Master Thesis

Optimization of Progressive Cavity Pumps in Mature Oil Fields with special focus on OMV Austria

Affidavit

I declare in lieu of oath, that I wrote this thesis and performed the associated research myself, using only literature cited in this volume.

(Datum) (Pichler Jacqueline)

Abstract

The following diploma thesis is discussing Progressive Cavity Pumps (PCPs) and their application in OMV E&P Austria. PCP manufacturers highlight great advantages compared to other pump assisted artificial lift methods; hence their application in the Oil and Gas industry is increasing. The main advantage is the ability of handling multiphase flow and relatively high sand contents which is beneficial especially in brown field development. The goal of this thesis is to find the find the reasons for the poor performance and to make recommendations for the future.

The first installation in Austria by OMV was done in 2003 and since then the PCPs are not operating in the desired mode/range. At the moment OMV Austria has 19 PCPs installed and most of them are not operating. The main causes for failures are tubing leaks and elastomer problems. Mean time between failures (MTBF) is low compared to other downhole pumps, as a result the PCPs are exceeding their economic limit.

Before the individual OMV wells will be discussed a general introduction to PCPs will be given. The working principle and the pump specifications are explained and the process of using performance charts is shown. Then the history of the individual wells will be presented. To support the well history a table with workover data and a production history plot is provided. Then the limits in operating conditions like sand, gas, depth and rate will be analysed from field experience. Afterwards there is a comparison of the PCP performance with other companies (RAG and Petrom). Then a tool will be introduced which is used to do failure analysis on site. Different operating parameters like torque or rpm can be measured and analysed with a software called MatriX. Afterwards centralizers and their performance in PCP installations will be introduced. Then relined tubing is introduced including OMVs field experience with relined tubing. A very big topic in PCP installations is the stator elastomer which will be handled in the next chapter. The different elastomers and their advantages and disadvantages are listed. In the end an economic study on the existing PCP wells has been done to analyse their performance. This study will be followed by a list of improvement potentials and optimization for the next installations. While improvement potential is more focused on the technical side the optimization part is specialized on documentation and failure analysis. To put more emphasis on the need of improvement the chapter HSEQ aspects will show up some near misses in OMV which are related to PCPs. The very last chapter presents smart well completions for PCPs. Two concepts will be presented the implementation of concentric tubing for PCP wells and the Dual Progressing Cavity Pump (DPCP).

Index

Affidavit....2
Abstract....3
Figures....6
Tables....8
Introduction....9
PCP theory and history in OMV....10
    Working principle....11
        Components....12
    PCP pump specifications....15
        Performance charts....18
        OMV suppliers....20
    Wells....20
        St. Ullrich 139....20
        Matzen 210....21
        Matzen 235....21
        Matzen 236....22
        Matzen 251....22
        Matzen 294....23
        Matzen 337....23
        Matzen 430....24
        Matzen 464....24
        Matzen 469....25
        Prottes 86....25
        Prottes 202....26
        Schönkirchen 39....26
        Schönkirchen 127....27
        Schönkirchen 230....28
        Schönkirchen 263....29
        Hochleiten 60....30
        Pirawarth 96a....30
        Pirawarth 79....31
Application range of PCPs....32
    Sand....32
    Operation depth....35
    Production rate....35
    Gas....36
Failure analysis of installed pumps....38
Comparison of OMV Austria installations runtime to other companies....40
    Petrom....40
    RAG....42
Spacing procedures and formulae....42
    Netzsch spacing procedure....42
    PCM spacing procedure....45
Sucker rod torque calculation....45
Centralizers....47
Relined tubing....48
    Liners....49
Elastomer swelling....50
    Stator Elastomers....50
        Nitril-rubber (NBR)....50

Hydrogenated Nitril-rubber (HNBR) ... 51
Fluor-rubber(FKM) ... 51
OMV Stator Elastomers ... 52
Economics of installed PCP ... 53
Results ... 56
Improvement potential for the next installations ... 57
Optimization ... 59
HSEQ aspects ... 60
Smart well completion ... 63
Concentric Tubing ... 63
Dual Progressing Cavity Pumping System (DPCP)[7] ... 65
Conclusions ... 67
References ... 68
Appendix ... 69

Figures

Figure 1 OMV PCP completions 10
Figure 2 surface driven PCP (a) and with downhole motor (b) [2] 11
Figure 3 different rotor types [1]....................12
Figure 4 different stator types [1]....................13
Figure 5 torque anchor STU139....................13
Figure 6 rotor and stator geometry of PCP 3 15
Figure 7 production history StU139....................21
Figure 8 production history Ma 210....................21
Figure 9 production history Ma 235....................22
Figure 10 production history 236 22
Figure 11 production history Ma 251 23
Figure 12 production history Ma 294....................23
Figure 13 production history Ma 337....................24
Figure 14 production history Ma 430....................24
Figure 15 production history Ma 464....................25
Figure 16 production history Ma 469....................25
Figure 17 production history P086....................26
Figure 18 production history P202....................26
Figure 19 production history S039....................27
Figure 20 production history S 127 28
Figure 21 production history S 230 29
Figure 22 production history S 263 30
Figure 23 production history HL 60....................30
Figure 24 damaged stator elastomer, Pir 96a ,June 2008 31
Figure 25 production history Pir 96a....................31
Figure 26 production history Pir 79 32
Figure 27 sample of Pir 79 from 19.07.2005....................32
Figure 28 solid settling velocity for 2 7/8” (and 3 ½” relined) tubing with 7/8” sucker rods 34
Figure 29 solid settling velocity for 3 1/2" tubing with 7/8" sucker rods 35
Figure 30 protection against vibrations for Drive Heads 36
Figure 31 gas anchors....................37
Figure 32 monitored PCP operation (Ma 251) 38
Figure 33 monitored start up of a PCP (Ma 210)....................39
Figure 34 monitored PCP operation (Ma 251) 39
Figure 35 MTBF for OMV pump assisted artificial lift wells....................41
Figure 36 MTBF for PCP in OMV 42
Figure 37 rotating centralizers 47
Figure 38 non-rotating centralizer [6] 47
Figure 39 non-rotating centralizer and the impact on the tubing wall 48
Figure 40 OMV PCP completions using normal and relined tubing 48
Figure 41 relined tubing after cutting the liner (right) and after creating a shoulder (left) 49
Figure 42 relined tubing with shrunk liner 49
Figure 43 collapse of relined tubing, Pir 96a, June 2008 50
Figure 44 downtime vs. productive time (status 1.4.09) 53
Figure 45 cash Flow for wells with PCP installation (status 1.4.09) 54
Figure 46 cash Flow comparison (status 1.4.09) 55
Figure 47 relative change in downtime 55

Figure 48 workovers per PCP well 58
Figure 49 failure mechanisms at PCP wells 58
Figure 50 PCP performance of relined PCP wells and wells with PCM elastomer........59
Figure 51 crane which lifted the rod sting of a PCP (near miss 2006) 60
Figure 52 DH lifting attachments...61
Figure 53 protection against vibrations of DH. 62
Figure 54 step 1 and step 2 in the implementation phase...63
Figure 55 step 3 of the implementation process (right) and the operating mode (left)...64
Figure 56 DPCP[7]..65
Figure 57 tubular single lobe PCP and multilobe PCP[2]...69
Figure 58 Netzsch spacing factors k for singlelobe PCP[2]...70
Figure 59 Netzsch spacing factors k for multilobe PCP[2]..71
Figure 60 Netzsch elastomer selection criteria [2]..72
Figure 61 PCM PCP pump performance chart 200TP1800 73
Figure 62 PCM PCP pump performance chart 200TP1800 74
Figure 63 pump performance chart 30TP2000...75
Figure 64 pump performance chart 30TP2000...76
Figure 65 OMV PCP completions with PCM and Netzsch elastomer...........................77
Figure 66 pump change 2003 – 2009 77
Figure 67 pump change per well 2003 – 2009...78
Figure 68 tubing leaks 2003 – 2009 78
Figure 69 tubing leaks per well 2003 – 2009...79
Figure 70 reasons for PCP Change 79

Tables

Table 1 well history STU 139 20
Table 2 well history Ma 210 21
Table 3 well history Ma 235 21
Tabelle 4 well history Ma 236 22
Table 5 well history Ma 251 23
Table 6 well history Ma 294 23
Table 7 well history Ma 337 23
Table 8 well history Ma 430 24
Table 9 well history Ma 464 24
Table 10 well history Ma 469 25
Table 11 well history P086 25
Table 12 well history P202 26
Table 13 well history S 039 27
Table 14 well history S 127 27
Table 15 well history S 230 28
Table 16 well history S 263 29
Table 17 well history HL 60 30
Table 18 well history Pir 96a 31
Table 19 well history Pir 79 31
Table 20 comparison of OMV and Petrom (status April 09) 40

Introduction

Every reservoir reaches a point in its life where the initial/natural driving force decreases to a certain limit where natural flow stops and artificial lift methods have to be applied in order to gain a high recovery. Artificial lift can be divided into two categories, gas lift and pump assisted lift. The most commonly used pump is the sucker rod pump, but this system has its limitations and is only operating efficient under certain conditions. Deviated well paths, gas and solids production are a big problems for sucker rod pumps. The PCP manufacturers promise their pump to be the solution to this problem. Multiphase flow is no problem for a PCP which makes the pumps attractive for wells with difficult operating conditions. Also deviated well paths are mentioned to be manageable.

The master thesis is structured the following way. In the beginning an introduction to PCP will be given including components, some design parameters and stress calculations. Then the individual OMV wells with PCP applications are listed with their history. The history of the well should give an overview of the life time of the well and the intervals between the workovers. Later some parameters influencing the PCP efficiency in certain ranges will be explained and discussed. These parameters include sand, depth, rate and gas. Then a tool will be introduced which is used to do failure analysis on site. Different operating parameters like torque or rpm can be measured and analysed with a software called MatriX. Afterwards centralizers and their performance in PCP installations will be introduced. Then relined tubing is introduced including OMVs field experience with relined tubing. A very big topic in PCP installations is the stator elastomer which will be handled in the next chapter. The different elastomers and their advantages and disadvantages are listed. In the end an economic study on the existing PCP wells has been done to analyse their performance. This study will be followed by a list of improvement potentials and optimization for the next installations. While improvement potential is more focused on the technical side the optimization part is specialized on documentation and failure analysis. To put more emphasis on the need of improvement the chapter HSEQ aspects will show up some near misses in OMV which are related to PCPs. The very last chapter presents smart well completions for PCPs. Two concepts will be presented the implementation of concentric tubing for PCP wells and the Dual Progressing Cavity Pump (DPCP).

PCP theory and history in OMV

This chapter will give a detailed explanation of the working principle of a PCP and their specifications and design parameters. Later the individual OMV PCP wells will be discussed in detail. Since OMV has installed only one PCP with a downhole motor in the past the main focus will be on surface driven PCPs. It has to be mentioned that OMV did already install PCPs in the past, 20 years ago. These wells will not be discussed in thesis.

OMV is producing two different oil qualities. Asphaltene oil (A-oil) and paraffin oil (P-oil), the difference is the density. A-oil has a density of 905 kg/m³ while the P-oil density is only 860 kg/m³. P-oil has the big disadvantage that it contains paraffines or waxes which come out of solution at a specific temperature. Usually the solution of the paraffin is from 1000 meters depth to the surface, due to the temperature decrease while the oil is flowing up. Therefore P-oil needs special treatment like heating or inhibition. On the market P-oil has a higher prize than the A-oil which makes the production economic again.

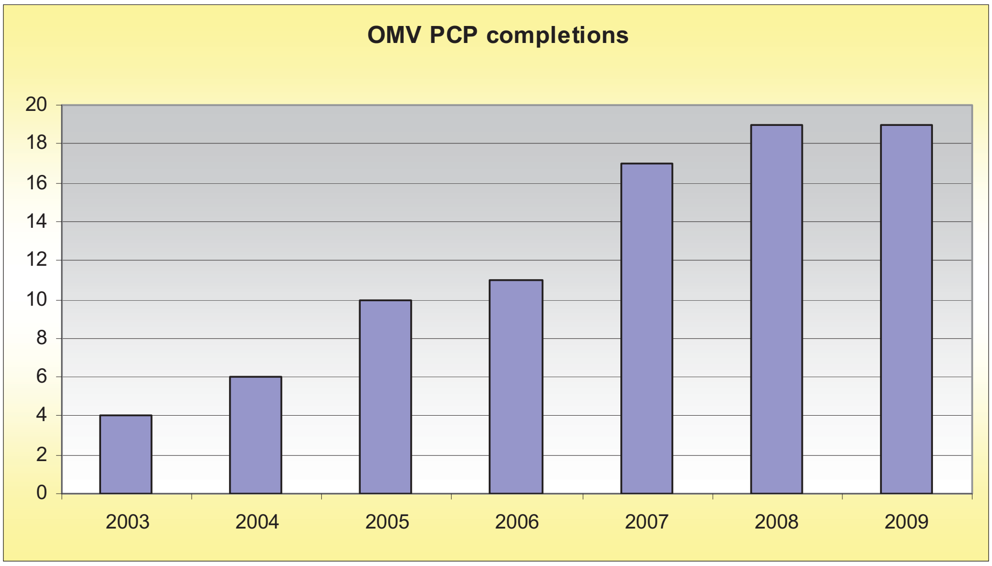


Figure 1 OMV PCP completions

Figure 1 shows the PCP completions from OMV. Today OMV has 19 wells completed with PCP. Only one of these 19 wells is producing P-oil, it is the well StU 139. All the other wells are producing A-oil. The PCP wells have an average operating depth of 1100 m (maximum 1500 m). The production rates differ; there are wells with production rates of 1 ton crude and wells with 50 to 66 tons. The smallest water cut of all wells is 27% and the biggest is 96%.

Nearly all PCP wells that have been selected for this type of artificial lift is dedicated to the difficult operating conditions. The previous artificial lift methods were gas lift or sucker rod pump.

Working principle

The principle of PCP was developed by Rene Moineau in the late 1920s. A PCP can either be surface driven (fig.2a) or a downhole motor can be used (fig.2b).

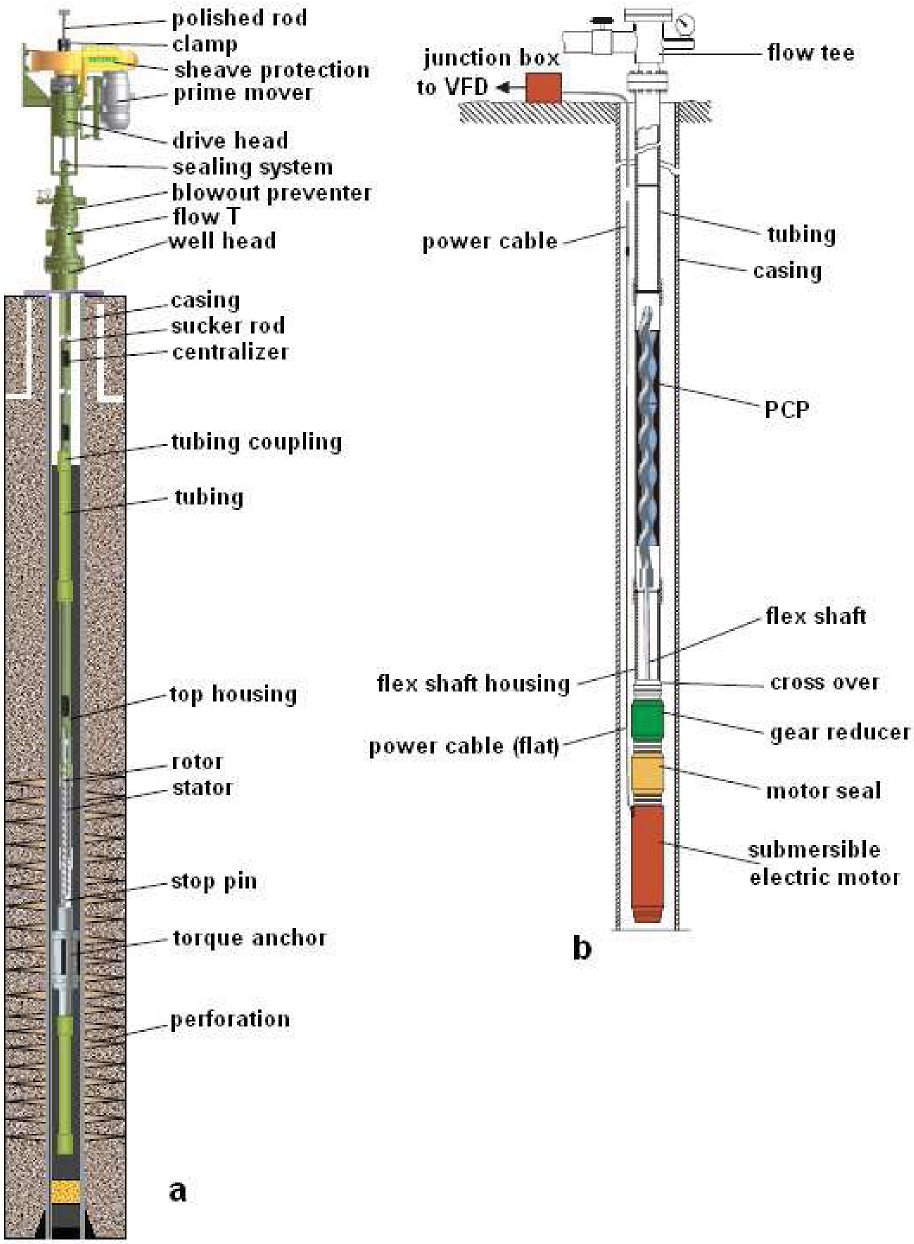


Figure 2 surface driven PCP (a) and with downhole motor (b) [2]

A helical steel rotor is rotating in an elastomer stator. The stator consists of a normal piece of pipe with the elastomer attached on the inside. The rotor usually is made of high-strength steel with a chrome coating. When the rotor is placed in the stator, so called cavities are responsible for the pressure build up. With the rotation of the rotor these cavities are transporting the fluid up wards over the length of the pump. Cavities can be described as helical chambers wrapped around the rotor.

When installed downhole the stator is screwed on to the tubing string and the rotor is connected with the rod string. The motor is at the surface and transmitting the power to rotate the string. If a downhole motor is used, it will be attached below the stator and no rod string is necessary. The weak point of this method is the cable which is required to transmit the power from the surface to the motor downhole. It is very expensive and sensitive to the conditions downhole. One main advantage of PCP installations is the missing of valves. Typically valves are sensitive parts of a pump. Since the PCP is operating without valves a big criterion for break down is eliminated. Another plus is the way the fluid is transported. Compared to other downhole pumps the fluid stream is continuous and without pulsations. This allows the transport of solids, because erosion is minimized.

Components

The PCP installation includes as a minimum the following components: drive head, rod string, rotor, tubing, pup joint, stator, stop bushing and torque anchor. Below the stator it is possible to install a gas anchor or sand pipes or sand filters.

Drive Head

A prime mover, usually an electric motor or a gas engine transmits power to the drive head (DH) to get the rod string rotating. An additional task of the DH is to carry the axial load of the string. To prevent leakage a stuffing box is installed below the well head. For safety reasons the DH also must be equipped with a break, to allow for a controlled back spin in case of shut down. If required torque limiters or monitoring systems can be connected to the DH as well. OMV is using both of these applications the torque limiter (850 Nm) and the monitoring system. In one of the later chapters the monitoring system will be discussed in more detail.

Rod String

The rod string is theoretical the same like with sucker rod pumps. OMV uses Grade D sucker rods with spray metal couplings for the PCP installations which are the same like for sucker rod pumps. Typical sizes in PCP wells are 7/8” and sometimes in the lower section 1”. The rotor is connected with the rod string via a coupling then depending on the design pony rods of different length make the connection to the rod string or directly a sucker rod single is screwed to the rotor. The rod string can be equipped with centralizers (rotating or non-rotating) according to the design plan. At the surface again pony rods are used to achieve the desired length of the string.

Rotor

The rotor usually is made of high-strength steel with a coating to prevent wear and corrosion. Normally this coating consists of chrome. The movement of the rotor is eccentric. Rotors are also available as hollow rotors to reduce the weight and hence safe energy/reduce the power consumption. The disadvantage is besides the price that they are more sensitive to erosion due to the smaller wall thickness.

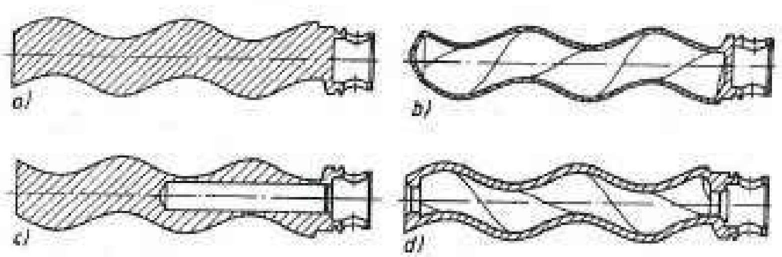


Figure 3 different rotor types [1]

Tubing

There are no special requirements for the tubing string. OMV uses 3 ½” and 2 7/8” tubing for their PCP installations. In special applications OMV uses 3 ½” relined tubing. The definition of relined tubing can be found in one of the later chapters.

Pup joint

The pup joint is a tubing of variable length directly above the pump. It serves the purpose of compensating the eccentricity of the rotor or to dampen the effect of eccentricity. Since the rotor is running eccentric a pup joint with an increased diameter is used to prevent erosion/shearing of the rod string on the tubing just above the pump. For example if the pump has an OD of 3 ½” the pup joint will be 3 ½” as well if the tubing string is designed with 2 7/8”.

Stator

The stator is a piece of pipe with the elastomer attached inside (fig.3 a). Good elastomer selection is absolutely necessary to ensure efficient operation of the pump. Damaged elastomer means the pump needs to be changed which is related to extra costs. Stators are also available with constant wall thickness (fig.2 b) which have the advantage can hold a higher pressure (12 bars instead of 5) and the clearance/fit between rotor and stator can be adjusted more precisely.

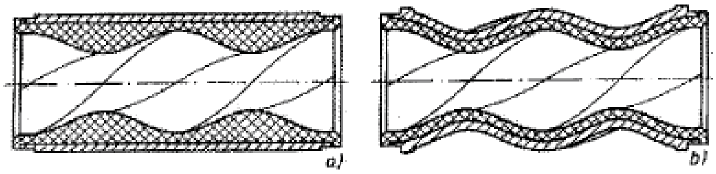


Figure 4 different stator types [1]

Stop bushing

The stop bushing is used for the rotor spacing. It is a piece of pipe with a pin inside, figure 45 illustrates this. When the rotor is run downhole the stop bushing gives an indication when the rotor is touching the stop pin. The hook load will be zero at this moment. Then the rod string needs to be lifted until the rod string elongation is overcome and then the rotor needs to be lifted the calculated distance. This distance corresponds to “d” in figure 45.

Torque anchor

This tool is installed below the stator. It prevents rotation of the tubing. Since the rod string is rotating the rotor in the stator, the stator would be forced to rotate as well if it would not be fixed somewhere. The torque anchor prevents rotation in one direction by gripping the inner wall of the casing.

Figure 5 torque anchor STU139

Gas anchor

The gas anchor is preventing a decrease in efficiency of a PCP due to gas production. It acts like a downhole separator, it separates the gas from the liquid. There are different gas anchors available on the market. OMV uses gas anchors from PCM or the Jakubec gas anchor for their PCP completions. The success of the gas anchor seems to be rather poor since at a certain gas oil ratio the pump efficiency decreases significantly. Out of OMVs experience the gas production of 1000 Nm^3/d defines this critical value.

Centralizers or rod guides

Since rod guides are discussed in one of the later chapters only the most important facts will be covered here. The purpose of rod guides is to prevent tubing damage by keeping the sucker rod string centralized. Different types of centralizers are available on the market, we differ rotating and non-rotating centralizers. OMV had lots of troubles with centralizers since they were increasing the wear on the tubing instead of protecting it. The new PCP completions do not have centralizers installed.

Backspin brake

For surface driven PCPs a backspin brake also called backspin control device or recoil control device is a safety tool which prevents an uncontrolled back spin of the rod string. A back spin can be the result of a shut down. The fluid column in the tubing wants to balance wit the fluid level in the annulus and therefore the rotor is accelerating backwards in the stator. This can lead to very dangerous situations. In one of the later chapters an incident will be discussed where exactly a backspin happened resulting in a dangerous situation for the field personnel. Generally two types of brake systems exist; the hydraulic system and the mechanic system.

PCP pump specifications

The following information is based on Boyun Guo, Williams C. Lyons, Ali Ghalambor: **"**Petroleum Production Engineering**",** 2007. This book gives some equations to calculate the operating parameters.
The PCP consists of a steel rotor and an elastomer stator. The geometry of these two components are illustrated in figure 6 where E equals eccentricity in inch, D is the rotor diameter in inch, Pr is the pitch length of the rotor in feet and Ps is the pitch length of the stator in feet.

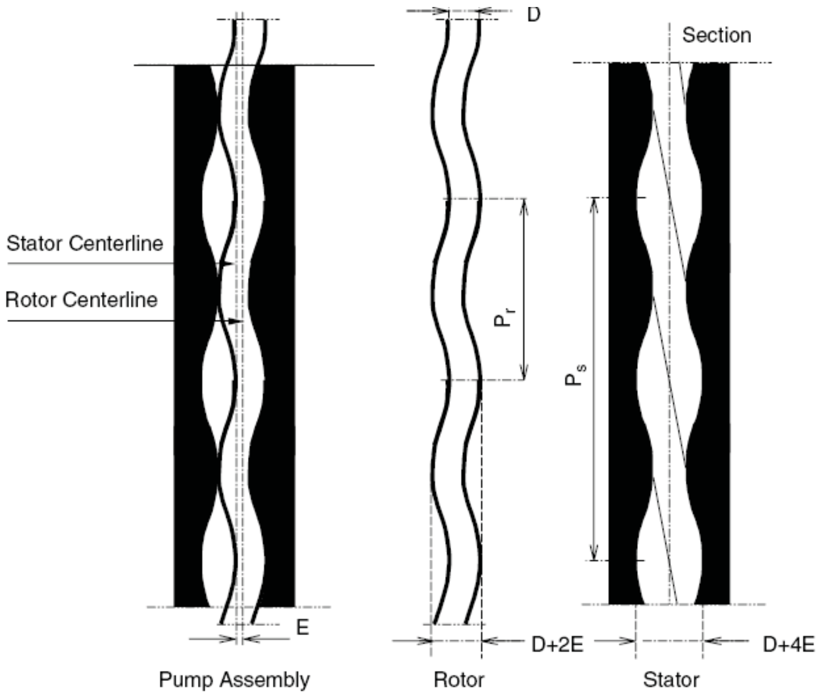


Figure 6 rotor and stator geometry of PCP 3

To define the geometry of the whole pump the lobes of the rotor and stator have to be given. A pump with a single helical rotor and a double helical stator is described a "1-2 pump", that means that Ps = 2 Pr. A multilobe pump the pitch length of the stator Ps is calculated the following way:

$$Ps = \frac{Lr+1}{Lr}\Pr, \qquad (1)$$

Where Lr is the number of rotor lobes. To calculate the volume displaced by one revolution of the rotor in ft³:

$$V_0 = 0.028 \cdot D \cdot E \cdot Ps, \qquad (2)$$

D…rotor diameter [in]
PCP mechanical resistance torque is expressed as:

$$T_m = \frac{144 \cdot V_0 \cdot \Delta P}{e_p}, \qquad (3)$$

The load in thrust bearing through the drive string is expressed as:

$$F_b = \frac{\pi}{4} \cdot (2E + D)^2 \cdot \Delta P \, , \tag{4}$$

Where F_b is the axial load in lbf. To calculate the required pump head the following formula is used:

$$\Delta P = (2 \cdot n_p - 1) \cdot \delta p \, , \tag{5}$$

Or

$$\Delta P = p_d - p_i \, ,$$

ep…efficiency [-]
p_d…pump discharge pressure[psi]
p_i…pump intake pressure [psi]
T_m…mechanical resistant torque [lbf-ft]
V_0…Volume displaced by one revolution [ft³]
ΔP…pump head rating [psi]
np…number of stator pitches
δp…head rating developed into an elementary cavity [psi]
PCP torque generated by the viscosity of the fluid in the tubing:

$$T_v = 2.4 \cdot 10^{-6} \cdot \mu_f \cdot L \cdot N \cdot \frac{d^3}{(D-d)} \cdot \frac{1}{\ln \frac{\mu_s}{\mu_f}} \cdot \left(\frac{\mu_s}{\mu_f} - 1\right), \tag{6}$$

μ_f…viscosity of the fluid at the inlet temperature [cp]
μ_s… viscosity of the fluid at the surface temperature [cp]
L…depth of the tubing [ft]
d…drive string diameter [in]
W_r…weight of the rod string considering/including buoyancy effects [lbf]
Fb…axial load due to delta p over pump/pump pressure load[lbf]
Total torque:

$$T = T_m + T_v \, , \tag{7}$$

Tv…pump viscous torque [Nm]
Total axial load:

$$F = F_b + W_r \, , \tag{8}$$

Calculate the axial stress in the string with:

$$\sigma_t = \frac{4}{\pi \cdot d^3} \sqrt{F^2 \cdot d^2 + 64T^2 \cdot 144} \, , \tag{9}$$

σ_t…tensile stress [lbf/in²]
This stress value should be compared with the strength of the rod with a safety factor.

These equations turned out to be not very useful in the industry because the **results are uncommon numbers** and also the required geometrical data are often not provided by the manufacturers. There seems to be a mistake already in equation 2. The second source of information on PCP design calculations is published from the Society of Petroleum Engineers (SPE) and is called "Petroleum Engineering Handbook". Volume four deals with Production operations and one chapter discusses the PCPs. The following information is based on **"**Petroleum Engineering Handbook Vol.4**",**2007 :
The volumetric displacement V_0 of a single lobe pump is usually specified by the pump manufacturer. If the data are not available the volumetric displacement V_0 of a single lobe pump is:

$$V_0 = 4 \cdot E \cdot D \cdot Ps\,, \tag{10}$$

With V_0… volumetric displacement [m³/d.rpm]
D…rotor diameter [m]
E…eccentricity [m]
Ps…stator pitch length [m]
The theoretical flow rate q [m³/d] can be determined by:

$$q = V_0 \cdot rpm\,, \tag{11}$$

Total torque is composed of the hydraulic torque (to overcome the differential pressure), the friction torque (to overcome the mechanical friction rotor/stator) and the viscous pump torque.

$$T = Th + Tf + Tv, \tag{12}$$

T…total torque [Nm]
Th…hydraulic torque [Nm]
Tf…pump friction torque [Nm]
Tv…pump viscous torque [Nm]

$$Th = C \cdot V_0 \cdot p_{lift}\,, \tag{13}$$

$$Tf = C \cdot V_0 \cdot (0.2 \cdot p_{\max}), \tag{14}$$

It is hard to find publications how to get Tf, 0.2 (20%) is taken from tests.

Tv can be estimated from tests as well. No data are available for the pump viscous torque in this book. Though it is possible to take equation 6 from "Petroleum Production Engineering".
With C=0.111

$$p_{lift} = \Delta P = p_d - p_i\,, \tag{15}$$

p_{max}…maximum pump pressure [kPa]
p_{lift}…differential pump pressure [kPa]
The total axial load can be calculated with:

$$F = F_b + W_r \tag{16}$$

Wr is again the weight of the rod string minus the buoyancy effect; the difference to is how to calculate Fb, the approach from this book is different:

$$Fb = C \cdot (\Delta p \cdot 0.6 \cdot (2 \cdot D + 13 \cdot E \cdot D + 16 \cdot E^2) - p_d \cdot d), \tag{17}$$

d…drive string diameter [mm]
D…rotor diameter [mm]
E…eccentricity [mm]
Fb…pump pressure load [N]
The combination of axial loads and torque can be expressed in an effective stress σ_e (Van Mises) which can be calculated with:

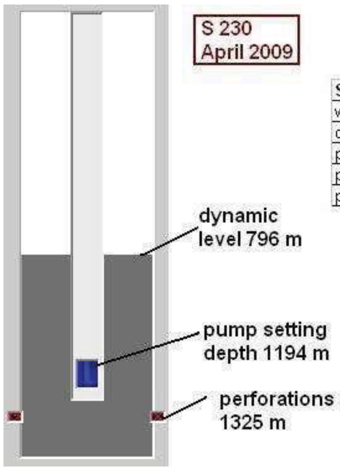
$$\sigma_e = \sqrt{\frac{C_1 \cdot F^2}{\pi^2 \cdot d^4} + \frac{C_2 \cdot T^2}{\pi^2 \cdot d^6}}, \tag{18}$$

σ_e...effective stress [MPa],
With the constants C1=16 and C2=7.680*10^8
This effective rod stress has to be smaller than the minimum yield stress of the rod string which is usually Grade D with 690 MPa including a safety factor of (minimum) 20 percent.
These equations turned out to create realistic values which can be used to calculate the stresses in the rod string at operating conditions.

Performance charts

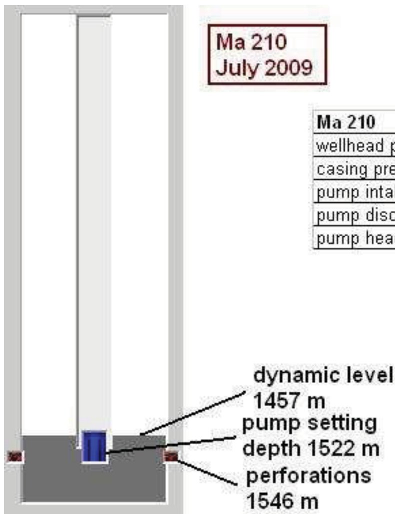
Each supplier has to provide performance charts for their pumps. In this chapter we will discuss how to use performance charts (see fig.61 and 62) and where the limitations are. Each pump model has a different chart, in our example we will use the performance chart of a PCM 200TP1800 pump. The pump type gives at 500 rpm and zero head a flow rate of 200 m^3/day. The chart is a visualization of the flow rates dependency on speed (in rpm) and hydraulic head (in m). Another feature is the possibility to calculate the required power (in horse powers) for given conditions.
On the vertical axis the flow rate is plotted in cubic meter per day (m^3/d) and barrel fluid per day (bfpd), on the horizontal axis the speed is given in rpm. In the chart there are two types of straight lines, the parallel lines show the linear relationship between flow rate and speed for different heads. Zero head means there is no downward slippage of the fluid. Normally the cavities in the pump are never completely tight which creates a differential pressure between the cavities -due to the weight of the fluid column exerted in the cavities- and induces therefore a downward slippage of the fluid. The second type of straight lines are the dashed lines which allows to estimate the required power at the drive shaft for a given rpm, flow rate and head.
All **calculations** are based on the assumption that the produced fluid is **100 % water**. As a consequence care should be taken considering the gas-liquid-ratio (GLR) and high viscosities. A high GLR affects the liquid flow rate which tends to be smaller due to the presence of gas. The problem induced by high viscosities is the influence of friction pressure losses in the tubing string. For the two conditions mentioned PCM owns a special software program to calculate the correct flow rates and power requirements.
To check the performance of the individual pumps the term “hydraulic efficiency” needs to be introduced. The hydraulic efficiency is per definition the ratio of the flow rate at given speed and head to the flow rate at same speed but zero head.

The well S 230 has installed a 30TP2000 PCP pump from PCM. 30 means a maximum flow rate of 30 m³/d (with zero head), TP indicates a tubing pump whereas 2000 stands for the head capability in meters. The well had in April 2009 a flow rate of 7.3 m³/d with a dynamic level of 796 m, a casing pressure of 3 bar and a tubing pressure of 3 bar. The pump is set at 1194 m. To calculate the pump head it is necessary to subtract the pump intake pressure from the pump discharge pressure and convert the result to meters. To get the pump intake pressure one has to evaluate the well flowing pressure (which is equal to the casing pressure plus the weight of the fluid column) and subtract the weight of the fluid column in the annulus. To obtain the pump discharge pressure the wellhead pressure has to be added to the weight of the fluid column in the tubing.



S 230	
wellhead pressure	3 bar
casing pressure	3 bar
pump intake pressure	5,2 bar
pump discharge pressure	122 bar
pump head	**1168 m**

A flow rate of 7.3 m³/d results in a pump head of 1168 m and an rpm of 190. To calculate the hydraulic efficiency it is necessary to determine the flow rate at zero head and 190 rpm from the performance chart (fig.63 & 64) which is 10.1 m³/d. Now one has to divide the flow rate at zero head with the actual flow rate. The result is the hydraulic efficiency which gives in this example 72 %.



Ma 210	
wellhead pressure	3 bar
casing pressure	4 bar
pump intake pressure	4 bar
pump discharge pressure	155 bar
pump head	**1546 m**

The well Ma 210 has installed a 30TP2000 PCP pump from PCM as well. The well had in July 2009 a flow rate of 1.3 m³/d with a dynamic level of 1475 m, a casing pressure of 4 bar and a tubing pressure of 3 bar. The pump is set at 1522 m. The calculation procedure is the same like before. The pump head is 1546 m which gives a hydraulic efficiency of 52 %.

Friction pressure losses have been neglected in these calculations since the flow rates are small.

OMV suppliers

Netzsch was the initial PCP supplier for OMV. Since many problems occurred with Netzsch pumpes, the production department decided in 2007 to change the supplier and contacted PCM. A main difference between the two suppliers is the proposed stator elastomer, Netzsch pumps are equipped with FKM elastomer and PCM pumps with NBR elstomers.
In 2000 a single PCP well with downhole motor was installed. This PCP was provided by Centrilift. Since the downhole driven PCP created many problems it was recompleted to a surface driven PCP.

Wells

The following chapter will give an overview over the history of each OMV well in Austria where a PCP is installed. First a table will show when an intervention was done and the results of the workover. Below the table a written history will explain in more detail also what happened between the interventions.

St. Ullrich 139

STU 139	**16.04.2009**	**20.04.2009**	PCP Change (PCM)	Stator damaged
STU 139	**03.04.2008**	**09.04.2008**	Recompletion PCP(PCM)	

Table 1 well history STU 139

This well was drilled in 1944, it is one of OMVs oldest wells. The progressive cavity pump (PCP) was installed **3.4.2008**. Before the PCP the artificial lift system was a sucker rod pump.
The density of the oil is 0.86 g/cm³ which give an API gravity of 33. This well is producing P-oil. Which means it includes paraffins.

The installation of the PCP was completed with 3 ½” relined tubing .Soon the rotor started to touch the stop pin, resulting in an increase in torque and finally in a broken pin. The rotor was lifted 20 cm during an intervention. After some time the production rate decreased and finally stopped. In February 2009 the well did not produce anymore. The intervention in April 2009 showed a destroyed elastomer. A new PCM PCP was installed again with 3 ½” relined tubing.
In 1994 there was a gas analysis done, the results are 80 volume percent of methane (CH_4) and 12 volume percent of carbon dioxide (CO_2). Sand content is below 1%.
An additional gas analysis in May 2009 showed a CO_2 content of 22 volume percent and a methane content of 74 volume percent. Since the NBR elastomer is sensitive to H_2S and CO_2 it is assumed that the gas was responsible for the destroyed stator. Also it is recommended to realize this relatively high CO_2 content as a potential for corrosion. When the well was equipped with a sucker rod pumping unit many interventions where done according to broken sucker rod and leaking tubing which may be the result of corrosion. For paraffin and corrosion inhibition Flotron CW 511 (consists of 1/3 CK 347-HD and 2/3 CK 517) is injected with 182 litres per month.

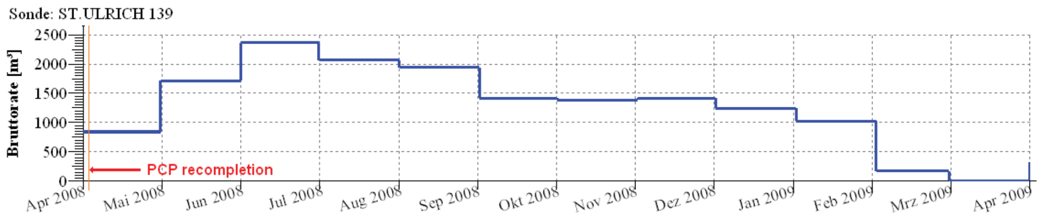


Figure 7 production history StU139

Matzen 210

MA 210	**16.03.2009**	**18.03.2009**	TUBING. leaking	hole and crack at 1180m
MA 210	**02.04.2008**	**08.04.2008**	Recompletion PCP(PCM)	

Table 2 well history Ma 210

This well was drilled in 1954. The PCM progressive cavity pump (PCP) was installed **02.04.2008**. Before the PCP the artificial lift system was a sucker rod pump.

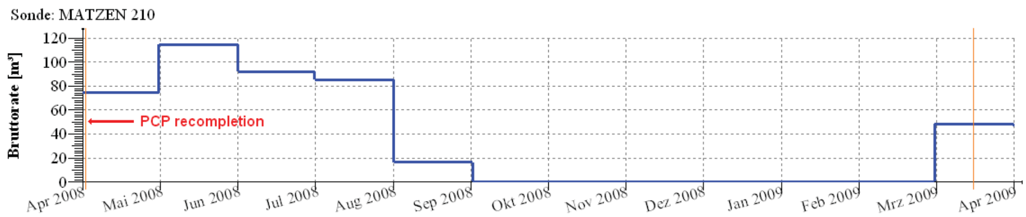


Figure 8 production history Ma 210

The installation of the PCP was completed with 2 7/8” tubing. Five months after the recompletion the well did not produce any more because of a hole and a crack. Maybe this was the result of injecting the corrosion inhibitor 3 months after the start of the well. After an intervention in March 2009 the new installation consists now of 3 ½” relined tubing, no centralizers at the rod and the same PCM PCP like before. This failure was not dedicated to the pump, more likely the rod string was shearing at the tubing. The time between the production stop and the required intervention is about 6 months.

Matzen 235

MA 235	**28.10.2008**	**28.10.2008**	Decrease PCP(rotor) depth	10 cm
MA 235	**27.11.2007**	**30.11.2007**	PCP Change	
MA 235	**08.11.2006**	**15.11.2006**	Recompletion PCP	Well is free flowing

Table 3 well history Ma 235

This well was drilled in 1956. The Netzsch progressive cavity pump (PCP) was installed **08.11.2006**. Before the PCP the artificial lift system was intermittent gas lift.

After the PCP installation it took 7 months until the well did not produce any more. End of 2007 a new pump was installed (Netzsch) because the old pump got stuck and the tubing was leaking. The well was producing nearly one year until the next intervention

where the rotor depth was decreased by pulling the rod string 10 cm. One week later the well did not produce anymore.
The well is planned for workover where the pump will be changed (PCM) and 3 ½” relined tubing will be run.

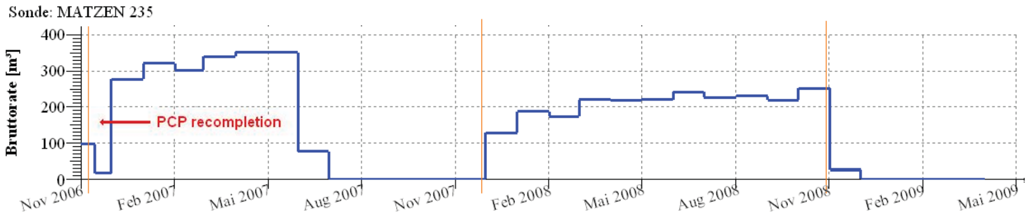


Figure 9 production history Ma 235

Matzen 236

MA 236	**19.12.2008**	**09.01.2009**	PCP Change(PCM), TUBING Change(relined)	
MA 236	**09.10.2007**	**15.10.2007**	PCP Change	
MA 236	**06.04.2007**	**12.04.2007**	Check PCP	PCP OK
MA 236	**19.02.2007**	**23.02.2007**	Recompletion PCP	

Tabelle 4 well history Ma 236

This well was drilled in 1957. The Netzsch progressive cavity pump (PCP) was installed **19.02.2007.** Before the PCP the artificial lift system was intermittent gas lift.

After one and a half months the pump was shut down because the torque limit was exceeded (elastomer swelling). After an intervention the same pump was installed again but at a slightly different setting depth. In October 2007 the pump needed to be changed due to elastomer swelling. The same happened in December 2008 where OMV decided to install a PCM pump which means a different elastomer is used. So far the pump is running without any problems. In figure 8 the long time period between the pump failure and the next/required intervention can be seen, from January 08 to January 2009 the pump was shut down.
It can be assumed that the Netzsch elastomer is incompatible with the crude from this well. This assumption is supported by the lab test from December 2007 which was done in Germany by Netzsch. The crude from the horizon 213B 31 was tested on different Netzsch elastomers and the one OMV was using (FKM 451) was definitely not recommended for installation due to massive volume increase. Netzsch recommended to use NBR02 which is a similar type of elastomer like the one provided by PCM.

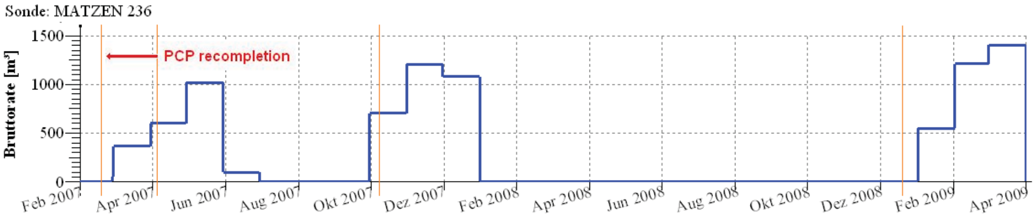


Figure 10 production history 236

Matzen 251

MA 251	**17.11.2008**	**21.11.2008**	PCP Change(PCM)	Stator damaged
MA 251	**02.03.2007**	**07.03.2007**	Recompletion PCP	

Table 5 well history Ma 251

This well was drilled in 1960. The Netzsch progressive cavity pump (PCP) was installed **2.3.2007**. Before the PCP the artificial lift system was intermittent gas lift.

The installation of the PCP was completed with 2 7/8" tubing. After one year of production the pump got stuck and was changed 8 months later with a PCM pump and 3 ½" relined tubing. The well is producing at the moment (23.4.09)

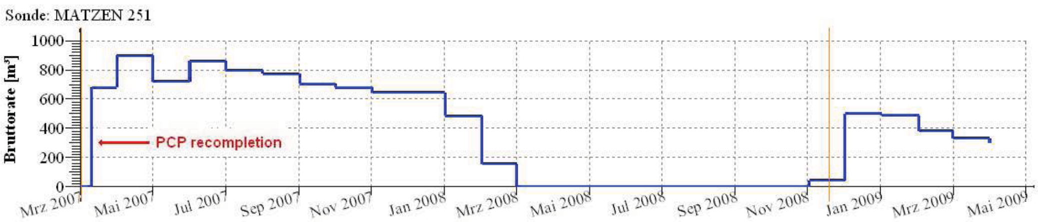


Figure 11 production history Ma 251

Matzen 294

MA 294	**23.11.2007**	**04.12.2007**	Recompletion PCP	*Stuck pump*

Table 6 well history Ma 294

This well was drilled in 1960. The Netzsch progressive cavity pump (PCP) was installed **23.11.2007.** Before the PCP the artificial lift system was intermittent gas lift.

The reason for recompletion was the high sand production which was eroding the well head. Since PCP were promised to handle solids production this well was a candidate for recompletion.
The installation of the PCP was completed with 2 7/8" tubing. Already after two months the well was shut down due to no production. After 3 moths a production test was done, but with no result. Since then the well is shut down.

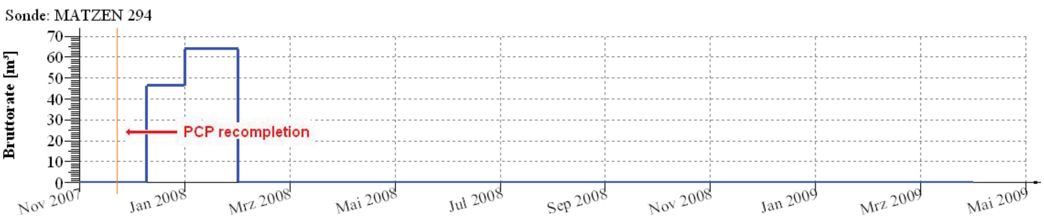


Figure 12 production history Ma 294

Matzen 337

MA 337	**22.10.2007**	**25.10.2007**	Recompletion PCP	*No production, low inflow*

Table 7 well history Ma 337

This well was drilled in 1963. The progressive cavity pump (PCP) was installed **22.10.2007**. Before the PCP the artificial lift system was intermittent gas lift.

After the installation the well was not producing enough oil. Less than one ton of crude could be recovered, so the well was shut down and is waiting now for workover.

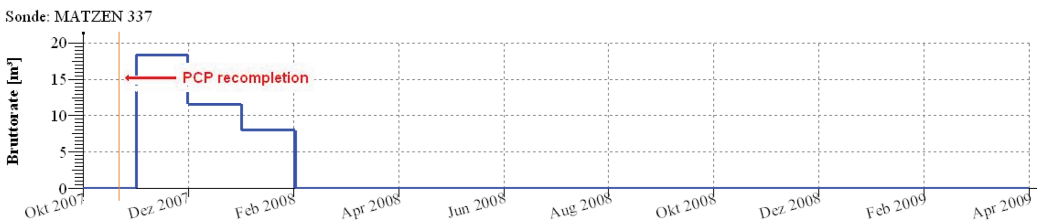


Figure 13 production history Ma 337

Matzen 430

MA 430	**11.02.2008**	**14.02.2008**	SCHWABB-PV (Production test)	8 m³
MA 430	**11.08.2006**	**16.08.2006**	PG Change	Damaged stop pin, stuck rotor
MA 430	**31.01.2006**	**22.02.2006**	Recompletion PCP(+Casingleak)	

Table 8 well history Ma 430

This well was drilled in 1967. The progressive cavity pump (PCP) was installed **21.02.2006**. Before the PCP the artificial lift system was intermittent gas lift.

Half a year after the recompletion the rotor got stuck in the stator and the pump was full of sand. The downhole equipment was removed from the well and 6 month later a production test was done to find out if the well has a sand problem. Based on this result OMV is deciding at the moment whether an open hole gravel pack (OHGP) will be installed/done or not.

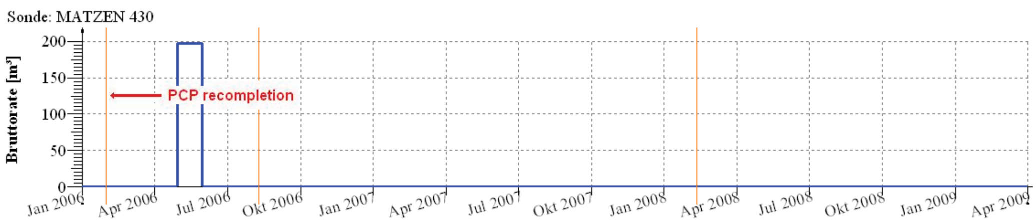


Figure 14 production history Ma 430

Matzen 464

MA 464	**27.01.2009**	**03.02.2009**	TUBING leaking, PG Change	TUBING washout
MA 464	**27.10.2008**	**27.10.2008**	Decrease PCP(rotor) depth	
MA 464	**29.11.2007**	**05.12.2007**	PCP Change	PCP full of sand, stuck rotor
MA 464	**03.10.2007**	**22.10.2007**	Recompletion PCP	

Table 9 well history Ma 464

This well was drilled in 1974. The Netzsch progressive cavity pump (PCP) was installed **3.10.2007**. Before the PCP the artificial lift system was intermittent gas lift.

The start up of the pump was already related to problems, the workover crew could not start the pump because the torque was to high, the pump was stuck and full with sand, so a new pump had to be installed (Netzsch). This pump was running nearly one year without any problems until the next workover had to be done where they decreased the rotor depth with 10 cm. Only a few days after the workover the well stopped producing, so another intervention had to be done. In January 2009 they installed new relined tubing, new rods and used the same pump like before because it was in a good condition. Only the tubing was leaking. It had a DURCHSCHLIFFRISS directly above the pump. With the new installation the pump is today still producing but this well has a big sand problem.

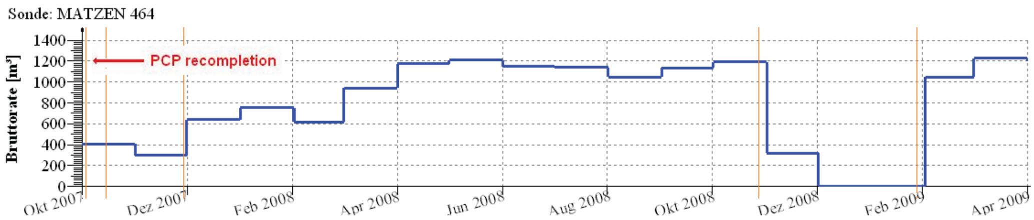


Figure 15 production history Ma 464

Matzen 469

MA 469	**18.12.2007**	**21.12.2007**	TUBING leaking	Stator damaged ,Elastomer rubbed off
MA 469	**25.10.2007**	**30.10.2007**	Recompletion PCP	

Table 10 well history Ma 469

This well was drilled in 1970. The Netzsch progressive cavity pump (PCP) was installed **25.10.2007**. Before the PCP the artificial lift system was plunger assisted gas lift.

One month after the recompletion the well did not produce anymore and an intervention was done. The elastomer in the stator was damaged and the tubing was leaking. With the new PCP installation the well was running for 1 month and again stopped producing. At the moment the well is waiting for intervention.

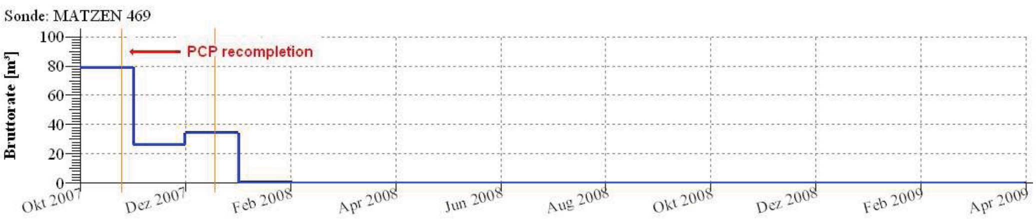


Figure 16 production history Ma 469

Prottes 86

P 086	**04.03.2009**	**09.03.2009**	PCP(PCM),TUBING & sucker rod Change	crack 1 single above pump
P 086	**28.10.2008**	**28.10.2008**	PCP Check	Increase rotor depth by 15 cm
P 086	**20.07.2006**	**26.07.2006**	TUBING leaking	1m long crack 3m above the pump
P 086	**16.09.2005**	**05.10.2005**	Recompletion PCP	

Table 11 well history P086

This well was drilled in 1960. The progressive cavity pump (PCP) was installed **26.09.2005**. Before the PCP the artificial lift system was a sucker rod pump.

Nine months after the recompletion the tubing string was leaking. During intervention a RISS was found directly above the pump. Since the pump itself was in a good condition it was run downhole again. Two years and 3 months later the rod string was lowered by 15 cm. In February 2009 the tubing string again was leaking and an intervention had to be done. Again the source of leaking was found directly above the pump. This time the pump was changed as well and a PCM pump was installed. Additionally relined tubing was run. Compared to the other PCP installations this pump showed a quite long running time which could possibly be the result of a relatively low water cut below 90 %.

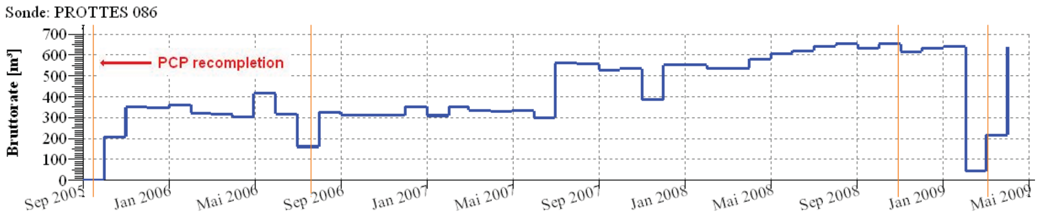


Figure 17 production history P086

Prottes 202

P 202	**10.06.2008**	**12.06.2008**	PCP Change, TUBING leaking	Stator shows bubbles, 47 singles damaged (red)
P 202	**24.08.2006**	**25.08.2006**	Recompletion PCP	

Table 12 well history P202

This well was drilled in 1993, as a gas storage well. 2004 they closed the perforations and opened a new horizon for production. The progressive cavity pump (PCP) was installed **24.08.2006**.

Two years after the PCP installation the well stopped producing. The tubing was leaking and the stator of the pump showed some development of bubbles. In June 2008 an intervention was done where the pump was changed and relined tubing was run. With the new installation the well is producing now for nearly one year without any troubles.

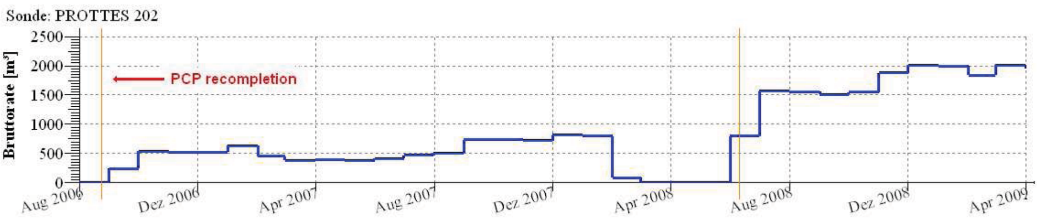


Figure 18 production history P202

Schönkirchen 39

S 039	**11.08.2006**	**21.08.2006**	PG Change (was twisted off)	*Since 8.9.06 no production*

S 039	**23.05.2006**	**30.05.2006**	PCP Change	
S 039	**23.12.2004**	**11.01.2005**	PCP Change	
S 039	**26.07.2004**	**30.07.2004**	TUBING. leaking	42 singles damaged (red)
S 039	**17.12.2003**	**14.01.2004**	TUBING. leaking	Long crack in single above PCP
S 039	**22.07.2003**	**24.07.2003**	PCP Check	PCP OK
S 039	**19.02.2003**	**24.02.2003**	Recompletion PCP	

Table 13 well history S 039

This well was drilled in 1974. The progressive cavity pump (PCP) was installed **19.02.2003**. Before the PCP the artificial lift system was a sucker rod pump.

It can be seen already in the table 12 that this well had many interventions. One year after the recompletion the tubing was leaking, directly above the pump there was a RISS. Again leaking tubing occurred half a year later. In January 2005, that means 2 years after the initial installation the pump was changed for the first time. This pump was running than for more than one year until it had to be changed as well. Unfortunately no information could be found about the condition of these pumps or the reason for change. 3 months after the last intervention a problem with the sucker rods occurred, they where unscrewed. The workover crew fixed the problem and two weeks later the well stopped producing. The well is shut down since September 2006.

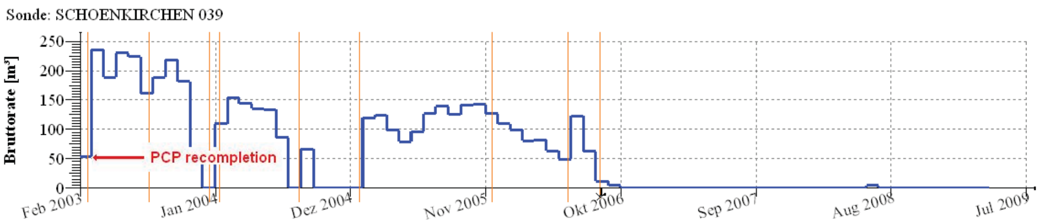


Figure 19 production history S039

Schönkirchen 127

S 127	**28.10.2008**	**28.10.2008**	Decrease PCP(rotor) depth	*since 7.11.08 no production*
S 127	**21.12.2007**	**09.01.2008**	TUBING Change	Rotor grinded in the upper section, long crack at 726m, 18 singles damaged (red)
S 127	**27.02.2007**	**01.03.2007**	PCP Change, TUBING Change	Stuck rod string
S 127	**09.02.2007**	**19.02.2007**	PCP Check, TUBING Change?	overpull when pulling the rotor, PCP OK
S 127	**12.04.2006**	**13.04.2006**	PCP Change	PCP + 2 sand pipes full of Sand
S 127	**06.04.2006**	**11.04.2006**	PCP Change	hole at 670m, 46 singles in bad condition,damage from centralizers. Pump got stuck after the start
S 127	**09.09.2005**	**16.09.2005**	Recompletion PCP	Well partially free flowing

Table 14 well history S 127

This well was drilled in 1956. The progressive cavity pump (PCP) was installed **09.09.2005**. Before the PCP the artificial lift system was a sucker rod pump.

Here a main difference to all the other wells is given, this well is kicking very often during workovers. The workover crew did already have a kick at the recompletion of the well. Half a year after the first PCP installation the tubing was leaking and also the pump needed to be changed. After the workover the crew tried to start up the pump and got stuck. They immediately removed the pump and it was full of sand. A new pump was run and it lasted 1 month till the well did not produce anymore. This happened/was in May 2006, the required workover was done in February 2007. Again there is not much information about the condition of the pump, the only thing that was documented is that the stop pin was broken. The workover even was documented as a sucker rod change, but reading the workover report did not show a change in sucker rods. The same pump was installed again and it was running one week until the pump got stuck. The rotor was stuck in the stator but could be released finally. The pump was changed. It took 9 months till the next workover was necessary. The tubing was leaking and had to be changed. 10 months later the rod string was pulled and one week later the well stopped producing. Nearly each intervention job resulted in a kick. Now the well is waiting for intervention (since January 2009).

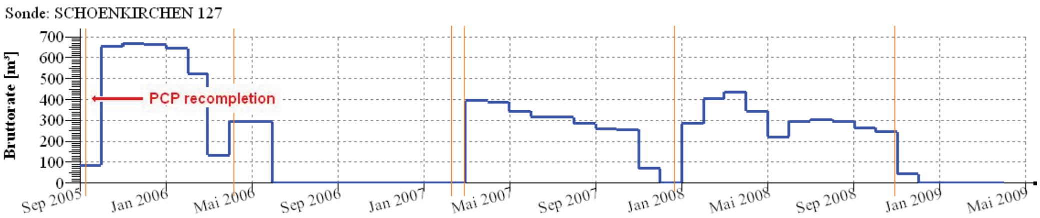


Figure 20 production history S 127

Schönkirchen 230

S 230	**06.07.2009**	**08.07.2009**	PCP Change, Tubing leak	Crack at 1168m, insert relined tubing
S 230	**14.10.2008**	**14.10.2008**	Decrease PCP(rotor) depth	
S 230	**18.05.2006**	**23.05.2006**	PCP Change	47 singles damaged (red)
S 230	**01.07.2003**	**17.07.2003**	TUBING. leaking	Tubing unscrewed (twisted off), cut & stuck
S 230	**11.04.2003**	**18.04.2003**	Recompletion PCP	

Table 15 well history S 230

This well was drilled in 1956. The progressive cavity pump (PCP) was installed **11.04.2003**. Before the PCP the artificial lift system was a sucker rod pump.
The well was perforated in a different section of the same horizon in 1998 resulting in a huge increase in oil production (from 3 to 10 tons per day). The disadvantage was the solids production that increased as well (from far below 1% to 1.2%). An Inside Casing Gravel Pack (ICGP) was installed in 2000 to manage the sand production which was already requiring an annual pump change. The production dropped to zero which was dedicated to wrong designed ICGP. It was renewed in 2001 and the perforation interval length was shortened, but without any success for the oil production. In April 2003 the ICGP was removed and a PCP was installed.
2 months after the PCP completion the will did not produce anymore. The workover showed leaking and unscrewed tubing and damaged protectors even with some remaining in the well. The pump was installed again since the failure was dedicated to

the tubing string. The completion was running fine for 2 and a half years when production stopped. Again the tubing string was leaking and the PCP was changed (after 3 years running time). In October 2008 it was decided that the rod string has to be lifted 10 cm. In June 2009 the well stopped producing. Tubing leak is assumed, the well is waiting for workover.
Relined tubing is planned for the next installation to prevent the tubing leaks.

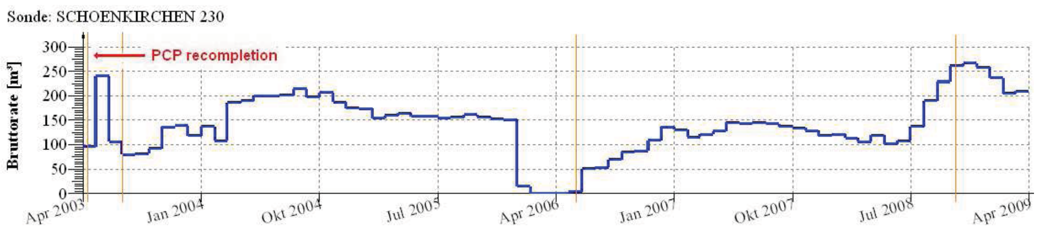


Figure 21 production history S 230

Schönkirchen 263

S 263	**26.02.2009**	**04.03.2009**	PCP Change (PCM)	Rotor stuck in the Stator
S 263	**15.12.2008**	**15.12.2008**	Decrease PCP(rotor) depth	Stuck rod string
S 263	**12.11.2008**	**17.11.2008**	PCP Change (PCM)	overpull when pulling the rotor
S 263	**15.11.2006**	**17.11.2006**	PCP Check	
S 263	**19.07.2005**	**21.07.2005**	PCP Change	Rotor & PG wear
S 263	**13.01.2005**	**18.01.2005**	PCP Check	PG&TUBING.eroded, PCP OK
S 263	**17.09.2003**	**23.09.2003**	Recompletion PCP	

Table 16 well history S 263

This well was drilled in 1955. The progressive cavity pump (PCP) was installed **17.9.2003**. Before the artificial lift system was a sucker rod pump.
The first PCP was running for slightly more than one year after the production stopped the first time. In January 2005 a workover was done to check for the pump. The crew found eroded sucker rods and tubing, the pump was in a good condition and inserted again. In May 2005 the rod string was lifted up 22cm and in June the pump stopped producing. The PCP was changed and the sucker rods above the pump showed signs of corrosion and erosion. In August 2006 the well was running dry, which means that the dynamic liquid level dropped below the pump. After a short production period of 3 days the well stopped production again. The workover in November showed wear on the sucker rod pins above the rotor and sand had to be circulated. A new pump and 3 ½ " relined tubing was installed. In February 2008 the pump had a running time of one year and three months until the next break down occured. (pump was stuck, could not be started after shut down, reason for shut down unknown) the well did not produce anymore and the next workover was done in November 2008. The pump was changed with a PCM PCP instead of the previously used Netzsch PCP. The pump got stuck one day after the workover was finished. In December 2008 the workover crew tried to pull the rod string without success. The well was waiting for workover until February 2009 where the installation was removed by pulling the tubing and the sucker rod string simultaneously. A new pump was inserted and the well is producing again.

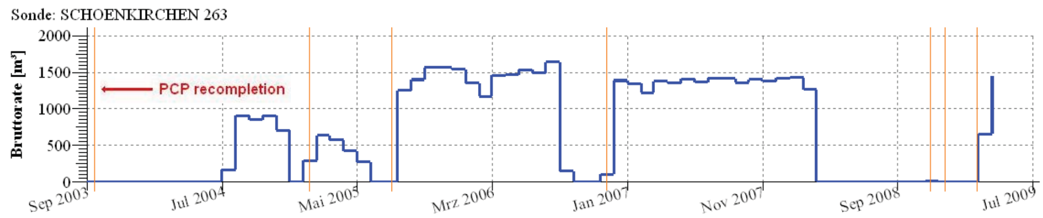


Figure 22 production history S 263

Hochleiten 60

HL 060	**04.02.2009**	**10.02.2009**	TUBING. leaking	crack und corr. hole
HL 060	**10.07.2008**	**14.07.2008**	PCP Change	Rotor damaged/broken
HL 060	**24.06.2008**	**26.06.2008**	TUBING. leaking	Riss at 1087m
HL 060	**26.11.2007**	**29.11.2007**	TUBING. leaking	hole at 572m
HL 060	**03.08.2005**	**09.08.2005**	Recompletion PCP	From ESPCP to PCP

Table 17 well history HL 60

This well was drilled in 2000. The electric submersible progressive cavity pump (ESPCP) was the first installation. The ESPCP was from Centrilift. OMV decided to remove the ESPCP and installed in **2005** PCP from Netzsch The well has a TVD 1041.5 and an MD of 1319. The well is deviated with a maximum inclination of 70 degrees. The kick off point (KOP) is at 476 m and then we have a continuous build section and at the end a small drop section.
After the recompletion the well was producing until November 2007 which corresponds to slightly more than 2 years. The next workover discovered a hole in the tubing, the same pump was installed it has taken no damage. After half a years again the well stopped producing. A crack was found in the tubing, therefore 3 ½ " relined tubing was run. Again the same pump was run. After one week the well stopped production because the rotor was broken. A new pump had to be installed. The old pump had a lifetime of nearly three years which is quite a good performance. After a running time of half a year the well stopped producing because of a hole and a crack in the tubing. The pump was okay and installed again.

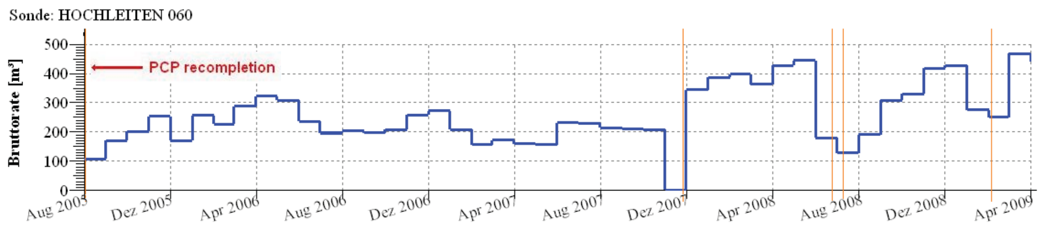


Figure 23 production history HL 60

Pirawarth 96a

PIR 096a	**08.07.2008**	**09.07.2008**	PCP removed from well	*No production since 26.6.08*
PIR 096a	**01.07.2008**	**02.07.2008**	PG Change (1 single)	Ponyrod broken at surface
PIR 096a	**23.06.2008**	**24.06.2008**	TUBING Change (normal)	PG & Rotor strongly corroded, Stator bubbles (fig. 24)
PIR 096a	**16.01.2007**	**18.01.2007**	TUBING. leaking > Change	

			(auf Relined), new PCP	
PIR 096a	**08.06.2006**	**13.06.2006**	TUBING. leaking, PCP Change	Hole at 917m
PIR 096a	**07.11.2005**	**09.11.2005**	TUBING. leaking	Corrosion hole at 940m
PIR 096a	**20.08.2004**	**31.08.2004**	Recompletion PCP	

Table 18 well history Pir 96a

This well was drilled in 2002. The progressive cavity pump (PCP) was installed **20.08.2004**. Before the PCP the artificial lift system was intermittent gas lift.

Figure 24 damaged stator elastomer, Pir 96a ,June 2008

15 months after the recompletion of the well the first workover had to be done/executed due to a tubing leak. At 940 m there was a hole in the tubing string. 7 months later the same problem occurred and even at a similar depth, again a hole at 917 m was found. During this second intervention the pump was changed as well, after a running time of nearly two years.
No data are available about the condition of the pump. 7 months later the tubing was leaking again so OMV decided to change to 3 ½" relined tubing. After one and a half years, during the next intervention the relined tubings collapsed due to gas migration between the tubing and the liner.
One and a half year later the tubing was changed with normal tubing and the stator of the pump was damaged (see fig.23). Additionally the rod string showed serious corrosion problems. Anyways, the well did not produce anymore after the workover.
One week later a pony rod at the surface broke and had to be changed. The next week the PCP was removed from the well.

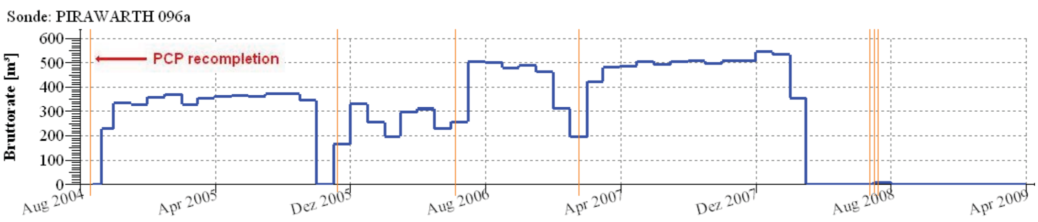


Figure 25 production history Pir 96a

Pirawarth 79

PIR 079	**27.07.2005**	**02.08.2005**	PCP Change	Rotor is stuck in the stator
PIR 079	**29.06.2005**	**07.07.2005**	Recompletion PCP	

Table 19 well history Pir 79

This well was drilled in 1973. The PCP was installed **7.7.2005**. Before the PCP the artificial lift system was intermittent gas lift.

10 days after the recompletion the pump got stuck. The rotor was stuck in the stator and the sucker rod was stuck in the tubing above the pump and had to be cut. A new pump was installed but after some days again the pump got stuck. This well already had a severe sand problem before a PCP was installed. Fig. 27 shows a sample taken 2 weeks after the recompletion. The sand can be seen very good as it has settled to the ground of the bottle.
In 2006/2007 (no data available) the drive head was removed from the well site and installed somewhere else. Today OMV is thinking about drilling a sidetrack.

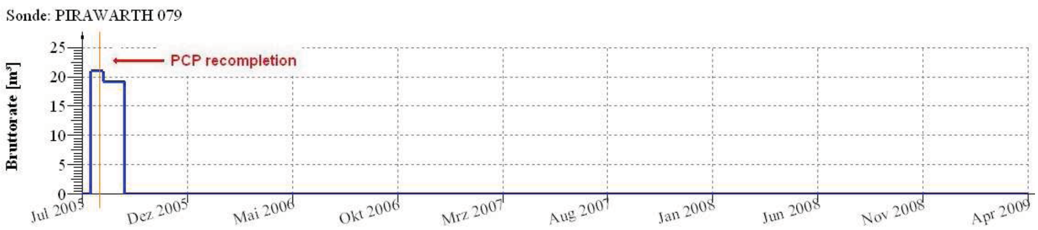


Figure 26 production history Pir 79

Figure 27 sample of Pir 79 from 19.07.2005

Application range of PCPs

Sand

Many oil wells tend to have sand in the crude. The manufacturers of PCPs praise the ability of their pumps to handle sand production with the appropriate system design. But like with any other downhole installation sand and other solids production can cause

severe problems, e.g increased equipment wear, increasing rod torque or flow restrictions (due to accumulation).
The advantage of PCPs compared to other lift methods (concerning sand production) is the continuous and pulsation-less production of the crude which reduces erosion. Also no valves are required which are very sensitive to sand.
One major/common problem is sand accumulation inside the tubing just above the pump. The reason for this plugging is that the flow rate in the tubing is not high enough to transport the sand up to the surface or the pump was stopped and after some time the sand remaining in the fluid column will settle down.
To predict sand settling some parameters have to be known. First of all the settling velocity is a function of the **grain diameter**. The bigger the grain size the fast it will settle down and the more flow rate I need to transport the particle up. Second, the properties of the produced fluid like **density and viscosity**. The upward force of the sand particle is supported by high density and high viscosity. The last influencing factor is the easiest one to control, the **fluid flow velocity** which is via the tubing inner diameter direct proportional to the flow rate. Each well/system has a critical velocity where settling occurs. The settling velocity can be calculated with **Stokes Law**:

$$v_{settling} = \frac{ds \cdot (\rho s - \rho f) \cdot g}{18 \cdot \mu},$$

$v_{settling}$…settling velocity [m/s],
ds…sand grain diameter
ρs…sand density , assumed 2600 kg/m³
ρf…liquid density [kg/m³]
g…gravity constant 9.81m/s²
μ…dynamic viscosity of the fluid [kg/m.s]

This settling process is undesired in the tubing string but might be helpful in the annulus from the perforation to the pump intake. Of course the sand should not accumulate directly below the pump intake, a sump below the pump allows the sand to settle instead of being produced. The deeper the sump the more time it takes until the sand reaches the pump level. This application is only recommended for certain wells where an economic study proves this method to be feasible, because the sand has to be removed from time to time. A workover rig or coiled tubing unit is required, which is related/associated to additional costs. If the time for the sump to fill up is higher than the mean time between failures (MTBF) for the well with sand production, the sump is an option to think of.
Other helpful tools to handle sandy wells are conventional sand control installations like screens, gravel packs, chemical consolidation or frac-packs.

ISO 14688 defines fine (0.062 to 0.2mm), medium (0.2 to 0.63mm) and coarse (0.63 to 2mm) sand according to the grain diameter.
Grain size distributions are available in the OMV database. Using these data requires knowledge about the type of sampling. Taking the sample from the separator or from the well head directly makes a difference. Even whether the sample was taken from the well during production or during circulation (workover) will show different results.
Except for one well all OMV wells with PCP installation have a sand content smaller 1%. Since many workovers proved severe sand problems although the fluid analysis showed small sand contents, it is possible that the production rate is too low to produce the sand up to the surface. Fig.3 shows the fluid velocity in the tubing compared to the solid settling velocity which is calculated by stokes law. The diagram is valid as well

for 3 ½" relined tubing since it has the same inner diameter like 2 7/8" tubing. The information one can get from this plot is the minimum required flow rate for transporting a defined grain size up to the surface. A grain size with a diameter of 0.5 mm needs a flow rate higher than 36 m³/d to be produced up to the surface in a 2 7/8" tubing. At 36 m³/d the settling velocity would be the same like the fluid velocity resulting in a floating of the particles. The problem hereby is not in the producing mode, but as soon as the pump is stopped the solids will settle down and plug the pump.

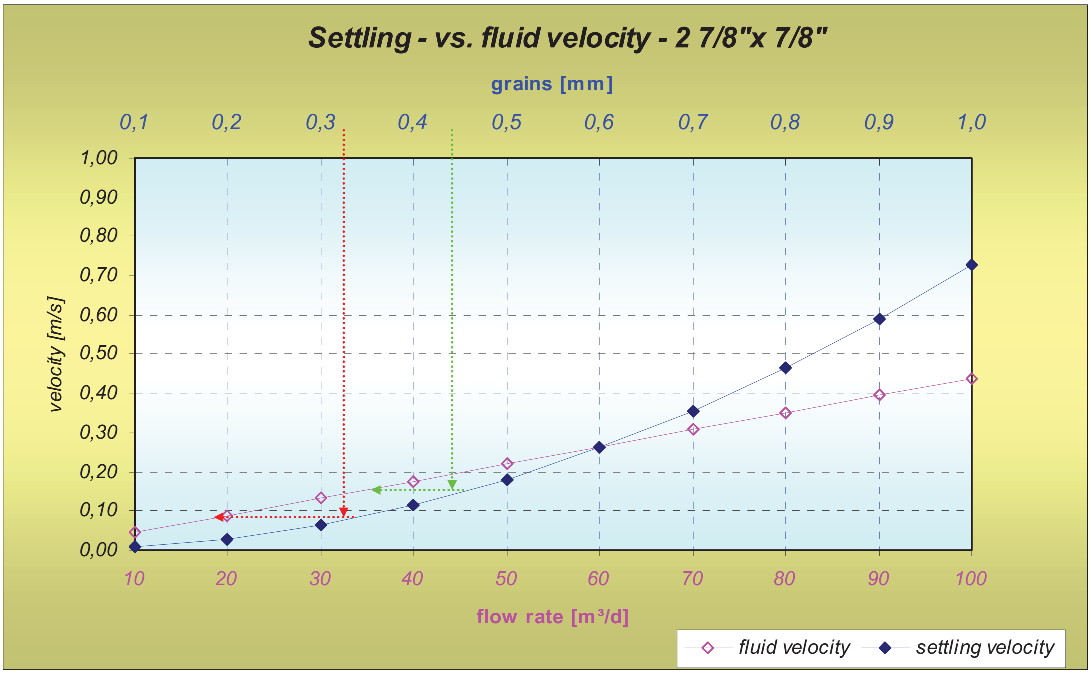


Figure 28 solid settling velocity for 2 7/8" (and 3 ½" relined) tubing with 7/8" sucker rods

It has to be mentioned that this plot assumes concentricity of the tubing and the rod string and no drag forces are considered. Also for simplicity no gas in included, only single phase flow is assumed.

If we look again at the 0.5mm grain which needed a flow rate higher than 36 m³/d in a 2 7/8" tubing, theoretically the flow rate should be higher in the 3 ½" tubing because the cross sectional area is bigger. Fig.4 verifies this assumption; the 0.5 mm grain requires a minimum flow rate of 69 m³/d.

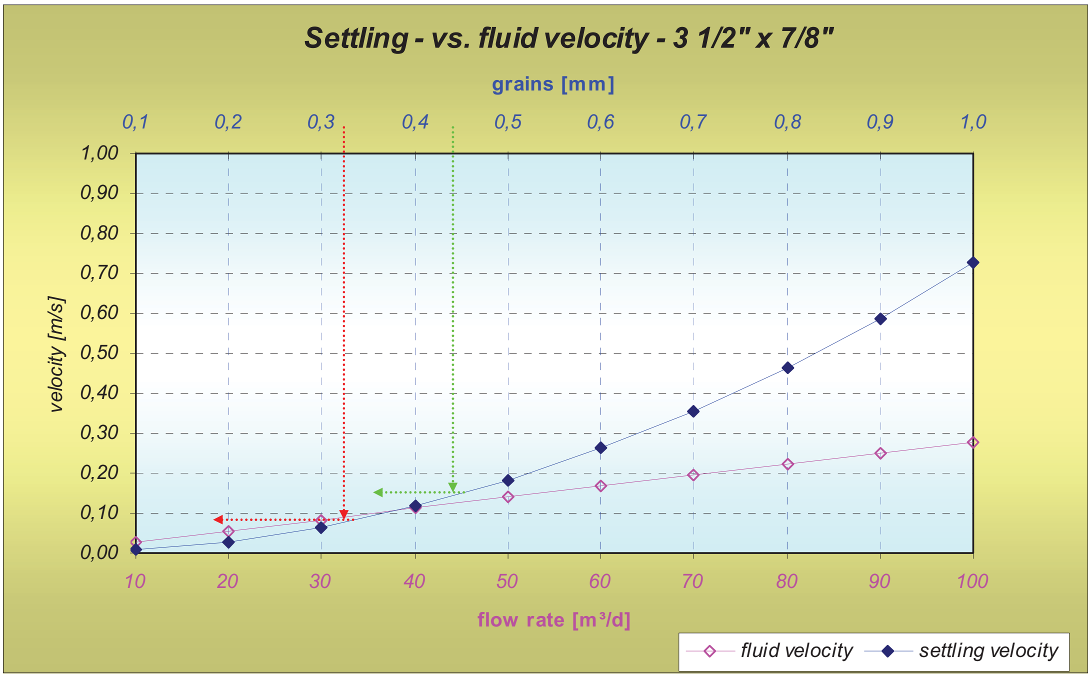


Figure 29 solid settling velocity for 3 1/2" tubing with 7/8" sucker rods

Operation depth

Since PCPs are limited with 340 bar pressure build up [8] with a maximum installation depth of 2200 m assuming the dynamic level just below the pump. This is a big disadvantage to piston pumps; they can produce higher pressures. As a result the pump setting depth is increasing as well. At least to a point where the elongation of the rod string counteracts an efficient displacement process.
The deepest OMV PCP installation is 1551 (Ma 294) therefore installation depth is not an issue for the OMV PCP wells.

Production rate

Since the Austrian oil field is a brown field many wells have low production rates and high potential to be pumped off. If the well is pumped off the pump can be quickly damaged since the cavities are not completely filled with liquid, resulting in heat generation which cannot be removed. Besides higher torque due to friction (lubrication) the stator elastomer can be burned. The pump looses its sealing capacity and needs to be changed.
The critical minimum production rate needs to be evaluated individually for each well. It is recommended to run the pump at low speed after start up and continuously measure the dynamic level which should be at least 100m above the pump. When the level is stable the pump rate can be increased in small steps according to the dynamic level response.
The situation is getting dangerous if the pump is running at high rpm because at some point the drive head at the surface starts vibrating. The maximum rpm that can be achieved with today's PCPs is 500 rpm. OMV found their individual optimum rpm range without any vibrations at 170 rpm. The variable speed drive (VSD) is operating from 100 to 300 rpm. Though all OMV PCP Driveheads should be saved against vibrations, see fig.6.

Figure 30 protection against vibrations for Drive Heads

Gas

There are two types of gas which are produced, the free gas which is in the reservoir at initial conditions (gas cap) and the dissolved gas where the pressure in the well drops below the bubble point pressure gas comes out of solution. Depending on the viscosity of the crude this gas will flow as a separate phase or it will be trapped in small bubbles within the crude. The second case is likely to happen in high viscous crudes. Gas in a PCP results in a decrease in volumetric efficiency simply because the space the gas needs in the cavities is reducing the produced fluid volume. Another negative impact of gas in the pump is change in pump friction due to less lubrication. This results in variations of the rod load which can even cause the rod to premature failure.
Since the perforations induce a pressure drop in the crude, at this point gas can dissolve. A pump setting depth below the perforations can act as a natural gravity gas separation. The gas will migrate up due to buoyancy and the liquid will enter the pump intake. If the pump needs to be installed above the perforations a gas separator (see fig.31) can be used.
OMV experienced that though the manufacturers praise their pumps to handle multiphase flow at a gas rate of 1000 Nm³/d the efficiency decreases significantly.

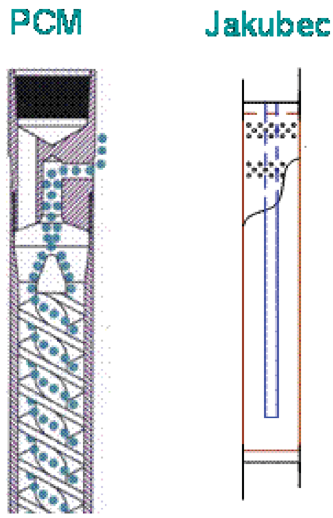


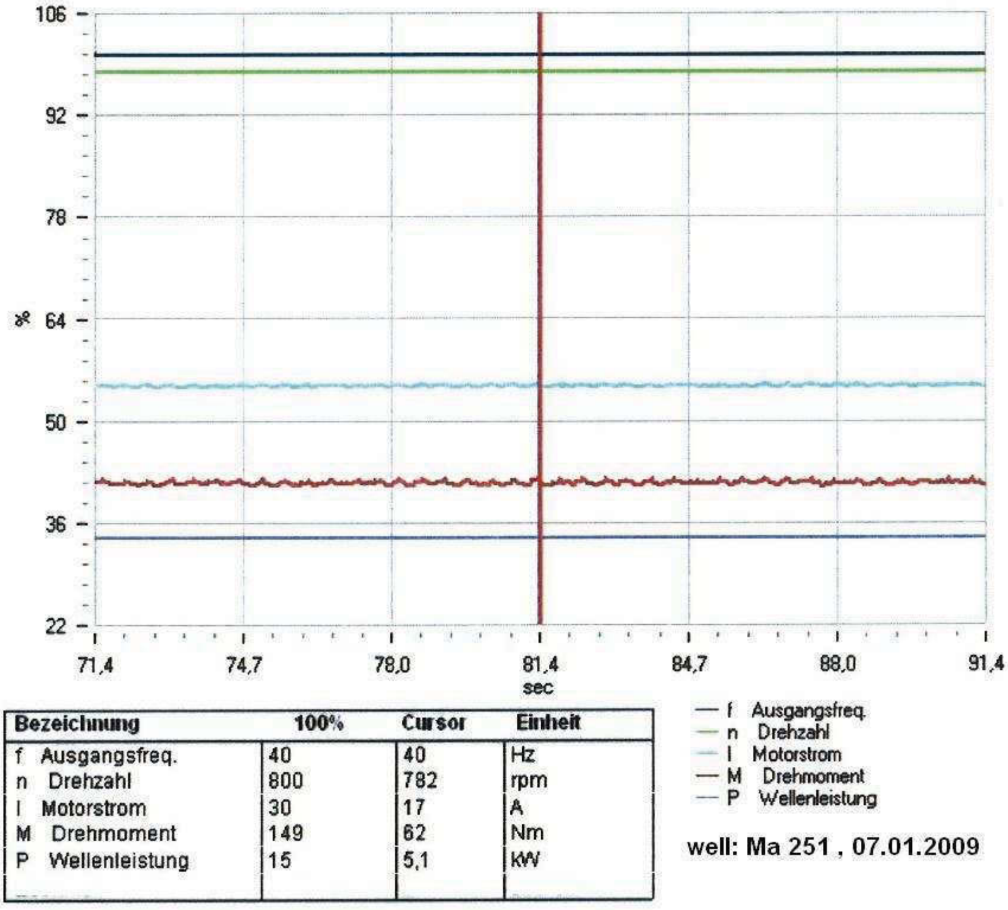
Figure 31 gas anchors

The PCM gas separator uses centrifugal forces to separate the gas from the liquid. This separation of gas before the pump intake prevents that the stator comes in contact with the gas which causes problems especially in case of CO_2 and H_2S. The manufacturer recommends locating the fluid intake below the perforations even if a gas anchor is used.

The Jakubec gas anchor uses gravitational forces to separate the gas from the fluid. The fluid enters the gas anchor through slots. Then the gas will migrate up and the liquid will go down due to the difference in density. The gas leaves the anchor and goes up into the annulus while the liquid enters the pump via the blue pipe inside the gas anchor. Gas anchors or separators can be used in combinations with different artificial lift methods like sucker rod pumps, electric submersible pumps or progressive cavity pumps.

Failure analysis of installed pumps

A helpful tool to do failure analysis for PCPs is to look at the operating parameters from the frequency inverter. These parameters can be torque, frequency, current, power and/or rpm. For good analysis it is important to compare the set value with the actual value. In the oilfield OMV uses frequency inverters from pDRIVE, they provide a software called MatriX to monitor and archive these parameters 200 seconds are the maximum monitoring time.



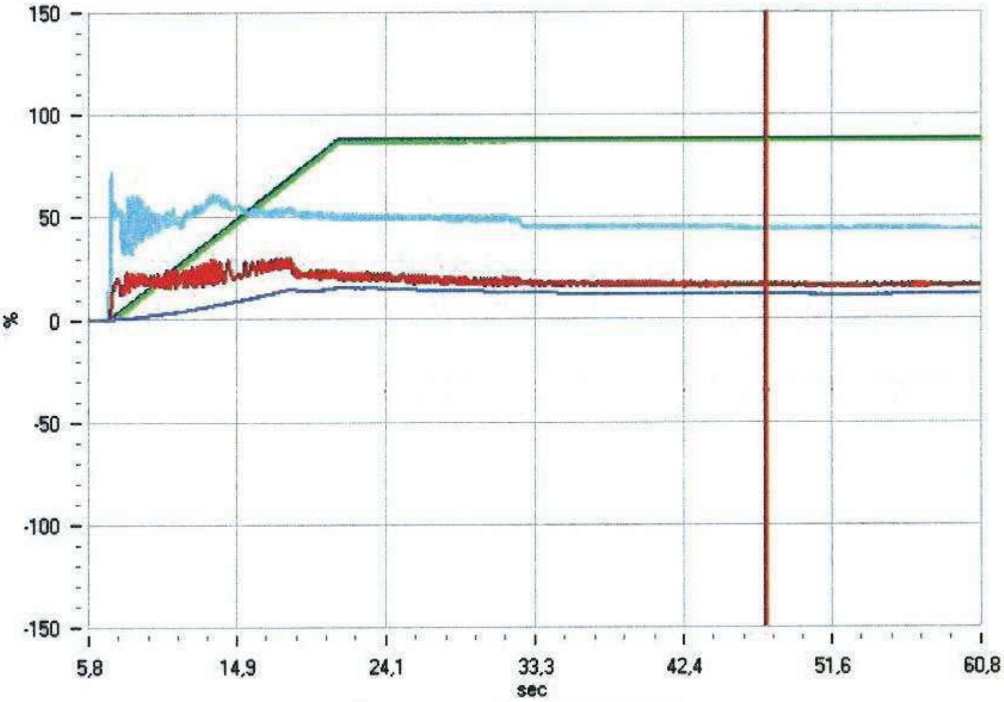
Bezeichnung	100%	Cursor	Einheit
f Ausgangsfreq.	40	40	Hz
n Drehzahl	800	782	rpm
I Motorstrom	30	17	A
M Drehmoment	149	62	Nm
P Wellenleistung	15	5,1	kW

Figure 32 monitored PCP operation (Ma 251)

Fig. 32 is an example of a normal operating mode. All the parameters are constant over time. With f…output frequency [Hz], n…motor speed [rpm], I… current [A], T…torque [Nm], P…shaft power [kW]. The red vertical line is the cursor which can be shifted over the monitored time. It shows the actual value at a specific monitoring time. In figure 30 the cursor is set at 81.4 seconds. Frequency, rpm, current, torque and power for this time can be seen in the table below the diagram. The 100 % stands for the maximum output.

Figure 33 shows a start up of a pump. The output frequency is increased continuously until the set value is reached. The current and the torque is fluctuating until it stabilizers after some seconds.

Figure 34 shows an inefficient operating mode of a pump.

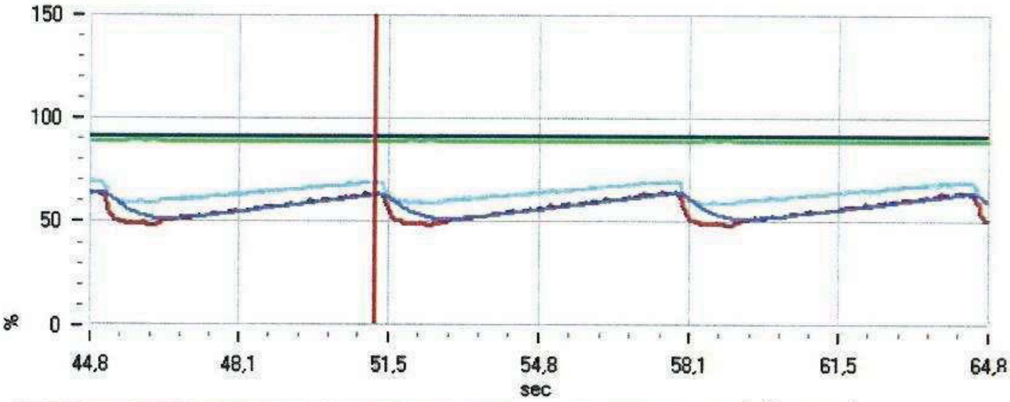


Bezeichnung	100%	Cursor	Einheit
f Ausgangsfreq.	40	35	Hz
n Drehzahl	800	693	rpm
I Motorstrom	31	14	A
M Drehmoment	149	24	Nm
P Wellenleistung	15	1,8	kW

— f Ausgangsfreq.
— n Drehzahl
— I Motorstrom
— M Drehmoment
— P Wellenleistung

well: Ma 210 ; 16.04.2008

Figure 33 monitored start up of a PCP (Ma 210)



Bezeichnung	100%	Cursor	Einheit
f Ausgangsfreq.	55	50	Hz
n Drehzahl	1100	972	rpm
I Motorstrom	30	21	A
M Drehmoment	149	93	Nm
P Wellenleistung	15	9,4	kW

— f Ausgangsfreq.
— n Drehzahl
— I Motorstrom
— M Drehmoment
— P Wellenleistung

well: Ma 251 ; 13.02.2008

Figure 34 monitored PCP operation (Ma 251)

When the clearance between the rotor and the stator is too small (due to elastomer swelling), the rotor screws itself into the stator resulting in a rod elongation. At some point the elongation is too much for the rod string and a sudden pull back out of the stator happens. This screwing-in and pulling-out process influences the torque, which is producing this typical triangular shape like in figure 34. Also it is possible that this condition/shocks are/is damaging the backspin brake in the drive head. Another reason for this screwing process can be bad lubrication due to gas. When the cavities are occupied by a certain volume of gas there is not enough liquid left to remove the heat due to friction and the elastomer is expanding due to the heat. As a result the fit between rotor and stator decreases and the rotor screws itself into the stator.

Comparison of OMV Austria installations runtime to other companies

Petrom

Petrom is a Rumanian oil company where OMV holds 51 % shares. In May 2009 a meeting was arranged in Ploiesti , Romania for PCP knowledge exchange. Since Petrom is operating many PCPs a comparison is advisable. Table 20 gives a quick overview on comparable parameters and conditions.

	Petrom	OMV
general:		
vendors	Netzsch and Upetrom	Netzsch and PCM
number of PCPs	1759	19
equipment:		
tubing	2 7/8", 3 ½" , 3 1/2" relined (few)	2 7/8", 3 ½" , 3 1/2" relined
rod string	7/8"	7/8"
centralizers	designed by CFER software	partially
pup joint	no	yes
torque anchor	yes	yes
drive head	Neptun	Netzsch
VSD	no	yes
elastomer	NBR and HNBR	NBR and FKM
operating conditions:		
depth	average 800m ; max. 2000m	average 1100m ; max. 1500m
GOR	0-100 Nm^3/m^3	up to 1000 Nm^3/m^3
rpm	100-250	100-300
sand problems	small	big
break down:		
MTBF	**163 days (2008)**	**271 (2008)**

Table 20 comparison of OMV and Petrom (status April 09)

While OMV is supplied with PCPs from Netzsch and PCM, Petrom gets their PCPs from Netzsch and Upetrom. The amount of 1759 PCPs in Petrom is high compared to the 19 PCPs OMV is operating. Looking at the distribution of failure mechanisms is difficult if there are not many wells; statistics have to be used with caution if the amount of PCP wells is too low. Also the time when the PCPs were installed the first time is an important factor to look at. OMV operated the first PCP in 2003 while Petrom already started in 1994. Having 6 years of experience with a new technology or 15 years makes a difference. Therefore the distribution of failure mechanisms of the Petrom wells is much more comparable than the OMV wells. On the other hand the documentation in Rumania is questionable. Here OMV does definitely have an advantage even if OMVs documentation for PCPs can be improved significantly. In one of the later chapters the documentation will be discussed in more detail. If we compare the Mean Time Between Failure (MTBF) OMV has 271 days and Petrom has 163. MTBF is the average time between break down of a system, in this case the PCP wells. A MTBF of 271 days means that a PCP well is operating in average 271 days before a break down occurs. To compare this with a sucker rod pumping unit in OMV, the MTBF equals 1298 days for the year 2008. While a sucker rod pump is running 3.5 years on average a PCP is only running 9 months. The next figure shows the different MTBF for sucker rod pumps, PCP and ESP from 2003 to 2009. For 2009 the actual values are used, variations are expected until the end of the year. It has to be mentioned that OMV is installing ESP since 2004; therefore the MTBF is increasing each year.

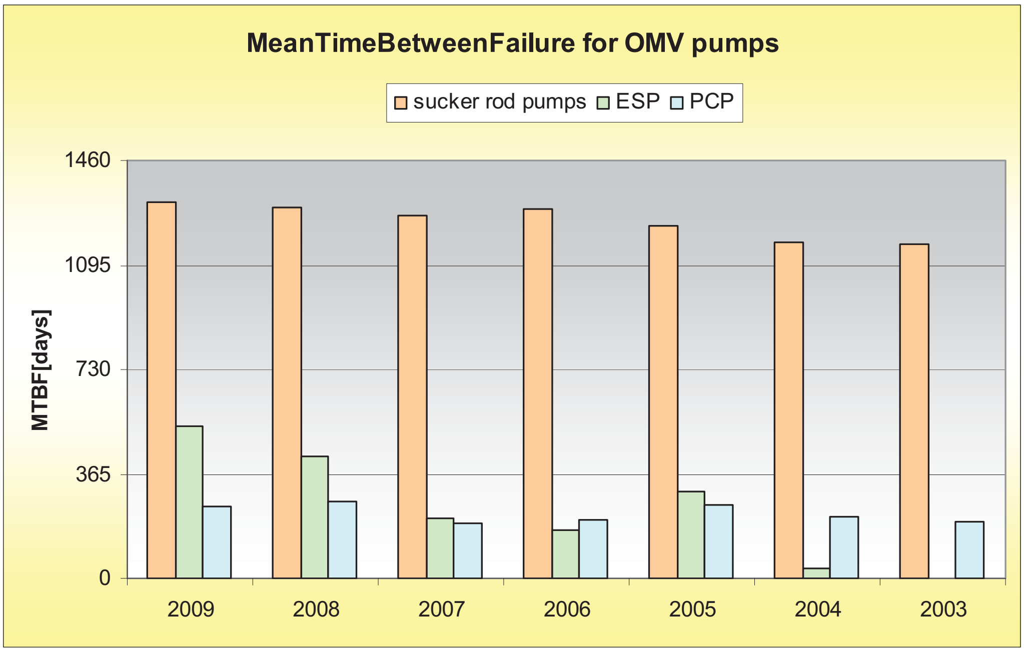


Figure 35 MTBF for OMV pump assisted artificial lift wells

The high MTBF of the sucker rods show a relative constant behaviour with a small increase over the last 6 years. Also the ESP pumps show an increase of MTBF, while the PCP MTBF stays more or less the same over the last 6 years.

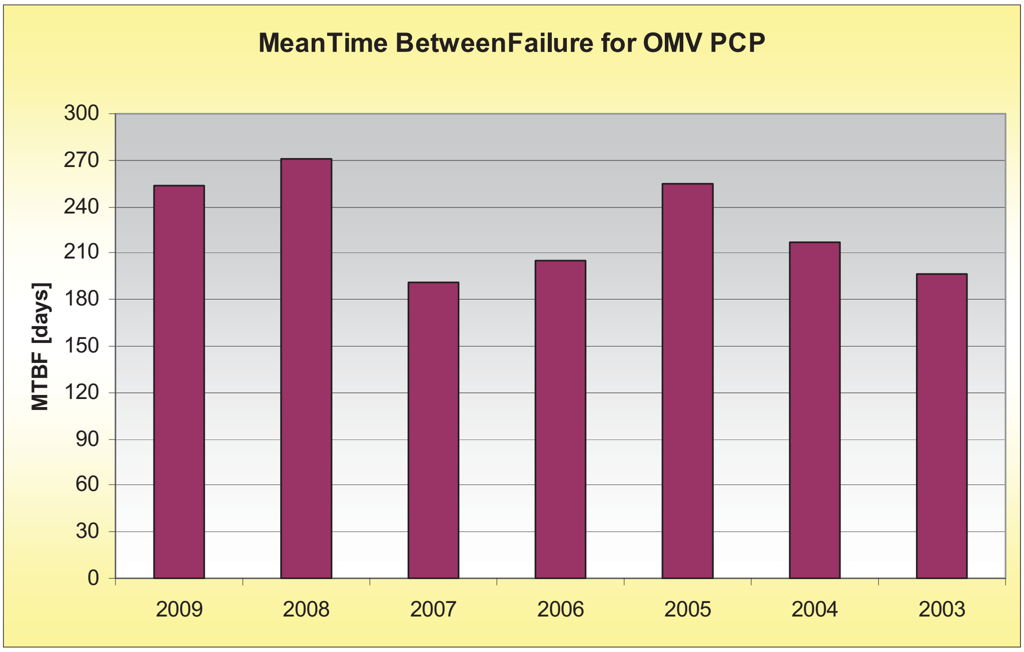


Figure 36 MTBF for PCP in OMV

RAG

RAG (Rohöl-Aufsuchungs Aktien Gesellschaft) is the second Austrian oil company besides OMV. RAG uses PCPs for gas well deliquification. They have three wells equipped with PCP, where one well is shut down at the moment (July 2009). The MTBF for the wells are between 210 and 240 days, which is 7 to 8 months. The supplier here is again Netzsch and the elastomer is NBR02.
Three wells are not enough to really justify a comparison but at least a rough estimation of OMVs operating range can be done. The MTBF between OMV and RAG do not differ too much.

Spacing procedures and formulae

To ensure optimum pump efficiency the pump needs to be spaced correctly. The end of the rotor has to be at a defined distance “d” to the stop pin (see fig. 56). Elongation due to weight or temperature etc. are responsible that the length that the rod string is lifted at the surface is not equal to this distance “d”. Also elongation in static mode differs from the elongation in the operating mode. Therefore the suppliers have established different formulae to calculate the required length the rod string has to be lifted. OMV did have wells/situations where the rotor was touching the stop pin which was resulting in a pump shut down even when taking into account all the spacing procedures during the installation. The following chapter will deal with the concept of these formulae and the factors which are included in these calculations.

Netzsch spacing procedure

Netzsch recommends to lift the rod string up the length “Y”:

$$Y[cm] = \frac{\Delta p \cdot L_0 \cdot k}{1000} + d + L_{static} \cdot 12 \cdot 10^{-6} \cdot (T_{fluid} - T_{air}) \cdot 100,$$

With Y [cm]…distance to lift
Δp [bar]…actual pressure differential
L_0 [m]…Length of rod string

k [-]… spacing factor(see fig.57 and fig.58)
d [cm]…distance to the stop pin under pressure load in accordance to the pump pressure capacity (recommended spacing);
L_{static} [m]…static fluid level
T_{fluid} [°C]…fluid temperature
T_{air} [°C]…average air temperature inside the empty tubing

d is recommended 30 cm if the pump pressure capacity is up to 120 bar and d is 50 cm if the pump pressure capacity is more than 120 bar.

The sucker rod experiences elongation first due to its own weight (Wr) which amplitude depends on the depth or length of the string.
Following, when the pump is running, a downward axial load is generated on the rotor as a consequence of the pumping action, also stretching and lengthening the entire rod string column. Depending upon how far the rotor end is from the stop pin, the sucker rod diameter and the differential of pressure across the pump, the pumping action can cause the rotor to reach the pin. The axial load (L), from reaction to pumping action, is determined by the area of the rotor (a_e), that effectively lift the fluid, and the actual required discharge pressure (P_d) delivered by the pump in operation:

$$a_e = \frac{\pi}{4} \cdot (D_{rotor}{}^2 - 654 \cdot 16 \cdot d_{Rod}{}^2),$$

$$L = a_e \cdot P_d,$$

Then, the total axial load (Lt) on rod string, shall be written as:

$$Lt = L + Wr,$$

or

$$Lt = (a_e \cdot P_d) + Wr,$$

However, considering that extension on rod string caused by the weight of rods (Wr) is already in place when the rod string is fully supported by the drive head, actually the lengthening on rods occurs when the pump is running due to pumping action only:

$$L = Lt = a_e \cdot P_d,$$

To determine the elongation on a rod string due to strengthening caused by the pumping action, the Hook's law shall be applied. Then:

$$\frac{\Delta\lambda}{\lambda_0} = \frac{\sigma}{E},$$

or

$$\Delta\lambda = \frac{\sigma \cdot \lambda_0}{E},$$

where $\Delta\lambda$ represents the elongation of the original rod string length λ_0, under current operational conditions, E is the Young's Modulus and σ is the tension originated by the axial load (L), due to pumping action, on the cross section area of the rod string.
The elongation $\Delta\lambda$ caused by the pumping action, as mentioned earlier, interferes in the distance between rotor end and stop pin. For this reason, when spacing a PC Pump an additional safety length d must be considered to allow the system to work properly. Therefore, the total spacing Y shall be written as:

$$Y = \Delta\lambda + d,$$

The above concept of elongation due to axial load is used by NETZSCH to establish the calculation for spacing presented on fig. 4 & 5, which considers the pumping action caused by a specific NETZSCH PC Pump:

$$Y = \frac{\Delta P \cdot \lambda_0 \cdot k}{1000} + d,$$

being ΔP the actual differential of pressure across the pump, in kgf/cm² or bar, λ_0 is the original length of rod string (or the length of tubing string until the pump is set), in meter, k identifies the spacing factor that includes the elongation due to the pumping action and d, as mentioned earlier, is the desired target distance between the rotor end and the stop pin while the system is in operation. The value of Y is obtained in cm.

NETZSCH has standardized the value of d depending upon the maximum pressure capability for each pump; 30 cm if the pump pressure is up to 120 kgf/cm² and 50 cm if the pump pressure is above 120 kgf/cm².

Elongation When Using Tubing Anchor – Calculations & Spacing

Additional length (e) has to be added to the recommended distance (Y) when performing spacing in completions where tubing anchor are used. This procedure is necessary to avoid that the expected differential thermal expansion of the rod string, relatively to tubing column, causes the rotor to reach the pin. It may happen because the sucker rod string may extend freely by the temperature while the tubing, locked by the anchor, remains practically stationary. Considering a linear thermal expansion of the rod string:

$$\frac{\Delta \lambda_\theta}{\lambda_0} = \alpha \cdot \Delta \theta,$$

or

$$\Delta \lambda_\theta = \lambda_0 \cdot \alpha \cdot \Delta \theta,$$

where $\Delta\lambda_\theta$ is the elongation caused on rods by the average temperature $\Delta\theta$ from bottom hole to wellhead, and α is the linear thermal expansion coefficient of the material of the rods. Certainly that fluid thermal gradient varies along the tubing string, consequently the overall thermal expansion of the rods shall be different from the calculus. However, the assumption of average temperature as described has been proven to be fairly acceptable for practical purposes.

The value of (e) shall be written as:

$$e = \Delta \lambda_\theta = \lambda_0 \cdot \alpha \cdot \Delta \theta,$$

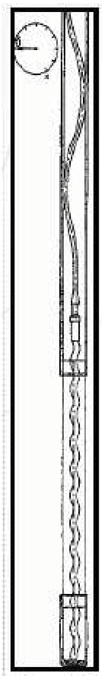
being expansion (e) on rods by temperature if the tubing string is anchored. Therefore the total spacing (Y) when the tubing string is anchored, by tubing anchor, considers both effects: pumping action and thermal expansion:

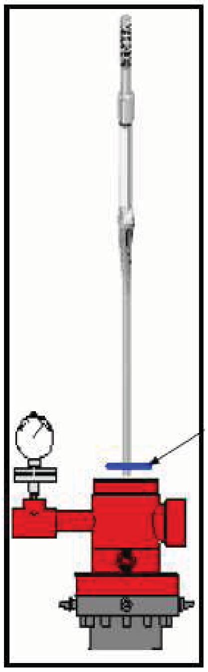
$$Y = \frac{\Delta P \cdot \lambda_0 \cdot k}{1000} + d + e,$$

PCM spacing procedure

The PCM spacing out procedure is a more practical one. PCM recommends the following steps during spacing out a pump:

1) Record the total weight of the string.
2) Run in the rotor into the stator, good indication is the rotation of the string when running into the stator





3) When the rotor reaches the stop bushing the weight should be zero, tag this position on the sucker rod string (see left figure).
4) Run in & out of the stator a few times, to be sure that the "**Zero String Weight Tag"** is always in line with the well head.
5) After marking the Zero String Weight Tag, pick up the Rod String very slowly until the Total String Weight is observed again. At this point, the Rotor is still inside the Stop Bushing but not sitting in it. Tag the Sucker Rod – This tag will be the "**Total String Weight Tag**".
6) Pick up the Rod String another 30 cm more and tag it. This tag will be the "**Stop Bushing Tag**" This indicates that the Rotor is out of the Stop Bushing.
7) The last tag of the space out will be the value calculated by **PCM's WinPetro Software** + a safety margin of 25 – 30 cm. This last tag will be the "**Space Out Tag**" and break one or 2 rods depending on the location of the last tag. Hydraulic Stretch + Thermal Stretch.
8) Lay the Polished Rod Assembly beside the Sucker Rod which was Tagged and place the Last Tag (Tag 4) parallel with the Polished Rod Tag. If the length of the Polished Rod exceeds the length of the Sucker Rod – Break out another Sucker until it exceeds the length of the PR. Add a Centraliser at the end of the PR and fill in the remaining length with Pony Rods. Add the Pony Rods to the Rod String.

	Netzsch	PCM
Thermal elongation	$\alpha \cdot \Delta\theta \cdot \lambda_0$	Software Winpetro
Hydraulic elongation	$\frac{\Delta P \cdot \lambda_0 \cdot k}{1000}$	Software Winpetro
Elongation due to weight	No given formulas, done by experience in the field	Tagged in the field (zero string weigth tag)

Sucker rod torque calculation

An excel sheet has been developed for torque calculations based on the equations in the Petroleum Engineering Handbook Volume 4 (2007) which were handled in one of the previous chapters. The sheet was then used for existing OMV PCP wells, the values are in the same range like calculated with the Winpetro software.

High torque can be induced by elastomer swelling. When the fit between the rotor and the stator is too tight the drive head will rotate the string but in the pump the rotor will not rotate in the stator anymore. Therefore a torsion force will be in the string. If the drive head keeps rotating until the string breaks the torque will be released at once. To

prevent this it is advisable to install a torque limiter. This device will stop at a pre defined torque and the pump is shut down. Even though there will be torque left in the string. Then the backspin brake will allow for controlled back spin to release the torque from the string.
The following equations are from the previous chapters, the abbreviations can be found there. The torque in the string is the sum of the following components:

$$T = Th + Tf + Tv,$$

T…total torque [Nm]
Th…hydraulic torque [Nm]
Tf…pump friction torque [Nm]
Tv…pump viscous torque [Nm]

The viscous pump torque can be estimated with the following formula:

$$T_v = 2.4 \cdot 10^{-6} \cdot \mu_f \cdot L \cdot N \cdot \frac{d^3}{(D-d)} \cdot \frac{1}{\ln \frac{\mu_s}{\mu_f}} \cdot (\frac{\mu_s}{\mu_f} - 1)$$

The pump friction torque can be calculated the following way:

$$Tf = C \cdot V_0 \cdot (0.2 \cdot p_{\max}),$$

The pump friction torque depends on parameters like interference fir between rotor and stator, rotor and stator material (coating), pump length and fluid properties. Therefore it can only be established empirically from bench test results

$$Th = C \cdot V_0 \cdot p_{lift},$$

The hydraulic pump torque is necessary to overcome the differential pressure from the pump.
The excel spreadsheet was tested with a well which was designed with Winpetro software. The result from the software was 170 Nm for the total torque and the spreadsheet gave a total torque of 165 Nm.
If the result is compared with the monitored torque from the MatriX software a big difference can be observed, since the monitored torque is calculated with the following formula

$$M = \frac{P \cdot 9550}{rpm}, \tag{19}$$

M…torque [Nm]
P…power [kW]
The problem with this equation is that the rpm are measured at the surface. If we consider the well depth and compare it with the diameter of the rod string it can easily be understand that the rpm at the surface are not the same like the rpm down hole at the pump. Down hole the rpm are decreasing due to friction which results in a higher torque than the monitored one.

Centralizers

To avoid contact of the drive string with the tubing centralizers can be installed. They prevent that the sucker rod string will shear on the inner wall of the tubing.

Two types of centralizers exist. First there are rotating centralizers (RC), they are directly mounted/injected on to the rods and secondly there are the non-rotating centralizers (NRC) which are screwed between two rods.
A sucker rod string with RC from OMV is undergoing the following stages; in the beginning the empty sucker rod is manufactured by Tenaris and then transported to Himberg (Austria) where the Company Ebenhöh is attaching the centralizers. Afterwards the sucker rod string with the attached RC are sent to the OMV pipe yard in Prottes (Austria).
Two types of RC have been used by OMV; the difference is defined by the shape of the wings. The wings are either parallel to the rod string (see fig.37a) or spiral grooved (see fig.37b). The intention behind the spiral grooved wings is the continuous contact area with the tubing wall. The parallel wings are better for axial rod movement and the spiral grooved wings are better for radial rod string movement.

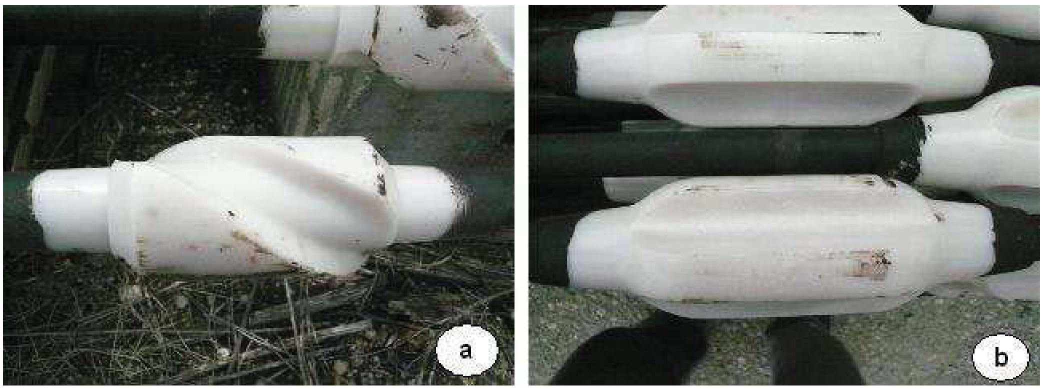


Figure 37 rotating centralizers

A non-rotating centralizer (NRC) acts like a bearing. While the drive string is rotating the non-rotating centralizer is not moving. The NRC is screwed between two sucker rod strings which results in the advantage of easy attachment. While the RC is shearing at the inner tubing wall the NRC keeps the rod string in place without damaging the tubing. NRC are available with parallel or spiral grooved wings.

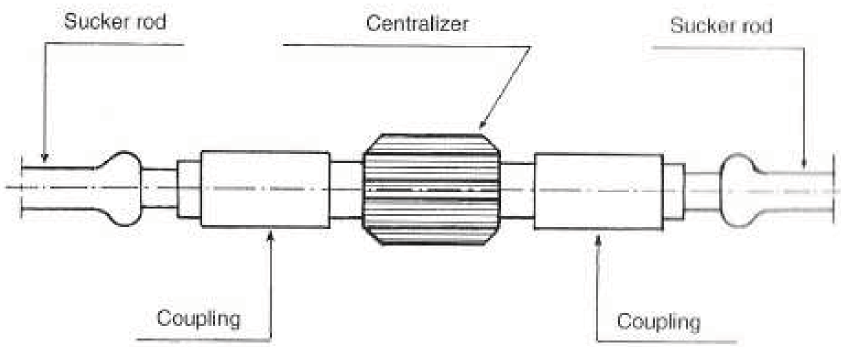


Figure 38 non-rotating centralizer [6]

OMV tried all kind of centralizers in their PCP applications/completions but observed an even higher/faster damage on the tubing wall. The protectors were shearing at the tubing wall which results in a reduction in wall thickness and finally in a leaking tubing string leading to a workover. Sand is influencing the working principle of the NRC and the RC. If the sand manages to find its way between the centralizer and the tubing wall the centralizer will shear the sand into the tubing resulting in erosion.

Figure 39 non-rotating centralizer and the impact on the tubing wall

Relined tubing

Relined tubing is an oil field pipe with a polymer liner inside. This liner protects the pipe and reduces the friction in case of contact with a centralizer or the rod string itself. Three different liner materials have been used by OMV. The first one was called PE100 which was used until 2006. Then the material PEX B was used until 2008 and for the future a new material PEX A is intended to be used. The manufacturer of these liners is Agro (Borealis). At the pipe yard in Prottes (Austria) the liners are fit into the pipes by the company Rabner. Usually OMV applies this technique only with 3 ½” pipe; adding the liner wall thickness results in an inner/drift diameter of 62 mm which is the same like for a conventional 2 7/8” tubing.

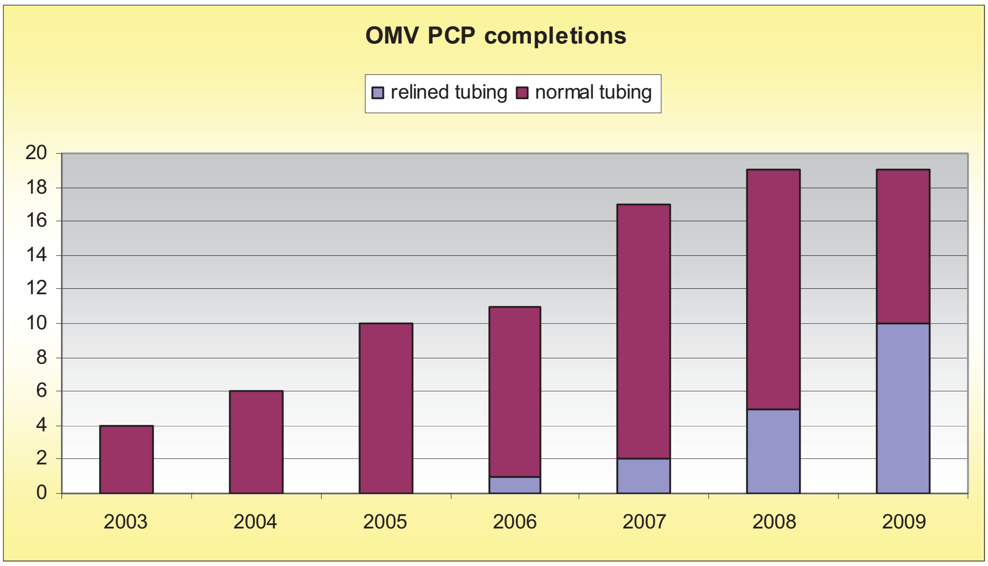


Figure 40 OMV PCP completions using normal and relined tubing

Liners

Most of the/Many interventions at PCP wells had to be done as a result of centralizers shearing at the inner wall of the tubing. The consequences are tubing leaks. The company TUBOSCOPE VETCO does pipe inspection for OMV and found out that the centralizers are responsible for this phenomenon. OMV tried many different combinations/types of centralizers; rotating and non-rotating centralizers but all of them were damaging the tubing. In 2007 OMV production department decided not to use centralizers any more to prevent shearing at the tubing. Additionally 3 ½" relined tubing was/is run. The process of fitting the liner into a pipe is simply done by pulling the liner through the pipe and cutting the ends with a small overlap of some centimetres (see fig.41 left pipe) then a hot surface is pressed onto this overlap and a shoulder is created (see fig.41 right pipe).

Figure 41 relined tubing after cutting the liner (right) and after creating a shoulder (left)

The first liners had the problem that due to temperature changes (summer to winter, day to night) the liner started to shrink (see fig.42) and the shoulder was pulled inside the pipe, thus leading to a reduction in drift diameter.

Figure 42 relined tubing with shrunk liner

This strong dependency of the PE 100 liner is a big problem. Therefore the material was changed to PEX B in 2006 which is more resistant to temperature changes. So far none of these liners created any troubles. It happened once that a relined tubing was collapsing, or to be exactly the liner was collapsing (fig.43) as a result of gas migrating between the liner and the pipe. As soon as the gas starts to expand behind the liner it is forced to collapse.

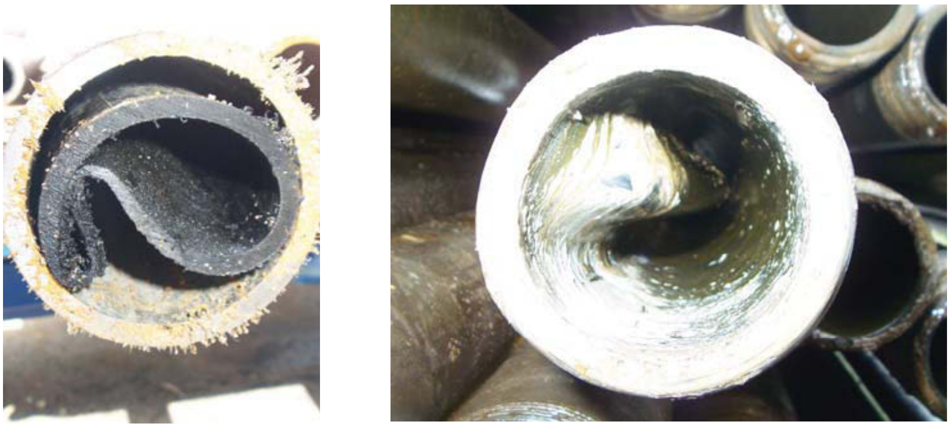


Figure 43 collapse of relined tubing, Pir 96a, June 2008

Elastomer swelling

Stator Elastomers

The most commonly used stator elastomers are Nitril-rubber (NBR), hydrogenerated Nitril-rubber (HNBR) and Fluor-rubber(FKM). The selection of the right elastomer varies on each individual well, in order to choose the correct material it is recommended to do compatibility tests. Many factors are influencing the behaviour of the elastomer, as there is temperature, pressure, chemical composition of the produced fluid, sand content, gas content. The wrong elastomer can lead to pump failure and damage immediately, therefore it is important to do some research before selecting an elastomer. The following part will deal with each of the elastomer types in detail to give an overview of the advantages and disadvantages.

Nitril-rubber (NBR)

Most elastomers in PCPs can be classified as conventional nitrile (NBR). The base polymers for these elastomers are manufactured by emulsion **polymerization** of butadiene with acrylnitrile(CAN). CAN contents in nitrile elastomers typically vary from 30 to 50%, with the cost of the elastomer increasing marginally with increasing CAN level. Most manufacturers distinguish between a medium nitrile (sometimes called Buna, which typically has an ACN content < 40%) and a high nitrile (> 40%). Increasing CAN levels produce increasing polarity, which improves the elastomer's resistance to nonpolar oils and solvents. However, higher CAN levels result in increased swell in the presence of such polar media as esters, ketones, or other polar solvents and leads to a decline in certain mechanical properties. It is important to note that aromatics such as benzene, toluene, and xylene swell NBR elastomers considerably, regardless of CAN level.

NBR elastomers are normally sulphur cured, and the combination of sulphur with the natural unsaturation of the elastomer can result in additional cross-linking and associated hardening in the presence of heat. As a result, NBR elastomers are not recommended for continous use at temperatures that exceed 100°C (212°F). For a similar reason, NBR elastomers also are not recommended for applications that contain high levels of H2S because the sour gas contributes additional sulphur, which leads to post-vulcanization and surface hardening. These changes result in a loss of resilience and elasticity, typically causing premature stator failure.

Hydrogenated Nitril-rubber (HNBR)

Conventional NBR elastomers, especially when sulphur cured, often contain a large degree of unsaturation in the form of double and triple carbon-carbon bonds in the base polymer. Relative to a more stable single bond, these unsaturated hydrocarbon groups are susceptible to chemical attack or additional cross-linking. This is the primary reason why NBRs experience problems upon exposure to high temperatures, H2S, and aggressive chemicals.

Though a hydrogenation process, it is possible to increase the saturation (i.e. decrease the number of double and triple carbon-carbon bonds) of the NBR polymer, thus stabilizing the associated elastomer. The degree of saturation can vary, but typically it is > 90% and can be as high as 99.9%. If the saturation is very high, then a sulphur cure system is no longer effective, and a peroxide cure must be used. These compounds are typically referred to as highly saturated nitriles (HSN) or hydrogenated nitriles (HNBR). For an equivalent volume, the cost of an HNBR elastomer is typically four times that of a conventional NBR, making the stators made from such an elastomer considerably more expensive.

The primary advantage of a HNBR is increased heat resistance. Sulfur-cured HNBRs can ideally be used up to 125°C (257°F), whereas higher-saturation peroxide-cured compounds can potentially be used in applications with temperatures up to 150°C (300°F). Other advantages, especially if the elastomer is peroxide cured, include improved chemical resistance and H2S tolerance. The meachanical properties of HNBR elastomers usually are similar to those of NBR elastomers.

Most PCP manufacturers offer HNBR stators, but the limited numbers of applications that warrant the higher cost have kept their use to relatively low levels. Historically, the HNBR polymers have been highly viscous and difficult to inject into stators, increasing manufacturing costs substantially. However, within the last few years, the polymer manufacturers have introduced lower-viscosity, high ACN HNBR elastomers. As a result, pump manufacturers have taken a renewed interest in these elastomers, which may lead to more use of HNBR compounds in stator products in the future.

Fluor-rubber(FKM).

FKMs have been expanding in availability and use over the last decade. Although a number of different varieties of FKMs are available, common to all is the presence of high levels of fluorine that saturate the carbon chain. The carbon-fluorine bonds in FKMs are extremely strong, giving this formulation heat and chemical resistance superior to that of most other elastomers.

FKMs are, to a large extend, made up of the fluoro-polymer and thus contain a low level of fillers and additives. As a result the mechanical properties of FKMs tend to be inferior to those of NBR and HNBR elastomers. In terms of chemical stability, they have excellent resistance to heat, although their mechanical properties tend to deteriorate further at high temperatures from already relatively low initial levels. A variety of cure systems are used for FKM elastomers, including peroxide, but they require an extended post-curing session to optimize their properties, adding considerably to manufacturing process costs. As a result, the cost for an equivalent volume of FKM elastomer may range from 20 to several hundred times that of a conventional NBR. This makes all but the lower-cost grades of FKMs uneconomical for PCP stators, and even those that are useable carry a high cost premium.

The primary advantage of an FKM elastomer is the increased heat and chemical resistance. FKM elastomers have the potential to be used up to 200°C as long as they are not subject to excessive mechanical loading (proper sizing of PCP is critical). In terms of fluid resistance, they have minimum swell with most oil field fluids, including aromatics which is the opposite OMV experienced in the field. Wells with a high water cut showed a tendency for elastomer swelling.

General use of FKM elastomers in PCP applications is relatively recent, with several PCP manufacturers now offering these products. Some success has notably been encountered in lighter oil applications in which NBR stators swell, necessitating multiple rotor changes. Despite being expensive, FKM stator products appear to be useable in certain applications, especially if the pumps are sized properly and extended run times are achieved.

OMV Stator Elastomers

All Netzsch PCPs in OMV are equipped with a FKM stator elastomer (451). Netzsch recommended using the NBR 286 elatomer but OMV insisted on using the FKM 451.
Today PCM provides OMV an NBR stator elastomer (159).

In 2002 OMV did compatibility tests in their laboratory for elastomer selection. Different elatomers from Netzsch, Baker Centrilift and Weatherford have been investigated/tested. The crude sample was taken from the well Schönkirchen 239 (horizon 209 91). Five wells from the actual PCP installations are producing from this horizon; Schönkirchen 039,127,230,263 and Prottes 202. According to the test result the FKM 451 from Netzsch was recommended but other options were mentioned as well due to its high costs.

In 2007 the University in Erlangen-Nürnberg did compatibility tests with Netzsch as their sponsor/orderer. The crude sample was from the horizon 213 B31. Two wells from the actual PCP installations are producing from this horizon; Matzen 236 and Matzen 251. The same Netzsch elastomers have been tested like in the OMV lab-tests in 2002. This test did not recommend the FKM elastomer due to swelling. The NBR 286 was recommended.

Since then many discussions have taken place about the results and the execution of the tests (pressure, temperature,…). The experts have different opinions and it is very difficult to get answer whose test result is right or wrong. Fact is that the FKM elastomer did create problems in the PCP applications, swelling occurred at many wells.

Economics of installed PCP

Figure 44 shows/illustrates that many PCPs have high downtimes. Based on the downtimes and the productive times a small economical study was done.

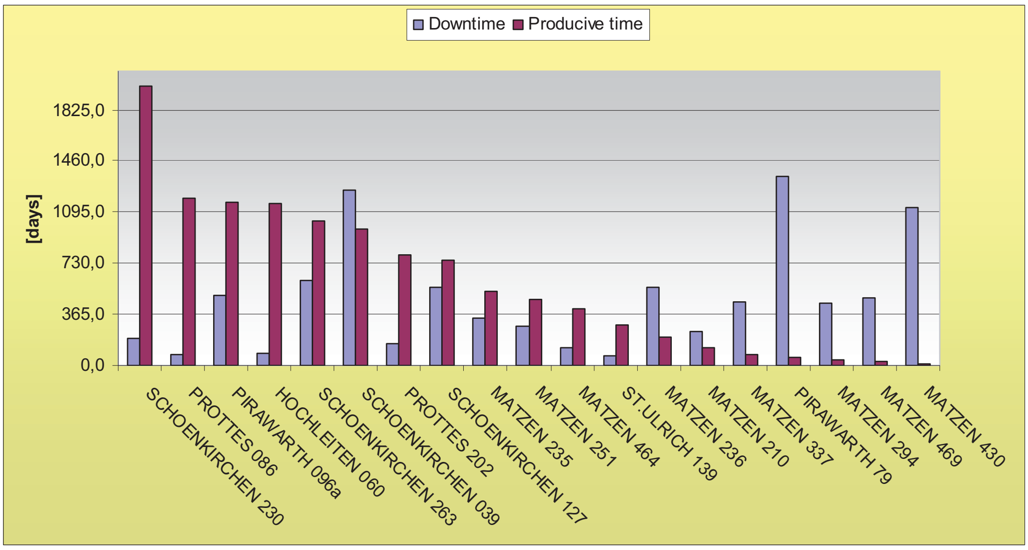


Figure 44 downtime vs. productive time (status 1.4.09)

In order to get a performance indicator of the PCP installations the costs of each well are compared to the revenues. Figure 45 clearly shows that up to 01.04.09 more than half of the wells have a negative cash flow.

To understand the configuration of this study the costs and revenues have to be defined. The costs consist of the workover costs plus the lost production, which means shutdown time multiplied by the averaged PCP oil production. The revenues simply come up with the producing time multiplied by the average produced tons of oil per time (in this case hours) times the oil price (euro per ton oil). It has to be considered that OMV is producing two types of oils which have different qualities. The so called asphaltene oil (A-oil) is calculated with 220 euro per ton and paraffin oil (P-oil) with 250 euro per ton though the oil price is continuously changing. But for simplicity a constant oil price is taken for the calculations. The difference between the two types of oil is the density; while A-oil has a density of 905 kg/m³ the P-oil has 860 kg/m³. The time value of money, the treatment costs of crude oil and the water treatment costs are not included in the calculations. Though for a qualitative analysis of the wells the information is fair enough.

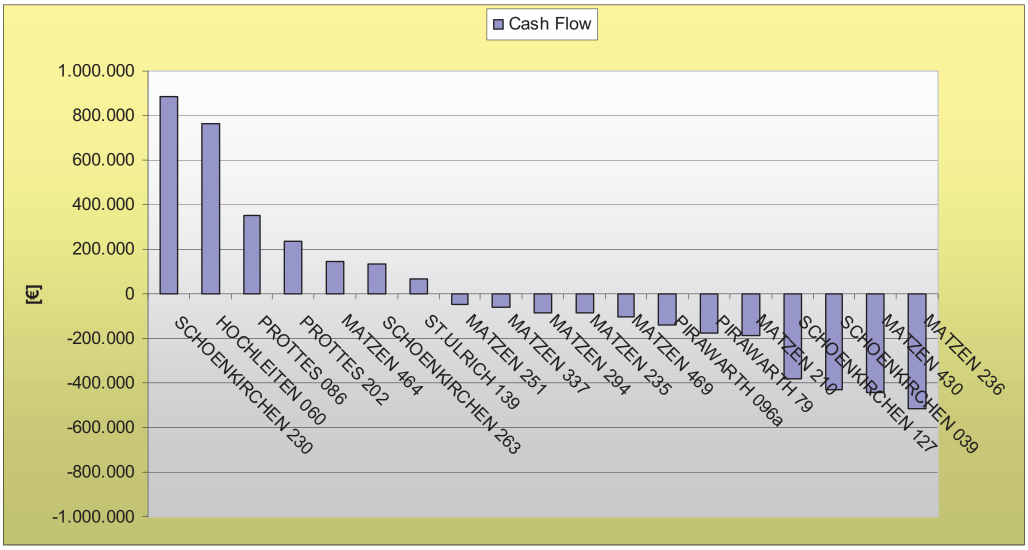


Figure 45 cash Flow for wells with PCP installation (status 1.4.09)

In fig.45 can be seen that only 7 wells out of 19 wells have a positive cash flow. This information alone does not give us an impression about the PCP performance. It is important to look at the cash flow before the PCP was installed. And compare the results to see if there was a decrease or an increase in cash flow. The problem is that many well are already quite old and the installation of the PCP started in 2002. The question arises for which period of time to compare the cash flows. Another problem is that some wells were having high downtimes before the PCP installation because the future artificial lift system had to be defined and designed.

That is what makes the comparison complicated. The data have to be used with caution since a comparison is not reasonable for each case. Anyways, for a rough estimation it works. All wells that received the PCP in year 2006 and later are compared back to year 2000. The PCPs that were installed between 2005 and 2002 are compared back to 1995. For example well St. Ullrich 139 was drilled in 1944 and the PCP was installed in April 2008. That means to get the cash flow before PCP installation; the revenues and costs from January 2000 until April 2008 are sum up. The revenues and costs are calculated in the same way like mentioned before.

In fig.45 the well Schönkirchen 230 has the highest cash flow of all the wells, but in fig. it becomes obvious that the cash flow has decreased to only half of the initial cash flow. It has to be mentioned that the well Hochleiten 60 is not suitable for this comparison; a cash flow before the PCP was installed can not be calculated because it is the initial completion. However, except for the wells Prottes 086 and Prottes 202 all wells have a big decrease in cash flow, especially St. Ullrich 139. Prottes 202 was a gas storage well before the PCP installation. That is why the cash flow in increasing and the relative change in downtime is more than 80%.

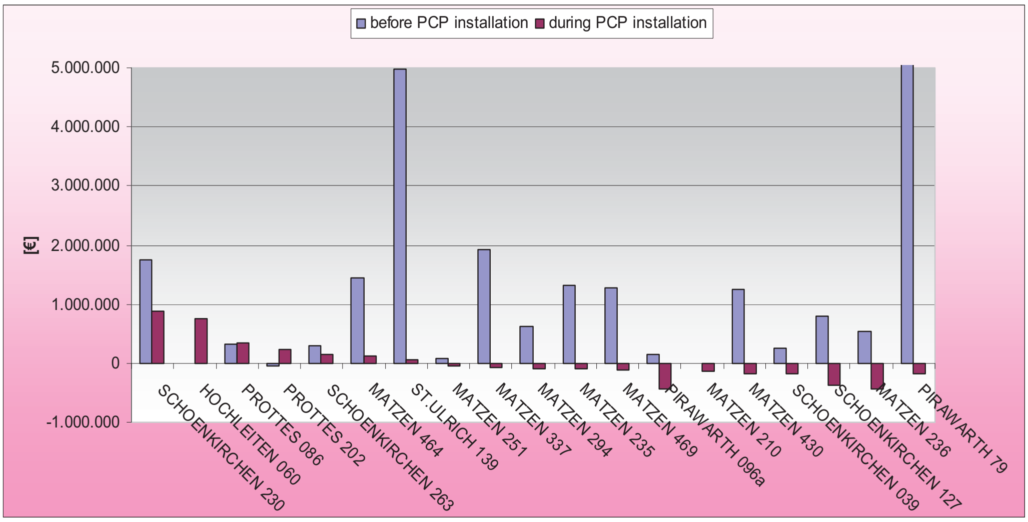


Figure 46 cash Flow comparison (status 1.4.09)

There are two possibilities how this can happen. First, the well has more downtime than before, which means less revenues and more lost production. Second, the well has nearly the same downtime like before or even less, but many workovers and interventions have to be done. The next fig. shows the relative change in downtime, which means the change in percentage compared to the productive time.
For example well Matzen 210 has 79% downtime and 21% productive time before the PCP installation and 66% downtime with 34% productive time with the PCP. That gives a relative reduction in downtime of 13%.

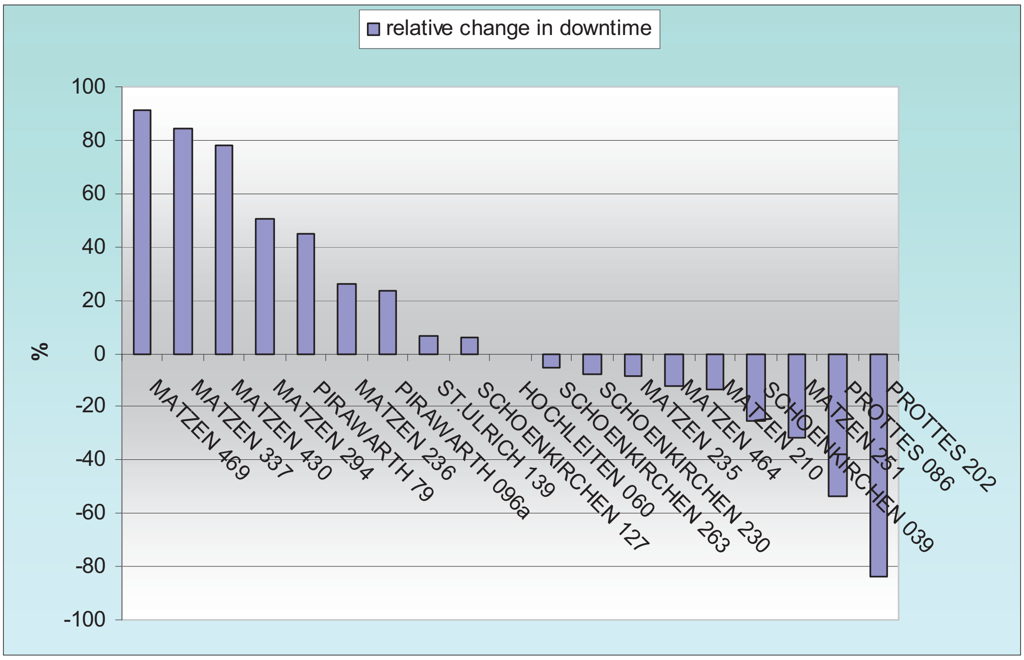


Figure 47 relative change in downtime

Results

Prottes 086. The productive time of the PCP is much higher compared to the down time. Also the cash flow is positive. This two parameters prove this well to be **economic**. Figure 47 shows a small increase in cash flow while figure 48 shows a significant decrease in downtime. This is the result of a two years downtime of the well as a sucker rod pump waiting for a gravel pack because of sand problems.

Hochleiten 60. The well has a very low down time and high productive time and the cash flow is also quite high. This well is **definitely economic**. The first PCP had a running time of three years and the second PCP has now a running time of one year and is still producing today (june 09). Comparison to the installation before is not possible because it has been drilled in 2000 and was completed as an ESPCP which created many problems.

Prottes 202 can be considered as **economic** because it has a positive cash flow and the productive time is much higher than the downtime. The first PCP had a running time of nearly two years and the second PCP has now a running time of one year and is still producing (june 09). Comparison to the installation before is not possible because it was a gas storage well and not a producing well.

Schönkirchen 230 has a downtime much smaller than the productive time and the best cash flow of all PCP wells. Compared to the sucker rod installation the well has reduced downtime with PCP installation but decreased cash flow by half. Taking a closer look at the well showed that even the costs are smaller. It happened that the revenues with the PCP are lower because the oil production rate is much smaller. Between December 1998 and June 2000 the well had an average oil production of 8 tons per day. Since the well was equipped with a PCP the average production is about 3 tons per day. The exact background can be read in the production history of the well in one of the previous chapters. Anyways the well is definitely **economic** and when relined tubing will be installed in the near future the number of workovers will decrease significantly because the running time of the pump is very high compared to the other PCPs. The tubing leaks are the source of failure which can be managed with relined tubing.

Schönkirchen 263 has a positive cash flow, though it was higher with the initial installation. The productive time is nearly double than the downtime.

Matzen 464 cash flow decreased significantly but is still positive. Downtime with PCP is less than half the productive time. Down time is less than with sucker rod pump (12%).

St. Ullrich 139 has a small but positive cash flow. Downtime is slightly higher than before (7%). With the PCP installation the productive time is more than double of the downtime. Since the first PCP was installed in 2008 it is not possible to make any performance analysis. The time period is simply too short.

These seven wells have a positive cash flow, the other 11 wells are not economical. Until 1.4.09 even 8 of them are not even producing, so the cash flow is decreasing each day due to lost production.

From these 11 wells 4 have to be mentioned separately because the wells Ma 294, Ma 337, Ma 430 and Ma 469 are shut down for a long time now. Ma 469 since January 2008. Ma 294 and Ma 337 are shut down since February 2008. The three wells Ma 469, Ma 294 and Ma 337 are shut down because of reservoir problems, so the failure can not be dedicated to the PCP. Ma 430 is a very bad example the well is not producing since June 2006. It was producing for one month, got stuck and is shut down until today. The well is waiting for an Open Hole Gravel pack (OHGP) to fight the sand problems.

Improvement potential for the next installations

Due to many problems occurring with PCP installations OMV decided to bring up a standard for their PCPs:

- Relined tubing 3 ½" (ID 2 7/8") to handle the erosion effect of the solids.
- Sucker rod string without centralizers to prevent shearing of the centralizers on the tubing wall.
- PCM PCP with NBR elastomer instead of Netzsch FKM polymer.
- Above the rotor 1 single sucker rod instead of pony rods to minimize the amount of couplings (which means bigger diameter) to reduce the possibility of having a contact between coupling and tubing.
- Above the pump 1 single 3 ½" tubing (not relined) to increase the diameter again to reduce the possibility of having a contact between coupling and tubing.
- Drive head from Netzsch because so far it is the only one with an ATEX certificate.
- Variable speed drive (VSD) to adjust the production rate.

Additionally to this standard some improvements are possible:

- Slim hole coupling to reduce the possibility of having a contact between coupling and tubing.
- Rpm range has to be in a certain range to prevent vibrations. From field experience 170 rpm have proven to be a good operation mode.
- Enough spare parts of the pumps for quick change to prevent long shutdown time and hence lost production.
- Compatibility test of elastomer with the crude will show if elastomer and crude will match.
- Material check/quality control of the pump in the laboratory would be advisable.
- 1,3 meters rod string lifting out of field experience

So far the effect of installing relined tubing does not show an impact on the amount of workovers. There is no trend that shows an increase or decrease in worlovers. This can be explained by the fact that so far only half of the wells are equipped with relined tubing. Figure 48 shows the amount of workovers per well. That means the amount of workovers is divided by the number of PCP wells. It has to be mentioned that the value for 2009 will change until the end of the year. Looking at figure 48 shows that there is no clear trend, no decrease or increase of workovers per well. Therefore a success of relined tubing or new elastomer (PCM) cannot be approved yet. It is possible to look at the performance of the wells which are equipped with relined tubing or which have installed a pump from PCM instead of Netzsch.

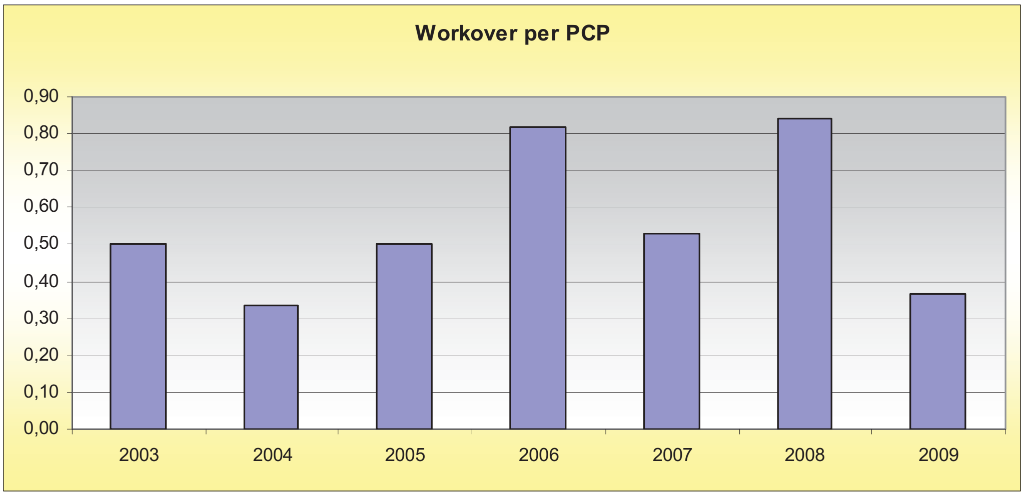


Figure 48 workovers per PCP well

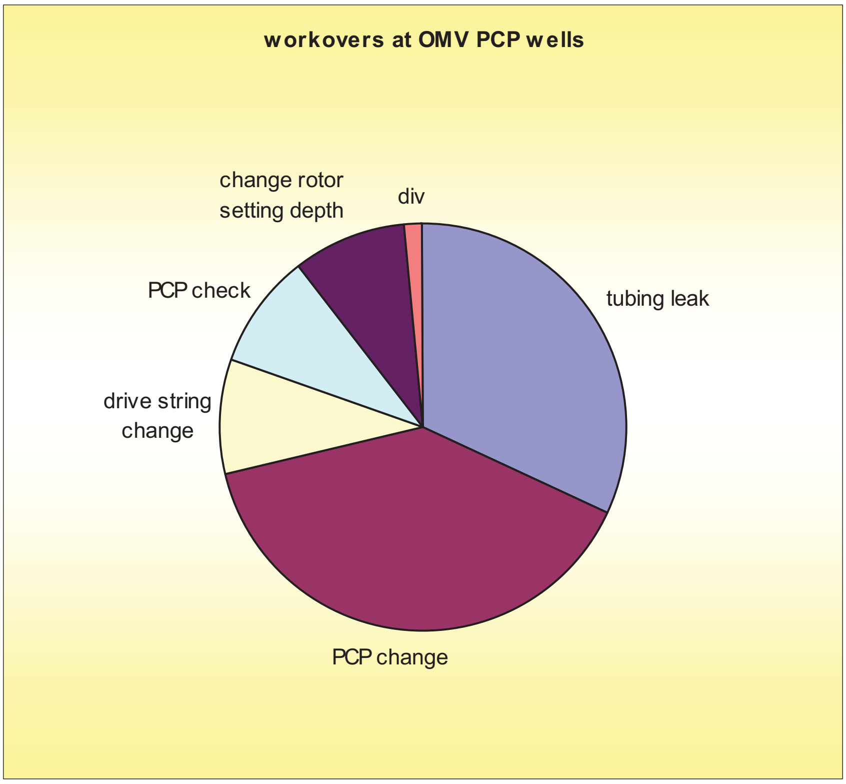


Figure 49 failure mechanisms at PCP wells

Figure 49 shows the failure mechanisms for all PCP wells. It can be seen very clearly that leaking tubing and PCP change makes most of the workovers. These big components can be reduced or even eliminated. The tubing leaks can be fought against with relined tubing and the PCP change can be reduced with the new elastomer from PCM. Figure 70 shows the different reasons for PCP change. Nearly one third of PCP changes have been done without documented reasons. The figure shows clearly that stuck pump and damages stator are the two main components. Figure 50a analyses the failure mechanism of the PCP wells which have been equipped with the stator elastomer from PCM. Compared to figure 49 the failure mechanism PCP change is reduced by half. The PCM elastomer is used since 2008. From there 5 workovers at new equipped wells took place. One of these 5 workovers was a PCP change and that was only happening because of a manufacturing problem. Theoretically so far none of the new pumps failed. If we compare figure 50b with figure 49 it can be seen that the relined tubing wells have a big decrease in tubing leaks. To be more precise, so far 11 workovers happened at the relined tubing wells and 2 of them are dedicated to tubing leaks.

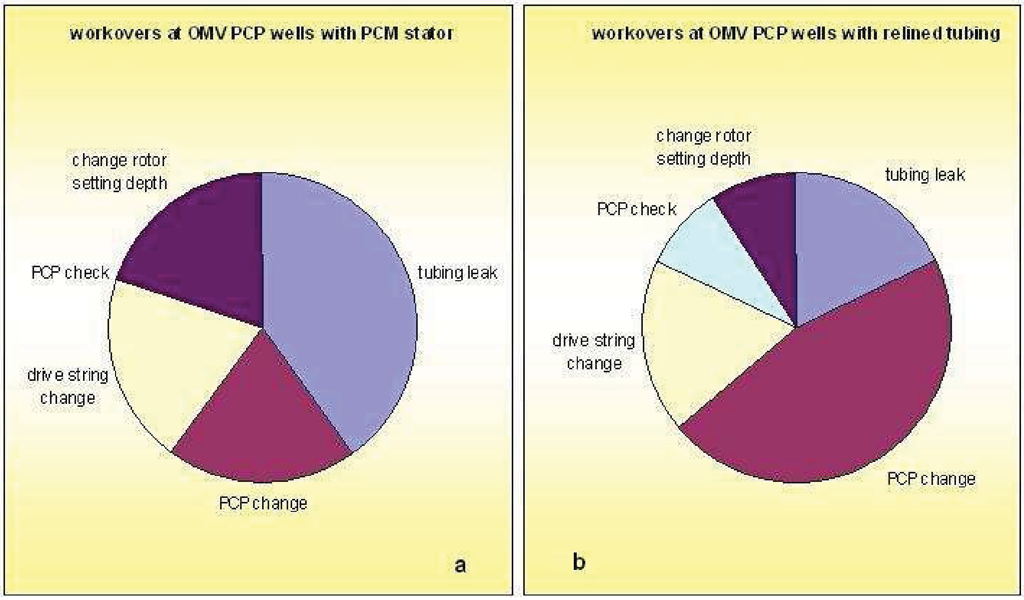


Figure 50 PCP performance of relined PCP wells and wells with PCM elastomer

Optimization

There is the need for improved documentation. The workover reports should be structured in a way that the desired/wanted information can be found easy and quick.

During the research in the database mistakes were found that where carried along all the time. For example the title of one workover report was “broken sucker rod”. By reading the whole report carefully there was no indication of a broken sucker rod. In a failure analysis sheet again the broken rod was mentioned. This wrong information has to be renewed. Also workover reports that were entered by mistake are present but nobody ever removed it from the data base, there is just a note in the report that the workover did not take place. That means the workover is counted in the statistics. If you want to see how many workovers a special well had this wrong information can lead to confusion. Unnecessary time needs to be spent to find out the mistake.

Also I would recommend taking more pictures. Some pumps where changed without any documentation why the pump needs to be changed or the condition of the pump. Each PCP should be analysed during/after a workover. That means at least the condition of the rotor and the stator, this information should be supported with pictures.

In chapter “failure analysis of installed pumps” the software MatriX is shortly introduced. So far this monitoring can only be done onsite and for 200 seconds. Like the sucker rod wells that are integrated in the Oil Well Automation (OWA) where the desired data can be accessed from each OMV computer in the network also the PCPs should have this continuous access to monitored information. It will be beneficial to know the operation parameters, especially when they getting out of the desired range. Action can be taken before the pump will be broken. This might avoid an intervention and hence safe costs. Until now all pumps are monitored twice a year, but the monitoring service is also available on request.

HSEQ aspects

Like with all oil field equipment wrong handling contains high potential for dangers. Discussing and analysing these dangers and exchanging experiences can prevent these dangerous situations. Since HSEQ is an essential part in the oil business this thesis will cover as well some near misses.

In May 2006 during a drive head change a dangerous incident happened in the Austrian oil field. The following chapter will discuss this incident in detail.
The goal of the operation was to change the drive head (DH) of the well Ma 430. First of all the engine was shut down which resulted in a (controlled) backspin of the rod string in order to release the torque. In the DH a hydraulic break is responsible to keep this backspin controlled, which means the rotational frequency stays in a defined range. The master valve was closed then. The rod string was attached to a rotatable crane hook to be lifted (fig.46).
During this lifting process the rod string lost the contact to the drive and break "claws" and the rotor was lifted in the stator downhole. This axial movement of the rotor in the stator destroyed the sealing capacity of the pump and the liquid column in the tubing was forced to flow down. As a consequence the rotor and the rod string started to rotate. The crane driver/operator quickly lowered the rod string back into the braking claws (no weight on the crane hook anymore) which reduced the rotational speed of the string immediately but the crane hook was still rotating with the same speed. The high centrifugal force of the crane hook forced the attached chain to deform the safety joint until the chain was shot away 15 to 20 meters. Afterwards the string was free of tension and the DH could be changed.

Figure 51 crane which lifted the rod sting of a PCP (near miss 2006)

Tubing fill-up

During some pump starts the workover crew filled the tubing with liquid. Since the liquid level in the casing is then a different one (usually lower) than in the tubing the rotor will turn in the wrong direction because of the difference in hydraulic pressure.

DH attachment to the wellhead

Also some problems are present when the DH has to be attached to the well head. The difficulty is that the polished rod stands out 2m of the hole. Now the DH needs to be lifted exactly above the polished rod and then the small hole in the middle of the DH needs to be located above the rod in a way that it can be lowered without any troubles. The difference between the outer diameter of the rod and the inner diameter of the hole in the DH is very small. The complication/problem is that the end of the polished rod is a pin with a slightly increased diameter which makes the process of running the rod in the hole even more difficult. Secondly the bails on the DH (to lift it up) are not efficiently located which prevents that the DH is absolutely vertical. The vertical position is necessary for the process of entering the rod into the DH hole. To make the entering of the rod easier a so called polish rod bullet is used. This construction is a type of cone screwed on the end of the rod. A simple example illustrates this. It is easier to put a cone in a hole (assuming the peak enters the hole first) than to put a cylinder in a hole. To fight the problem with the lifting bails on the DH the manufacturers promised to revise their construction.

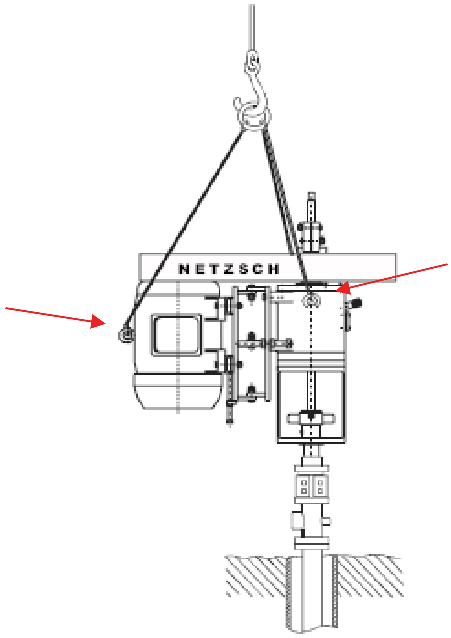


Figure 52 DH lifting attachments

When the DH is located above the wellhead (still on the crane)- it is connected via a flange- the screws are tightened. Then the weight of the DH is supported by the wellhead and the crane can be removed. It happened that after the attachment of the DH on the well head the crew wanted to start up the pump and the DH started to move. They did not tighten the screws a second time after the DH was sitting on the wellhead, so they were lose and the DH tried to "rotate".

Protection against vibrations of DH

OMV made the experience that at a certain rpm, usually in the higher range, the DH starts to vibrate. Due to safety regulations it is recommended/compulsory to fix the DH in a way vibrations are prevented. Figure 53 shows the well STU 139 where this protection is attached.

Figure 53 protection against vibrations of DH.

Smart well completion

This chapter will discuss smart well completions for PCPs. Two concepts will be presented, Concentric Tubing and Dual Progressing Cavity Pump. Both technologies are new and OMV does not have any experience with them so far. While DPCP is not fitting for OMV purposes, the Concentric Tubing may offer a solution to the problems OMV experienced with the PCP completions.

Concentric Tubing

This concept is already used for sucker rod pumps, but the concept can be applied as well on PCPs. The big advantage is that the problems OMV experienced with the tubing string in conventional PCP completions could be decreased. Since the rod string is in pure oil it is safe from corrosion and erosion effects are dampened. An additional feature is the production through the second annulus which prevents contact of the rod string with water, gas or solids. Without sand the shearing of the rod string on the tubing wall is not so dangerous anymore. Also the energy consumption can be decreased as a consequence of the reduction in friction. As a result of all these features the MTBF can be increased significantly, especially due to the fact that 30 % of the workovers are done because of tubing leaks.

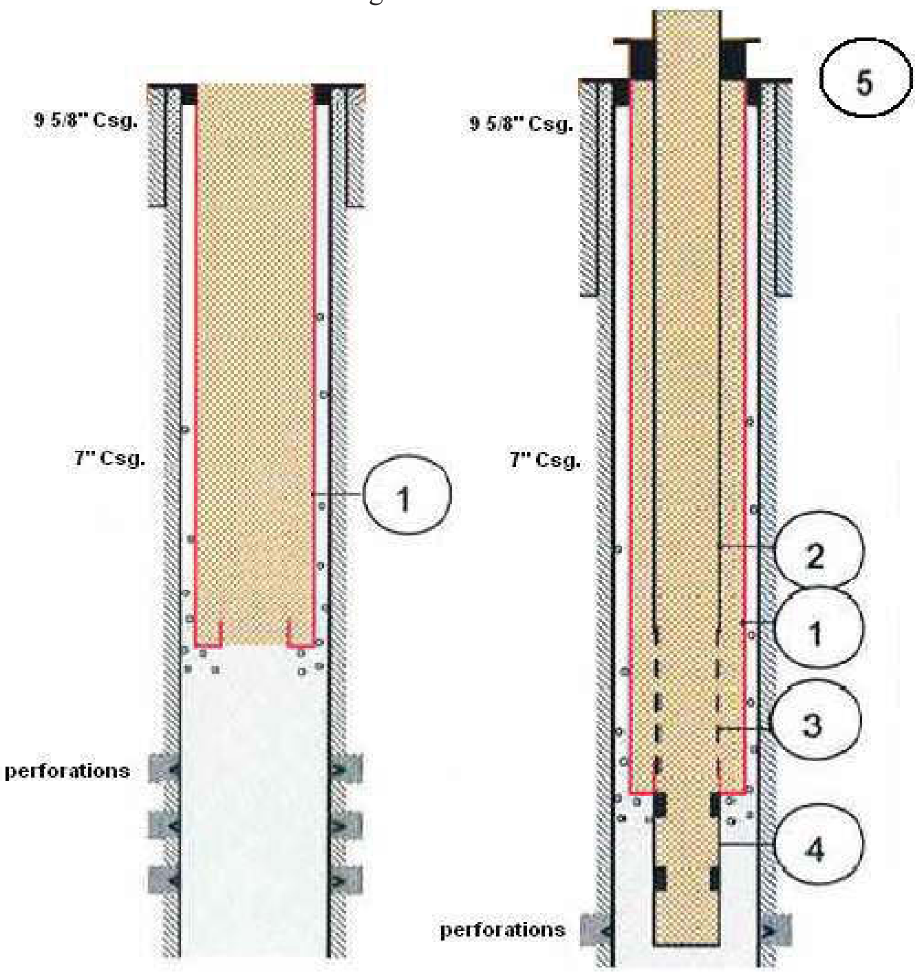


Figure 54 step 1 and step 2 in the implementation phase

The implementation of such a system is easy and no special equipment is required. First of all an outer tubing string (1) needs to be run and hung off in the wellhead (5), see fig. 54. Then the inner tubing (2) with a predrilled section (3) on the bottom and a landing nipple (4) for an insert pump is run and hung off in the wellhead. Now an additional outer annulus is established. The insert pump (8) can be run downhole on sucker rods and set afterwards, see fig.55 . On the surface the stuffing box (6) needs to be fixed. Then the workover fluid can be replaced from the inner tubing by tank oil. The installation is finished; the well is ready for production. During operation the crude is coming from the perforations, entering the pump, passing through the outer annulus and is produced up to the surface (see brown arrow figure 55). The rod string (7) will remain in the tank oil all the time, no crude is entering there due to the density difference between the tank oil and the crude.

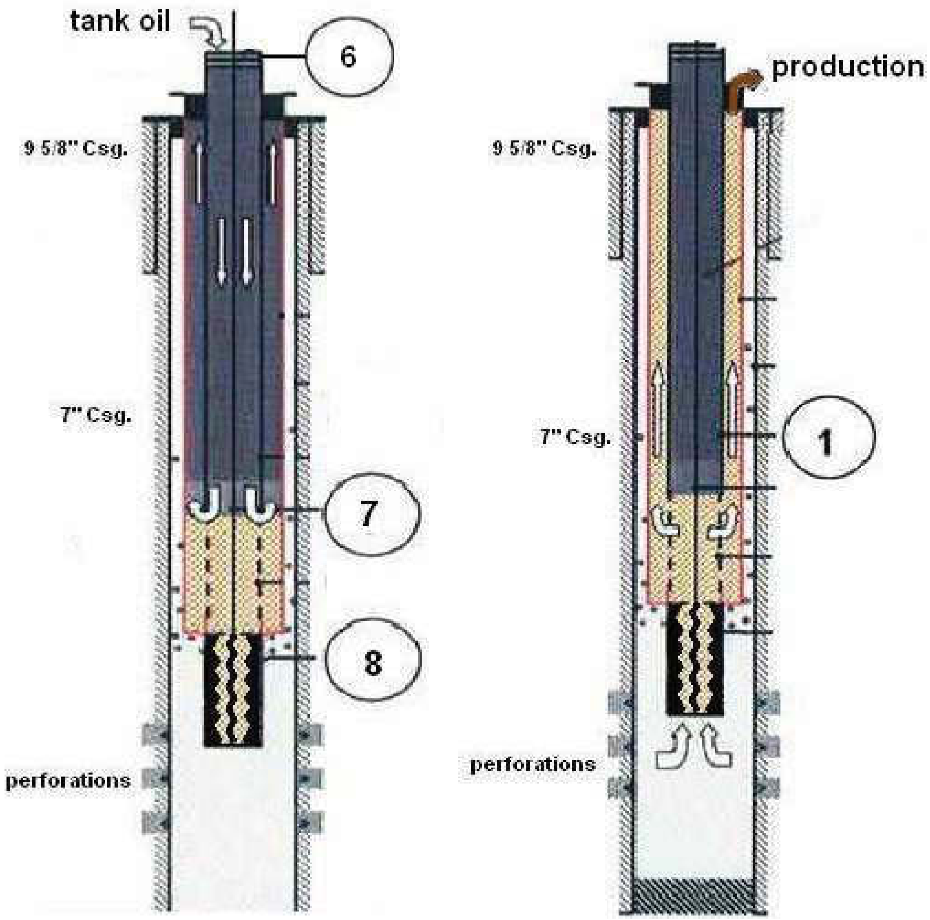


Figure 55 step 3 of the implementation process (right) and the operating mode (left)

Dual Progressing Cavity Pumping System (DPCP)[7]

This installation invented in 2008 by Univ.-Prof. Dipl.-Ing. Herbert Hofstätter allows for higher production rates. Two pumps are installed in series but they operate in parallel, hence the production rate can be increased significantly. Even though this installation is not necessary for OMVs PCP wells the concept shall be introduced shortly in this thesis.

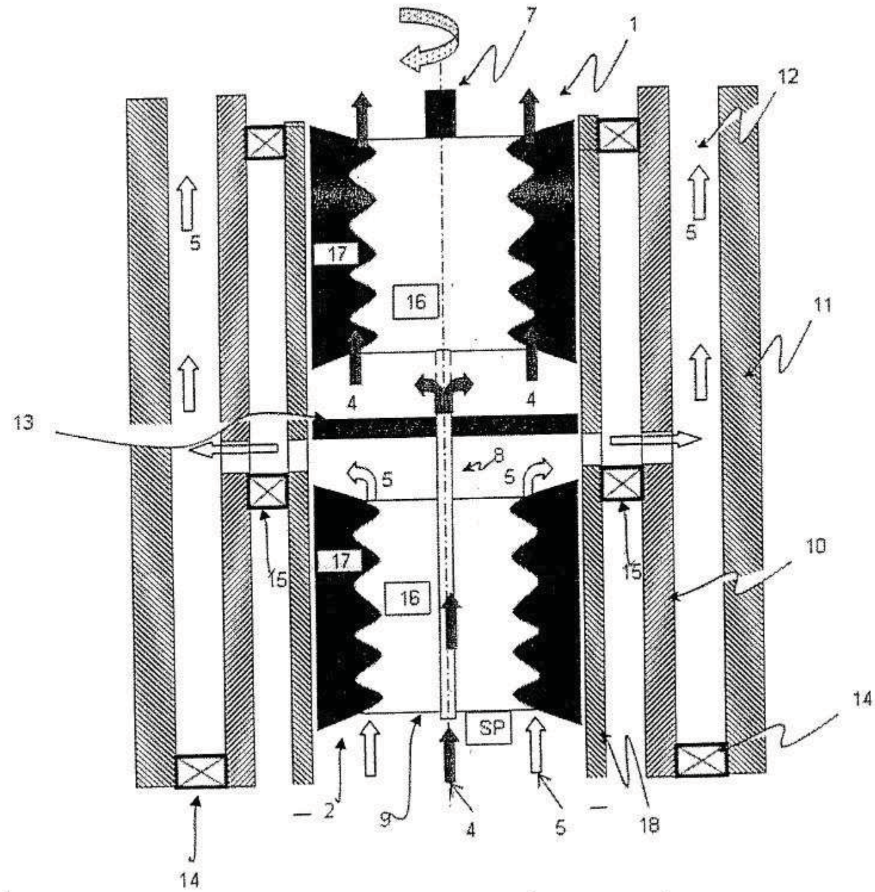


Figure 56 DPCP[7]

1…first pumping unit
2…second pumping unit
3…pumping system
4…first flow path
5…second flow path
6…prime mover
7…force transmitting element
8…rod element
9…suction side
SP…suction point

10…inner tubing
11…outer tubing
12…fluid drain
13…barrier element
14…sealing element
15…inner sealing
16…rotor element
17…stator element
18…housing

To make the explanation easier the upper pump shall be called pump 1 and the lower pump shall be called pump 2. The fluid enters pump 2 and goes into the annulus just below pump 1. From there the fluid is produced up to the surface (indicated by the white arrows). The other part of the fluid is passing the hollow shaft in pump one and is entering pump 1 (see black arrows), from there the fluid is produced via the tubing up to the surface.

This invention makes the PCP attractive for offshore applications since the production rate can be increased significantly even at higher installation depths.

Conclusions

PCP is an artificial lift method that is praised to handle difficult operating conditions like multiphase flow, deviated well paths, high viscous oils and sand production. In reality there are limitations that decrease the PCP efficiency drastically. OMV has installed 19 PCP wells in the Austrian oilfield and the performance of the pumps is not satisfying.

Since many failures are dedicated to tubing leaks it is recommended to continue installing relined tubings with a rod string without any centralizers. If this does not show an improvement the previously discussed concentric tubing can be used to overcome the tubing leaks. Also many workovers are related to elastomer problems. This should be compensated with the new elastomer from PCM. It is recommended to do elastomer compatibility tests for new installations to assure correct elastomer selection. By decreasing or even eliminating these two big failure mechanisms the performance of the PCPs can be increased significantly. So far changing the elastomer and installing relined tubings do not show an impact on the number of workovers. There is no trend visible yet, since only a few pumps are actually equipped with the new elastomer and relined tubing.

The author recommends being patient while keeping in mind that PCP is a quite new technology having a big potential to handle difficult wells if operated correctly. To assure good performance in the future for wells that cannot be operated with sucker rod or ESP pumps it is necessary to gather knowledge and experience from todays wells.

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6.Cholet H.(1997): Progressing Cavity Pumps. Paris: Editions Technip. ISBN 2-7108-0724-6

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8. http://www.pcm-pump.com/oil-gas/artificial-lift-pump.html

Appendix

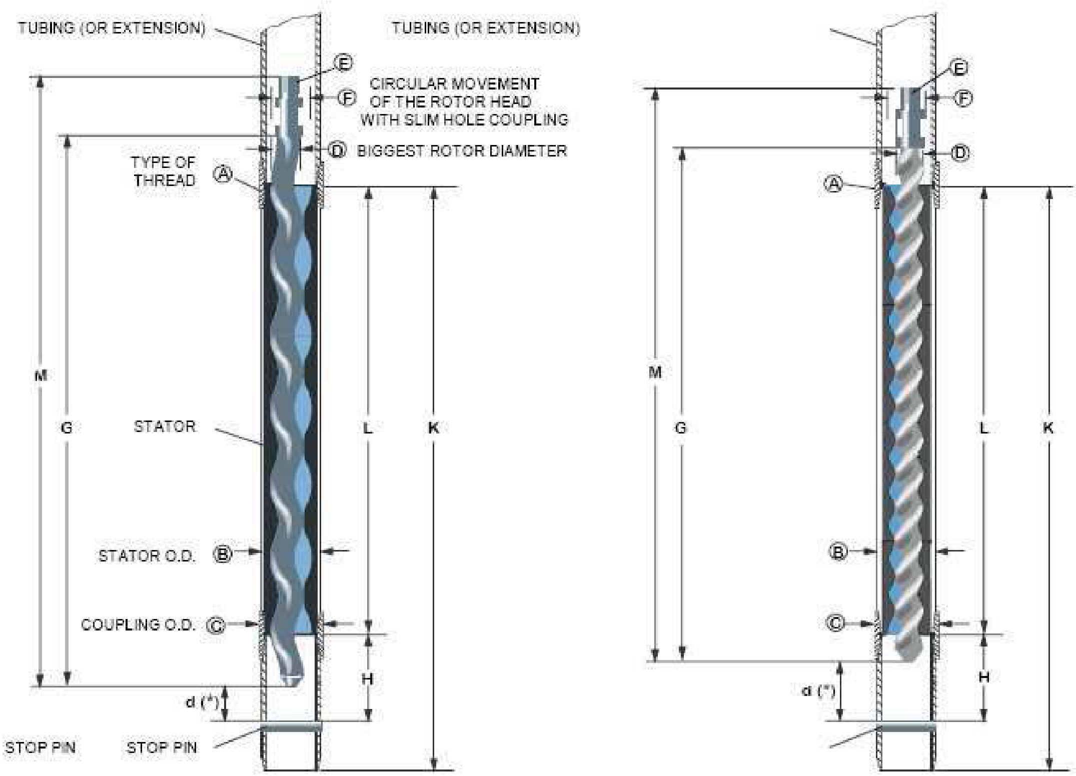

Figure 57 tubular single lobe PCP and multilobe PCP[2]

Spacing Factor "k" - Singlelobe PC Pumps

NETZSCH PC Pump Models	Usual API Rod Sizes									
	5/8	3/4	7/8	1	1 1/8	1 1/4	1 1/2	PCPRod 1000	PCPRod 1500	PCPRod 2500
	Spacing Factor "k"									
NTZ 166*XX ST 0.2	0,000									
NTZ 166*XX ST 0.8	0,022									
NTZ 166*XX ST 1.1	0,021									
NTZ 238*XX ST 1.6	0,134	0,078	0,045							
NTZ 238*XX ST 3.2	0,101	0,055	0,028							
NTZ 238*XX ST 4.0	0,099	0,054	0,027							
NTZ 238*XX ST 6.2	0,154	0,092	0,055							
NTZ 278*XX ST 4.0	0,194	0,120	0,076							
NTZ 278*XX SIT 6.4	0,098	0,053	0,027							
NTZ 278*XX ST 7.0	0,217	0,136	0,088							
NTZ 278*XX ST 10	0,270	0,173	0,114							
NTU 278*XX ST 10	0,265	0,170	0,112							
NTZ 278*XX ST 14	0,278	0,178	0,118	0,079						
NTZ 350*XX ST 16.4	0,475	0,315	0,219	0,157	0,114	0,083	0,043	0,071	0,130	0,071
NTZ 350*XX ST 20	0,491	0,327	0,227	0,163	0,119	0,087	0,046	0,075	0,136	0,075
NTZ 350*XX ST 25	0,494	0,329	0,229	0,164	0,120	0,088	0,046	0,076	0,137	0,076
NTZ 350*XX STS 60	0,580	0,388	0,273	0,198	0,146	0,109	0,061	0,095	0,166	0,095
NTZ 400*XX ST 33		0,357	0,250	0,180	0,132	0,098	0,054	0,085	0,151	0,085
NTZ 400*XX ST 40		0,385	0,270	0,196	0,145	0,108	0,060	0,094	0,164	0,094
NTZ 400*XX ST 50		0,387	0,272	0,197	0,146	0,109	0,061	0,095	0,166	0,095
NTZ 400*XX ST 62			0,272	0,197	0,146	0,109	0,061	0,095	0,166	0,095
NTZ 400*XX ST 78			0,271	0,196	0,145	0,108	0,061	0,094	0,165	0,094
NTZ 400*XX ST 120			0,266	0,193	0,142	0,106	0,059	0,092	0,162	0,092
NTZ 450*XX STS 40.2			0,551	0,411	0,315	0,246	0,156	0,220	0,352	0,220
NTZ 500*XX STM 65			0,419	0,310	0,235	0,181	0,111	0,161	0,264	0,161
NTU 500*XX ST 98			0,654	0,489	0,377	0,296	0,191	0,265	0,421	0,265
NTZ 550*XX ST 98			0,670	0,501	0,386	0,304	0,196	0,272	0,431	0,272
NTZ 500*XX STM 100			0,419	0,310	0,235	0,181	0,111	0,161	0,264	0,161
NTZ 550*XX ST 145			0,651	0,488	0,375	0,295	0,190	0,264	0,419	0,264
NTZ 658*XX ST 330			1,162	0,878	0,684	0,545	0,364	0,492	0,760	0,492

Figure 58 Netzsch spacing factors k for singlelobe PCP[2]

NETZSCH PC Pump Models	Spacing Factor "k" - Multilobe PC Pumps									
	Usual API Rod Sizes									
	5/8	3/4	7/8	1	1 1/8	1 1/4	1 1/2	PCPRod 1000	PCPRod 1500	PCPRod 2500
	Spacing Factor "k"									
NTZ 166*XX DT 4.6	0,040	0,013								
NTZ 238*XX DT 14	0,178	0,109	0,067	0,040						
NTZ 278*XX DIT 14.6	0,116	0,066	0,036	0,016						
NTZ 278*XX DT 16			0,121	0,081						
NTZ 278*XX DT 20			0,120	0,081						
NTZ 278*XX DT 25			0,122	0,082						
NTZ 278*XX DT 32			0,120	0,081						
NTZ 350*XX DT 33			0,218	0,156	0,113	0,083	0,043	0,071	0,130	0,071
NTZ 350*XX DT 40			0,221	0,158	0,115	0,084	0,044	0,072	0,131	0,072
NTU 350*XX DT 40			0,218	0,155	0,113	0,082	0,043	0,071	0,129	0,071
NTZ 400*XX DT 50			0,267	0,193	0,143	0,106	0,059	0,093	0,162	0,093
NTZ 400*XX DT 66			0,265	0,191	0,141	0,105	0,059	0,092	0,161	0,092
NTZ 400*XX DT 83			0,263	0,191	0,141	0,105	0,058	0,091	0,160	0,091
NTU 400*XX DT 83			0,263	0,191	0,141	0,105	0,058	0,091	0,160	0,091
NTZ 400*XX DT 110			0,265	0,191	0,141	0,105	0,059	0,092	0,161	0,092
NTZ 400*XX DT 142			0,261	0,189	0,139	0,104	0,057	0,090	0,159	0,090
NTZ 450*XX DT 74			0,433	0,320	0,243	0,188	0,116	0,167	0,273	0,167
NTZ 450*XX DT 150			0,426	0,315	0,239	0,185	0,114	0,164	0,269	0,164
NTZ 500*XX DT 138			0,562	0,419	0,321	0,251	0,160	0,224	0,359	0,224
NTZ 500*XX DT 170			0,561	0,418	0,321	0,251	0,159	0,224	0,359	0,224
NTZ 500*XX DT 226			0,560	0,418	0,320	0,250	0,159	0,224	0,358	0,224

Figure 59 Netzsch spacing factors k for multilobe PCP[2]

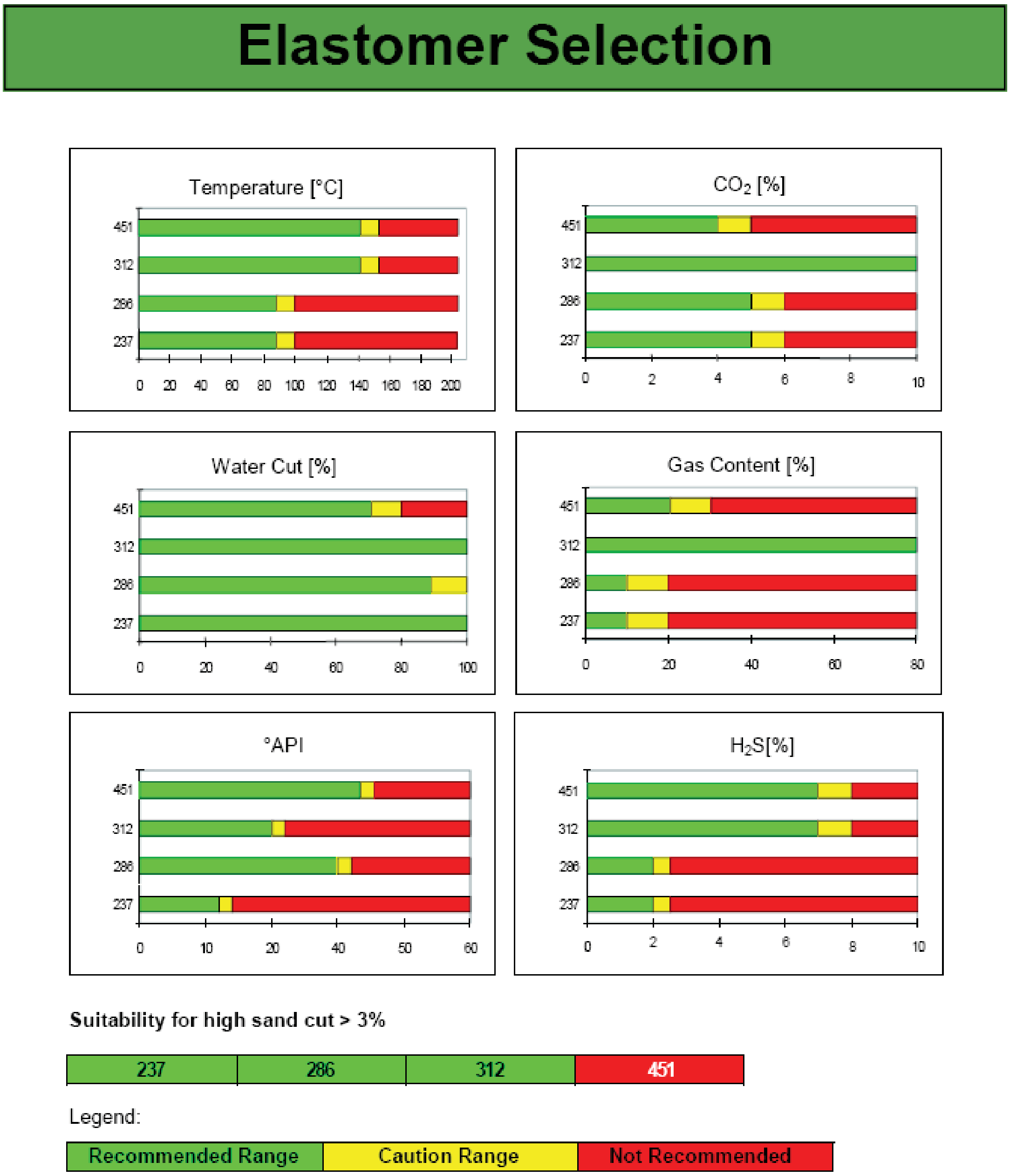

Figure 60 Netzsch elastomer selection criteria [2]

PCM

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PCM MOINEAU OILFIELD

Specifications 200 TP 1800

ISO 200/18

ROTOR			PUMP ASSEMBLY		
TOTAL LENGTH	8.800 m	28'10.4"	Nb OF STAGES (2)	32	
LENGTH OF HELIX	8.600 m	29'2.6"	HEAD CAPABILITY	1800 m	5900 ft
CREST TO CREST DIAM (1)	51.0 mm	2.01"	DISPLACEMENT	266 cc	
HEAD DIAM (1)	52.0 mm	2.05"	CAPACITY PER RPM	0.392 m3/d	2.46 bpd
THREAD	1 3/8" API	1" rod	VOLUME AT 500 RPM	196 m3/d	1232 bpd
			O.D.	108 mm	4.25"
STATOR			**STOP BUSHING**		
Nb OF ELEMENTS	3		STAND-OFF LENGTH	0.3 m	1 ft
LENGTH	8.250 m	27'0.8"			
O.D.	108 mm	4.25"			
THREADS	3"1/2 EUE male				

(1) Largest of the two is rotor O.D.
(2) Stage defined as equivalent to one pitch length of stator

COMPATIBILITY PUMP-ROD-TUBING (1)			
Tubing size Max. weight Min. I.D.	Rod size and type of lower coupling	Radial clearance between tubing and rod-rotor connection	Requirement for tubing-stator connection
2 7/8" 6.50 lbs/ft 62.0 mm 2.44 in	1" sh or 1" std	negative	3 1/2" x 4' pup joint and one 2 7/8" x 3 1/2" cross over
3 1/2" 9.30 lbs/ft 76.0 mm 2.99 in	1" sh 1" std	4 mm 5/32" 2.2 mm 5/64"	
4" 9.50 lbs/ft 90.1 mm 3.56 in	1" std 1 1/8" std	9.2 mm 23/64" 6.9 mm 17/64"	

(1) assuming tubings are EUE
Important recommendation : never use a rod centralizer at top of rotor

Figure 61 PCM PCP pump performance chart 200TP1800

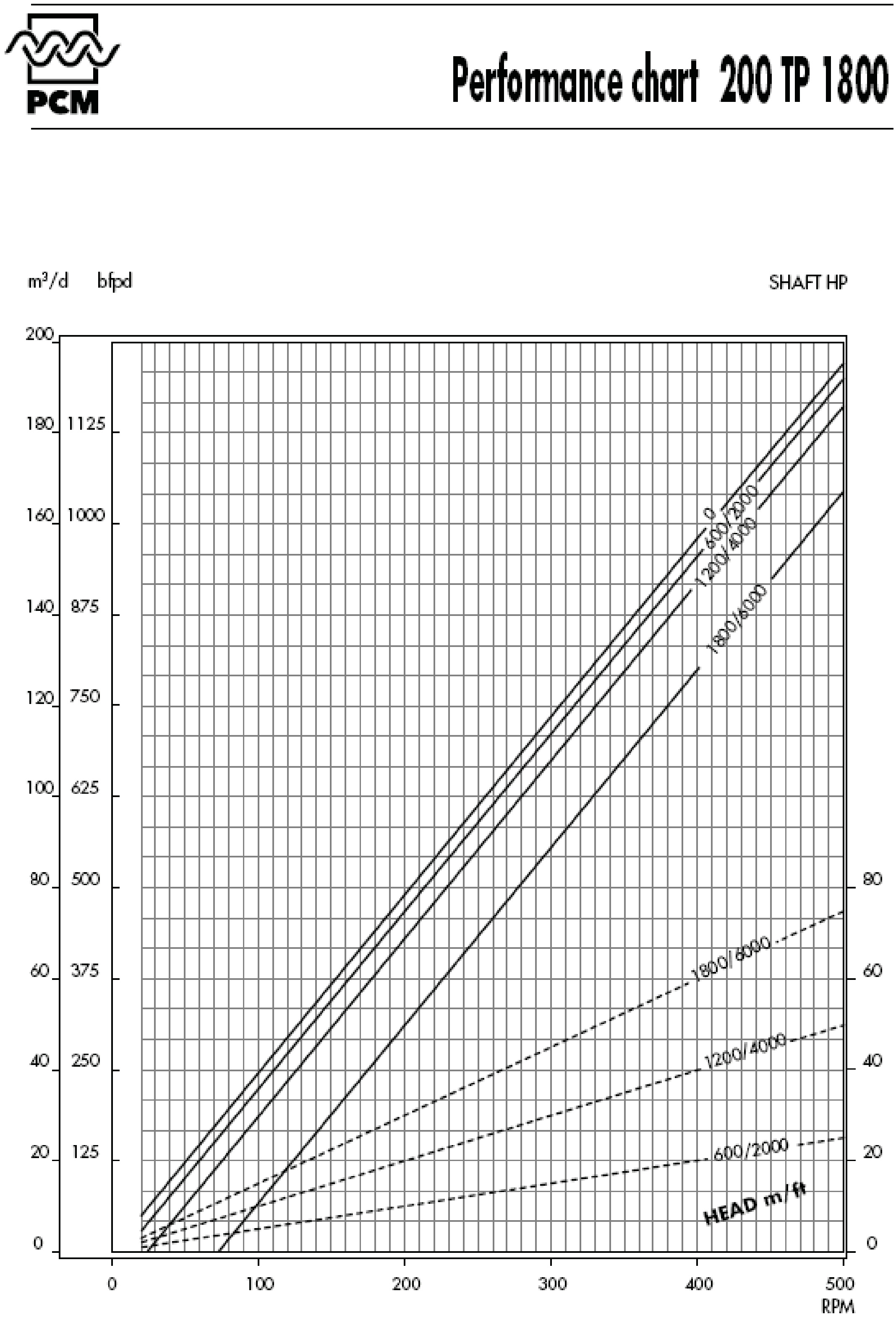

Figure 62 PCM PCP pump performance chart 200TP1800

PCM

PCM MOINEAU OILFIELD

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Tel (33) 1 41 08 15 15 - Telex 634 129 F - Fax (33) 1 41 08 15 99
http://www.pcmpompes.com Email: oil@pcmpompes.com

Specifications 30 TP 2000

ISO 30/20

ROTOR		
TOTAL LENGTH	4.435 m	14'6.6"
LENGTH OF HELIX	4.210 m	13'9.75"
CREST TO CREST DIAM (1)	32.5 mm	1.28"
HEAD DIAM (1)	40.0 mm	1.57"
THREAD	1 1/16"API	3/4" rod

PUMP ASSEMBLY		
Nb OF STAGES (2)	42	
HEAD CAPABILITY	2000 m	6600 ft
DISPLACEMENT	37 cc	
CAPACITY PER RPM	0.054 m3/d	0.34 bpd
VOLUME AT 500 RPM	27 m3/d	170 bpd
O.D.	78 mm	3.07"

STATOR		
Nb OF ELEMENTS	3	
LENGTH	3.915 m	12'10.1"
O.D.	78 mm	3.07"
THREADS	2"3/8 EUE male	

STOP BUSHING		
STAND-OFF LENGTH	0.3 m	1 ft

(1) Largest of the two is rotor O.D.
(2) Stage defined as equivalent to one pitch length of stator

COMPATIBILITY PUMP-ROD-TUBING (1)			
Tubing size Max. weight Min. I.D.	Rod size and type of lower coupling	Radial clearance between tubing and rod-rotor connection	Requirement for tubing-stator connection
2 3/8" 4.70 lbs/ft 50.7 mm 2.0 in	3/4" std or 7/8" s.h.	0.2 mm 1/64"	2 7/8" x 4' pup joint and one 2 3/8" x 2 7/8" cross over
2 7/8" 6.50 lbs/ft 62.0 mm 2.44 in	3/4" std 7/8" std 1" s.h.	5.8 mm 7/32" 3.5 mm 1/8" 1.1 mm 1/32"	3"1/2 x 4' pup joint and one 2" 7/8 x 3"1/2 cross over
3 1/2" 9.30 lbs/ft 76.0 mm 2.99 in	3/4" std 7/8" std 1" std	12.8 mm 1/2" 10.5 mm 13/32" 5.7 mm 7/32"	

(1) assuming tubings are EUE
Important recommendation : never use a rod centralizer at top of rotor

Figure 63 pump performance chart 30TP2000

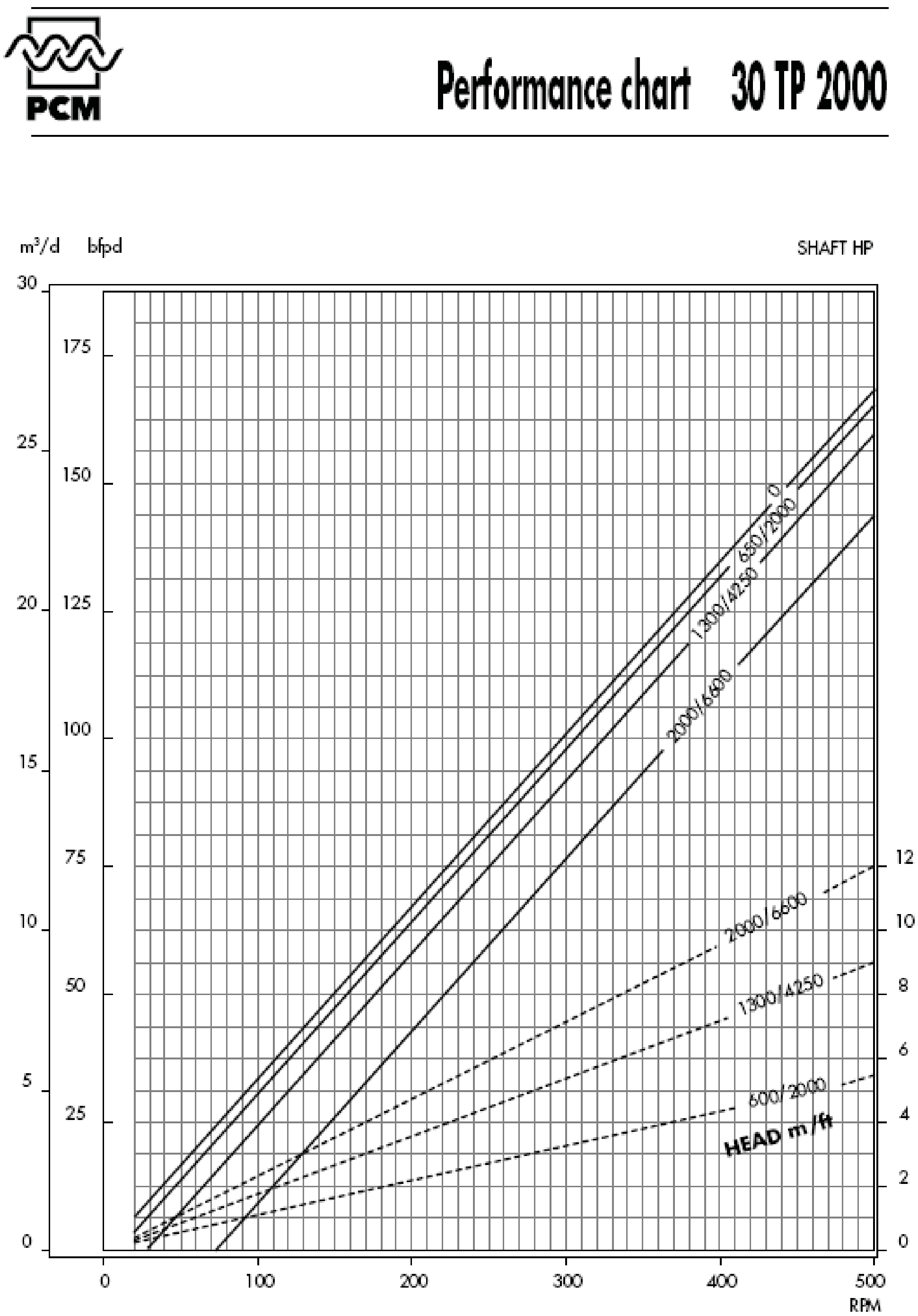

Figure 64 pump performance chart 30TP2000

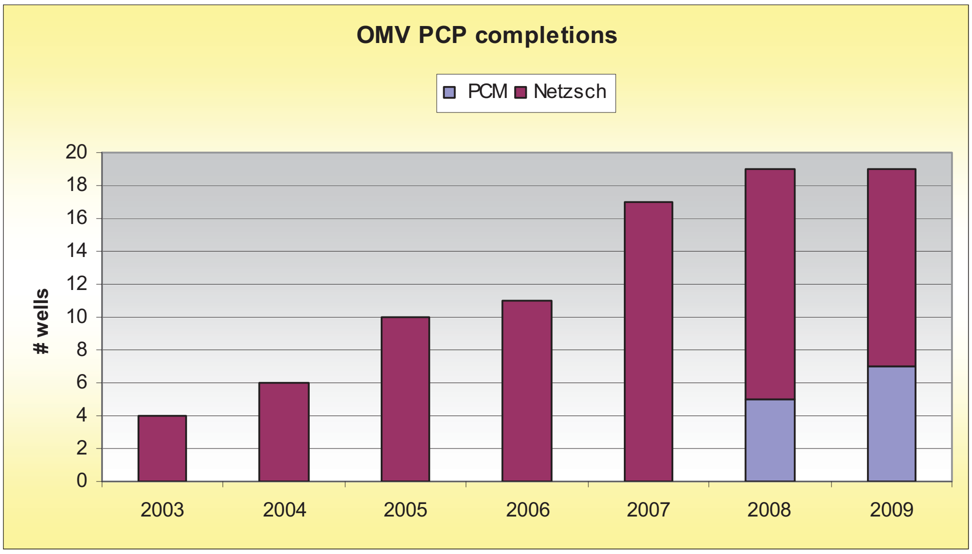

Figure 65 OMV PCP completions with PCM and Netzsch elastomer

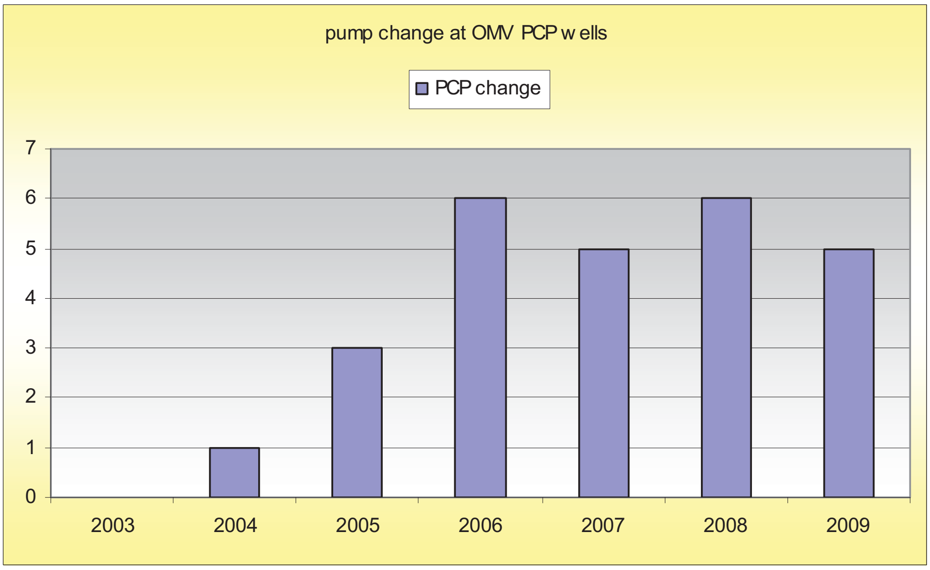

Figure 66 pump change 2003 – 2009

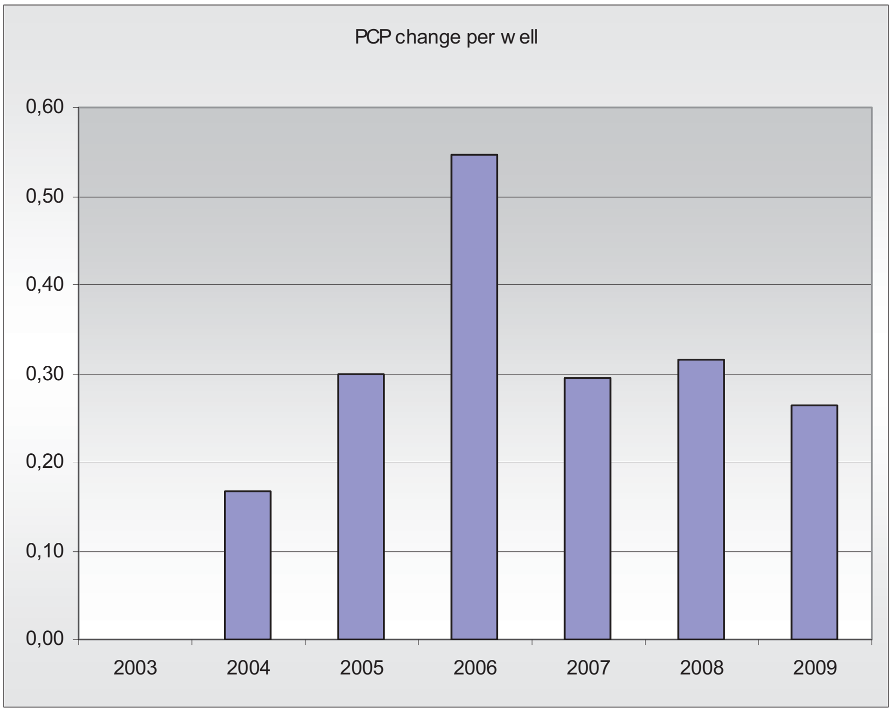

Figure 67 pump change per well 2003 – 2009

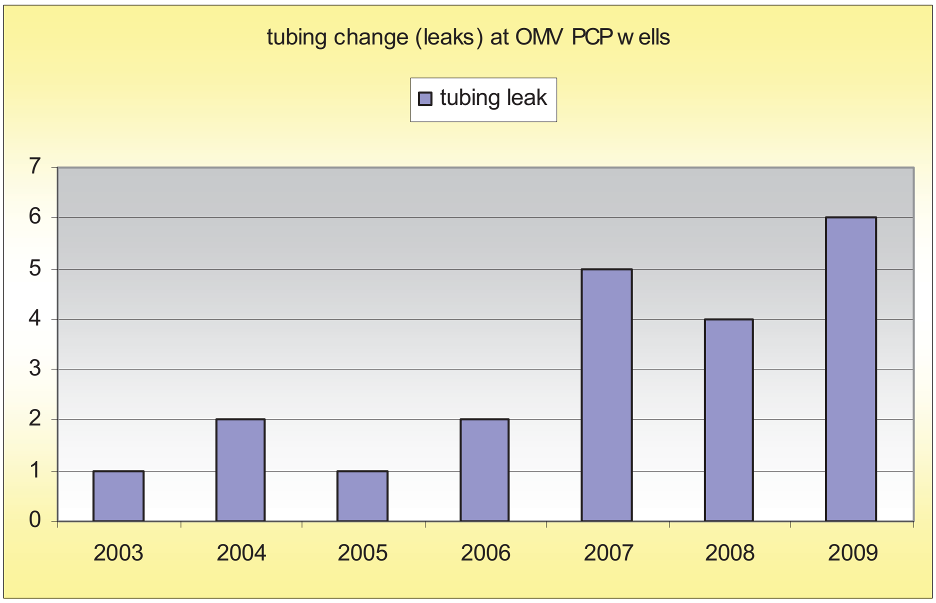

Figure 68 tubing leaks 2003 – 2009

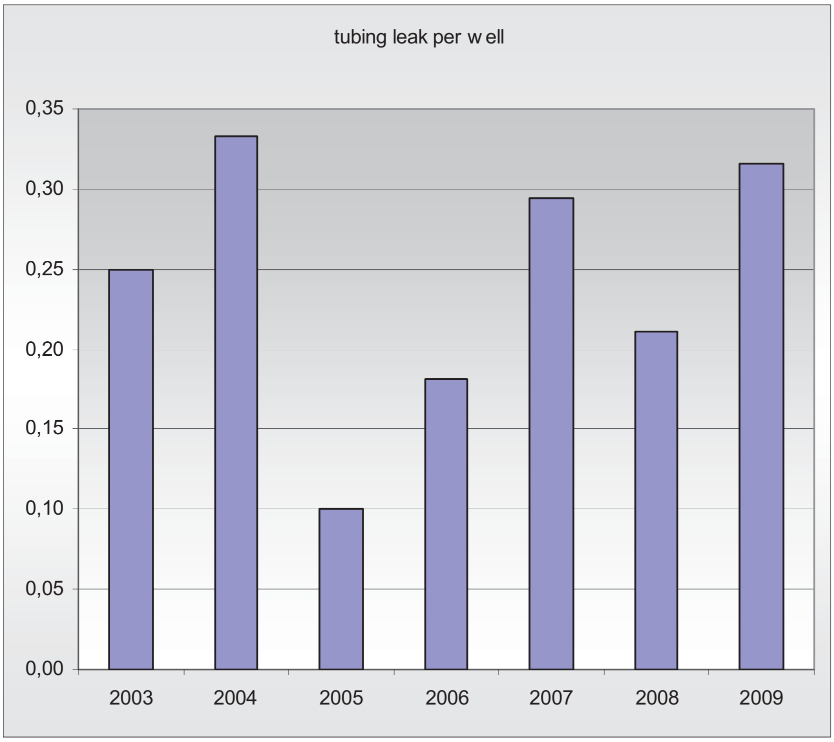

Figure 69 tubing leaks per well 2003 – 2009

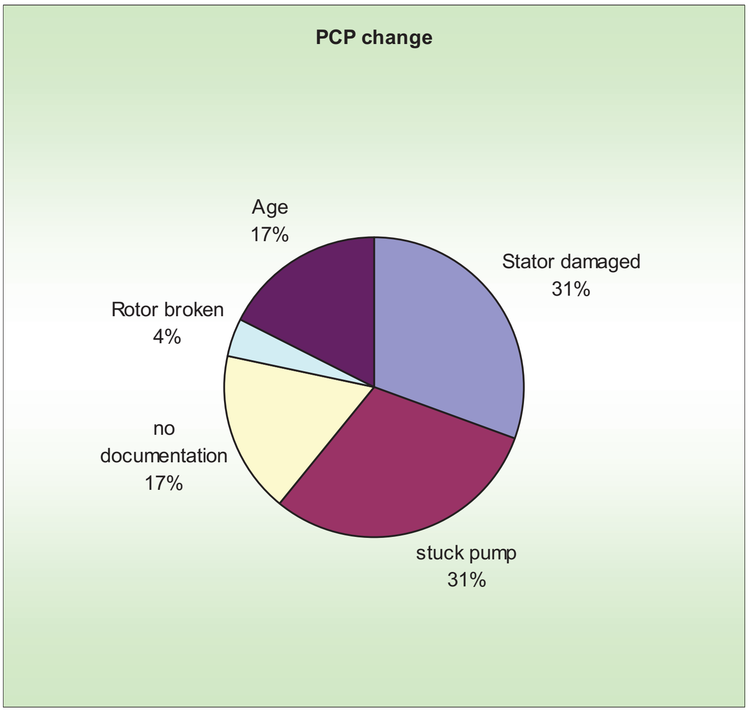

Figure 70 reasons for PCP Change