Analyse trends in well parameters such as oil, gas and water production, GOR, water cut, wellhead flowing pressure and temperature for these wells.
- Analyse cumulative production data to find the best historical producers.

Select Suitable Candidates

Figure 2 – Workflow describing the well screening process

Dynamic Synthesis.

The first step of the process was to score the wells by the following criteria using information from the Dynamic Synthesis, a comprehensive summary of all data available for each well that had already been compiled by TOTAL:

- *Production mechanism* - It was important to consider the production mechanism, as some wells in the Central part of the field may possibly be pressure supported by injectors in the Frontal Central part of the reservoir, and so seawater breakthrough may be a future possibility. Wells under natural depletion scored a point.

- *Reported scaling* – Wells with an anticipated scaling issue or already displaying signs of scaling may require frequent milling operations, preventing the installation of a velocity string. Wells with no scale reported scored a point.
- *Well understanding* – Wells were given a point for this criterion if their understanding was good or better.
- *GOR and water cut* – This data was obtained from the latest well test data. A point was given for wells with a GOR above 500 Sm^3/Sm^3, and another for a water cut below 5%. A high GOR is desired as high gas rate wells are better at unloading wellbore liquids than low GOR wells due to high gas velocities. Ideally no water production is preferred as water can lead to liquid loading problems in the well.
- *Operational issues* – Those considered included the possible re-use of the well slot for a new well in the new drilling campaign, as well as the requirement for a higher priority well intervention before a velocity string could be considered, such as re-perforation.

Based on this scoring system, 4 out of the 11 wells were deemed suitable for further analysis (D15, D18, D24Z and D29Z).

Well Test Data.

Historical well test data for the 4 remaining wells was then used to analyse trends in GOR and water cut in order to confirm that the latest well test data accurately represented previous trends. All wells were found to have sporadic records of water production and low water cut, except D18, which showed a rising trend in water cut. Wells D29Z and D18 showed rising trends in already high GOR.

Daily Production Data.

The final step in the well screening process involved analysing trends in oil, gas and water production, GOR, water cut, wellhead flowing pressure (WHFP) and temperature (WHFT) data. Cumulative gas production data was converted into boe by applying a conversion factor of 8.34 $kboe/MSm^3$, and added to cumulative oil production data in order to determine figures for cumulative production for each well. The wells were ranked based on cumulative hydrocarbon production and cumulative water production as a means of identifying the wells with the best productivity, because strong historic producers will make good candidates for well intervention. The results from this process are shown in Table 1.

Table 1 – Summary of results from daily production data analysis

Well name	Notes from daily production data analysis	Rank
D29Z	Primarily a gas producer, high GOR, low water cut, possible liquid loading (erruptivity problem)	1
D15	Low GOR, low water cut, fluctuating WHFP and production, signs of liquid loading	2
D18	High GOR but high water cut, declining trend in production	3
D24Z	Low GOR, low water cut, cyclic well so production is erratic	4

Candidate Well Selection Results.

Based on the well screening process, well D29Z was identified as the most suitable candidate for further velocity string installation analysis due to its high GOR, low water cut, strong historic production and lack of operational issues. D15 was also highlighted as a possibility for further analysis due to its strong historic production and evidence of liquid loading, requiring immediate remediation. Well D18 was not considered further due to rising water production, and well D24Z was not considered further due to its low GOR and cyclic production. Well D35Z would have been a good candidate but the reservoir where this well is located hasn't sufficiently depleted, and so a velocity string could possibly act as a choke and prevent the well from producing at its potential rates.

Generating Vertical Lift Performance Curves

In order to determine which type of completion configuration (velocity string or tail pipe) is optimal, Nodal Analysis must be used. The expected current production rate is given by the intersection of the current reservoir Inflow Performance Relationship (IPR) curve with the Vertical Lift Performance (VLP) curve that corresponds to a particular velocity string or tail pipe diameter. The IPR describes the relationship between bottomhole flowing pressure (BHFP) and production rate at a given reservoir pressure. The VLP describes the tubing performance at given operating conditions. The expected future production rate is given by the intersection of the future IPR (when the reservoir pressure has dropped further) with a given VLP curve. Models for each well with the current completions were calibrated and matched to historic well test data using Prosper, a well performance modelling, design and optimisation tool (version 11.5, Petroleum Experts, March 2011). This ensured that each model could accurately predict future well performance using previous well performance data.

Model Calibration for the Current Completion.

Multiphase Flow Correlations.

Model calibration required the use of a multiphase flow correlation which could describe the pressure drop in the well. Various multiphase flow correlations have been developed. Those developed by the likes of Duns and Ros (1963), Fancher and Brown (1963) and Beggs and Brill (1973), are empirical and so their range of applicability is somewhat limited. Other correlations, such as the proprietary correlations developed by Petroleum Experts (see references 18.) have also been developed and are more mechanistic in nature, thus representing physical phenomena more closely. Their aim is to calculate the pressure drop at every point in a well in order to accurately mimic the wells performance. The total pressure drop in a well consists of the components shown in equation 3:

$$\left[\frac{dP}{dL}\right]_{total} = \frac{g}{g_c}\rho_m \sin\theta + \frac{f\rho_m {v_m}^2}{2g_c d} + \frac{\rho_m v_m}{g_c}\frac{dv_m}{dl} \quad \text{.....(3)}$$

The first term represents hydrostatic pressure losses, and is the biggest factor in vertical and inclined flow (during the occurrence of liquid loading, the presence of liquid causes an increase in the BHFP, causing wells to load up and possibly die). The second term represents the frictional pressure loss, and becomes a more significant contributor to the overall pressure drop in a well when flow rates are high (e.g. in a gas well). The third term represents the pressure drop due to acceleration, and is generally negligible.

Prosper was used to compare pressures calculated at gauge depth using various tubing correlations with the gauge pressures measured during several bottomhole pressure (BHP) survey operations in order to identify the correlations that most accurately predict the pressure drop in a well. This step was important, as it is essential to accurately predict pressures in order to accurately predict rates. The correlations used were the modified Duns and Ros, Fancher Brown, Petroleum Experts 2, 4 and 5 (PE2, PE4, PE5), OLGAS 2P and 3P (proprietary correlations), and Tacite (a TOTAL in house correlation generally used for oil wells with a high water cut).

IPR Generation.

There are several models available for use in order to generate the IPR curves. The simplest is the P.I. Entry model, which uses the reservoir pressure and a pre-defined value for the Productivity Index (PI) to calculate rates above the bubble point pressure, and the Vogel IPR to calculate rates below the bubble point pressure. This model can only be used if it is assumed that the PI for a given well stays constant over its life. To validate this, the PI for each well test was evaluated using the BHFP calculated from the tubing head pressure (THP) with the chosen multiphase correlation, the recorded rates and the corresponding reservoir pressure (interpolated from available measured reservoir pressure data). The PIs for each well test were then plotted against time. If it was observed that the PI remained relatively constant over time (excluding the initial early life drop in PI), then it was acceptable to use the P.I. Entry model. The IPR curve could then be generated by selecting an appropriate value for the PI (which was chosen by performing a sensitivity analysis) and matching the curve to well test data.

Model Accuracy Validation.

Once the IPR and VLP curves for the current completion had been generated, a final check for accuracy was to compare the production rates calculated using the THPs from the well test data with the measured rates from the well test data. If the difference was small enough, it confirmed that the model was adequate for use when evaluating the predicted performance of each well.

Completion Options.

Critical Velocity Analysis.

The best completion type (velocity string or tail pipe) was chosen by analysing the variation of critical velocity and no-slip fluid velocity with measured depth for the current completion of each well. If there was only a problem in lifting the no-slip velocity above the critical velocity in the lower part of the completion, a tail pipe would be the best option as it would be considerably shorter in length (and hence cost) and easier to install than a velocity string. If there were problems raising the no-slip velocity above the critical velocity higher up in the completion then a velocity string would be the best option.

VLP Generation.

The VLP curves for all considered options were generated and then plotted for three cases; a case representing the current reservoir and production performance (case 1), a case representing mid life reservoir and well performance (case 2), and a case representing late life reservoir and well performance (case 3). This was done for the following reasons:

- To evaluate whether or not there was currently an evident liquid loading problem in the well.
- To determine the best time to install a velocity string or tail pipe if there was not currently a liquid loading problem with the current completion.

- To confirm whether velocity strings or tail pipes could still produce when the reservoir pressure had dropped to the late life case.

Vertical Flow Performance (VFP) Tables, which describe the tubing performance for a range of THPs, GORs and water cuts, were then generated for use in the reservoir simulation model in Eclipse (E300, 2009.2, Schlumberger).

A preliminary choice of the most optimal completion option was determined by selecting the option that was able to:

- Keep the no-slip velocity above the critical velocity at all points in the well.
- Provide an acceptable reduction in production rates.
- Provide a significant reduction in the well erruptivity limit (below which flow becomes unstable, represented by the minimum of the VLP curve, and so a reduction would signify a delay in loss of erruptivity).
- Produce at the required depleted reservoir pressures.

Figure 3 shows an example installation where a velocity string is able to provide a reduction in the erruptivity limit, and produce at lower reservoir pressures.

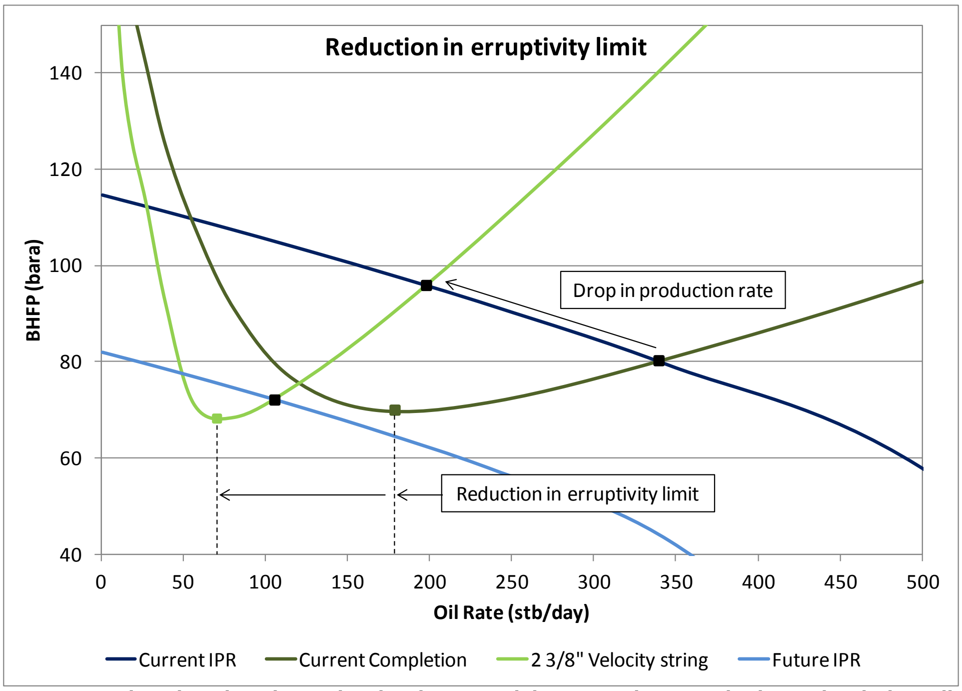


Figure 3 – A plot showing the reduction in erruptivity rate when a velocity string is installed

Evaluating the Impact on Reserves

The impact on reserves of installing a velocity string or tail pipe was evaluated by running reservoir model simulations in Eclipse. The reservoir model had already been history matched with respect to pressure and saturation (GOR and water cut), and the study mainly focused on production rate prediction. The process involved the following:

- To ensure continuity in flow rates from the historical to forecast period, modify the PI multiplier of the well in the reservoir model to match THPs from historical production data (and thus rates) for the last year with THPs from the simulation generated using the VFP table for the current completion.
- Generate production forecasts for the current completion and for the proposed velocity string or tail pipe options.
- Compare cumulative oil and gas production to evaluate the impact that the new installations have on reserves.

After the simulation had been run for the current completion, it was possible to determine when the well would be expected to die. The installation of a new velocity string or tail pipe was then scheduled for around that time. The current reservoir model is run with the wells controlled by a THP limit corresponding to the suction pressure of the export pumps on the Dunbar platform. The THP limit is lowered to 35 bars for all wells in the field during Q3 2012 and the simulation is run up to December 2031. Simulations for a THP limit of 40 bars were also run in order to determine the impact of degraded pump performance on the reserves associated with a velocity string or tail pipe installation.

Results and Analysis

D29Z.

D29Z is a high GOR well that has been a strong historical producer since first production in 2002. It was favoured in the well screening process for these reasons, along with its low water cut. As can be seen from Figure 4, up to 2008, wellhead flowing temperature slowly declined, but post 2008 it began to fluctuate while the wellhead flowing pressure was stable, indicating possible liquid loading or an eruptivity problem.

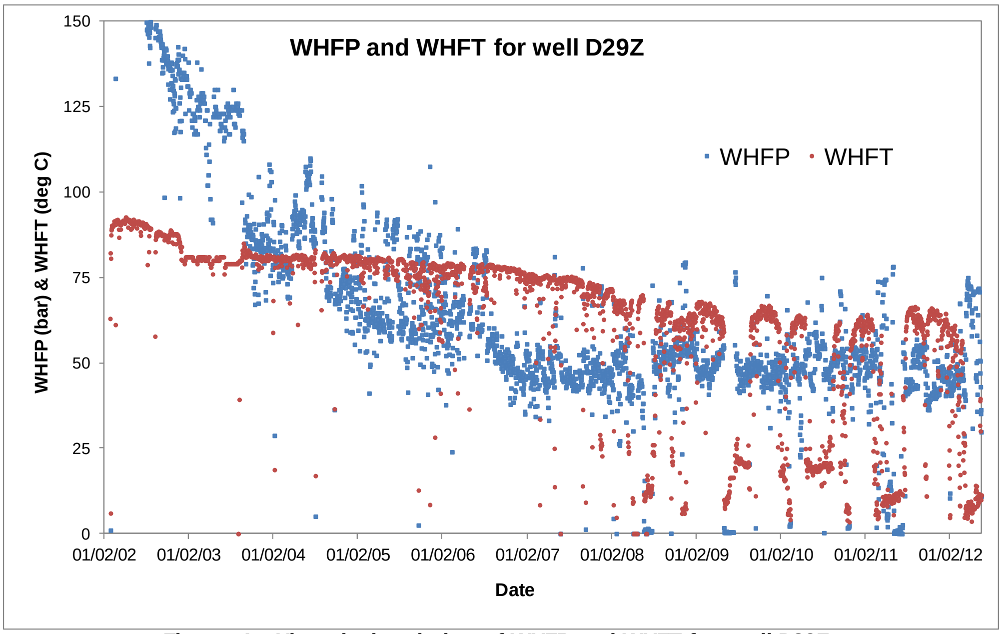


Figure 4 – Historical variation of WHFP and WHFT for well D29Z

All wells in the Dunbar field are modelled in Prosper as oil wells. The case for D29Z is different. Despite producing the same reservoir fluid, the area drained by this well is already depleted (below the saturation pressure) and so it produces more gas than oil. It would therefore be more accurate to model it as a gas well using a retrograde condensate model. However, for consistency with the other wells in the field it should be modelled as an oil well. D29Z was also initially a low GOR well. Two models were therefore created for the current completion, which contains mainly 4½" production tubing; an oil model and a retrograde condensate model, in order to determine whether this mainly gas producing well could be modelled as an oil well.

Oil Model.

The accuracy of the various multiphase tubing correlations was compared using downhole measurements and historical well test data consisting of tubing head pressure and temperature, water cut, liquid rate, gauge depth and pressure, reservoir pressure and GOR. Test data were excluded from the comparison if the average absolute error (in calculated gauge pressure vs. measured gauge pressure) across the correlations was greater than 10% (as well test data is sometimes questionable). The proprietary OLGAS 3P correlation was found to be the most accurate, having an error of 2.5%.

The IPR was generated using the P.I. entry model, and was matched to liquid rates and BHFPs from well tests from the last two years (see left plot in Figure 5). The IPR was matched to three sets of well test data out of a possible six (also due to questionable data quality). Analysis of the variation of well PI with time showed that the PI remained relatively constant, and a sensitivity performed in Prosper resulted in the best match with well test data using a PI of 1.8 Sm^3/day/bar.

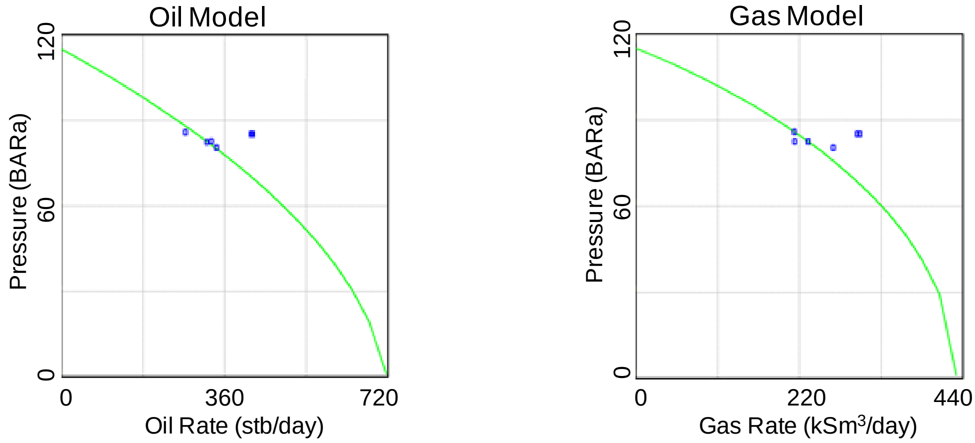


Figure 5 - IPR plot for well D29Z using the oil model (left) and retrograde condensate model (right), from Prosper

The quality of the oil model was then validated by computing the producing liquid and gas rates for the various THPs of the well tests. For the three sets of well test data out of a possible six that were matched with the IPR, the average error in the calculated gas rates was 2.2% (gas rates were checked as the well produces more gas than oil, and so there is more confidence in the gas rates measured during well tests than oil or liquid rates). This was small enough to validate the accuracy of the model.

Retrograde Condensate Model.

The same process was performed for the retrograde condensate model. When comparing the multiphase tubing correlations, the same well test data was used, but liquid rates were replaced with gas rates. Again the OLGAS 3P correlation was found to be most accurate, having an error of 3%.

The IPR was generated with a Multirate Forcheimer with pseudo pressure model, which takes account of non-Darcy pressure losses (see right plot in Figure 5), and matched to gas rates and BHFPs from the same three sets of well test data as the oil model. The IPR has the form shown in equation 4, where A and B are constants:

$$m(p_r) - m(p_{wf}) = Aq_g + Bq_g^{\,2} \quad \ldots\ldots(4)$$

The quality of the model was then validated with a similar check, where calculated producing gas rates were compared to measured gas rates. The average absolute error in the calculated gas rates for the well tests used to match the IPR was 3.6%, again small enough to validate the model.

Model Comparison.

The purpose of creating the two models for the well was to identify whether or not this mainly gas producing well could be modelled as an oil well for consistency with other wells in the field. Given that the overall aim is to evaluate how the no-slip velocity varies with depth in the well in relation to the critical velocity, a comparison was made between the no-slip velocities, critical velocities and pressures calculated by both models. Prosper calculates the critical velocities automatically for the retrograde condensate model using equation 5. No calculation is done for the oil model, and so equation 5 is used to calculate the critical velocities for the oil model in order to ensure a fair comparison:

$$v_t = 2.04\frac{\sigma^{1/4}(\rho_l - \rho_g)^{1/4}}{\rho_g^{\,1/2}} \quad \ldots\ldots(5)$$

It was observed that the oil model underestimates the critical velocity by 6%, while overestimating the no-slip velocity by 6%. The error in pressures calculated at various depths in the well averaged 0.16%. These errors were deemed small enough to assume that the oil model accurately describes this mainly gas producing well.

Velocity String and Tail Pipe Optimisation.

The velocity strings evaluated were set from the base of the SSSV (measured depth 295m) to the top of the pre-perforated liner (measured depth 6493m), while the tail-pipes would be hung-off the no-go nipple (measured depth 5786m) and run down to the top of the pre-perforated liner. They were evaluated for the operating cases shown in Table 2.

Table 2 – Summary of data for the operating cases analysed for well D29Z

Case	Time	Reservoir Pressure (bara)	THP (bara)	GOR (Sm^3/Sm^3)
1	Current (last well test)	115	42.5	5237
2	Mid life	90	35	3579
3	Late life	80	35	3579

The variation of no-slip velocity with well measured depth was analysed. Figure 6 (left chart) shows this variation, with the current completion, a 2⅜" velocity string and 2⅜" tail pipe as an example for case 1. It can be seen that for the current completion there appears to be no apparent issue of liquid loading in the well (no-slip velocity above critical velocity at all points in the well), but there is a problem area within the well where a sudden drop in no-slip velocity is observed. This is just above the pre-perforated liner, and is due to the change of diameter from the 4½" pre-perforated liner to 7" liner, before reaching the 4½" production tubing. This may cause production problems in the future as the reservoir pressure continues to decline, and so the installation of a velocity string or tail pipe at some point in the future would be recommended.

The chart shows that the tail pipe gives a strong improvement in no-slip velocity above the pre-perforated liner, compared to the modest improvement provided by the velocity string. However, the tail pipes (and current completion) are unable to produce in the late life case when the reservoir pressure has dropped to 80 bars, as their VLPs do not intersect the

IPR for that case. Figure 7 shows that the velocity strings can produce when the reservoir pressure drops to 80 bars. Therefore a velocity string is the only viable option. Figure 6 (right chart) also shows the variation in no-slip and critical velocity with measured depth for the three velocity strings considered during the operating conditions in case 3. It shows that the 2⅞" velocity string is the only one that is able to keep the no-slip velocity above the critical velocity at all points in the well. The 2⅞" velocity string also gives the lowest reduction in production rates for all cases considered. The oil and gas rate are both reduced by 38% compared to the production levels for the current completion in case 1.

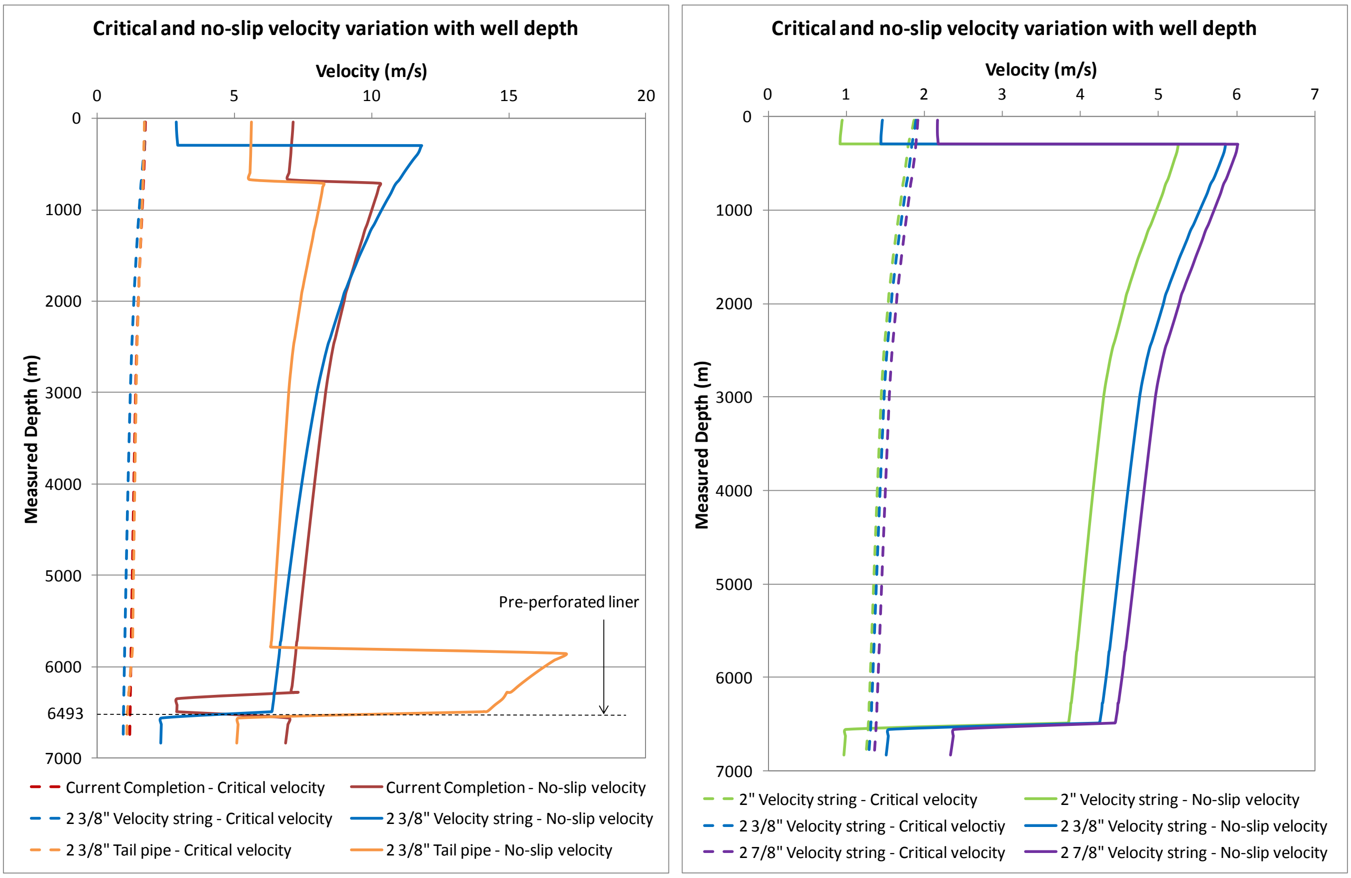


Figure 6 - Critical velocity and no-slip velocity comparison for the current completion, 2⅜" velocity string and tail pipe (left) and for the three velocity strings considered (right)

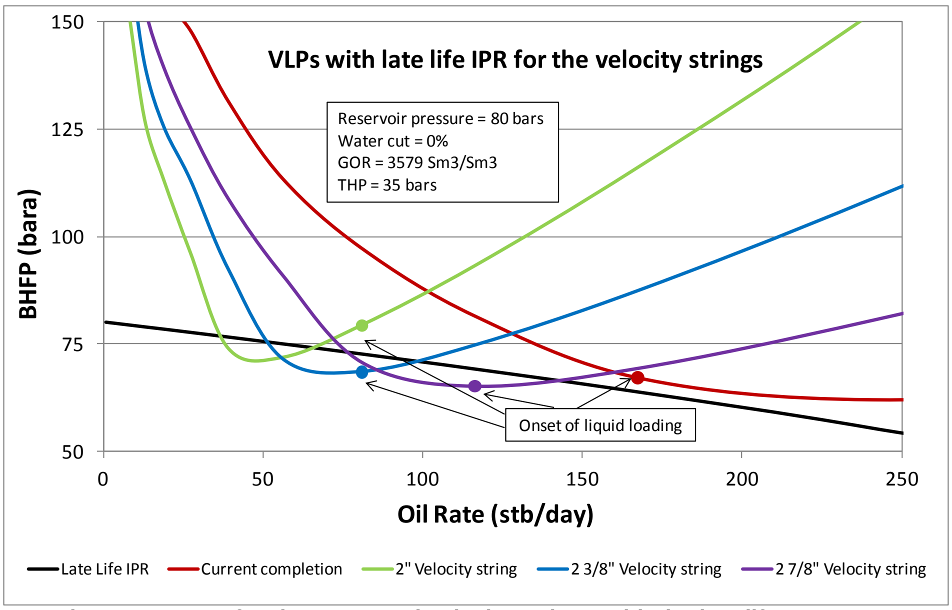


Figure 7 – VLPs for the proposed velocity strings with the late life IPR case

Figure 7 also shows that the onset of liquid loading for the current completion (as given by the critical rate) is lower than its erruptivity limit, confirming that the well does not have a liquid loading problem. The onset of liquid loading is close to the erruptivity limit for the 2⅞" velocity string, but greater than the erruptivity limit for the 2" and 2⅜" velocity strings, signifying that the well may encounter future liquid loading problems with these installations. This is another reason to favour the 2⅞" velocity string.

The VFP Tables for the three proposed velocity strings were generated using THPs from 20 to 300 bars, GORs from 150 to 10,000 Sm^3/Sm^3 and water cuts from 0 to 99%.

Impact on Reserves.

Reservoir model simulation was used to determine the impact on reserves. The production rates simulated using the VFP Table for the current completion were matched with the production history for the period July 2011 to July 2012. A well PI multiplier of 0.3 was applied in order to gain a suitable match. With the current completion the well is forecast to die in April 2015. A velocity string can be installed in Q1 2015 when a drilling rig will be available for the installation, which will be present as part of the new drilling program.

Table 3 summarises the gain in cumulative production for each velocity string option from the simulations. Both the 2" and 2⅜" velocity strings are able to produce to the end of the forecast period, while the well is forecast to die in January 2027 with the 2⅞" velocity string installed.

Table 3 – Summary of the cumulative production gain from the simulations for the velocity strings

Completion	End of life date	Cumulative Production Gain (boe %)
Current	April 2015	0%
2" Velocity string	December 2031	22%
2⅜" Velocity string	December 2031	26%
2⅞" Velocity string	January 2027	22%

It can be seen that the 2⅜" velocity string adds the most to cumulative production, but the 2⅞" velocity string is considered as the best option for the following reasons:

- It has the highest production rates, ensuring faster hydrocarbon recovery (see Figure 8).
- It is able to keep the no-slip velocity above the critical velocity at all points in the well at lower reservoir pressures.
- It is the only velocity string option that prevents possible liquid loading in the future.

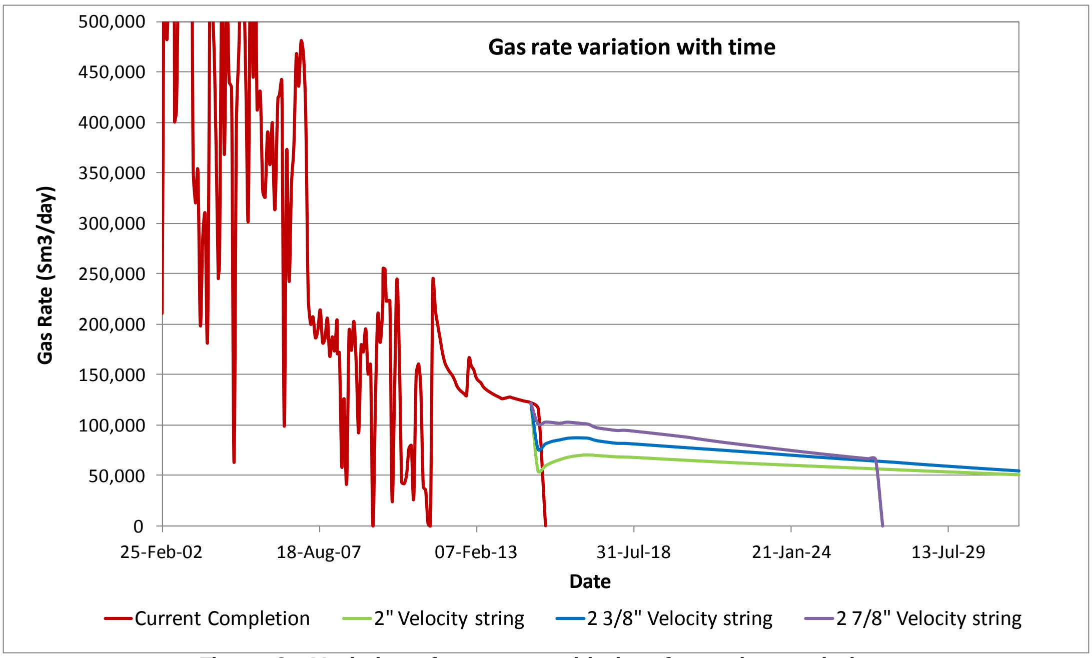


Figure 8 – Variation of gas rates with time for each completion

For the case when the THP limit is 40 bars the current completion is forecast to die in November 2013, and installing a velocity string in Q1 2015 results in a cumulative production increase of 24%, 29% and 25% for the 2", 2⅜" and 2⅞" velocity strings respectively. The cumulative production increase is higher compared to the 35 bar THP limit case because the well is forecast to die earlier.

Well D29Z drains two independent layers; the middle and lower Statfjord. The lower layer is a confined volume, whilst the middle layer is connected to the Brent reservoir. The left chart in Figure 9 shows how cumulative gas production varies further with reservoir pressure when the 2⅞" velocity string is installed for the middle Statfjord, and the chart on the right shows it for the lower Statfjord.

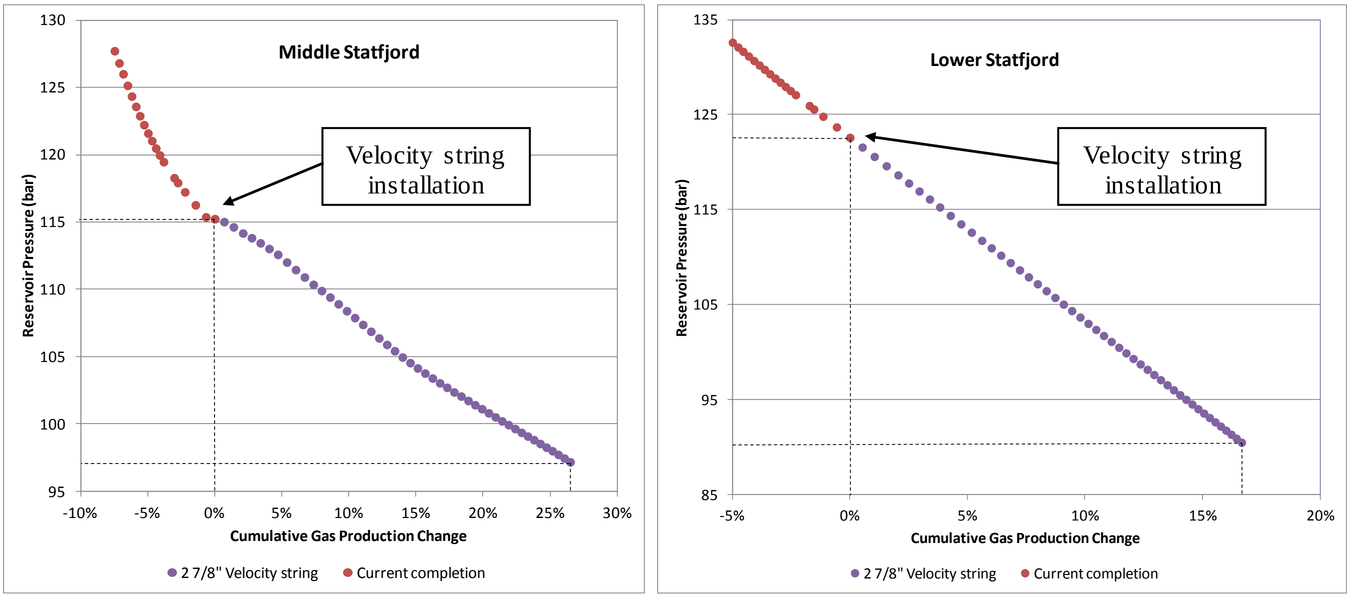


Figure 9 – Variation of reservoir pressure with cumulative gas production for the middle Statfjord (left) and lower Statfjord (right)

The plot for the middle Statfjord is not straight because this part of the reservoir is connected to the Brent reservoir, and so there is some communication. This also means that production from this part of the reservoir is higher. The plot on the left shows an anticipated drop in abandonment pressure of 17 bars, whilst the plot on the right shows a more optimistic anticipated drop in abandonment pressure of 31 bars. By installing a velocity string, the abandonment pressure is reduced and production is increased, concurring with the case in Figure 7 where the velocity string is capable of producing to lower reservoir pressures than the current completion.

Reserves Gain Uncertainty.

A similar plot of variation of reservoir pressure with cumulative gas production can be constructed using historical production data, and is shown in Figure 10. It shows that the production decline rate for the well has dropped over time, and so gas production is increasing for a given drop in reservoir pressure.

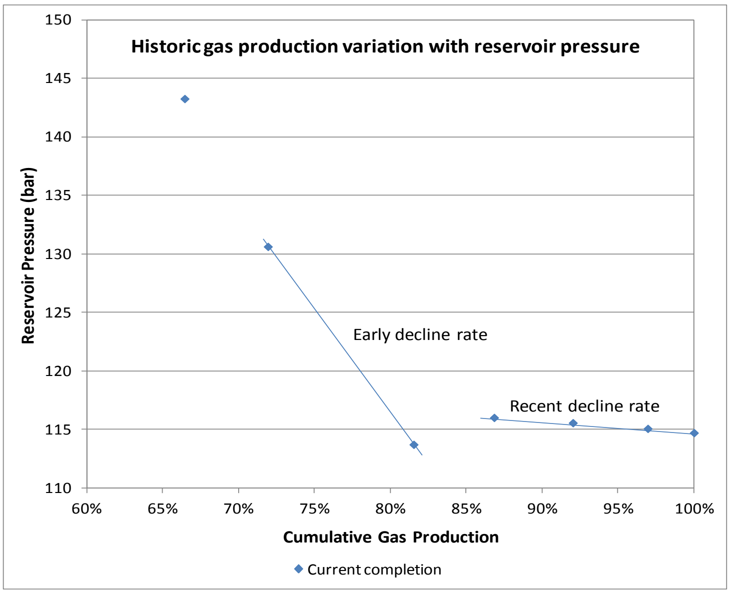
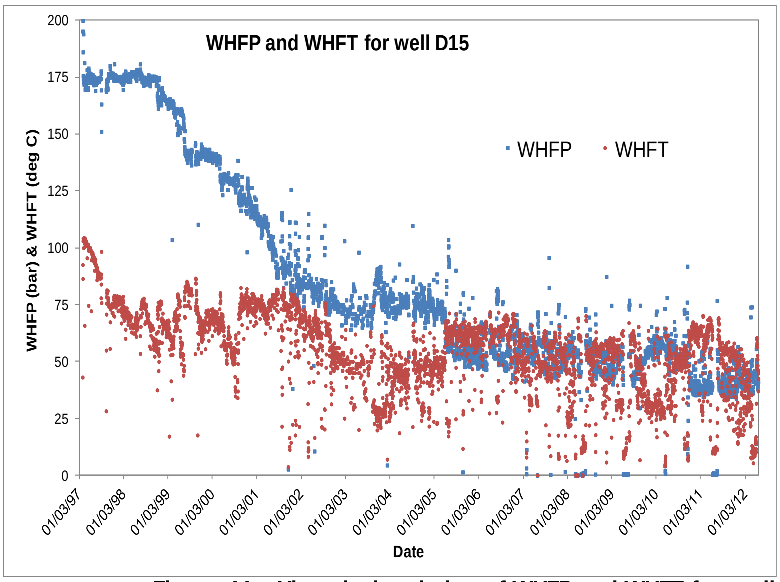


Figure 10 - Variation of reservoir pressure with cumulative gas production using historic production data

A 26% gain in cumulative gas production is expected with the 2⅞" velocity string installed. Using the conservative early decline rate and the conservative anticipated drop in abandonment pressure of 17 bars gives an expected gain in gas production of 11%. Given that this is roughly 40% of the current expected gain in gas production, it can be concluded that the gain in cumulative production in this case would be 40% of the 22% increase in cumulative production currently expected, i.e. a 9% gain. This can be thought of as a lower bound expected gain in cumulative production.

D15.

D15 is a low GOR oil well, but has a low water cut and has been a strong historical producer since first production in 1997. Well tests have indicated signs of liquid loading. An oil model was created for the current completion, which also contains mainly 4½" production tubing. Figure 11 (left) shows that the well has also experienced fluctuations in WHFT with moderately stable WHFP.



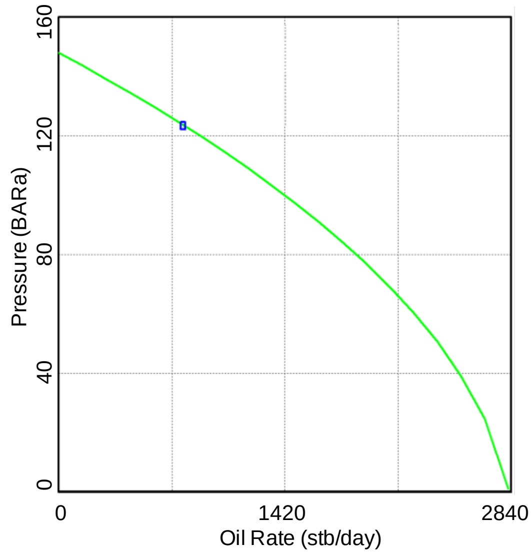


Figure 11 – Historical variation of WHFP and WHFT for well D15 (left), IPR plot from Prosper (right)

Oil Model.

The accuracy of the various multiphase tubing correlations were compared using historical data from well tests and from data acquired when production logging tools were run. The Fancher Brown correlation was found to have the lowest average error (3.0%), but was not used because it is empirical and so has a limited range of applicability. It also does not account for slip between the gas and liquid phases. Tacite was the next most accurate (3.4% average error), but was not used because it was designed for oil wells with a high water cut, which is not the case here, and also hasn't been updated recently. OLGAS 2P and 3P were the next most accurate (3.8% average error). OLGAS 3P was used in order to retain consistency with the analysis for well D29Z.

The IPR was generated using the P.I. entry model and was matched to the data from the last well test (see right chart in Figure 11). Analysis of the variation of well PI with time didn't provide a trend as smooth as that for D29Z, but was still sufficient for the use of the PI entry model. A sensitivity performed in Prosper resulted in the best match with well test data using a PI of 5.5 Sm^3/day/bar. The quality of the oil model was validated by calculating the producing liquid and gas rates for the THP from the last well test. The error in the calculated oil rate was 5.5%, and was 5.4% for the calculated gas rate. This was small enough to validate the accuracy of the model.

Velocity String and Tail Pipe Optimisation.

The velocity strings evaluated were set from the base of the SSSV (measured depth 674m) to the liner hanger bore (measured depth 3555m). The tail-pipes would be hung-off the no-go nipple (measured depth 3529m) and run down to the liner hanger bore. This is because there was an increase in diameter from the 4½" production tubing to the 6" liner hanger bore in the current completion. Figure 12 shows that the no-slip velocity with the current completion drops below the critical velocity at this point in the completion, indicating a possible liquid loading problem, which can be solved with the installation of a velocity string or tail pipe. Figure 12 also shows as an example that the installation of a 2⅜" tail pipe provides an improvement in the no-slip velocity in this part of the well. The velocity strings and tail pipes were evaluated for the operating cases shown in Table 4.

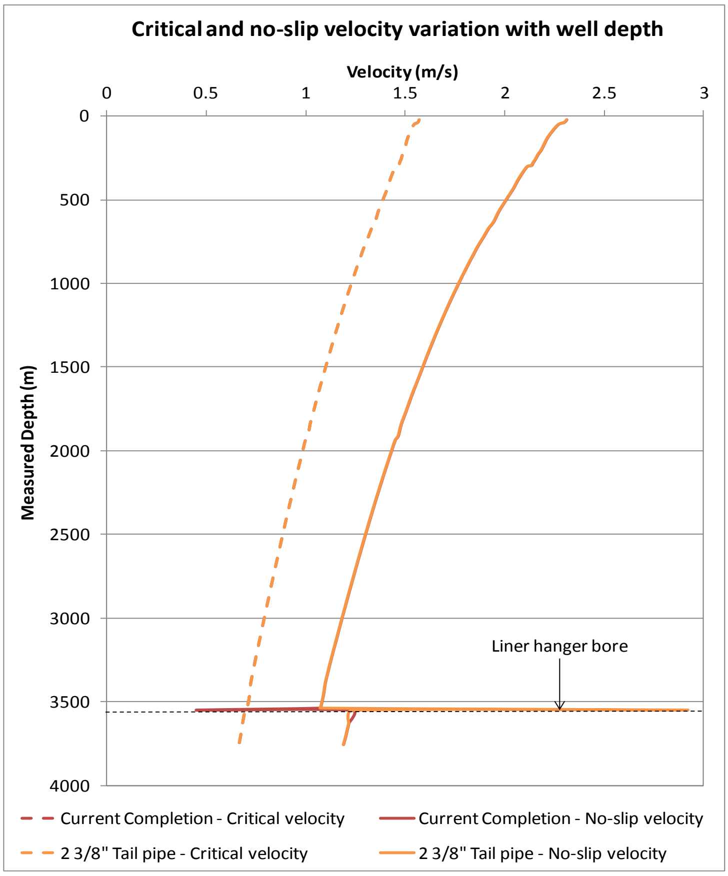


Figure 12 - Critical velocity and no-slip velocity comparison for the current completion and 2⅜" tail pipe

Table 4 – Summary of data for the operating cases analysed for well D15

Case	Date	Reservoir Pressure (bara)	THP (bara)	GOR (Sm^3/Sm^3)
1	Current (last well test)	148	38	513
2	Mid life	114	35	1279
3	Late life	95	35	1279

It was observed that the current completion could produce in all cases, although it can be seen from Figure 13 that the well produces in the unstable part of the VLP curve (intersection with the current IPR curve to the left of the erruptivity limit), indicating a liquid loading problem. No velocity string or tail pipe options were capable of producing at a lower reservoir pressure than the current completion. The velocity strings were unable to produce in case 1, though they could for case 2 (because of the simulated increase in GOR), and only the 2⅞" option could produce in case 3. The tail pipes were able to produce in all cases, and so would be the only viable option. On the basis that there would be no gain in abandonment pressure and therefore no gain in reserves, the only advantage of installing a tail pipe could be to reduce the erruptivity limit in order to stabilise production.

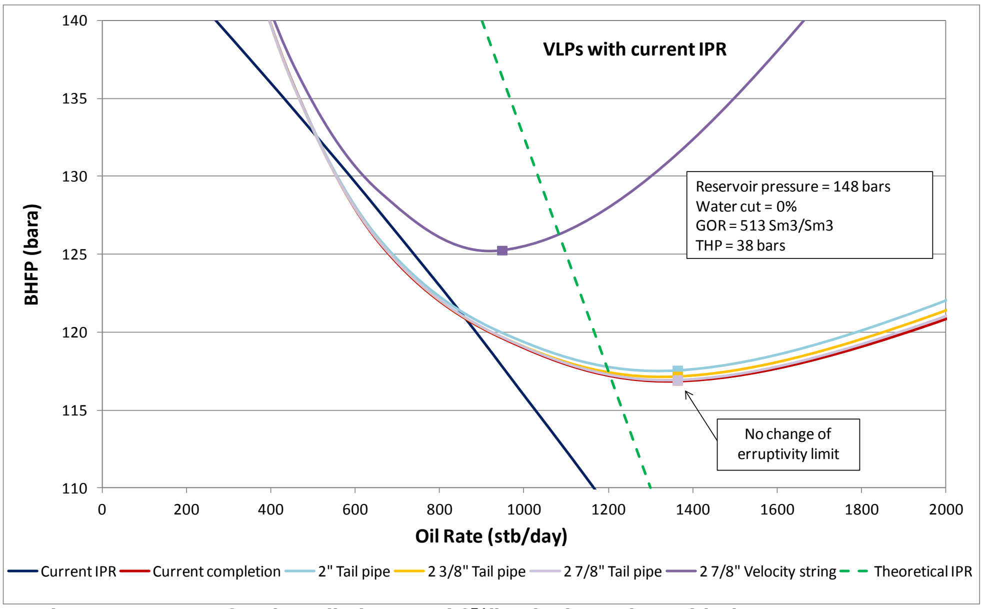


Figure 13 – VLPs for the tail pipes and 2⅞" velocity string with the current IPR case

Figure 13 shows that there is no change in erruptivity limit for any tail pipe option, and so there are no attainable advantages of installing a tail pipe is this particular well. While the 2⅞” velocity string does offer a reduction in the erruptivity limit, it can only produce in cases 2 and 3, and does not provide a reduction in abandonment pressure. For these reasons it is not a practical option. However, a scenario could exist where a higher reservoir pressure and lower PI combination would give the “Theoretical IPR” shown in Figure 13, resulting in the 2⅞” velocity string producing in the stable region while the current completion would produce in the unstable region. This highlights the impact that the IPR shape (reservoir pressure and PI combination) has on the success of a possible velocity string installation.

Discussion

A well selection process has been defined and used to select candidate wells for potential velocity string or tail pipe installation in order to extend producing lifetime and remediate any potential liquid loading concerns. Wells D29Z and D15 were identified as successful candidates for further analysis. It has been shown that the installation of a 2⅞” velocity string can reduce the erruptivity limit and lower the abandonment pressure (and therefore increase reserves) for well D29Z. This was not the case for well D15. This can be explained by further investigating the sources of pressure loss in the well.

Hydrostatic pressure losses dominate the shape of the VLP curve for flow rates below the erruptivity limit, and frictional pressure losses dominate the shape for flow rates above the erruptivity limit. The velocity strings do not work for D15 because of substantial hydrostatic pressure losses in the well. Figure 14 shows how hydrostatic and frictional pressure losses vary with oil rate for the current completion and 2⅞” velocity string option for wells D15 and D29Z. Both plots were generated for their respective case 1 scenarios.

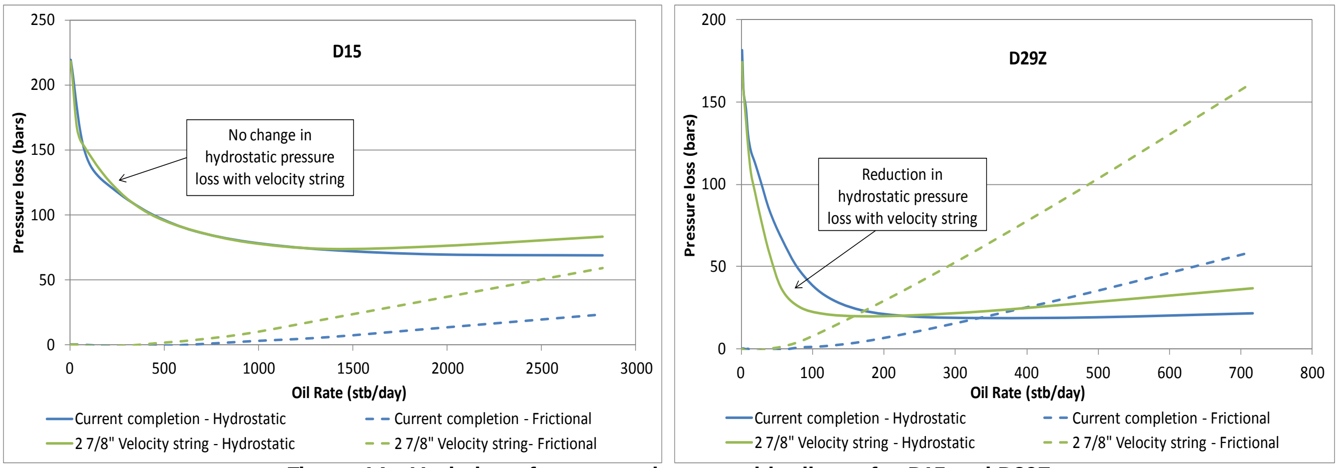


Figure 14 – Variation of pressure losses with oil rate for D15 and D29Z

The plots show that hydrostatic pressure losses dominate for D15 at all rates, whilst it is only the main contributor to the overall pressure loss in well D29Z at low rates. The case for D29Z also shows lower hydrostatic losses with the velocity string installed at low rates compared to the current completion, resulting in the VLP curve having a lower minimum pressure, enabling the well to produce at lower reservoir pressures. This is not the case for D15, and it can be seen in Figure 14 that the velocity string has almost the same hydrostatic pressure losses as the current completion at low rates. This is explained by the fact that the GOR for this well is lower, and so the higher liquid content in the flowing fluid results in a higher liquid holdup, mixture density, and consequently higher hydrostatic pressure losses, independent of the size of the completion. The hydrostatic pressure loss term in equation 3 is controlled by mixture density and well deviation. D15 has both a higher mixture density and lower maximum well deviation (22° vs. 76°) when compared to D29Z. Reservoir fluid characteristics also contribute to this effect. Although both wells produce the same reservoir fluid, D15 and D29Z are located in different compartments within the Dunbar field. D29Z is in a more depleted part of the reservoir and as a result produces a lighter oil. The denser fluid produced by D15 contributes to the higher hydrostatic pressure losses in the well. Table 5 summarises the differences between wells D29Z and D15 that result in velocity strings benefiting D29Z, but having no benefit for D15. Other means of improving well productivity for D15 can be explored, such as re-perforation, or the use of an ESP given the low GOR nature of the well.

It has been shown that various factors impact whether a velocity string or tail pipe installation can provide any benefit for a well. Given the wide scope of factors in play, well by well screening is required to determine whether any installation may eventually be successful or not.

Table 5 – Differences between D29Z and D15 that impact the success of a velocity string

Well	Maximum Well Deviation	Oil Density (kg/m^3)	Gas Specific Gravity	Reservoir Pressure (bara)	Current GOR (Sm^3/Sm^3)	Completion	Average Liquid Holdup	Average Mixture Density (kg/m^3)
D29Z	76°	725	0.73	115	5237	Current	0.52	91
						2⅞" velocity string	0.36	80
D15	22°	811	0.96	148	513	Current	0.80	347
						2⅞" velocity string	0.71	335

Conclusions

Having defined an initial well selection criterion with the use of three sources of data, two wells (D29Z and D15) have been identified as candidates for the installation of a velocity string or tail pipe due to their high GOR (D29Z only), strong historic production, low water cut and possible signs of liquid loading. By analysing the performance of various velocity string or tail pipe options with regard to ability to increase no-slip velocity above the critical velocity, reduction in erruptivity limit and ability to produce at a lower reservoir pressure than the current completion, a successful option was identified for well D29Z. The well was found to have no apparent liquid loading problem. The 2⅞" velocity string option, installed just before the well stops producing with the current completion, is predicted to lower the abandonment pressure and increase cumulative production by 9-22%. An installation in this well thus provides a means of extending producing lifetime and increasing cumulative production.

A viable option was not found for well D15 because it did not have a favourable GOR or fluid characteristics when compared to well D29Z. Although tail pipe options could produce for every case analysed, they offer no reduction in the erruptivity limit. The heavier fluid means that hydrostatic pressure losses dominate the well, even with the installation of a velocity string, which is meant to reduce the erruptivity limit. A velocity string or tail pipe installation in this well would therefore provide no benefit, and so other means of well intervention, such as re-perforation or ESP installation, may be considered for this well in order to improve productivity.

Given the wide range of factors that eventually determine a well's suitability for a velocity string or tail pipe installation (such as GOR, fluid characteristics, IPR shape, well inclination), individual well by well screening is necessary. The ultimate aim of evaluating whether it is actually feasible to develop a standardised well selection process for application to neighbouring fields with similar characteristics could be the subject of further work.

Further Work

Additional analysis may potentially consist of the following:

- Analysis of second tier wells with high GOR, low water cut and strong historical production, where scale hasn't been confirmed, but can be by performing a slick line operation, such as D19.
- Further investigation into the implications of fluid characteristics on the viability of velocity string or tail pipe installations in relevant wells.
- The study was based on Nodal analysis using Prosper, which does not take account of transient effects. Liquid loading behaviour is mainly transient, and so the overall understanding of the phenomena could be improved if a program like OLGA (SPT Group), which takes account of transient effects, is used.
- The analysis has focused on tubular flow thus far, but can be extended to annular flow (i.e. flow between the current tubing string and a velocity string or tail pipe) or tubular-annular flow in order to see the impact on production rates and abandonment pressure, if any.
- An economic analysis in order to investigate the real cost and potential return of a velocity string or tail pipe installation for successful wells.

Nomenclature

A = tubing cross-sectional area, ft^2
d = tubing internal diameter, ft
f = friction factor, dimensionless
g = acceleration due to gravity, 32.2 ft/sec^2
g_c = gravitational conversion factor, 32.2 ft/sec^2
l = tubing length, ft
$m(p_r)$ = pseudo reservoir pressure, psia^2/cp
$m(p_{wf})$ = pseudo bottomhole flowing pressure, psia^2/cp

p = pressure, psia
q_g = gas flow rate, scf/day
q_{gc} = critical gas rate, MMscf/day
T = fluid temperature, °R
v_m = mixture velocity, ft/s
v_t = critical velocity, ft/s
z = gas compressibility factor, dimensionless
ρ_g = gas density, lbm/ft^3
ρ_l = liquid density, lbm/ft^3
ρ_m = mixture density, lbm/ft^3
σ = liquid/gas surface tension, dynes/cm
θ = tubing angle of inclination from horizontal, °

SI Metric Conversion Factors

bbl x 1.589 873 E-01 = m^3
in. x 2.54* E+00 = cm

* Conversion factor is exact.

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Appendices

Appendix A – Critical Literature Review

MILESTONES IN THE UNDERSTANDING OF GAS WELL LIQUID LOADING AND THE USE OF VELOCITY STRINGS AS A SOLUTION
TABLE OF CONTENT

SPE Paper No.	Year	Title	Authors	Contribution
32, JPT	1961	"Estimating Flow Rates Required To Keep Gas Wells Unloaded"	J. O. Duggan	Provided field men with an easy and quick way to determine what flow rate was roughly required to keep a gas well unloaded using a chart.
2198, JPT	1969	"Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells"	R. G. Turner, M. G. Hubbard, A. E. Dukler	Derived an equation describing the minimum gas velocity required to keep a gas well continuously unloaded. Produced a nomograph which can be used to determine the gas flow rate required to unload gas wells of various tubing diameters.
3473, JPT	1972	"A Practical Approach to Removing Gas Well Liquids"	E. J. Hutlas, W. R. Granberry	Reviewed the methods used in the past and at the time to remove liquid from gas wells, and discussed a practical method of gas well candidate selection for liquid removal.
10170	1981	"Minimum Gas Flow Rate for Continuous Liquid Removal in Gas Wells"	M. I. Ilobi, C. U. Ikoku	Developed an alternative model for predicting the minimum gas flow rate required to remove liquid from a gas well.
SPE Production Engineering	1989	"Expanding the Range for Predicting Critical Flow Rates of Gas Wells Producing From Normally Pressured Waterdrive Reservoirs"	E. R. Upchurch	Used empirical correlations (Gray correlation) to develop a method for estimating critical flow rates for gas wells producing with water/gas ratios of more than 150 bbl/MMcf.
20280, JPT	1991	"A New Look at Predicting Gas-Well Load-Up"	S. B. Coleman, H. B Clay, D. G. McCurdy, H. L. Norris III	Verified that Turner *et al.*'s equation without the 20% correction can be used to estimate the critical flow rate required to keep a gas well unloaded, focusing on wells with wellhead flowing pressures below 500 psi.
24860	1992	"Predicting Gas Well Load-Up Using Nodal System Analysis"	A. K. Moltz	Identifies the improved accuracy of predicting liquid loading in low pressure gas wells using nodal analysis that uses compositional wellbore fluid modelling, which provides the reservoir pressure in addition to the gas flow rate at which loading will occur.
78568	2002	"Prediction of Critical Gas Flow Rate for Gas Wells Unloading"	E. A. Osman	The model developed provides predictions of critical gas flow rate with higher accuracy than previous models when compared to test data.
104605	2007	"On the Flow Performance of Velocity Strings To Unload Wet Gas Wells"	P. Oudeman	Developed a suitable model for predicting the pressure drop in the velocity string-tubing annulus for gas/liquid flow.
107467	2007	"Securing the Future in Mature Gas Fields"	W. Schinagl, M. Denny	Discusses the adaptation of onshore gas well deliquification technologies for application in offshore environments such as the North Sea.
115933	2008	"Critical Review of Existing Solutions to Predict and Model Liquid Loading in Gas Wells"	F. A. Solomon, G. Falcone, C. Teodoriu	Highlights the importance of the inclusion of transient flow assumptions in models used for calculating critical gas flow rate.

SPE 32, JPT (December 1961)

Estimating Flow Rates Required To Keep Gas Wells Unloaded

Author: Duggan, J. O.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Provided field men with an easy and quick way to determine what flow rate was roughly required to keep a gas well unloaded using a chart.

Recognised the impact of gas well liquid loading on GPM tests.

Objective of the paper:

To estimate the flow rate required to keep gas wells unloaded and publish curves permitting field men to determine whether a well is flowing at a sufficient rate.

Methodology used:

Used back-pressure data from selected wells to find the minimum wellhead gas velocity required, and used a velocity formula to convert wellhead velocity to wellhead flow rate for various tubing sizes, assuming a 0.6 gravity gas.

Conclusion reached:

1) A minimum gas wellhead velocity of roughly 5 ft/s is required to keep gas wells unloaded.
2) The empirical approach is not faultless but works well when it applies.
3) Producing wells in the unloaded condition will give more representative test results.

Comments:

Empirical approach using field data for selected wells, no theoretical basis.

SPE Journal (March 1963)

Prediction of Pressure Gradients for Multiphase Flow in Tubing

Authors: Fancher, G. H., Brown, K. E.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Developed a multiphase flow correlation that can be used to determine the pressure gradient in a well.

Objective of the paper:

To develop a multiphase flow correlation that can be used to determine the pressure gradient in a well, using data from an experimental well.

Methodology used:

1) Used an 8,000 ft experimental field well to conduct flowing pressure gradient tests for various flow rates and gas/liquid ratios.

Conclusion reached:

1) The proposed correlation is valid for the range of flow rates and gas/liquid ratios used in the tests with an accuracy of ±10%.
2) The gas/liquid ratio is a significant parameter in multiphase flow.

Comments:

6th World Petroleum Congress (June 1963)

Vertical Flow of Gas and Liquid Mixtures in Wells

Authors: Duns, H., Ros, N. C. J.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Developed a multiphase flow correlation that can be used to determine the pressure gradient in a vertical well.

Objective of the paper:

To develop a multiphase flow correlation based on experimental data that could be used to determine the pressure gradient in a well more accurately than other models that existed at the time.

Methodology used:

1) Used experimental data to develop an empirical correlation that can be used to model the vertical flow of a gas and liquid mixture.

Conclusion reached:

1) The results from the correlation are promising, but it must be noted that there are several factors that may cause the pressure gradient in a well to differ from that seen in experimental data.

Comments:

SPE 2198, JPT (November 1969)

Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells

Authors: Turner, R. G., Hubbard, M. G., Dukler, A. E.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Derived an equation describing the minimum gas velocity required to keep a gas well continuously unloaded. Produced a nomograph which can be used to determine the gas flow rate required to unload gas wells of various tubing diameters.

Objective of the paper:

To determine the principal mechanism governing gas well liquid loading and to predict the minimum flow rate required for continuous gas well liquid unloading.

Methodology used:

Analysed two models and compared to experimental data to determine the prevailing mechanism for liquid removal from a gas well:

1) Liquid film on the wall of a tubular conduit where liquid moves up by interfacial shear.
2) Liquid drops entrained in a vertically flowing high velocity gas core.

Conclusion reached:

1) Minimum velocity required to unload a gas well is that which will move the largest liquid droplet that can exist in the gas stream.
2) The equation derived must be adjusted upwards by 20% to ensure removal of all drops.
3) The gas/liquid ratio doesn't impact the minimum lift velocity in the observed ranges of liquid production (water or condensate) up to 130 bbl/MMcf (properties of denser fluid to be used if both present).
4) Wellhead conditions are a controlling factor in most cases.

Comments:

Treats gas core and liquid film separately, though notes there is probably a continuous exchange of liquid between them.

Some key data was incomplete:

1) Interfacial tension for the well fluids used was not measured but estimated based on molecular weight.
2) Bottom-hole temperatures were not reported, but estimated using area geothermal gradient charts.
3) Density of gas and liquid phases were not available for most data, and were estimated.
4) Whether the wells were loaded or not at the time of data collection.

SPE 3473, JPT (August 1972)

A Practical Approach to Removing Gas Well Liquids

Authors: Hutlas, E. J., Granberry, W. R.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Reviewed the methods used in the past and at the time to remove liquid from gas wells, and discussed a practical method of gas well candidate selection for liquid removal.

Objective of the paper:

To provide a practical approach to evaluating liquid removal from gas wells.

Methodology used:

Compared advantages and disadvantages of previous and current methods for removing liquid from gas wells, namely Pumping Units, Liquid Diverters and Gas Lift, and Tubing Strings.

Conclusion reached:

1) Production of large volumes of liquid alone is not enough to distinguish a gas well as a candidate for liquid removal.
2) The economics of liquid removal should be evaluated before installation.
3) The best devices at the time for removing liquids from gas wells were pumping units for shallow fields with low pressure and a combination of a liquid-diverter and gas-lift installation for deeper, high pressure fields.
4) Smaller tubing strings can be used in wells where severe formation damage from killing operations may occur.

Comments:

Provides a method to analyse the economics of installing a system to remove liquids from a gas well.

SPE 4007, JPT (May 1973)

A Study of Two-Phase Flow in Inclined Pipes

Authors: Beggs, H. D., Brill, J. P.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Developed a multiphase flow correlation to determine the pressure gradient in inclined wells for different flow conditions.

Objective of the paper:

To investigate the effect of pipe inclination on liquid holdup and pressure loss in pipes with gas/liquid flow.

Methodology used:

1) Used experimental data for various flow rates from 90 ft transparent pipes to develop a multiphase flow correlation that predicts the pressure gradient in inclined pipes.
2) Measured liquid holdup using pneumatically actuated, quick-closing ball valves.
3) Measured the pressure drop using pressure taps.

Conclusion reached:

1) Pipe inclination has an impact on liquid holdup and pressure loss for most flow conditions in pipes with two-phase flow.
2) Liquid holdup reaches a maximum at a pipe inclination of approximately +50° and minimum at a pipe inclination of approximately -50°.
3) Friction losses in two-phase flow are affected by liquid holdup.
4) A correlation was developed that can predict the liquid holdup and pressure gradients in two-phase flow at any angle of inclination.

Comments:

Used air and water as the two phases.

SPE 10170 (October 1981)

Minimum Gas Flow Rate for Continuous Liquid Removal in Gas Wells

Authors: Ilobi, M. I., Ikoku, C. U.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Developed an alternative model for predicting the minimum gas flow rate required to remove liquid from a gas well.

Objective of the paper:

To create a model for predicting the minimum gas flow rate required for continuous removal of liquid in gas wells for more general application.

Methodology used:

Developed a model for analysing the removal of liquid from a gas well using modified correlations for predicting entrainment, film thickness and pressure drops developed by Hughmark (1973), as well the Duns and Ros pressure drop correlation.

Conclusion reached:

1) The most important factors affecting liquid entrainment are tubing size, pressure, gas specific gravity and liquid hold-up.
2) High specific gravity gas is a better carrier of liquid droplets.
3) Entrainment is dependent on actual gas velocity as well as superficial gas velocity.
4) The model is insensitive to liquid concentrations above 175 bbls/MMscf.
5) It cannot categorically be stated how close the model is to actual data, due to insufficient data.

Comments:

Developed the model based on a combination of previous work.

Used assumptions for gas specific gravity, bottom hole temperature, and temperature gradients and used assumptions made by Turner for liquid gravities in order to compare model to field data.

SPE 10254 (September 1982)

Small-Diameter Concentric Tubing Extends Economic Life of High Water/Sour Gas Edwards Producers

Author: Weeks, S. G.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Not too much, just details a field case where the installation of small-diameter concentric tubing has extended the economic life of a field.

Objective of the paper:

To detail the installation of small-diameter concentric tubing to remediate liquid loading problems in a tight gas field.

Methodology used:

1) Compared available technology and concluded that the use of small-diameter tubing was the only viable option on a cost basis due to well depth and the sour environment.
2) Analysed various tubing intake curves against current reservoir performance to determine the most suitable tubing diameter.

Conclusion reached:

1) Seven small-diameter tubing installations were performed and continuous production was maintained.
2) The annual production decline rate in the field dropped from 60% to 25% following the installation of small-diameter concentric tubing. This and the reduction in operational attention required resulted in an increase in net operating profit.

Comments:

Discusses problems with corrosion, which were dealt with in this case by installing small-diameter concentric tubing.

The Edwards field was a tight gas field.

SPE Production Engineering (August 1989)

Expanding the Range for Predicting Critical Flow Rates of Gas Wells Producing From Normally Pressured Waterdrive Reservoirs

Author: Upchurch, E. R.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Used empirical correlations (Gray correlation) to develop a method for estimating critical flow rates for gas wells producing with water/gas ratios of more than 150 bbl/MMcf.

Objective of the paper:

To develop a method for estimating the critical flow rate for gas wells producing with high water/gas ratios.

Methodology used:

Used Gray empirical multiphase flow correlation to take account of slippage between phases and flow regime effects (not previously done due to lower liquid/gas ratios), and compared to field tests to verify accuracy.

Conclusion reached:

1) Empirical techniques can be used to estimate the critical flow rates for many gas wells producing with high water/gas ratios from normally pressured waterdrive reservoirs.
2) The critical flow rates predicted compare well with previous theoretical models used at low water/gas ratios, and with field tests at high water/gas ratios.

Comments:

Uses Gray correlation.

SPE 20280, JPT (March 1991)

A New Look at Predicting Gas-Well Load-Up

Authors: Coleman, S. B., Clay, H. B., McCurdy, D. G., Norris III, H. L.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Verified that Turner *et al.*'s equation without the 20% correction can be used to estimate the critical flow rate required to keep a gas well unloaded, focusing on wells with wellhead flowing pressures below 500 psi.

Objective of the paper:

To compare results from field tests with previous theory on the critical flow rate required to keep gas wells unloaded.

Methodology used:

Applied Turner *et al.*'s theory to field tests and production charts, focusing on wells with wellhead flowing pressures below 500 psi (Turner *et al.*'s data was above 500 psi).

Conclusion reached:

1) The critical flow rate required to keep gas wells unloaded can be predicted adequately using Turner *et al.*'s liquid droplet model without the 20% upward correction.
2) Wells that exhibit slugging behaviour may not adhere to the liquid droplet model due to a different transport mechanism.
3) Verified Turner *et al.*'s theory that wellhead conditions control the onset of liquid loading.
4) For the examined liquid/gas ratio range of 1-22.5 bbl/MMscf, the amount of liquid present had no impact on the critical gas flow rate (as per Turner *et al.*).
5) In most cases the primary source of load fluid is condensed water.

Comments:

Noted that gas gravity, interfacial tension and temperature have little impact on the accuracy of calculations for critical gas velocity.

SPE 24792 (October 1992)

Design and Installation of a 20,500-ft Coiled Tubing Velocity String in the Gomez Field, Pecos County, Texas

Authors: Adams, L. S., Marsili, D. L.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

A field case illustrating the use of coiled tubing for velocity strings.

Objective of the paper:

To review candidate selection, installation design, implementation and production results of a 20,500 ft coiled tubing velocity string in a Gomez Field gas well. First use of master control preventer for a coiled tubing installation.

Methodology used:

1) Analysed the given well due to its marginal economic production rate and potential loss of reserves.
2) Used P/Z and production data to determine the source of liquid loading.
3) Used the Turner *et al.* equation and a Chevron in-house steady state multiphase flow simulator to determine the critical gas flow rate.
4) Screened methods to alleviate liquid loading on an economic and operational basis.
5) Designed the installation using a Chevron in-house nodal analysis simulator.

Conclusion reached:

1) Project success shows reliability and economic effectiveness of coiled tubing technology (two successful coiled tubing velocity strings were installed in the Gomez Field).
2) Simulation results were accurate in predicting the most effective setting depth for liquid unloading and stabilised after workover production rates.

Comments:

Highlights economic attraction of using a velocity string to remediate liquid loading.

SPE 24860 (October 1992)

Predicting Gas Well Load-Up Using Nodal System Analysis

Author: Moltz, A. K.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Identifies the improved accuracy of predicting liquid loading in low pressure gas wells using nodal analysis that uses compositional wellbore fluid modelling, which provides the reservoir pressure in addition to the gas flow rate at which loading will occur.

Objective of the paper:

To identify the requirement for compositional wellbore fluid modelling in the application of nodal analysis to low-pressure gas wells in order to accurately match performance and predict the onset of liquid loading.

Methodology used:

1) Used extensive computer wellbore modelling to deduce that previous applications of nodal analysis have not taken the water contained in the produced gas or its phase change into account, hence the requirement for compositional modelling.
2) Used compositional modelling to more accurately model outflow performance and predict the onset of liquid loading.

Conclusion reached:

1) Nodal analysis can be used to accurately predict the reservoir pressure and flow rate at which liquid loading will occur.
2) Condensed water production can increase the pressure required to keep a well unloaded, especially for wells with a water/gas ratio greater than 3 bbl/MMscf.
3) The increased water production that occurs with declining reservoir pressure and its phase behaviour must be accounted for in nodal analysis to reliably predict performance.
4) Load-up prediction and reserve estimation should be based on the onset of slug flow in the wellbore, as the use of wellhead conditions tends to overstate flow performance and reserve recovery.

Comments:

Notes that previous applications of nodal analysis have used black-oil wellbore modelling to evaluate the tubing pressure drop, where water is assumed to be in a liquid phase.

Nodal analysis can provide the rate as well as the pressure at which liquid loading will occur, thus providing an alternate pressure figure to the abandonment pressure, for which reserves can be estimated.

SPE 46030 (April 1998)

Coiled Tubing Velocity Strings – Expanding the Cases

Authors: Martinez, A., Martinez, J.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Stresses the importance of a velocity and liquid holdup criteria in unloading a gas well and preventing further loading.

Objective of the paper:

To provide a guide to predicting the results that drive coiled tubing size selection.

Methodology used:

1) Used software to model liquid loading.
2) Chose preferred tubing size based on achievement of a velocity and liquid hold-up criteria.

Conclusion reached:

1) The coiled tubing size best for initiating unloading is not necessarily the best for achieving maximum steady state production rates.
2) For a given coiled tubing size the ease of unloading and preventing further liquid loading can be predicted using the velocity-liquid holdup profile compared to the criteria of a 7-12 ft/s velocity in the lower third of the tubing and a liquid holdup of 0.2 or less in the lower portion of the tubing.

Comments:

Uses ProdEng, WelGrad and WelDel software.

SPE 78568 (October 2002)

Prediction of Critical Gas Flow Rate for Gas Wells Unloading

Author: Osman, E. A.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

The model developed provides predictions of critical gas flow rate with higher accuracy than previous models when compared to test data.

Objective of the paper:

To present an Artificial Neural Network model for predicting the minimum gas flow rate for continuous liquid unloading.

Methodology used:

1) Used 50% of the data sets published by Turner *et al.* and Coleman *et al.* to train the model, 25% to cross-validate the relationships established during the training process, and 25% to test the model for accuracy.
2) Developed the model using back propagation networks.

Conclusion reached:

The model provides more accurate predictions of critical gas flow rate (Correlation coefficient of 0.9911, absolute average percentage error 4.61%) when compared to previous models.

Comments:

SPE 72092, JPT (April 2004)

Solving Gas-Well Liquid-Loading Problems

Authors: Lea, J. F., Nickens, H. V.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Further discussion of the various methods of alleviating gas well liquid loading.

Objective of the paper:

To describe the issues with liquid accumulation in gas wells in terms of recognition and solutions to the problem.

Methodology used:

Discussion of the various technologies available for liquid removal from gas wells.

Conclusion reached:

1) Liquid loading can be recognised from well symptoms, critical velocity and/or nodal analysis.
2) Merits of the various methods used at the time to solve gas well loading.

Comments:

Doesn't seem to be much new information presented, more a review of technologies available at the time.

SPE 88523 (October 2004)

Liquid Unloading in a Big Bore Completion: A Comparison Among Gas Lift, Intermittent Production, and Installation of Velocity String

Authors: Arachman, F., Singh, K., Forrest, J. K., Purba, M. O.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Compared three technologies for a semi-permanent solution to gas well liquid loading for wells with a big bore completion.

Objective of the paper:

To compare the various technologies available at the time (gas lift, intermittent production and velocity string) to solve problems of liquid loading for a low-pressure gas condensate well with a big bore completion, technically and economically.

Methodology used:

1) Uses published data for the Arun Field, Indonesia.
2) Assumed the installation of the three technologies individually and modelled the impact on gas recovery using nodal analysis.

Conclusion reached:

1) Installation of a coiled-tubing velocity string will increase the gas velocity and help mitigate liquid loading.
2) Critical and maximum erosional velocity as well as operational issues such as logistics, transportation and installation, drive the optimum diameter and length of the velocity string.

Comments:

Does not include a detailed economic analysis.

The velocity string is the option where design is most crucial, and was modelled with the installation of 2,000 feet of tubing in the deepest part of well (i.e. not from the surface) due to excessive pressure losses.

SPE 104605 (March 2007)

On the Flow Performance of Velocity Strings To Unload Wet Gas Wells

Author: Oudeman, P.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Developed a suitable model for predicting the pressure drop in the velocity string-tubing annulus for gas/liquid flow.

Objective of the paper:

To assess the validity of methods that predict the pressure drop in annuli for gas/liquid flow.

Methodology used:

1) Modelled the pressure drop in the annular space between the tubing and velocity string using methods developed for tubing strings, but with an effective diameter or hydraulic diameter to correct for the difference between tubular and annular flow.
2) Analysed the dependency of Gray correlations on flow geometry, modifying to take annular geometry into account in order to interpret results from the field test.
3) Compared the best approach (hydraulic diameter) with field data to assess the validity of the method.

Conclusion reached:

1) Velocity strings are a cost effective way of extending gas well life and increasing ultimate recovery.
2) The use of Nodal analysis to select an adequate tubing size requires accurate methods for predicting the pressure drop in the tubing as well as the velocity string-tubing annulus.
3) A comparison between field data and various models found that the hydraulic diameter approach was the most accurate.

Comments:

At high rates hydraulic roughness is a crucial factor, but is rarely known to a high degree of accuracy.

SPE 107048 (March 2007)

Liquid Unloading of Depleted Gas Wells in the North Sea and Continental Europe, Using Coiled Tubing, Jointed Pipe Velocity/Insert Strings, and Microstrings

Authors: de Jonge, R. M., Tousis, U.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Discusses technologies available for remediating gas well liquid loading, with a detailed discussion of the design and use of velocity strings in the North Sea and Continental Europe.

Objective of the paper:

To summarise and contrast the use of the technologies mentioned in the title and the offshore operational challenges encountered during their application.

Methodology used:

1) Discusses various factors affecting the design, optimisation (using multiphase flow modelling) and installation of the various technologies, as well as their application offshore.
2) Compares the various technologies technically and produces a decision tree which can be used to determine when each technology should be applied, based on previous experience.

Conclusion reached:

1) Installations of velocity strings or micro strings with surfactant injection are techniques that can be used to resolve gas well liquid loading.
2) Based on previous experience a decision tree was made to assist in selecting a suitable installation type.

Comments:

Discusses installation of strings from the surface using a surface hanger, or below the sub surface safety valve (SSSV) using a packer hanger.

SPE 107467 (June 2007)

Securing the Future in Mature Gas Fields

Authors: Schinagl, W., Denny, M.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Discusses the adaptation of onshore gas well deliquification technologies for application in offshore environments such as the North Sea.

Objective of the paper:

1) To highlight the problems with liquid loading and discuss the technologies being used to mitigate it in North Sea gas fields.
2) To present the results of the first batch surfactant trials in Southern North Sea fields and the use of combination methods that combine artificial lift technologies.

Methodology used:

1) Discusses previous theory by Turner *et al* on critical gas flow rate.
2) Discusses gas well deliquification technologies available at the time and their application to North Sea gas wells.

Conclusion reached:

1) Liquid loading is a significant factor that restricts gas production in mature gas wells (in some cases losses due to liquid loading can account for 30% of total production).
2) Deployment of correct deliquification technologies is essential in order to secure the future of these gas wells.
3) Technologies that are used onshore need to be adapted for offshore environments such as the North Sea.

Comments:

Notes that the main limiting factor in the selection of a gas well deliquification technology is the well configuration (casing, tubing, inclination, depth etc).

SPE 115933 (September 2008)

Critical Review of Existing Solutions to Predict and Model Liquid Loading in Gas Wells

Authors: Solomon, F. A., Falcone, G., Teodoriu, C.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Highlights the importance of the inclusion of transient flow assumptions in models used for calculating critical gas flow rate.

Objective of the paper:

To discuss the multiphase flow phenomena associated with liquid loading and review extensively current modelling solutions to predict and diagnose the impact of liquid loading, as well as screen remedial options for liquid loading and attempt to model dynamic interactions between the reservoir and wellbore.

Methodology used:

Review of previous methods used to calculate the critical gas flow rate, their assumptions and their accuracy.

Conclusion reached:

1) Industry understanding of liquid loading phenomena in gas wells remains poor, especially the dynamic interaction between the reservoir and wellbore.
2) The criteria for estimating the minimum gas flow rate are based on steady-state assumptions and so do not take account of transient flow.
3) Despite the wide range of two-phase modelling techniques available, difficulty still remains in capturing transitions from annular to churn flow, churn flow to slug flow, and slug flow to bubble flow, which may kill a well.
4) Even with the use of transient wellbore modelling, predictive models used to link well dynamics with the intermittent response of a reservoir are unreliable, implying the boundary conditions are being incorrectly defined.
5) The oil and gas industry needs reliable predictive models to help select the best options for liquid loading remediation, and more research is needed.

Comments:

Notes that models used tend to be based on steady-state analysis and so do not take account of transient phenomena typical of liquid loading.

SPE 130870 (January 2010)

Oman, 2 7/8” Velocity Strings in Deep and Tight Gas Wells

Authors: Goedemoed, P., Al Muselhi, F., Al Manji, A.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

At the time these velocity string installations were the longest and heaviest hung off single packers in a live well. Helped develop technology for future applications.

Objective of the paper:

To describe the modelling and challenges faced during the installation of velocity strings in a deep and tight gas field in Oman.

Methodology used:

1) Trialled velocity strings in five wells to analyse the adequacy of the technology used.
2) Used dynamic pressure surveys to understand the liquid loading mechanism present.
3) Reservoirs modelled in Prosper (PLT logging and well test data used to create a 12 layer reservoir model).

Conclusion reached:

1) The velocity strings installed were successful in deferring the onset of liquid loading and providing stable gas and condensate production.
2) The onset of liquid loading can be predicted to a 10% accuracy using Turner *et al.*’s equation.

Comments:

Used a specially designed retrievable packer that was able to sustain the large velocity string weight.

SPE 130632 (March 2010)

Deliquification of South Texas Gas Wells Using Corrosion Resistant Coiled Tubing: A Six Year Case History

Authors: Poppenhagen, K. L., Harms, L. K., Wilkinson, R., Glover, D. E.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

The paper reiterates that coiled tubing can be used as a solution to liquid loading in gas wells, and shows that corrosion resistant coiled tubing can be effectively used in wells experiencing problems related to CO_2 corrosion.

Objective of the paper:

To show that corrosion resistant coiled tubing can effectively be used as a solution to gas well liquid loading in wells affected by CO_2 corrosion.

Methodology used:

1) Discusses the advantages of using velocity strings as a means of resolving liquid loading in gas wells.
2) Runs through the process of selecting the correct metallurgy for the corrosion resistant coiled tubing.
3) Discusses the results of installations in several wells and cost implications.

Conclusion reached:

1) Corrosion resistant coiled tubing is an effective way of resolving liquid loading in gas wells experiencing problems related to CO_2 corrosion.
2) Nodal analysis can be used to select candidate wells.
3) Corrosion resistant coiled tubing can be lower cost to maintain and operate than other forms of artificial lift.

Comments:

SPE 138672 (November 2010)

Gas Well Deliquification

Author: Hearn, W.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Further discussion of the technologies available for gas well deliquification and a logical selection process that can be used for their application. Also mentions technologies available for use offshore when a sub-surface safety valve (SSSV) is required.

Objective of the paper:

To discuss the four most commonly used artificial lift technologies for gas well deliquification and to introduce a selection process for their use.

Methodology used:

1) Discusses the use of reciprocating rod lift, foamer injection, plunger lift and gas lift as means of gas well deliquification.
2) Selection process involves the assignment of high and low scores to readily available surface gathered data (liquid rate, flowing tubing pressure, water cut and gas/liquid ratio) to determine the most appropriate technology for gas well deliquification.

Conclusion reached:

1) New systems have been developed to remediate liquid loading in gas wells where a SSSV is present.
2) The selection process can be used to determine the most appropriate technology to use, only requiring readily available surface gathered data.

Comments:

Discusses technologies that have been available for a long time, but have been adapted for use offshore in wells with a SSSV.

SPE 141215 (March 2011)

Gas Well Deliquification Using Microwave Heating

Authors: Kamal, M., Ghodke, N., Patwardhan, S. D., Al-Dogail, F.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Discusses the use of dielectric heating using microwaves as a new form of gas well deliquification.

Objective of the paper:

To discuss the use of this new technology as a form of gas well deliquification and the results obtained from experiments. Also mentions the advantages of current methods.

Methodology used:

1) Discusses the advantages and disadvantages of current forms of gas well deliquification.
2) Experiments were performed using microwave heating to evaporate water in various saline and petrol/water/sand mixtures in order to simulate wellbore fluids. Various heating times were evaluated.

Conclusion reached:

1) Different mixture combinations react differently to microwave heating.
2) Different microwave frequencies can be selected for different tubing materials.
3) Microwave heating can be used effectively to vaporise moderately saline water. A longer duration of heating is required for high salinity water.
4) Sand production assists the well deliquification process.

Comments:

Based on lab experiments, no application to the field yet.

***Gas Well Deliquification*, second edition, Elsevier Inc., Burlington, MA (2008)**

Authors: Lea, J., Nickens, H. V., Wells, M.

Contribution to understanding of gas well liquid loading and use of velocity strings as a solution:

Provides a more complete analysis of the symptoms associated with gas well liquid loading.

Objective of the book:

To provide a discussion of the causes and phenomena associated with gas well liquid loading, as well as the various technologies available to remediate it.

Methodology used:

1) Discusses the problems associated with gas well liquid loading, and detection of its symptoms.
2) Discusses the critical velocity criteria developed by Turner *et al.* (1969) and the use of nodal analysis to analyse well performance.
3) Details the use of tubing sizing, wellhead compression, plunger lift, foaming, hydraulic pumps, beam pumps, gas lift, electrical submersible pumps, progressive cavity pumps and other methods to combat gas well liquid loading.

Conclusion reached:

1) There are several methods available which are effective in remediating problems caused by gas well liquid loading.

Comments:

Provides a more complete analysis and explanation of gas well liquid loading, its associated phenomena and the means to remediate it, as opposed to providing new views.

Appendix B – Maps of the Dunbar field

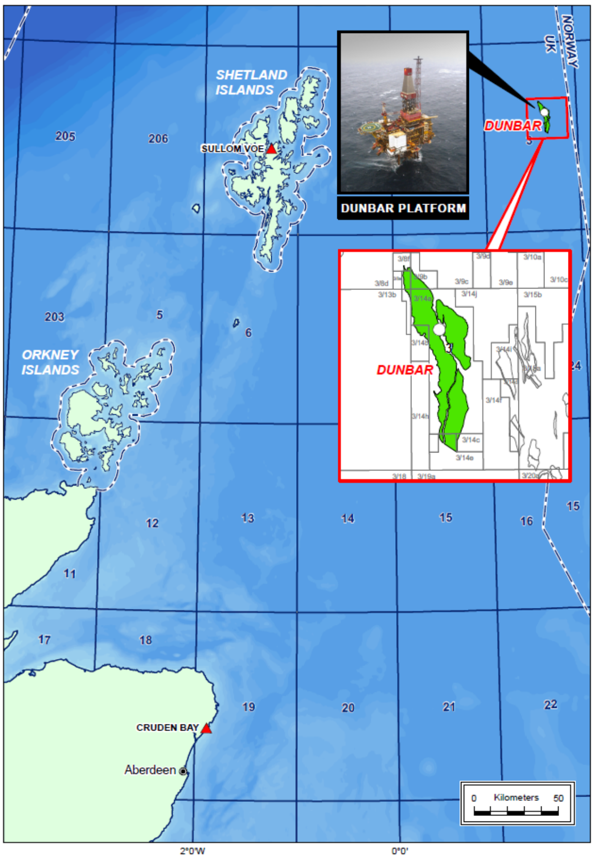

Figure B- 1 - Map showing the location of the Dunbar field (source: TOTAL E&P UK Draughting Office)

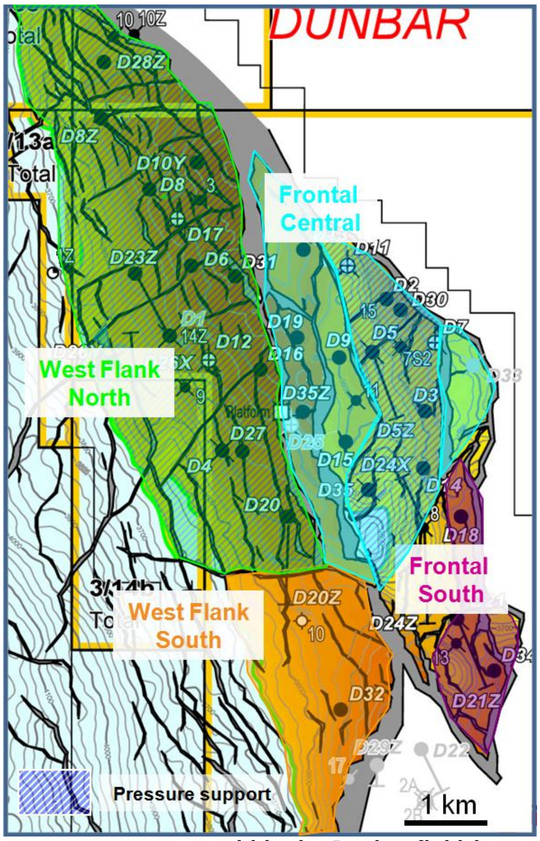

Figure B- 2 – Different compartments within the Dunbar field (source: TOTAL E&P UK)

Appendix C – Data from the well screening process

This appendix contains data used as part of the well screening process. Table C-1 gives a detailed breakdown of the scoring system used to analyse the 11 wells in the parts of the Dunbar field under natural depletion as part of the analysis using information from the Dynamic Synthesis. It shows that wells D29Z, D15, D18 and D24Z were deemed suitable for further analysis in the well screening process. Table C-2 gives an overview of the trends observed in GOR and water cut for the 4 wells analysed using well test data in the well screening process.

Table C- 1 - Scoring details for each well used in the well screening process

Well Name	Location	Production Mechanism	Well Understanding	Scale	Latest Well test Data		Operational issues?	Score	Further Analysis?
					GOR (Sm3/Sm3)	Water cut (%)			
D20Z	West Flank South	Natural depletion	Poor	Milled for scale in May 2010, possibility of return	448	1.4	None	3/6	No
D29Z	West Flank South, Statfjord	Natural depletion	Unknown - no dynamic synthesis available	Not reported	5303	11.7	None	4/6	Yes
D32	West Flank South	Natural depletion	Average	Not reported	885	22.9	High water cut due to water breakthrough from aquifer, rising with time	3/6	No
D13	Central	Possible water support from Frontal Central	Good	Probable	588	16.4	Well slot being re-used for a new well, high water cut so possible scaling issue	2/6	No
D15	Central	Possible water support from Frontal Central	Good	Not reported	362	0.0	None	4/6	Yes
D19	Central	Possible water support from Frontal Central	Average	Possible, can be confirmed with a slickline operation	999	4.9	None	3/6	No
D35Z	Central	Natural depletion	Average	Not reported	3268	20.8	Still producing in high pressure mode	3/6	No
D18	Frontal South	Natural depletion	Average	Not reported	1194	22.3	None	4/6	Yes
D21	Frontal South	Natural depletion	Average	Not reported	286	4.7	Well slot being re-used for a new well	3/6	No
D24Z	Frontal (south)	Natural depletion	Average	Not reported	183	0.0	None	4/6	Yes
D34	Frontal South	Natural depletion	Average	Not reported	402	0.0	Need to re-perforate to improve productivity	3/6	No

Table C- 2 – GOR and water cut trends from well test data

Well name	GOR (Sm^3/Sm^3) and water cut profile
D15	Stable GOR (last was 362), sporadic water recorded, low water cut
D18	Rising GOR (last was 1194), sporadic water recorded, rising water cut
D24Z	Stable but low GOR (last was 183), previous sporadic water recorded, recent near zero water cut
D29Z	Upward trend in GOR (last was 5303), sporadic water recorded, generally low water cut

Appendix D – Prosper data for well D29Z

This appendix contains a summary of the various data used to calibrate the Prosper model for well D29Z. This includes the data used to match the multiphase flow correlations and to generate the IPR for the oil and gas models. It also contains a chart (Figure D-4) showing the inability of the tail pipes to produce at low reservoir pressures, as well as the reduction in production rates observed with the installation of the velocity string and tail pipe options compared to the current production rates with the current completion.

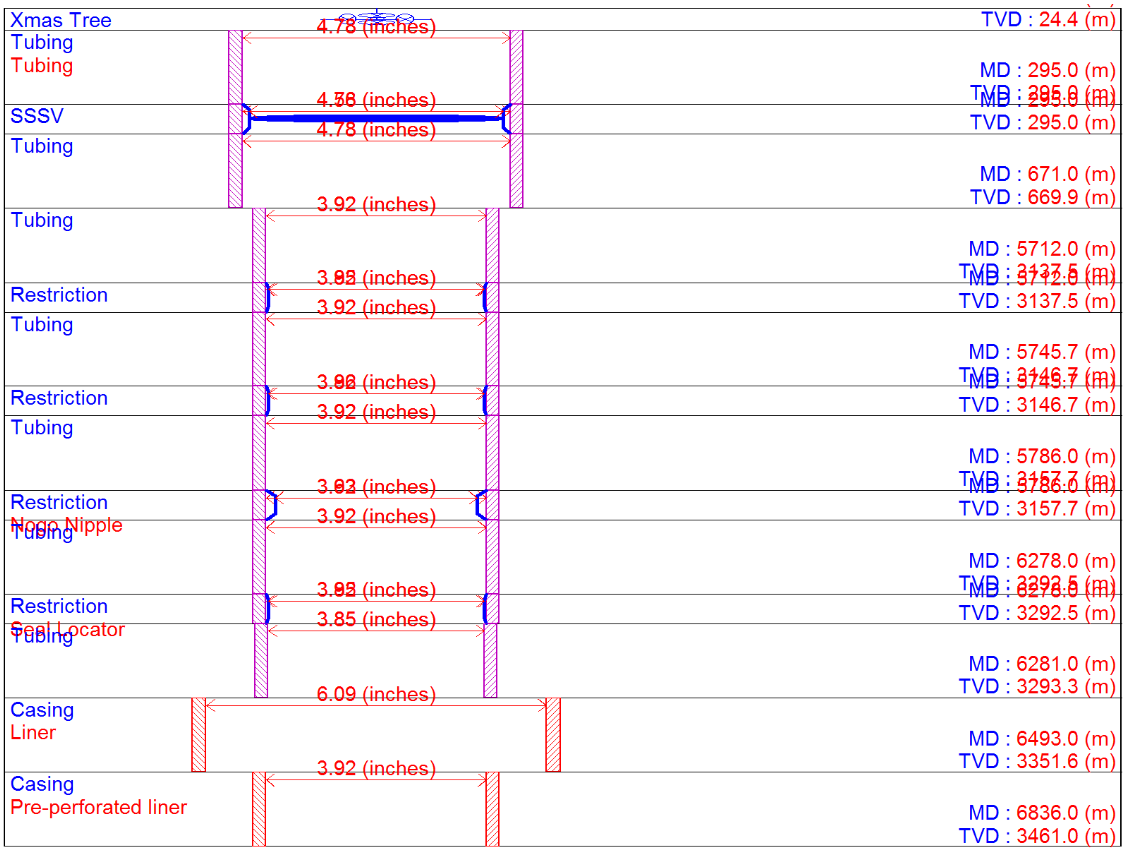

Figure D- 1 - D29Z completion schematic, from Prosper

Table D- 1 - Summary of the well test data used to match the correlations for D29Z

Test Date	Tubing Head Pressure (bara)	Tubing Head Temperature (Deg C)	Water cut (%)	Liquid rate (stb/d)	Gauge Depth (m)	Gauge Pressure (bara)	Reservoir Pressure (bara)	GOR (sm3/sm3)
15-Aug-11	42	66	13.6	419	5712	81	114.7	5,237
07-Oct-10	52	62	0.9	332	5712	85	115.1	4,100
24-Sep-09	50	60	0.0	496	5712	86	115.6	3,152
13-Oct-08	55	64	4.7	285	5712	88	116.0	5,527
04-Dec-07	48	71	0.0	287	5712	87	113.7	6,048
03-Oct-06	51	78	0.0	452	5712	102	130.6	6,707
26-Feb-06	62	79	0.0	905	5712	113	143.3	3,355
26-Feb-02	253	83	0.7	6488	5712	420	481.0	739

Table D- 2 – Errors in gauge pressures calculated by the various correlations for the D29Z oil model

		Duns & Ros Modified	Fancher Brown	PE2	PE4	PE5	OLGAS 2P	OLGAS 3P	Tacite		
Test Date	Gauge Pressure (bara)	Error	Error	Error	Error	Error	Error	Error	Error	Average Absolute Error	Test Included?
15/08/2011	81	27%	-10%	9%	-12%	-3%	-4%	-3%	-3%	9%	Yes
07/10/2010	85	-11%	-11%	14%	-11%	-11%	-11%	-9%	-1%	10%	No
24/09/2009	86	-11%	-11%	-11%	-11%	-11%	-11%	-11%	-11%	11%	No
13/10/2008	88	-9%	-9%	15%	-9%	-7%	-6%	-4%	7%	8%	Yes
04/12/2007	87	-14%	-14%	-14%	-14%	-14%	-14%	-14%	-14%	14%	No
03/10/2006	102	1%	-4%	0%	-7%	-4%	-4%	-4%	-3%	3%	Yes
26/02/2006	113	6%	-1%	6%	-6%	7%	2%	2%	4%	4%	Yes
26/02/2002	420	4%	1%	4%	-1%	2%	2%	2%	1%	2%	Yes
Average error (ex. bad tests)		7.7%	4.1%	5.6%	5.7%	3.8%	2.9%	2.5%	3.0%		

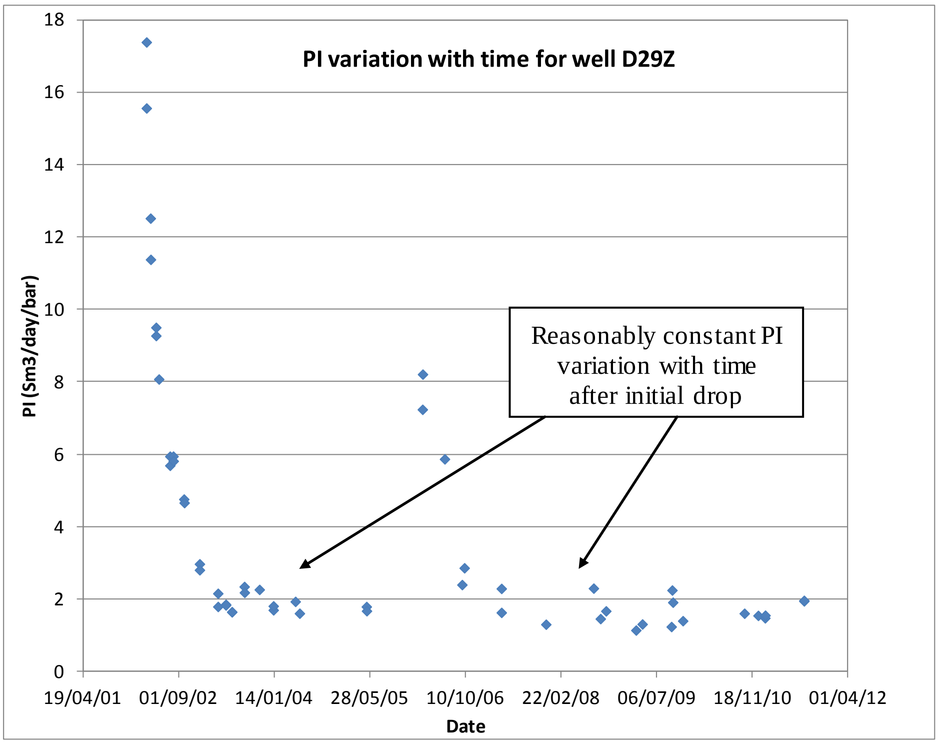

Figure D- 2 – Variation of PI with time for D29Z

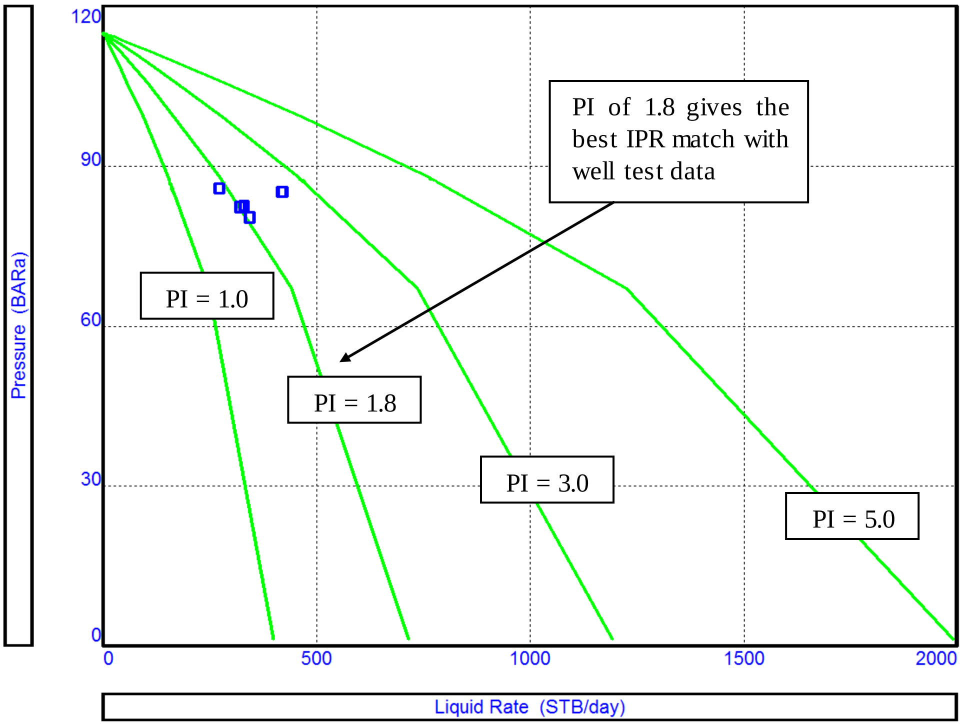

Figure D- 3 – PI sensitivity for the D29Z oil model, from Prosper

Table D- 3 – Well test data used to match the IPR and validate the two models for D29Z

										Oil Model		Retrograde Condensate Model	
Test Date	Gas Rate (kSm3/day)	BHFP (bara)	Reservoir Pressure (bara)	PI (Sm3/day/bar)	Water cut (%)	Water Gas Ratio (Sm3/Sm3)	GOR (Sm3/Sm3)	THP (bar)	IPR matched with data?	Calculated Gas Rate (kSm3/day)	Gas rate error	Calculated Gas Rate (kSm3/day)	Gas rate error
07/10/2010	214	82.5	115.1	1.60	0.9	2.270E-06	4100	51.8	Yes	228	6.2%	216	1.0%
18/12/2010	233	82.3	115.0	1.54	1.1	2.399E-06	4615	50.9	Yes	233	0.1%	220	-5.3%
23/01/2011	214	85.8	115.0	1.48	1.2	2.474E-06	4963	54.2	Yes	214	0.3%	205	-4.4%
24/01/2011	266	80.4	115.0	1.55	1.6	3.314E-06	4960	46.0	No	257	-3.3%	239	-9.9%
15/08/2011	301	85.1	114.7	1.94	13.6	3.018E-05	5237	42.2	No	274	-9.1%	253	-16.0%
15/08/2011	298	85.1	114.7	1.96	13.4	3.010E-05	5144	42.5	No	273	-8.6%	252	-15.5%

Average absolute error = 2.2%

Average absolute error = 3.6%

Table D- 4 – Errors in gauge pressures calculated by the various correlations for the retrograde condensate model for D29Z

Test Date	Gauge Pressure (bara)	PE2 Error	OLGAS 2P Error	OLGAS 3P Error	Average Absolute Error	Test Included?
15/08/2011	81	10%	-5%	-3%	6%	Yes
07/10/2010	85	-11%	-11%	-11%	11%	No
24/09/2009	86	-11%	-11%	-11%	11%	No
13/10/2008	88	-9%	-5%	-4%	6%	Yes
04/12/2007	87	-14%	-14%	-14%	14%	No
03/10/2006	102	-1%	-4%	-4%	3%	Yes
26/02/2006	113	-2%	3%	3%	2%	Yes
26/02/2002	420	-10%	2%	2%	4%	Yes
Average error (ex. bad tests)		6.4%	3.6%	3.0%		

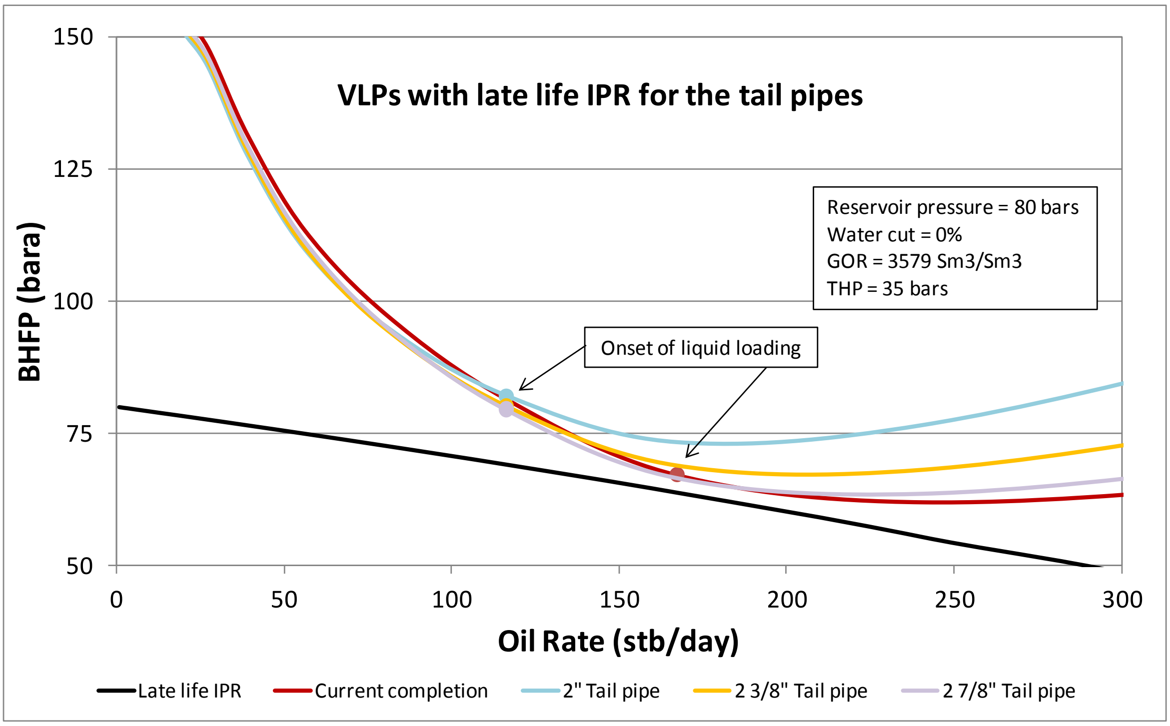

Figure D- 4 – VLPs for the tail pipes with the late life IPR case for D29Z

Table D- 5 – Production rates with the various D29Z completions for different cases

	Completion	Current	2" Velocity string	2 3/8" Velocity string	2 7/8" Velocity string	2" Tail pipe	2 3/8" Tail pipe	2 7/8" Tail pipe
Current Reservoir Pressure = 115 bara	Oil Rate (stb/d)	338	97	144	211	226	274	310
	Gas rate (kSm3/d)	281	81	120	175	188	228	258
	BHFP (bara)	80.2	105.8	101.3	94.5	92.8	87.5	83.3
Mid Life - Reservoir Pressure = 90 bara	Oil Rate (stb/d)	266	88	130	186	174	222	254
	Gas rate (kSm3/d)	151	50	74	106	99	126	144
	BHFP (bara)	62.9	82.1	78.0	72.1	73.5	68.2	64.4
Late Life - Reservoir Pressure = 80 bara	Oil Rate (stb/d)	0	64	96	137	0	0	0
	Gas rate (kSm3/d)	0	36	55	78	0	0	0
	BHFP (bara)	0.0	74.2	71.1	66.9	0.0	0.0	0.0

Table D- 6 – Percentage rate reductions for the various D29Z completions for different cases

	Completion	Current	2" Velocity string	2 3/8" Velocity string	2 7/8" Velocity string	2" Tail pipe	2 3/8" Tail pipe	2 7/8" Tail pipe
Current Reservoir Pressure = 115 bara	Oil Rate reduction vs current	0%	-71%	-57%	-38%	-33%	-19%	-8%
	Gas Rate reduction vs current	0%	-71%	-57%	-38%	-33%	-19%	-8%
Mid Life - Reservoir Pressure = 90 bara	Oil Rate reduction vs current	-21%	-74%	-62%	-45%	-49%	-34%	-25%
	Gas Rate reduction vs current	-46%	-82%	-74%	-62%	-65%	-55%	-49%
Late Life - Reservoir Pressure = 80 bara	Oil Rate reduction vs current	-100%	-81%	-72%	-59%	-100%	-100%	-100%
	Gas Rate reduction vs current	-100%	-87%	-81%	-72%	-100%	-100%	-100%

Table D- 7 – Cumulative production gain for the various D29Z completions with a THP limit of 40 bars

Completion	End of Life Date	Cumulative Production Gain (boe %)
Current	Nov-13	0%
2" Velocity string	Dec-31	24%
2 3/8" Velocity string	Dec-31	29%
2 7/8" Velocity string	Apr-27	25%

Appendix E – Prosper data for well D15

This appendix contains a summary of the various data used to calibrate the Prosper model for well D15. This includes the data used to match the multiphase flow correlations and to generate the IPR for the oil model. Table E-4 shows the inability of the velocity strings to produce with the current IPR case. It also shows that the 2⅞" velocity string is the only velocity string option that can produce in the late life IPR case.

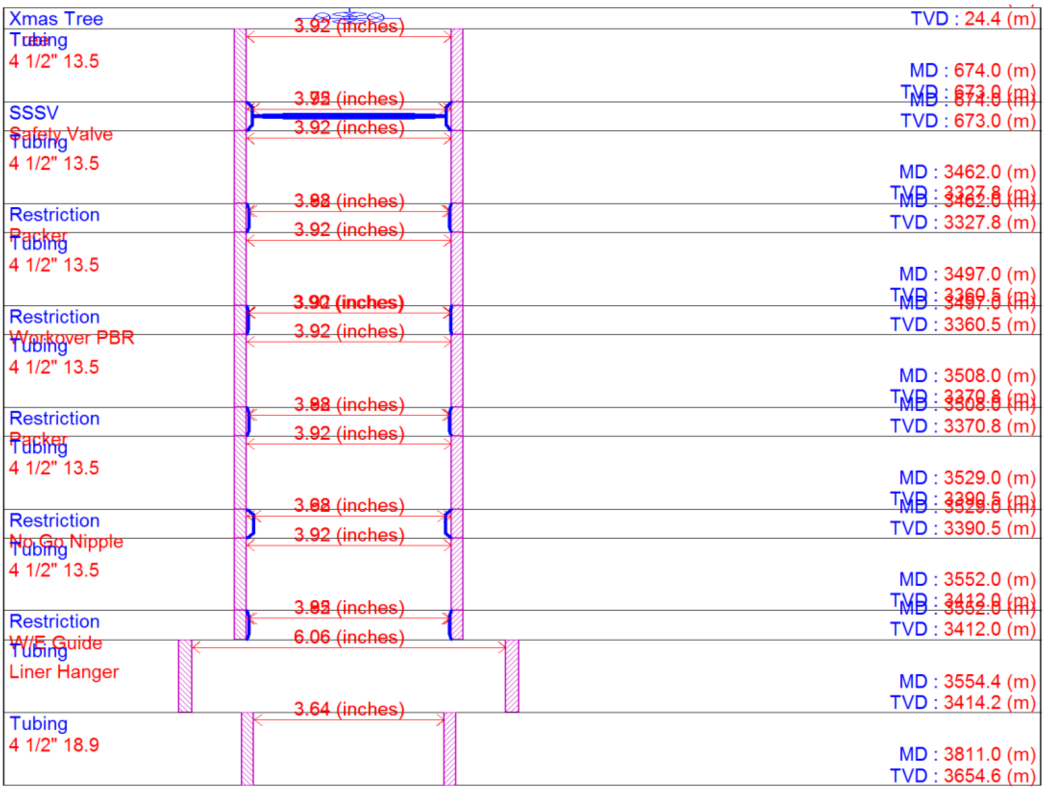

Figure E- 1 – D15 completion schematic, from Prosper

Table E- 1 - Summary of the well test data used to match the correlations for D15

Test Date	Test type	THP (bara)	THT (Deg C)	Water cut (%)	Liquid rate (stb/d)	Gauge Depth (m)	Gauge Pressure (bara)	Reservoir Pressure (bara)	GOR (sm3/sm3)
24-Apr-97	Well test	176	102	0.1	8,189	3529	353	384.6	465
20-Oct-97	Well test	169	81	0.1	2,858	3529	305	349.1	516
19-Sep-98	Well test	176	68	0.5	1,573	3529	311	338.0	536
09-Dec-00	PLT	95	84	0.0	3,108	3476	197	251.6	1,036
09-Dec-00	PLT	115	83	0.0	2,253	3476	212	251.6	1,123
11-Dec-00	PLT	125	70	0.0	1,254	3476	222	251.6	1,364
11-Dec-00	PLT	132	61	0.0	533	3476	234	251.6	1,315
23-Apr-04	Well test	86	28	0.0	602	3800	160	170.3	917
23-Apr-04	Well test	79	34	0.0	861	3800	151	170.3	916

Table E- 2 - Errors in gauge pressures calculated by the various correlations for the D15 oil model

		Duns & Ros Modified	Fancher Brown	PE2	PE4	PE5	OLGAS 2P	OLGAS 3P	Tacite		
Test Date	Gauge Pressure (bara)	Error	Error	Error	Error	Error	Error	Error	Error	Average Absolute Error	Test Good?
23/04/2004-2	151	18%	6%	11%	12%	23%	16%	16%	14%	14%	No
23/04/2004-1	160	26%	11%	13%	25%	33%	20%	20%	20%	21%	No
11/12/2000-2	234	6%	0%	1%	5%	9%	2%	2%	3%	4%	Yes
11/12/2000-1	222	-2%	-2%	1%	-2%	3%	0%	0%	-1%	1%	Yes
09/12/2000-2	212	2%	2%	5%	1%	6%	4%	4%	2%	3%	Yes
09/12/2000-1	197	3%	2%	8%	-4%	9%	4%	4%	3%	5%	Yes
19/09/1998	311	6%	5%	6%	5%	5%	5%	5%	5%	5%	Yes
24/10/1997	305	5%	5%	6%	5%	6%	5%	5%	5%	5%	Yes
24/04/1997	353	5%	5%	6%	6%	6%	6%	6%	6%	6%	Yes
Average error (ex. bad tests)		4.1%	3.0%	4.6%	4.0%	6.4%	3.8%	3.8%	3.4%		

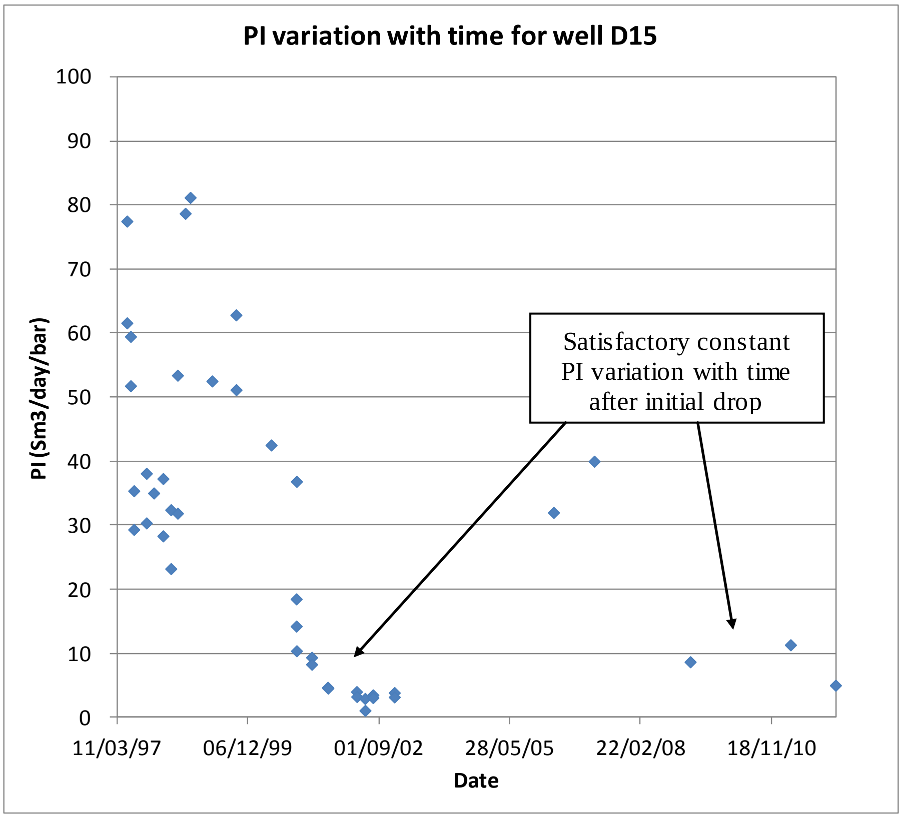

Figure E- 2 - Variation of PI with time for D15

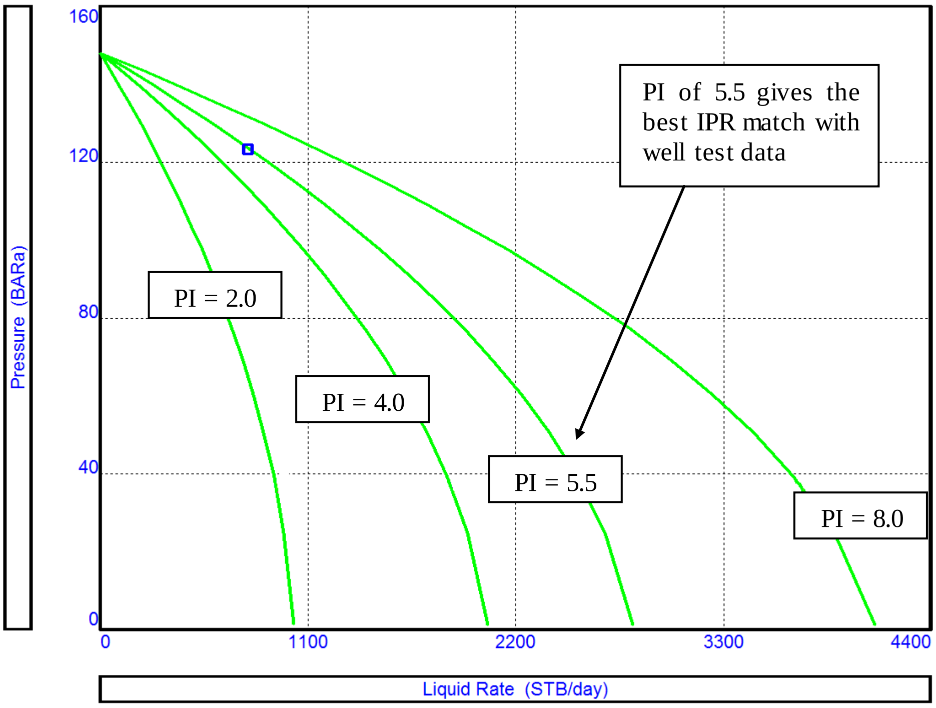

Figure E- 3 - PI sensitivity for D15, from Prosper

Table E- 3 - Well test data used to match the IPR and validate the D15 oil model

Test Date	Liquid Rate (bbl/d)	Gas Rate (kSm3/day)	BHFP (bara)	Reservoir Pressure (bara)	PI (Sm3/day/bar)	Water cut (%)	GOR (Sm3/Sm3)	THP (bar)	IPR matched with data?	Calculated Liquid Rate (bbl/d)	Oil rate error	Calculated Gas Rate (kSm3/day)	Gas rate error
24/03/2012	783	64	123.3	148	5.04	0.0	513	38.4	Yes	740	-5.5%	60	-5.4%

Table E- 4 - Production rates for the various D15 completions for different cases

	Completion	Current	2" Velocity string	2 3/8" Velocity string	2 7/8" Velocity string	2" Tail pipe	2 3/8" Tail pipe	2 7/8" Tail pipe
Current Reservoir Pressure = 148 bara	Oil Rate (stb/d)	812	0	0	0	791	808	808
	Gas rate (kSm3/d)	66	0	0	0	65	66	66
	BHFP (bara)	122.5	0.0	0.0	0.0	123.2	122.6	122.6
Mid Life - Reservoir Pressure = 114 bara	Oil Rate (stb/d)	941	268	427	631	912	929	936
	Gas rate (kSm3/d)	191	55	87	128	185	189	190
	BHFP (bara)	83.0	106.0	101.0	94.2	84.1	83.5	83.2
Late Life - Reservoir Pressure = 95 bara	Oil Rate (stb/d)	489	0	0	326	471	484	490
	Gas rate (kSm3/d)	99	0	0	66	96	98	100
	BHFP (bara)	79.8	0.0	0.0	85.1	80.4	79.9	79.7