Chair of Petroleum and Geothermal Energy Recovery

Master Thesis

Life cycle cost analysis of artificial lift systems in OMV mature assets in Austria

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Leoben, 08.06.2016

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Acknowledgement

First of all, I would like to thank my mother, Ursula Kunodi, for her never-ending support during my entire life. Without her care, understanding and financial support, the successful completion of my studies and this master thesis would not have been possible.

I would also like to thank the people working at the Chair of Petroleum and Geothermal Energy Recovery at the Montanuniversity of Leoben for all they have done for me and taught me during my master and bachelor studies. Special thanks go out to Univ.-Prof. Dipl.-Ing. Dr.mont. Herbert Hofstätter for giving me the opportunity to write this thesis and his support and ideas throughout the thesis and also to Sepp Steinlechner, MBA for his support, his helpful input and his prompt responses at any time during this project.

My appreciation goes to OMV as the industry partner of this project, especially Dipl.-Ing. Bernd Kometer and Dipl.-Ing. Patrick Bürßner, for providing me with the data that are the basis of this thesis.

I would also like to thank my sister, the rest of my family and all of my friends for their unconditional support during this time and for always having an open ear when I needed one.

Finally, I would like to thank my boyfriend for his understanding during this last few months, for helping me to think things through when I was stuck and for being so supportive in all situations.

Abstract

Life cycle cost analysis of artificial lift systems in OMV mature assets in Austria

Selecting the correct artificial lift method is crucial for the long-term profitability of most producing oil and gas fields. OMV uses five different types of artificial lift systems (ALS) in mature fields in Austria; sucker rod pumps, linear rod pumps, progressive cavity pumps, electrical submersible pumps and gas lifting. Although much data are collected by OMV with regard to costs, a conclusive method indicating the most suitable artificial lift system in terms of cost efficiency is currently not available for application within OMV.

For the purpose of this thesis a review of the five relevant artificial lift systems including their technical limits and knock-out criteria was performed with special focus on the challenges these systems face in OMV's mature fields.

In order to assist the selection process of the ALS, the life cycle costing method was applied as a basis for all further analyses in accordance with ISO 15663-1:2000. The ISO standard thereby subdivides the method into four distinct steps: diagnosis and scoping, where alternative solutions are established and defined, data collection and breakdown of costs, analysis and modelling, which includes sensitivity analysis and finally reporting and decision making.

The possible alternatives to be ranked by the tool were specified by OMV in form of the commonly used five ALSs. The life cycle costs of an ALS depend on various factors during installation, operation and abandonment. The data provided by OMV was analysed with the purpose to define within this thesis the cost elements as well as to compile different parameters, like energy consumption, environmental costs and average run life. These factors were used to calculate total cost of ownership, as well as the net present value using the discounted cash flow method. Key performance indicators (KPI) were introduced to facilitate the ranking of the ALSs. A sensitivity analysis was performed to define the influence of the input parameters on the outcome of the life cycle costing and to ascertain the plausibility of this outcome.

In the scope of this thesis a tool was developed as an Excel spreadsheet, calculating the life cycle costs for the five ALSs as comparison for individual wells. This is enabled by defining adjustable input parameters like e.g. gross production rate, initial water cut, oil price and expected life time. This input is then used to adapt the cost list based on well specification and installations. The output of this tool are the calculations, results and KPIs of the life cycle costing including an explicit ranking of the applicable ALS. The purpose of this tool is to assist OMV her decision making process.

The tool was tested with available data of one existing well, already in production, to ascertain its applicability. The test well was equipped with gas lifting installations and after going through the life cycle cost systematics using the tool, the result happened to turn out as gas lift to represent the most favourable solution.

The conclusion of this thesis is that a life cycle cost analysis can be an integral part of any decision making process for the right ALS in mature fields, if applied with care.

Kurzfassung

Lebenszykluskostenanalyse von Födersystemen in produzierenden Ölfeldern der OMV in Österreich

Die Auswahl des richtigen Födersystems ist entscheidend für die langfristige Rentabilität von Öl- und Gasfeldern. OMV nutzt fünf verschiedene Arten von Födersystemen in Österreichs Ölfeldern; zwei Arten von Gestängepumpen, Exzenterschneckenpumpe, elektrische Tauchpumpe und Gashebeanlage. Obwohl viele Daten von OMV bezüglich Kosten dokumentiert werden, ist eine schlüssige Methode, das am besten geeignete System im Hinblick auf die Kosteneffizienz zu ermitteln, innerhalb der OMV noch nicht in Anwendung.

Eine Untersuchung der fünf relevanten Födersysteme und ihrer technischen Grenzen bzw. Knock-out-Kriterien wurde durchgeführt, wobei OMV spezifische Herausforderungen für Födersysteme besondere Berücksichtigung fanden.

Um den Auswahlprozess des Födersystems zu unterstützen, wurde eine Lebenszykluskostenmethode (LZK) gemäß ISO 15663-1:2000 eingesetzt, die eine Unterteilung in folgende vier Arbeitsschritte vorsieht: Diagnose und Problembestimmung, in welcher alternative Lösungen etabliert und definiert werden; Datenerfassung und Kostenaufschlüsselung, in der die Strukturierung der Kosten festgelegt wird; Analyse, welche eine Sensitivitätsanalyse einschließt, und abschließend die Berichterstattung und Entscheidungsfindung.

Die möglichen Alternativen die durch diese LZK-Analyse priorisiert werden sollen, wurden in Form der verwendeten fünf Födersysteme von der OMV festgelegt. Die von der OMV dafür zur Verfügung gestellten Daten wurden analysiert, um sowohl die Kostenelemente als auch bestimmende Parameter, wie zum Beispiel Energieverbrauch, Umweltkosten und durchschnittliche Laufzeit der Systeme zu definieren und zu bewerten. Diese Faktoren wurden verwendet um die Gesamtbetriebskosten sowie den Barwert zu berechnen. Leistungskennzahlen wurden eingeführt, um das Ranking der Födersysteme zu erleichtern. Eine Sensitivitätsanalyse wurde durchgeführt, um die Plausibilität der Ergebnisse zu ermitteln.

Im Rahmen dieser Arbeit wurde ein Excel-Spreadsheet programmiert, welches die LZK für die fünf Födersysteme berechnet, und über die Definition von ausgesuchten Parametern für unterschiedliche Födersonden anwendbar ist. Dazu gehören Bruttoproduktionsrate, anfänglicher Wasseranteil, Ölpreis und die erwartete Lebenszyklusdauer, welche verwendet werden, um die Kosten gemäß den Sonden-Spezifikationen und -installationen anzupassen. Als Endergebnis werden Daten und Kennzahlen der Lebenszykluskosten einschließlich einer expliziten Reihung der Alternativen ausgegeben, die den Ingenieur der OMV bei der Auswahl und Planung der verschiedenen Födersysteme in Zukunft unterstützen werden.

Um die Funktion des Spreadsheets zu überprüfen und dessen generelle Anwendbarkeit darzustellen, wurde ein realer, komplexer Fall einer Födersonde mit Gashebeanlage getestet. Die so ermittelte Reihung der Födersysteme ergab ebenfalls die Gashebeanlage als kostengünstigste Alternative. Weitere Fälle wurden aufgrund mangelnder Daten nicht untersucht, sollen jedoch von OMV intern weitergeführt werden.

Jedenfalls konnte in dieser Masterarbeit deutlich dargestellt werden, dass die Lebenszykluskostenanalyse für die Auswahl von Födersystemen grundsätzlich sinnvoll einsetzbar ist.

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ALS	Artificial lift system
SRP	Sucker rod pump
LRP	Linear rod pump
PCP	Progressive cavity pump
ESP	Electric submersible pump
GL	Gas lift
LCC	Life cycle costing
TCO	Total cost of ownership
TVoM	Time value of money
CAPEX	Capital expenditure
OPEX	Operational expenditure
NPV	Net present value
IRR	Internal rate of return
WI	Well Intervention
GLR	Gas liquid ratio
VSD	Variable speed drive
DPI	Discounted profitability index
PEEK	Polyether ether ketone
EPDM	Ethylene propylene diene monomer
m	Meter
m^3	Cubic meter
lbs	Pounds
in.	Inch
ft.	Feet
EUR	Euro
USD	US Dollar
h	Hour

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1 Introduction

Oil flows naturally to the surface when the pressure at the bottom of the well exceeds the sum of pressure losses along the flow path. Artificial lifting is a method where energy is added to the flow stream to increase the flow rate. Different techniques are used for different conditions and environments. [1, p. 303]

With a worldwide production of 309,000 barrels of oil equivalent per day in 2014, OMV is Austria's largest oil producer. OMV operates 750 oil wells in Austria and most of these have artificial lift systems (ALS) installed. [2] One goal of this master thesis is to create a list of costs generated over the entire life cycle of these assets. A decision concerning an acquisition should not be based solely on part of the costs, e.g. initial procurement costs. In an increasingly competitive business environment it is important that all cost elements for each asset are found and cost drivers are identified so that the best decisions concerning operation, maintenance, budget and cost effectiveness can be made.

1.1 Objective

The scope of this work is to analyse life cycle costs (LCC) of all artificial lift methods used by OMV in Austria, namely sucker rod pumps, linear rod pumps, progressive cavity pumps, electrical submersible pumps and gas lifting. The first section of this thesis, a literature review, consists of two parts. One is written based on research about artificial lift systems and the other gives an overview over information on LCC found in literature. The next section covers data analysis and describes the main cost drivers on which the LCC is based on, ranging from acquisition to abandonment of the system. After the interpretation of the results and as part of every LCC, a sensitivity analysis has been prepared to determine the validity of the found result.

As the data for this thesis is gathered from existing wells with already installed ALSs operated by OMV in Austria and Romania, there will be less focus on technical characteristics and requirements needed for the selection of ALS. Nevertheless, to be able to make sensible (economical) decisions, specifics of the production, knowledge of the well operation, and failure data need to be known. [3, p. 339]

At the end of this work it will be decided if this compilation of costs can be used as an additional tool for selecting ALS in the future. To achieve this goal, an Excel spreadsheet was created to be used for the calculation of LCC for different well set ups. Due to confidentiality reasons, all values of costs displayed in this thesis have been multiplied with a chosen factor.

2 Literature review

Purpose of this chapter is to give an overview of the information regarding different artificial lift systems, as well as Life Cycle Costing that can be found in literature.

2.1 Artificial lift systems

Depending on the source, the percentage of wells worldwide equipped with artificial lift range from over 50% to 93,8%. [4, p. 56] [5, p. 691] [6, p. 14].

Usually, boreholes start as naturally flowing wells, meaning that the bottomhole pressure is higher than the sum of pressure losses occurring on the path from the reservoir to the separator. A well stops flowing due to a decrease in bottomhole pressure or an increase in pressure losses to the surface. An artificial lift system is installed to either produce from an otherwise dead well or to increase the production rate from a flowing well. [7, pp. 1-2]

All ALSs can be subdivided into three parts: Surface installations, downhole installations and the section connecting those two.

OMV has five different types of artificial lift systems installed in their mature fields in Austria and in OMV PETROM's fields in Romania: Sucker Rod Pump (SRP), Linear Rod Pump (LRP), Progressive Cavity Pump (PCP), Electrical Submersible Pump (ESP) and Gas Lift (GL).

2.1.1 Sucker rod pump

Sucker rod pumping is the oldest and most widely used type of ALS worldwide. It is estimated that over 85% of all wells produced with ALSs have rod pumps installed. [8] OMV currently has 502 SRPs in operation in Austria. [9]

Figure 1 shows a typical SRP with a conventional mechanical pump drive

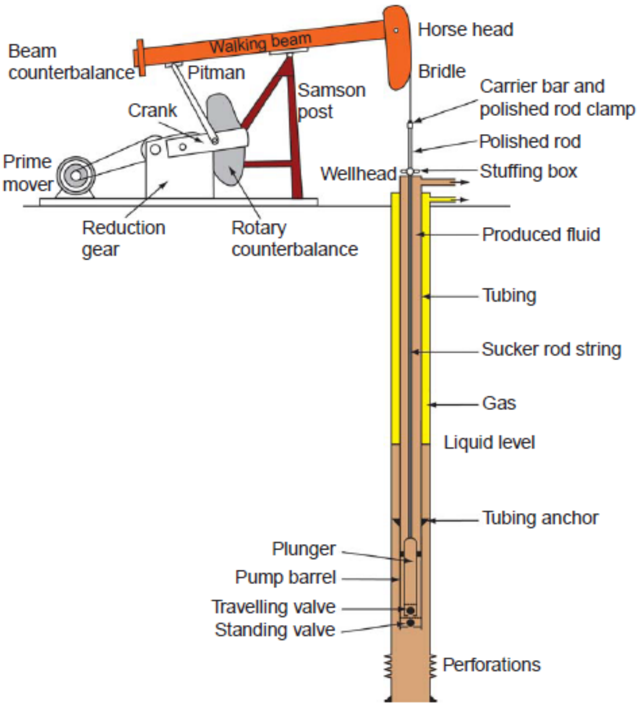


Figure 1: Basic components of a sucker rod pump [1, p. 354]

For a sucker rod pump, or any other artificial lift system, to be able to work efficiently the specifics of the well have to be taken into consideration and various parts of the pump have to be adjusted for obtaining the desired production. Different basic bore diameters and plunger lengths of the downhole pump, as well as the number and lengths of the strokes by the surface pumping unit limit the possible gross production rate. Although the exact set-up differs from well to well, typically on the specifics of these items, most SRP installations have similar parts installed.

The most important downhole installation is the downhole pump. In general, a downhole pump consists of standing and travelling valves, plunger, barrel and seating assembly, as can be seen in Figure 1. OMV operates two types of pumps. The tubing pump has the barrel attached to the tubing while the plunger is attached to the sucker rods. They are mostly used for shallow wells and large production rates and should not be installed in wells with high gas rate. In rod pumps, also called insert pumps, barrel and plunger are attached to sucker rods. The pump is seated in the tubing string, which allows for easier installation and service. These insert pumps are used for smaller pumping rates in deeper wells.

The sucker rod string connects the travelling valve of the pump with the pump unit on the surface. Sucker rods (SR) are a key component of this type of ALS. Rods vary in length between 25 and 30 ft. (7,62 and 9,14 m) and in diameter from 5/8 to 1 1/8 in 1/8-inch increments. Three main grades of steel are used for SR depending on the desired minimum and maximum tensile strength (Grade C, K and D). Grade K has improved corrosion related properties, due to up to 2% nickel in its composition, and Grade D includes plain-carbon alloy and special alloy steels. In special cases SR are made from protruded fibreglass. The choice of SR is depending on many factors, like size of pump and tubing, pump setting depth, production rate, liquid viscosity, corrosion, solids production and precipitation. The rods are connected to a string via rod couplings. Rod centralizers, also called rod guides are used to keep the rods and couplings away from the tubing to reduce wear and erosion of the material. These guides, which vary in number per rod, are either installed in the field or welded on and are made from different materials. The sucker rod string also consists of sinker bars which are special steel bars or large-diameter sucker rods placed directly above the downhole pump in order to keep tension on the sucker rod string and avoid buckling and associated pump failures. As the last part of the rod string, the polished rod connects the pump unit to the surface.

The surface unit of an SRP is referred to as pump jack or pumping unit and is the mechanism that converts the rotary motion of the prime mover into the reciprocating vertical movement needed for the polished rod. Different geometries of beam-type pumping units exist; the most commonly used is the conventional unit. Pumping Units can be identified by a reference number, referring to the make of a pump (Conventional C, Mark II M, Air balanced A, ...), the peak torque rating in thousands of in.-lbs., the polished rod ratings in 100 lbs and the maximum stroke length in inch. The crank influences stroke length which limits the gross production rate. Longer strokes and fewer strokes per minute translate for similar gross production. Due to its size, the installation of the pump unit is not part of the normal installation job and thus, accounted as an extra cost point. Additionally, the pumping unit consists of many heavy and large parts, requires a foundation appropriate for the weight of the pump unit in order to assure it to remain in the correct position and does not sink into the ground.

An SRP can have either an electric or a combustion powered prime mover. If an electric motor is installed a variable speed drive (VSD) can control the strokes per minute and thereby, influence the gross production rate. In a gas or diesel motor, the rotation per minute depends on the availability of gas. The selection of the prime mover has an impact on the energy consumption of the pump and therefore, a high impact on the operating costs. Generally, gas engines cause higher investment costs but also have longer service life, reducing maintenance costs. They can normally run on any wellhead with sufficient gas output, except on sour gas wells. Electric motors are mostly favoured due to low cost, easy control and adaptability to automatic operations.

Further necessary installations are the wellhead which connects tubing and casing to the surface, the flowline connection for transportation of fluids coupled with a check valve which prevents fluids that are already produced to flow back into the well and a stuffing box which normally includes an electronic leakage measurement and seals off the tubing to prevent leakage of well fluids. [6]

Furthermore, monitoring equipment is installed. Both downhole and on the surface a number of sensors and measurement installations can be used to monitor pressure and temperature. Equipment for real time dynamometer graph analysis, well problem diagnosis, automatic speed control, remote control and fluid level measurements are used. Load sensor, position sensors and an interface can be used for pump automation. Optional sensors to collect data concerning number of strokes per minute, beam position, SR rotator, stuffing box and polished rod load can also be part of the installation. [7, pp. 11-12]

2.1.2 Linear rod pump

The LRP is a rather new method of artificial lifting. In Austria, OMV currently plans the first LRP installations, but OMV PETROM are already running a number of them in Romania. This system uses the downhole installations and sucker rods of a SRP (see 2.1.1 Sucker rod pump) in combination with a mechanical rack and pinion drive arrangement on the surface of the well, as shown in Figure 2. [10] The up and down movement of the rack gear and the pumping mechanism is caused by the pinion gear which is driven by a reversible motor. An advantage of this kind of surface installation in comparison to the SRP, is the reduced size and weight.

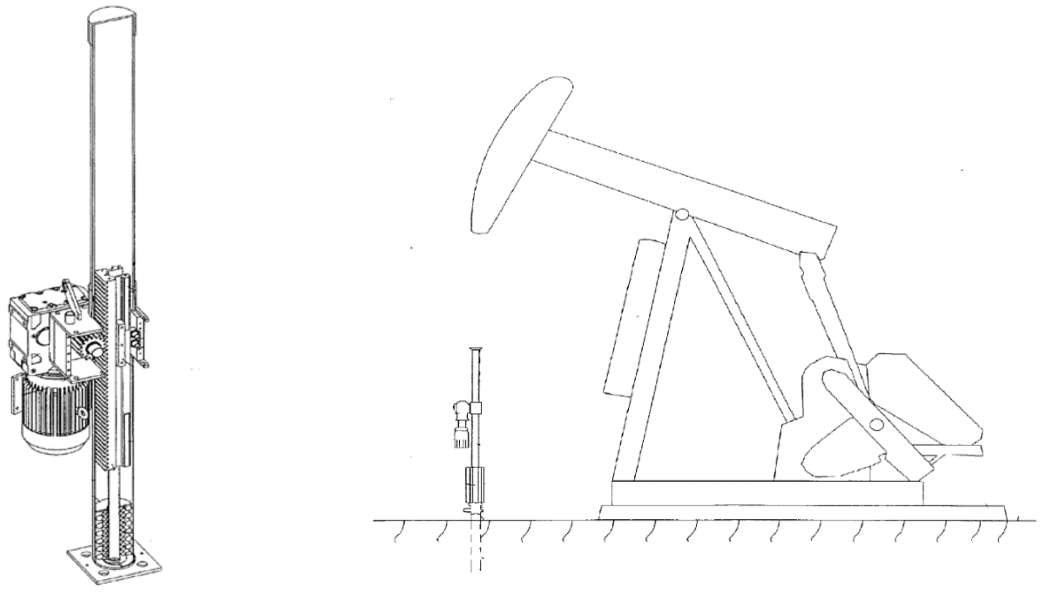


Figure 2: Surface installation of a linear rod pump [10] [11]

2.1.3 Progressive cavity pump

PCPs are positive displacement pumps which transfer fluids by eccentrically rotating a metal spiral rotor inside a spiral stator, either made of elastomer or metal. Cavities taper down toward their ends and overlap with their neighbours, so that, normally, no flow pulsing is caused by the arrival of cavities at the outlet. The volume of the displacement depends on the geometry of rotor and stator, as shown in Figure 3, the diameter of the rotor, the rotational speed (rotations per minute) and the pitch length of the stator. [1, p. 349] Due to slip losses, production rate will be reduced when higher counter pressure is encountered.

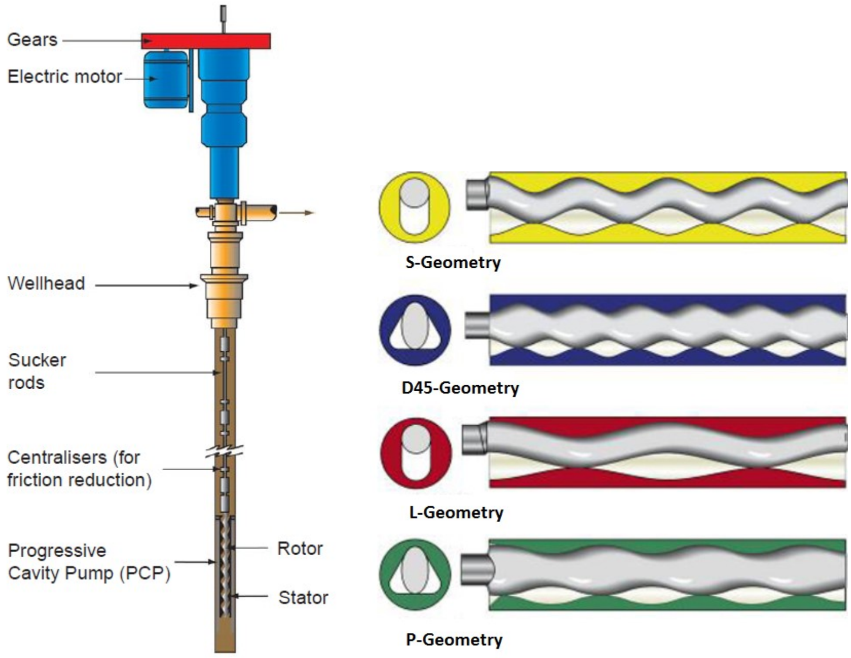


Figure 3: Schematic of different rotor / stator profiles [12]

In the standard set-up for oil wells the stator is attached to the tubing while the rotor is attached to sucker rods (see 2.1.1 Sucker rod pump) with a polished rod on top. The sucker rods are rotated by an electric motor which is installed at the wellhead or by a downhole electric motor. A stuffing box needs to be installed at the wellhead to ensure a hydraulic seal between well and surface.

PCPs are usually installed when highly viscous liquids, like heavy crudes are to be produced, or a high water cut or solids production is to be expected. It works well in deviated and horizontal wells, when equipped with a downhole motor as high deviation may cause extensive wear on the sucker rods. Further advantages of a PCP are a minimum areal footprint on the surface and low visibility. Due to VSD it is highly flexible in terms of production. A PCP can also be used in reverse action, if fluid is pumped through the stator and the rotor is set in motion. This can also be a disadvantage when the pump is stopped and the liquid column flows back giving the motor additional load to bear. [6]

2.1.4 Electrical submersible pump

ESPs are downhole pumps consisting of an electric motor and a centrifugal pump which normally are deployed on the tubing string. ESPs operate by introducing centrifugal forces on the fluids that are to be produced. The production fluid first passes through an impeller gaining radial velocity and then through a diffusor, where this velocity is transformed into pressure. Every stage is just able to overcome a certain head (in feet or meters) in the borehole, so the number of stages installed decides rate, pressure and required power of the pump. Non-conductive oil in the housing is used to lubricate motor bearings and to transfer the heat, which also is dissipated by fluids outside the motor chamber. A protector prevents produced fluids from entering the electrical motor and connects the pump to the motor. It also contains trust bearings to carry axial load and equalizes the inside pressure to the wellbore pressure.

Figure 4 shows a schematic diagram of an ESP configuration. The downhole motor, the driving force of the pump, is connected by an electric power cable to the surface. Depending on the specifics this cable can be either round and attached to the tubing or a flat-cable running along the pump and motor protector. The coating of the cable either consists of EPDM (ethylene propylene diene monomer) or PEEK (polyether ether ketone), depending on the swelling properties of the produced fluids. The wellhead requires a specific design for this cable outlet. ESPs usually have electrical control equipment installed at the surface including VSD, data acquisition and communication equipment, and motor controllers to provide control and protection. A soft start controller can be installed at the surface to minimize start up currents and transient loads on motor and pump. [6]

ESPs can react very sensitive to free gas which mostly comes from segregation of the phases in the impeller of the pump. The amount of gas a pump is able to handle depends on its specific speed. Therefore, radial discharge pumps with low specific speed are more susceptible to gas problems than axial pumps. If gas cannot be prevented to enter the ESP system, e.g. by using natural separation in the casing annulus, special pumps need to be installed that can handle the gas along with the liquid without losing effectiveness. [1] ESPs are installed when a high flow rate is to be expected from a well as they can produce up to 4700 m^3 per day.

To determine and optimize the well performance, associated pump, motor and cable selections have to be given careful considerations. An ESP can be deployed by tubing, coiled tubing, or cable at the necessary setting depth.

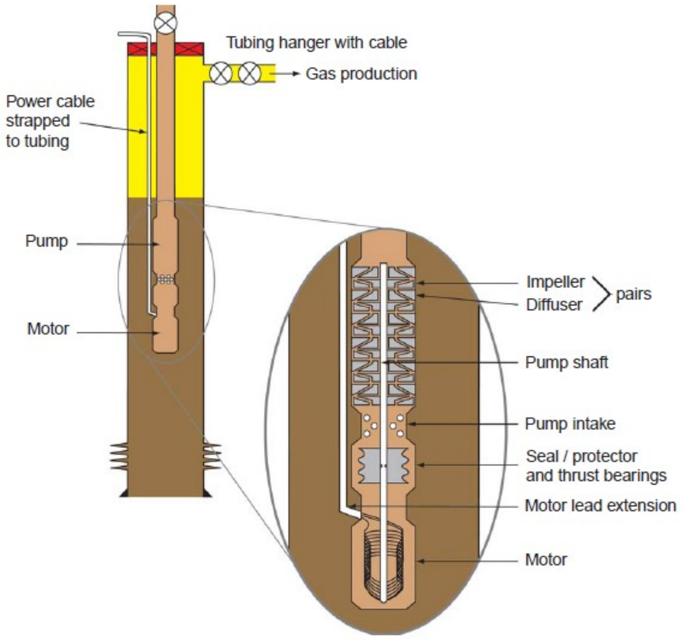


Figure 4: Typical ESP configuration [1, p. 320]

2.1.5 Gas lift

Gas lift is the only ALS that does not require installation of a downhole pump. As it is regarded as simple and flexible, and if the required gas is available, gas lifting installations are often chosen as ALS.

Fluid is produced by lowering the weight of the liquid column via injection of gas into the production string through a number of gas lift valves. The gas flows downhole either through the casing or an injection line and then enters the production stream through a carefully positioned valve. The resulting pressure drawdown permits the flowing of the well. A gas lift valve is a pressure regulator which is opened and closed by injecting pressure into the tubing and/or casing. Those valves usually contain a spring or nitrogen charged bellows to either oppose the lift gas pressure or the flowing fluid pressure to support the closing action.

Two types of gas lifting exist. Continuous gas lift operates by continuously injecting gas into the production tubing, resulting in higher consumption of gas but lower injection pressures. The other option is intermittent gas lift, which is often used for low-rate wells and uses a different kind of valve. A timer controls gas injection and an accumulated fluid slug is produced with each injection. [1] GL requires very stable gas injection pressures as fluctuations lead to an opening and closing of the valve.

The start-up procedure of fluid pressure operated gas lift valves is a very complicated and has to be executed very precisely. Depending on the liquids produced, it may take relatively long until the desired rates can be produced. Prior to starting all valves are open. The lift gas is then injected into the annulus and flows through the top valve, lifting the liquid above this valve. As the fluid column is lightened, the flowing well pressure decreases upon which the upper valve to close. This process is repeated until the deepest operating valve is reached. Gas can only pass through the operating valve while all valves above are closed to prevent excessive use of gas. [6]

GL is often used to produce high volumes and work well with a high gas liquid ratio (GLR) also in highly deviated or deep wells or in small diameter well completions. Due to the lower number of downhole installations GL can be used in high temperature environments.

As a prerequisite, GL needs availability of gas within the specifications to function. Therefore, GL may not always be applicable. The designing of the valves and the required spacing is very important as the ALS would otherwise not function and thus turn out rather time consuming. The produced gas from the well must be separated nearby to be made available again for injection leading to an increase in operational costs. Furthermore, a low specific oil gravity or a high viscosity may result in poor lifting capacity.

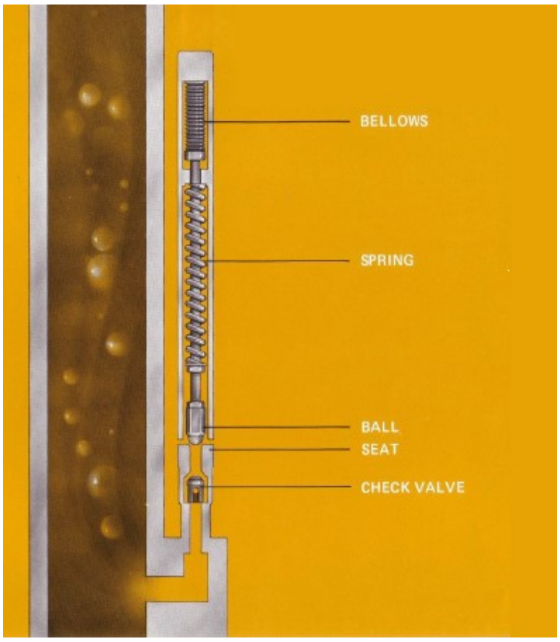


Figure 5: Pressure operated gas lift valve, [cutout] [6]

2.1.6 Comparison of ALSs

The following table gives an overview over some of the technical key parameters for the selected artificial lift systems used by OMV. These parameters are generalized here and may not be applicable to all cases or special designs.

Table 1: Comparison of key parameters for different ALSs [8] [13]

	SRP	LRP	PCP	ESP	GL
installation depth [OMV]	450 –2,750 m	[500-2,000 m]	790 –1,200 m	850 –2,650 m	700-2,780 m
flowrate [OMV]	1-250 m³/d	[1-250 m³/d]	23 - 55 m³/d	90 - 1,460 m³/d	1 - 220 m³/d
high volume lift capabilities	acceptable	acceptable	limited to volume between stator and rotor	very good,	very good
gas handling	good	good	good	very sensitive	very good
water cut	not sensitive	not sensitive	not sensitive	not sensitive	may reduce efficiency
fluid gravity	>8° API	>8° API	>35° API	>10° API	>15° API
solids	good	good	very good	acceptable	very good
deviation	sensitive	sensitive	sensitive, not sensitive with a downhole motor	not sensitive	not sensitive
overall pump efficiency	good total system efficiency	good total system efficiency	high when energy consumption is low	good for high rate wells	better for wells with low injection volumes
flexibility	very high	very high	high	moderate with VSD	very high, limited by tbg. size
prime mover	Gas or Electric Motor	Electric Motor	Electric Motor	Electric Motor	Compressor
servicing	Workover	Workover	Workover	Workover or wireline	Workover or slickline
potential failure causes	Over torque due to stuck pipe, bent rod, leaking plunger, dog leg severity	SR corrosion fatigue, connection failure, guide related damage	settling sand during shutdown causes high torque, SR fatigue	Abrasions due to solids, temperature related failure, dog leg severity	Stuck valve due to debris, incorrect injection gas pressure, corrosion of valve stem

2.2 Life cycle cost analysis

This section of the thesis will give an introduction to life-cycle costing based on a literature review.

2.2.1 Background

The term life cycle costing was first used in 1965 in a report titled ‘Life Cycle Costing in Equipment Procurement’ prepared by the Logistics Management Institute, Washington, D.C., for the Assistant Secretary of Defence for Installations and Logistics, U.S. Department of Defence, Washington, D.C. [14] Since 1974, several states in the USA have made it mandatory to conduct a life cycle analysis before planning, designing and constructing any state building. Thereafter, life-cycle costing has been adapted as means to support the decision-making process.

The petroleum industry started using life-cycle costing with increasing frequency in the 1990ies. The concept, that systems should be planned, designed, installed and operated with regard to affordability and the total system value of the intended life cycle has been applied by various companies and was discussed in numerous papers. For instance, Philips Petroleum Co. in Norway used LCC to assess a redevelopment project in the Norwegian North Sea. LCC was applied to choose between different equipment packages, surface treatments and seawater piping systems. [15] Ecopetrol S.A. in Colombia used LCC to ascertain the feasibility of the design change of a hydraulic pumping unit. [16]

In Europe, standards for the petroleum industry have been published to define the objectives of life-cycle costing. ISO 15663-1:2000, ISO 15663-2:2001 and ISO 15663-3:2001 were published in 2000 and 2001 and provide guidance on the use of life-cycle costing techniques within the petroleum and natural gas industry. [17] NORSOK O-CR-002, standardizes life cycle cost calculation methods for production facilities in Norway. [18]

2.2.2 General application of life cycle costing

Many definitions of LCC exist, example given: ”The life cycle cost of an item is the sum of all funds expended in support of the item from its conception and fabrication through its operation to the end of its useful life.” [19]

LCC are generally used for evaluating and selecting the most economic option of alternatives. They can be used as an assisting tool for either decision making or for justifying technical solutions based on their total costs. To only use one single criteria for equipment selection, e.g. acquisition costs, often results in bad financial decisions. John Ruston said: ‘It’s unwise to pay too much, but it’s foolish to spend too little.’ This can be seen as the objective of an LCC: choosing the most cost effective approach from a series of alternatives. [20]

LCC may be applied for different reasons like affordability studies where the impact of the LCC on long term budgets is measured. In source selection studies LCC among competing suppliers are compared and in design trade-offs the impact of specific designs to the LCC are analysed. Further examples for applying LCC are, repair level analysis, supplier sales strategies, or warranty and repair cost analysis. [20]

As stated above, in general, the goal of an LCC is to select the most cost effective solution. Effectiveness of a system can be defined as the measure of a system to being able to fulfil requirements including availability, reliability, maintainability and capability.

$$Effectiveness = Availability * Reliability * Maintainability * Capability \qquad (1)$$

Availability is defined as the probability of a system to be available for use. It is a measure of how frequent a system is up for running and it allows estimating of uptime for a system within a given interval. It is typically expressed as “Uptime”, or average run life of failed installations (ARLF) and “Downtime”, also called mean time to repair (MTTR). [21]

$$Availability = \frac{Uptime}{Uptime+Downtime} \qquad (2)$$

Reliability is a measure of the probability for failure-free operation during a given interval (e.g. a year) and if the system operates satisfactorily for a defined time window and under defined conditions.

$$Reliability = \exp(\frac{-365}{Uptime}) \qquad (3)$$

Maintainability is defined as the probability that a failed system can be restored to its operational state and the time needed to complete this maintenance. New projects should always be planned in accordance with health, safety and environmental requirements. A design can be measured by the ease, economy, safety and accuracy in scheduled or unscheduled maintenance. [21]

$$Maintainability = 1 - \exp(\frac{-t}{Downtime}) \qquad (4)$$

Capability compares the productive output to the productive input and gives indication to the systems capability to perform its intended function. [21]

Goal of performing an LCC is to be able to select the solution with highest effectiveness and lowest LCC.

Often, conflicts of interest may occur between different departments or project functions. The project engineer may wish to minimize capital costs, production may want to maximize uptime hours and accounting may prefer to maximize project net present value as the only criterion. LCC tries to match these conflicts by concentrating on cost, facts and time.

2.2.3 Methodology

Life cycle costing of a physical asset should commence when purchase is first considered. Then, the overall process is iterative and may need to be repeated a number of times as costs and estimates have to be assessed and re-assessed with each stage during a life cycle.

Literature presents many similar ways to perform LCC. ISO 15663-1:2000 suggests dividing the LCC into 4 steps each containing various tasks.

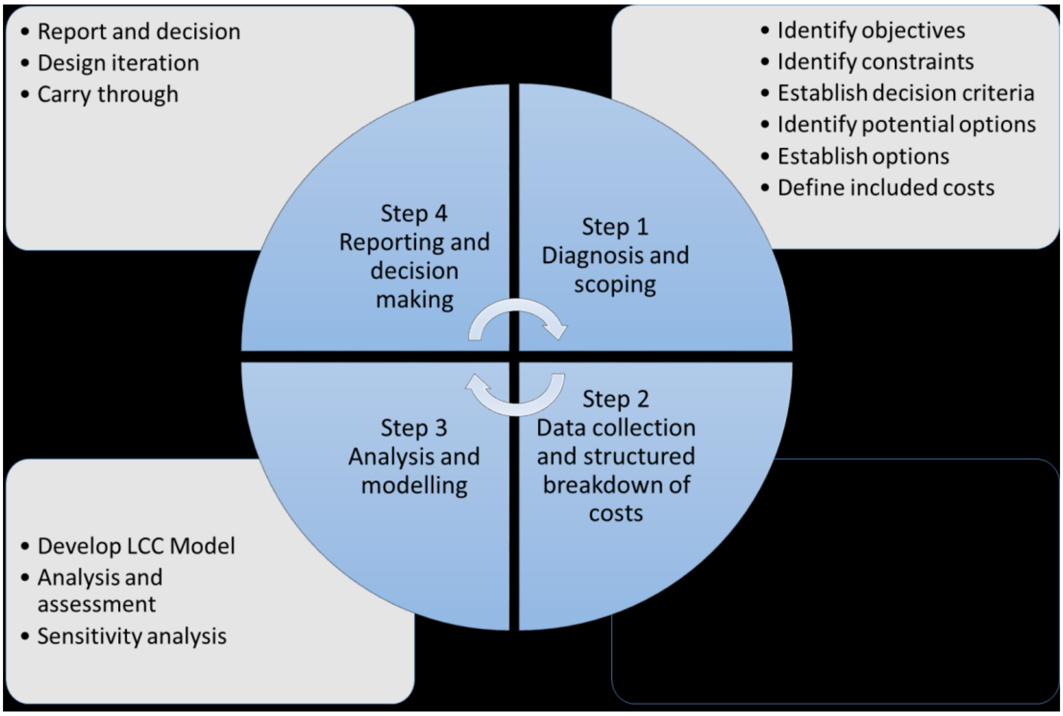


Figure 6: LCC-Workflow as suggested by ISO 15663-1:2000 [17]

In the first part of the LCC, **step 1 diagnosis and scope**, it is essential that the problem is defined correctly. This includes identification of objectives, constraints and possible alternative options that fulfil all technical requirements. During this stage, a team of engineers conducts studies and brainstorms for alternative solutions. Problems and significant financial criteria must also be recognized in step 1. Furthermore, one of these identified options should be selected and established.

In **step 2 data collection and structured breakdown of costs**, data from reliable and valid sources are collected, identified and sorted. Following that, potential cost drivers have to be identified and the cost elements defined. This is done by recognizing common costs for each of the options. These are often excluded from the LCC as they do not influence the ranking of the alternatives. As a next step the cost structure needs to be defined. This step involves grouping costs, so that possible trade-offs can be identified and all major costs and activities should be listed and defined to avoid misinterpretation. Another objective of the cost structure is to enable the detection of the impact that cost changes will have on the result of the LCC. The cost structure also depends on the depth and range of the LCC study. [22] One possibility is using a general life cycle cost model, where the LCC is not tied to any specific system or equipment but rather divided into e.g. recurring and nonrecurring costs, or acquisition, operation & maintenance and disposal costs. Over the years, many mathematical models for specific LCC models have been developed to estimate life cycle cost of specific systems or items, for example for switching power suppliers or for health care facilities. [17] [20] [21]

Step 3, analysis and modelling consists of three very important steps. First an analytical cost model, as simple as possible, must be developed or chosen for estimating purposes. It describes the cost of an item as a function of one or more independent variables. A depreciation rate has to be defined and data should be prepared for the net present value (NPV) calculations. Also, an appropriate methodology to evaluate the LCC has to be found. The second phase of Step 3 is the actual analysis and assessment of the LCC. The output should include all technical and economic aspects and should allow a ranking of the options. It is important to question the outcome and to analyse if the individual cost totals coincide with the initial estimations. Once the results have been accepted a sensitivity analysis has to be performed to determine the plausibility of the outcome. Usually this is done by performing a sensitivity analysis on each parameter and examining the range over which the decision does not change. [17]

Step 4, reporting and decision making includes establishing the optimum economic solution and reporting of the recommendation. This report may consist of the preferred option, further iterations and further studies, where potentials may lie for further improvement over the chosen alternative. [17]

2.2.4 Limitations

- LCC is, like all cost based analysis techniques, subject to certain limitations, which need to be known and included into reasoning during the assessment.
- As LCC is not an exact science same sets of data will result in different answers and recommendations when done by different companies.
- The outcome of an LCC is in general not considered right or wrong, but rather reasonable or unreasonable. LCC outputs are only estimates obtained from collected data and can therefore never be more accurate than the inputs and the intervals used for the estimates.
- As a consequence, and due to the fact that normally more data is required than available, LCC estimates lack accuracy.
- LCC should not be used as a tool for budgeting as it is not concerned with determining the financial viability of a development but is used for comparing and ranking different viable options for a specific asset. [20]

3 Life cycle costing for artificial lift systems

Objective of this master thesis is to research if LCC can be used to select an artificial lift system for a future field or well. Therefore, an LCC had to be conducted and main cost drivers for 5 artificial lift systems (SRP, LRP, PCP, ESP and GL) that are operated by OMV in Austria had to be identified. This was done by evaluating the data from installations of existing wells with ALS installations.

3.1 Step 1: Diagnosis and scoping

OMV is an integrated international oil and gas company, active both in upstream and downstream businesses. In Austria OMV operates over 600 wells equipped with ALSs as can be seen from Table 2. From these wells, the majority is produced by beam pumps, with gas lifting as the second most installed system, as shown in Figure 7. With the recent drop in oil prices it is even more important to analyze costs of different ALSs over their entire life cycle and to find a way to decide on the most cost effective ALS during the planning phase of new installations.

Table 2: Number of ALSs operated by OMV in Austria, sorted by type

SRP	478
GL	101
ESP	43
PCP	3
Total	625

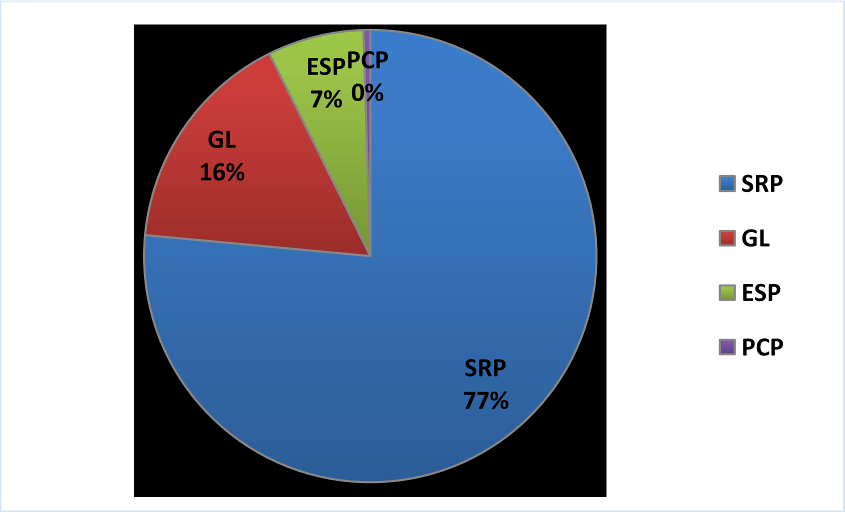


Figure 7: Distribution of ALSs in OMV Assets in Austria in [%]

When deciding on technical feasible alternatives it is essential that all design criteria are considered. A major decision factor hereby is the desired production rate during the operational phase of the system, as different ALSs operate within different ranges. So, an ESP would be favorable for wells of high flow rate, while sucker rod pumps also work efficiently at lower rates.

Another aspect to be considered are the properties of the fluids to be produced, such as oil viscosity, oil gravity and gas liquid ratio. Many ALSs can have difficulties and may experience an increased number of failures when installed in wells with to high specific gravity due to over torque which could eventually lead to catastrophic events for part of the installations. Furthermore, the corrosive nature of fluids has to be considered. Although, corrosion inhibitors are generally introduced into the producing systems, ALSs with a higher number of downhole installations are usually more prone to corrosion related failure.

During the planning phase of the ALS a special focus has to be put on depth, wellbore size and wellbore trajectory, especially in regard to dog leg severity. Often ALSs have limitations in their application in depth, as structural integrity cannot be granted due to high loads on the surface equipment. To different degrees, most ALSs have restrictions regarding dog leg severity. While an ESP may only have difficulties during the installation of an ESP when facing uneven wellbore trajectories, due to the fact that the maximum allowable shaft stress should not be exceeded, ALSs containing sucker rods can have increasing difficulties due to the reciprocating movement of the downhole installations and the hereby resulting increase in friction between sucker rods and tubing wall.

Another design criterion are a wells sand and solid production, and its probability for scales and paraffin deposits as many ALSs can react sensitive to solids in the production stream. Even more so after an unplanned stand-still of the pump or ALS, as during the restarting process additional loads due to the settling of the sands have to be transported. Furthermore, sand production can plug flow paths and valves and may lead to higher erosion in the flow stream particularly, in wells with high flowrates.

All ALSs need some kind of power unit and regardless of the source of energy most systems react sensitive to unplanned stops. Therefore, a stable energy supply is essential. This requires special consideration when operating in areas and countries with unstable or unreliable energy grids. Furthermore, considerations concerning operating staff, their experience and different difficulties they may face with different ALSs should be included when selecting feasible alternatives for an LCC.

One simple selection method for deciding on alternatives is to consider an ALSs capability in depth and rate identifying their corresponding operational ranges.

Most of OMV’s wells in Austria operate within a specific range of depth and gross production rate. Figure 8 shows in a graph of gross rate in cubic meter per day versus installation depth in meters the outlines of the areas where the different ALSs are operated

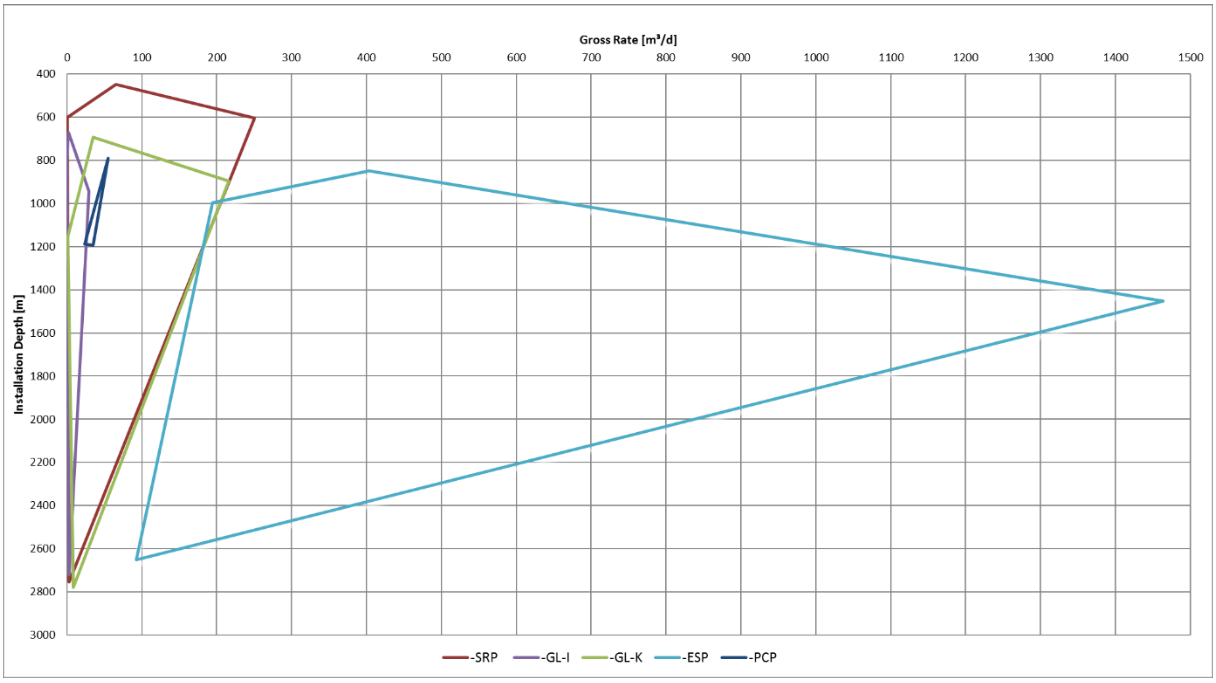


Figure 8: Outlines of different ALSs in gross rate versus installation depth

Figure 8 also visualizes the fact that although OMV only operates a smaller number of ESPs they operate in the widest range of flow rates, with gross rate up to over 1400 cubic meter per day. SRP are used for wells with moderate flow rate but are installed in depths of 400m to over 2700 m. OMV only runs 3 PCPs which are operated within a very small margin of depth and gross rate. The exact placements of wells within the rate versus depth diagram are shown in Appendix B: , Figure 32.

The technical installations and a general comparison of the different ALSs are described in the literature review in chapter 2.1, Artificial lift systems. Goal of this thesis is to analyze different cost factors which influence the life cycle costs of each type of artificial lift system. To be able to generate an output which enables a general comparison of these ALSs within different specifications a more universal approach had to be taken. Therefore, absolute definitions of technical requirements and limitations cannot be included in this part of the LCC and have to be made individually for each well to be completed.

After the different ALSs have been established as possible alternatives costs were analyzed for each system. Therefore, cost estimates, SAP-extracts and cost lists used by OMV were researched. The list of data file references and when they were generated are listed in 8. Data File References of this thesis.

3.2 Step 2: Data collection and structured breakdown of costs

The right selection of an ALS is dependent on many different attributes, which influence the type and specifications of the installations as well as the operation of the ALS over its life cycle.

Part of this master thesis is to compile a comprehensive list of possible cost elements for the already described five ALSs.

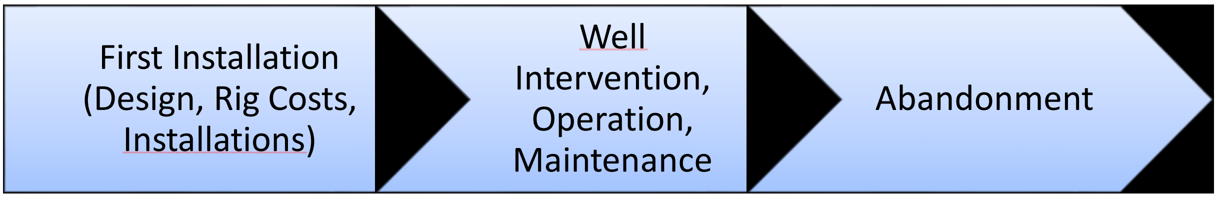


Figure 9: Schematic of a life cycle of an artificial lift system

Generally, the life cycle of an ALS consists of three major parts, as shown in Figure 9. The first is the planning, acquisition, and first installation of the system. The second part is the operational life of the ALS including energy costs, but also the maintenance, repair and replacement of broken and worn parts. Last part of the life cycle, is considered to be the abandonment of the well, which includes removal of installations and securing of the well. Yet, the specific cost elements of these groups vary from ALS to ALS.

After reviewing cost estimates for different ALSs and wells a cost structure was decided on. This structure is divided into 5 categories of costs, as seen in Figure 10 with sub sets each, depending on the type of ALS. All cost elements are allocated either to First Installation, Well Interventions (WI), opex (operational expenditures), Deferred Production or Abandonment.

Generally, capital expenditures (capex) are funds by a company to acquire assets, such as an ALS and include all costs occurring during first installation while opex is the money a company spends on ongoing daily operations. However, within OMV, tubing used during first installation is accounted to opex.

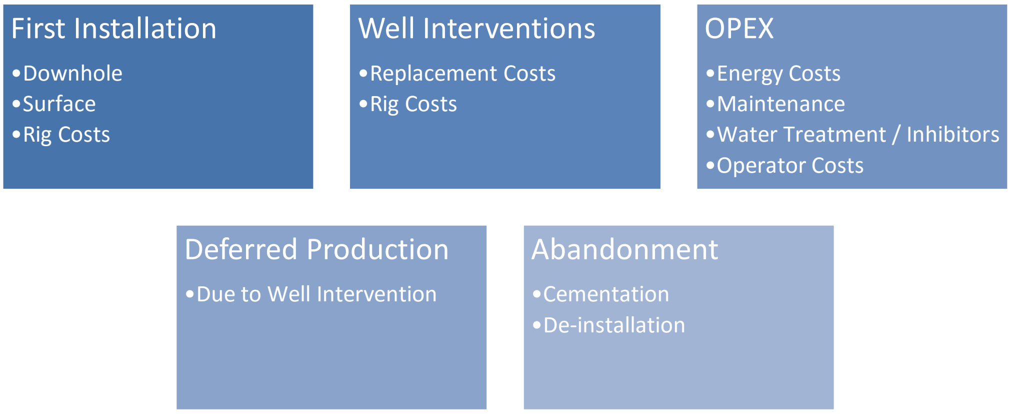


Figure 10: 5 Categories of cost structure

3.2.1 First installation costs

First installation costs are all costs incurred until production is started including planning, acquisition and installation and are, with the exception of tubing costs, accounted to capex.

3.2.1.1 Planning & design

First cost element in the life cycle of any ALS is its design and planning phase, which consists not only of the time needed by a company's personnel to plan the exact set up and installations put into the well but also includes procurement costs for required design software, which may need to be kept updated and can lead to further costs. This is accounted with a fixed overhead amount.

3.2.1.2 Installations

A mayor impact to the total costs are the costs due to downhole and surface installations. The different installations needed for each ALS is described in 2.1 Artificial lift systems.

3.2.1.3 Rig costs

Not only the installations themselves have a big impact in the overall costs of the first installation but also the labour and equipment necessary to actually install these items.

This also includes site preparation before the installation of the ALS can be started, in particular the well site needs to be prepared for the workover rig. The surface has to be put into the proper condition by levelling, securing it against any spillage of fluids and assuring adequate connections to the power grid.

Another cost factor relates to labour costs. A work over normally involves a standard crew of 4-5 people. The time needed for a well intervention (installation of ALS) varies and depends on depth, complexity of the system, experience of the crew and can be influenced by unpredictable events such as injury or loss of equipment. Furthermore, each employee working in the field is provided with several sets of personal protective equipment, like fire-resistant overalls, helmet, goggles, boots, etc. Regularly, the cloths are cleaned by OMV and returned to staff in field.

The rig itself is highly important for setting up an ALS. OMV operates five work over rigs, mounted on trucks with an extendable mast. Each rig is accompanied by an office container equipped with computer and office supplies, shower, toilette, changing room, and coffee machine. A container with general tools like hammer, wrenches, lubrication for tubing connections is also part of the rig. Other specific tools like scraper or retainer are ordered if need be from the storage.

As surface space is a limited resource during a well intervention, nearly constant transport of tubing, rods and equipment is necessary between tubing storage and well site. This requires precise planning to avoid any loss of time.

Further costs arise in context of storage. To be able to respond without delay to an equipment demand in case of a well intervention or work over, planned or unplanned, some equipment is permanently stored in a storage facility. Personnel working in the storage facility prepare inventory for delivery, inspect them and if needed repair equipment and tools and put them away again upon return.

3.2.1.4 Summary: First Installation

First installation costs are costs that sum up all expenses that have to be paid before revenues due to production can be earned. Table 3 gives an overview of the cost structure of first installation costs and an estimation of these costs in Euro.

Table 3: First installation costs

First Installation	Cost structure		Dependency	Cost estimates in [EUR]
	Planning & Design		Fixed value	~3,500
	Rig Costs	Personnel	Installation time per ALS	~16,000 - 48,000
		Logistics, Rig…	Fixed value	~22,000 - 27,000
	Downhole Installations	Tubing, Pump, GL valves…	Installations	~60,000 - 220,000
	Surface Installations	Wellhead…	Installations	~75,000 - 177,000

3.2.2 Well intervention costs

Well Interventions are high recurring costs that occur at regular intervals and depend on various factors. A well intervention needs to be performed when an ALS stopped working. Then the installations are removed from the well, inspected, repaired or exchanged if non-functional. The following costs and parameters can be allocated to well intervention costs.

3.2.2.1 Rig costs

Each well intervention needs a workover with most of the already mentioned cost elements like site preparation, work force, rig and equipment, logistic and storage. Additionally, each work over means a stop in production and a loss of revenue for the period of time when the pump is not running.

3.2.2.2 Replacements

Depending on cause of the malfunction, the respective parts of the installations have to be replaced. Generally, during well interventions, tubing, sucker rods, down hole pumps or gas lift valves, respectively have to be replaced with working equipment which may be either new or used. If possible, the equipment is repaired and returned to storage otherwise it is disposed of.

3.2.2.3 Average run life of an installation (ARLF)

To be able to calculate the number of times a pump needs to be replaced during its life cycle, the average run life, the ‘uptime’, of each ALS needs to be estimated. Each installation is subjected to an expiring date depending on the intensity of use of the pump. Also, flow rate, installation depth and the combination of parts used influence the run life. Usually ESPs and GLs have a very long run life due to a lesser amount of moving parts installed. This reduces the wear of the parts as well as the probability of erosion. All systems that use sucker rods (SRP; LRP and PCP in case of a surface motor) have elevated risk of tubing or sucker rod failure even more so in deviated wells or wells with high dog leg severity. Furthermore, some ALSs react more sensitive to solids in production stream then others. In order to estimate different ARLF for each pump, old data and input from existing wells were analysed. For the case of ARLF for SRP first, various wells with different flow rates were compared with each other. As can be seen in Figure 11, a clear correlation between flow rate and run life can be observed. Additionally, average run life for each downhole pump was assessed as well as the relationship between ARLF and the surface unit was researched.

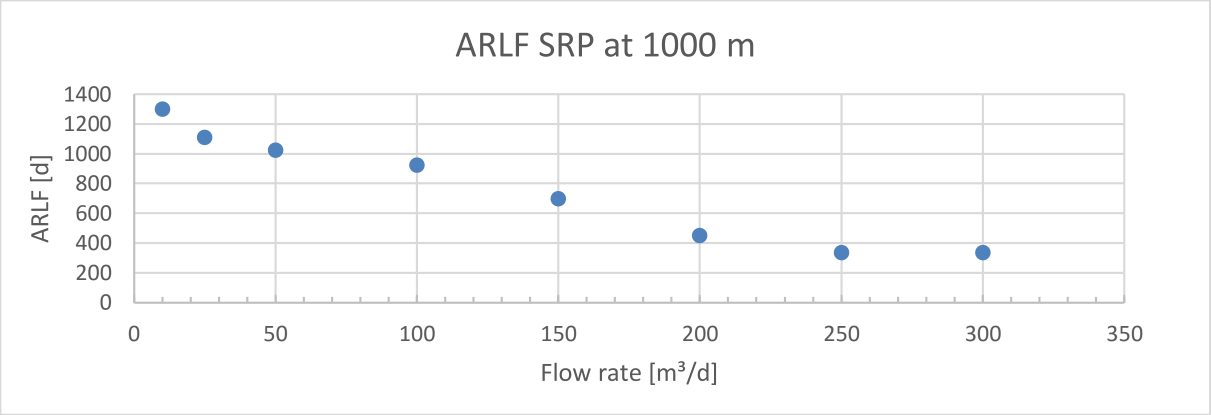


Figure 11: Average run life of a SRP at 1000 m depth

3.2.2.4 Mean time to repair (MTTR)

MTTR can be seen as the ‘downtime’ of an ALS and is the time needed to repair it, starting from the moment the failure is noticed until the fixed pump is running again. It depends on the complexity of the system and the number of items that need to be replaced, as well as the depth of the installation and the experience and number of people working on the repair. Basis for this estimation was a statistic on the averaged repair time per lifting system, generated by OMV (see data file references and 9.2 Appendix B: Graphs and Diagrams).

3.2.2.5 Summary: Well Intervention

Costs due to well intervention are high recurring costs and a high influencing factor on the overall cost of an ALS. Table 4 shows the costs and factors influencing well intervention costs as estimations for these values.

Table 4: Well intervention costs and influencing factors

Well Intervention	Cost structure		Dependency	Estimation	Unit
	Replacements	Tubing, GL Valves, Sucker rods	Installations and ALS	~ 34,000 - 153,000	[EUR]
	Rig Costs	as in First Installation	ALS	~ 45,000 - 86,000	[EUR]
	MTTR		average repair time per ALS	~ 35 - 135	[hours]
	ARLF	SRP	flow rate, installations, depth	~ 0 - 1100	[days]
		LRP		~ 0 - 1100	[days]
		PCP		~ 0 - 623	[days]
		ESP		~ 650 - 1550	[days]
		GL		~ 780 - 3100	[days]

3.2.3 Operational expenditures

Operational expenditures are the recurring day-to-day costs that come with operation and maintenance of the ALS. As OMV has currently no LRP installed in Austria, it has been decided upon together with OMV, that most of the parameters calculating the recurring costs are assumptions based on the behaviour of SRP. The parameters for all other ALSs are estimations based on past performance of the systems in similar settings.

3.2.3.1 Energy costs

Energy costs are high regular costs occurring from the daily operation of an ALS. They are calculated by the overall energy consumption of a system multiplied by the current price of electricity. The energy consumption of a pump system is influenced by type and efficiency of the prime mover, as well as the energy needed to lift the liquid to the surface. Other influencing factors are downhole pump, surface pumping unit, depth, production rate, monitoring equipment and density of the production fluid. If the prime mover is powered by gas, the energy costs can be lowered drastically, as this gas is taken without processing directly from the annulus.

In case of gas lifting the energy costs are obtained by the consumption of lift gas and the processing costs of the gas, which has to be available.

3.2.3.2 Operator costs

People are responsible for monitoring and keeping control over the operation of the ALS. This cost element includes labour costs and training costs. In general, personnel that is technically trained is eligible to higher income. Therefore, operator cost has a big impact on the operational costs of artificial lift systems.

3.2.3.3 Monitoring and maintenance costs

An operator of oil field is obligated by law to monitor their wells regularly. This includes a visual inspection of each well site as well as monitoring it electronically. During such inspections, small maintenance work on the surface may be done directly such as refilling motor oil into the prime mover. More serious maintenance work however, or if damage is discovered, or if the pump is found to be not running, require a respective examination conducted and a well intervention will probably have to be prepared. Furthermore, the maintenance of the streets leading to and the surface surrounding the well site also need to be maintained. All of this needs personnel and time, as well as materials and transportation to the various well sites that add to the costs.

3.2.3.4 Environmental costs

Environmental costs include all costs attributed to additional activities that are needed to ensure that the environment is not affected. The most important cost factor in this category is the cost of water treatment. Most mature wells have a high water cut, meaning that a high amount of water is produced. Water treatment facilities are built to remove pollutants from this water which is then injected into water disposal wells.

3.2.3.5 Chemical injection costs

Reservoir conditions and fluid properties may lead to a corrosive environment within the wellbore or the build-up of precipitations, like scale or paraffin. To counteract these chemical reactions, wells often require continuous injection of treatment chemicals through a chemical injection line. Often this is provided with help of control lines to place the chemicals at the desired injection point in the well. The amount of chemicals required depends mostly on production rates. The estimates for this cost factor were obtained from a list for inhibitor costs provided from OMV (listed in the data file references).

3.2.3.6 Summary: Operational Expenditures

Operational expenditures are costs occurring due to daily production and are therefore costs that arise each year. As can be seen in Table 5, the three factors with the highest recurring costs are energy costs, operator costs and costs due to chemical injection.

Table 5: Operational Expenditures

Operational Expenditures	Cost structure		Dependency	Cost Estimations in [EUR] per year
	Energy	Electricity or Gas	flow rate, ALS	~ 15,000 - 30,000
	Maintenance Costs	Maintenance, Workshop	ALS	~ 1,500 - 5,000
	Operator Costs	Personnel	fixed value	~ 40,000
	Environmental Costs	Water treatment	flow rate	~ 3,300
	Chemical Injection	Inhibitors	flow rate, ALS	~ 15,000 - 35,000

3.2.4 Deferred production costs

An ALS is running to enable production of hydrocarbons. Therefore, every time a pump is not running for any kind of reason, production and consequently, revenues are lost. Generally, a planned repair or replacement will take less time than an unplanned one. Mean time to repair starts at the point of time a pump stops working, continuous until a well intervention is started, to the moment everything is installed and ready for production again. In case of GL further time may be lost as production can only be regained slowly.

A pump may also be stopped to run tests. To receive more data about the conditions in a well, including volumetric flow rate and pressure, well tests are performed. An inflow performance test is often run by lowering a pressure element by wireline into the wellbore. As the rod string would hinder this procedure, the well has to be killed and the sucker rods have to be pulled out. All of this leads to lost accumulation and a loss of revenues.

The loss in revenue can be called an indirect cost which is calculated by the following formula:

$$Lost\ Production = Gross\ Production * (1 - Water\ Cut) * MTTR * Oil\ Price \tag{5}$$

3.2.5 Abandonment costs

Abandonment costs of a well in the oil and gas industry take account of all costs that are occurring due to activities necessary to safely shut the well permanently. This includes removal of equipment, plugging of the well with cement, as well as any environmental clean-up which may be necessary. This procedure is also referred to as removal and abandonment (R&A) or plug and abandonment (P&A). It is important that any hydrocarbon leaks to the surface and into groundwater are prevented from the beginning. However, the well must be checked to assure it is free from obstructions before it is plugged. For safely de-installing the equipment and cementing the well a rig is used, including all costs already defined in rig costs. Additionally, after a well is secured, the surface has to be restored again to initial conditions.

3.3 Step 3: Analysis and modelling

The selection of the preferred alternative is based on the evaluation of the LCC and the key performance indicators (KPIs) that function as either exclusion criteria or ranking criteria of the different ALSs.

3.3.1 Net present value (NPV) calculations

In order to consider time value of money (TVoM), the discounted cash flow method was used to calculate the NPV. This method is used to discount future cost to present value.

$$Present\ Value = \frac{FV}{(1+i)^{(n-0.5)}} \tag{6}$$

Where FV equals the future value of cost at the end of the nth year, (n-0.5) equals the number of years discounted at half year, and i equals the discount rate. As discount rate for LCC calculations the weighted average cost of capital is used added by a risk factor of 5%. The weighted average cost of capital (WACC) is defined as the rate a company is expected to pay on average to all its shareholders to finance its assets and it represents the minimum return that a company shall earn on an asset. It applies for investment capital from internally generated funds, from short- and long-term debt and from equity sources. WACC for petroleum producing companies often lies in a range between 8 and 10 percent. [23].

NPV, also referred to present value cash surplus, is the sum of its discounted cash flow over the years of the asset, and represents the value of the asset to its investor at a given point in time.

For the calculation of the NPV, costs for each ALS as described in step 2, were researched. These costs depend on installation depth of the ALS, top of perforation, gross production rate, initial water cut, duration of the life cycle, WACC, oil price and royalties. Royalty is a duty based on gross revenue, calculated either at the well head or at the sales point, which petroleum production companies have to pay to the host country. [24]

3.3.2 Key performance indicators (KPI)

To be able to reject or accept and to rank alternative solutions, KPIs were created and analysed.

3.3.2.1 Net present value

The most important output and ranking criteria for the LCC is the NPV itself. Usually, a project is only proceeded with, if it shows a positive NPV. An NPV equal to zero would neither add nor destroy value. [24] [25]

3.3.2.2 Costs per cubic meter of oil produced

To facilitate the ranking of the alternatives the costs per cubic meter of oil produced was determined for each ALS. This was carried out for both the discounted costs and the total cost of ownership. However, even though calculations of all ALSs were done with the same input regarding flow rate, the differences in average run life lead to discrepancies in the total oil production per ALS and further differences in the costs per cubic meter. This KPI is a very effective ranking criterion.

3.3.2.3 Total cost of ownership (TCO)

Another ranking criterion is the total cost of ownership, which is defined as the sum of all expenditures uninfluenced by time and discounting. Its purpose is to determine direct and indirect costs of the asset.

3.3.2.4 Average run life of a failed installation

Another method that can influence the ranking of alternatives is the average run life of an ALS, as it also indicates the number of fails that can be anticipated during the life cycle of the asset. Not only does the repair of each failure cause additional cost, also with each well intervention the risk of an accident or injury increases. Furthermore, as OMV only has a limited amount of workover rigs available, choosing an ALS with a low ARLF can lead to schedule problems during well interventions.

3.3.2.5 Internal rate of return

The internal rate of return (IRR) is the discount rate for which the NPV equals zero. The IRR thus can function as a reject-or-accept criteria. If the IRR is higher than the hurdle rate, which is the minimum rate of return required on a project, an investment proposal shall be accepted, otherwise not. However, it is of disadvantage that it does not consider the total investment volume and moreover, that it cannot always be applied. Certain cases can result in inconclusive IRR or no IRR at all. [25]

3.3.2.6 Discounted profitability index (DPI)

The discounted profitability index is also known as discounted return on investment (DROI) and measures a project’s value per money unit invested. It is used as a ranking criterion. [25]

$$DPI = \frac{NPV}{present\ value\ of\ CAPEX} \tag{7}$$

3.3.2.7 Discounted pay-out period

The pay-out or payback period is based on the discounted accumulated cash flow of an asset and defines the period until recovery of the initial investments. On the cumulative cash flow curve it is the point in time when breakeven occurs. As it also expresses the time period a project is exposed to risk, a shorter pay-out period is preferable to a longer one. [24]

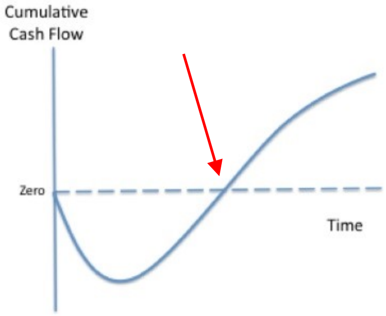


Figure 12: Example of a typical cumulative cash flow curve

3.3.2.8 Cost Effectiveness

One of the most important ranking criteria for life cycle costing is the cost effectiveness which balances the LCC of an ALS with its effectiveness (see chapter 2.2.2 General application of life cycle costing). In case of this LCC this means that the system effectiveness of each ALS has to be calculated. As already mentioned, the system effectiveness is calculated by multiplying availability with reliability, maintainability and capability. The first factor is the ratio between uptime and total time, while the second factor describes the probability of having a well intervention within one year. Maintainability is calculated over the amount of repair a system needs compared to the total time of running, but is also further influenced by other factors such as high dog leg severity. Capability is the ratio between operational input and output.

Cost effectiveness is expressed by a graph, showing system effectiveness on the x-axis and costs on the y-axis as shown in Figure 13. In cases A to C the more effective alternative is clearly identifiable. In case D, an additional decision is required, whether a higher effectiveness or lower costs is preferred by the company conducting the LCC.

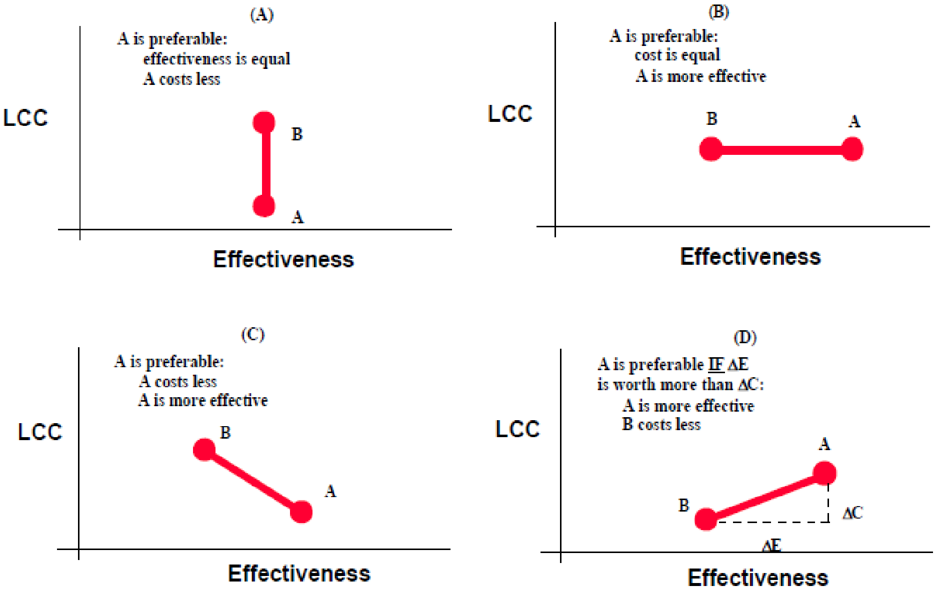


Figure 13: Possible outcomes of trade-off studies for cost effectiveness

3.3.2.9 Summary KPIs

The KPIs mentioned above were defined to support the interpretation of the results and are the output of an LCC. Some of them are used as an exclusion criterion while others are used to facilitate the ranking of the alternative solutions.

KPIs	Name	Abbreviation	Dependency
	Net present value	NPV	discounted cash flow
	Costs of m^3 of oil produced		uptime and downtime of the ALS, flow rate, water cut, oil price
	Total cost of ownership	TCO	all costs per ALS
	Average run life	ARLF	flow rate, depth, installations, ALS
	Internal rate of return	IRR	cash flow
	Discounted profitability index	DPI	NPV, capex
	Discounted pay-out period		discounted cash flow
	Effectiveness		costs, system effectiveness

3.3.3 Health, safety and environment

When working in the field of exploration and production of hydrocarbons, considerations concerning health, safety and environment (HSE) should always be put in focus.

Keeping risks as low as reasonably possible for OMV, her stakeholders, and the environment is OMV’s priority. [26]

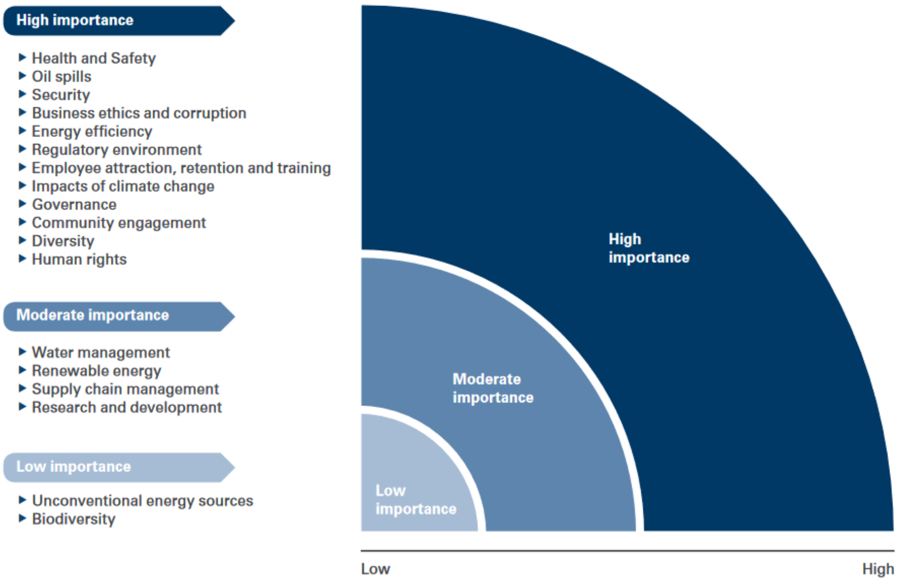


Figure 14: OMVs allocation of different risk factors to importance

In general, risks are part of the business and various unpredictable events can occur during the life time of an ALS. Within OMV and OMV PETROM accidents are subdivided into fatalities and lost time incidents. OMV E&P had two work-related fatalities in operations maintenance in 2015. OMV’s lost time injury rate which is calculated by the number of lost time injuries within a period divided by the total hours worked in said period, dropped from 2014 to 2015 from 0.53 to 0.29. [27]

Although not explicitly expressed, average run life of failed systems can give indication to risks due to well intervention (WI). Each well intervention is an extraordinary activity on an oil well, with risks for the work crew, like heavy objects that can be dropped from heights and explosive atmospheres surrounding the wellbore. Installation of an ESP bears an additional risk due to the cable connected to the pump which must be lowered into the well. This cable is under high tension, if breaking it can lead to dangerous injuries. Therefore, if ARLF is high, and thus the number of well interventions during the life cycle is low, the number of risks the workers are exposed to can be reduced. However, a value of risk per ALS is highly influenced by the experience of the workforce installing the ALS and is difficult to ascertain systematically.

Some of the environmental considerations of an ALS include noise pollution. Due to the fact that some of OMV’s production wells are in the near vicinity of populated area, the acoustic level of an operating artificial lift system must be within an acceptable limit as seen in Figure

15. Depending on the ALS, a constant noise level between 80 and 110 dB can be generated by the respective surface equipment. [28]

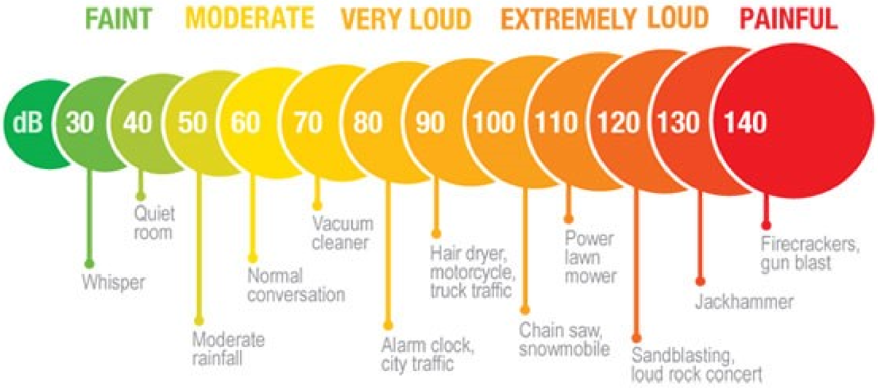


Figure 15: Noise levels of everyday sounds [29]

Other environmental considerations include exhaust and particle emissions, waste water emissions, ground water consumption and accumulation of hazardous and non-hazardous waste.

As an LCC is an analysis of systematic costs that can be categorized for different alternatives, HSE is not explicitly considered in this LCC analysis apart from water treatment costs and ARLF.

3.3.4 Sensitivity analysis

As part of every LCC analysis a sensitivity analysis has to be performed in order to determine the plausibility of the outcome and to measure the effect of a given input on a given output. As some cost elements in the model are estimations, net present value and total cost of ownership contain several uncertainties. Sensitivity analysis show which variable would cause large deviations from the result if they differ from expectations.

To account for these uncertainties a tornado chart was completed both for NPV calculations and the total cost of ownership (TCO) calculations. In both cases the variable input parameters were adjusted up to 10 percent in either direction, and the change of the output value was observed.

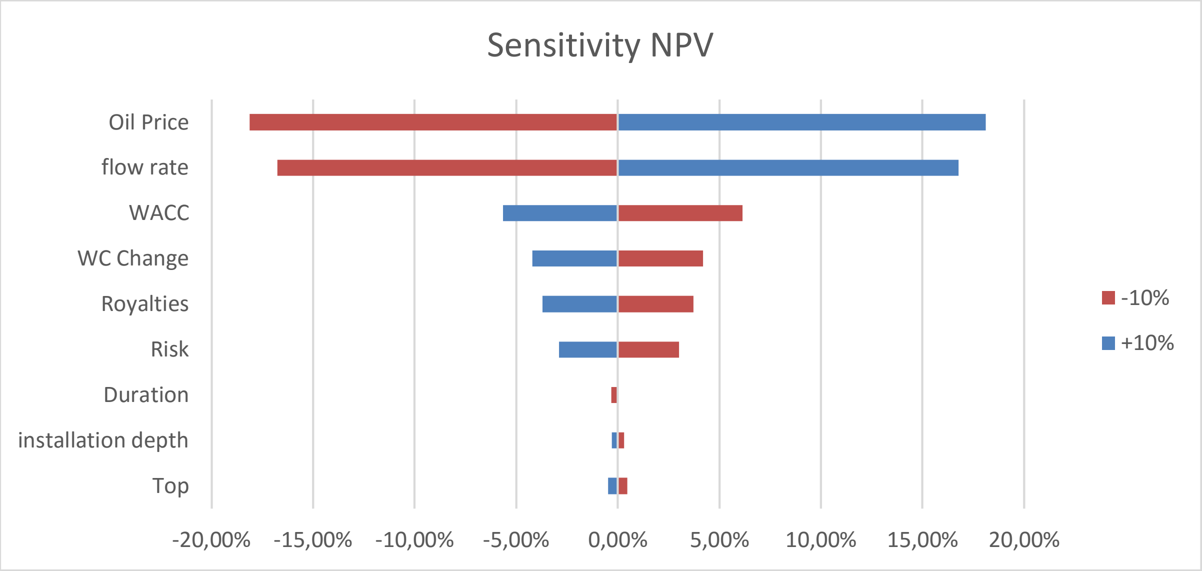


Figure 16: Tornado chart for NPV calculation

As shown in Figure 16 the inputs with the highest influence to NPV are the oil price, leading to a deviation of 18 percent, and the flow rate, leading to an approximately 16 percent deviation whereby most of the input variables have values below five percent.

An identical sensitivity analysis was performed for the TCO calculation. As the TCO does not include revenues, influence of the oil price was expected to be and is much lower, as can be seen in Figure 17. The oil prices residual influence is due to deferred production. The duration of the life cycle has with over eight percent by far the highest influence on the outcome of the TCO. This is due to the fact that with an increased life cycle operational expenditures and well intervention costs will be added every few years.

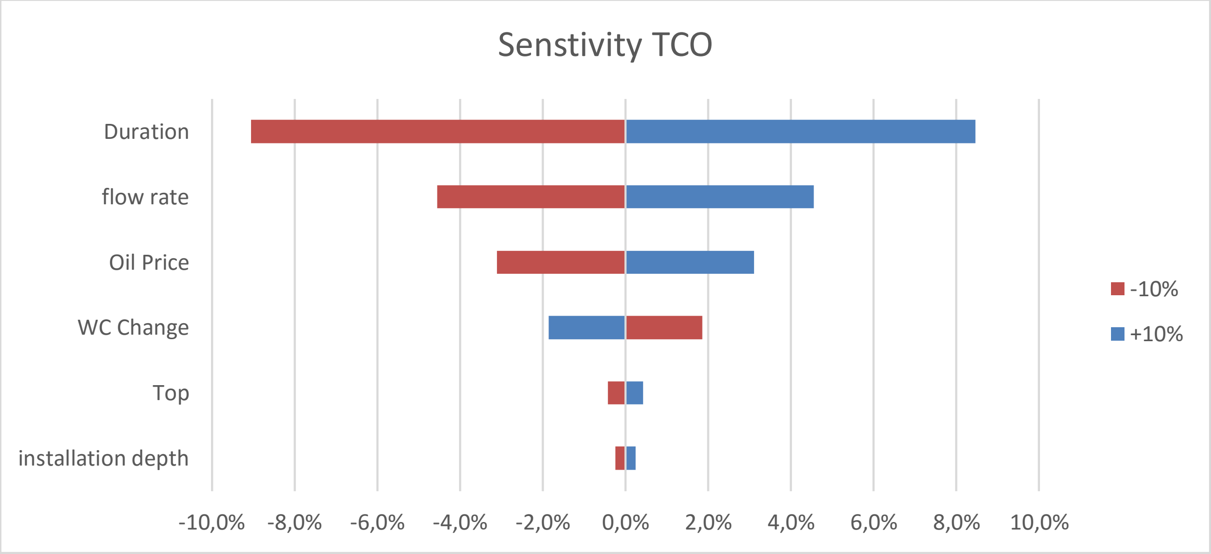


Figure 17: Tornado chart for TCO

Furthermore, a Monte-Carlo simulation with 1,500 runs was performed using the values of the test well (see chapter 4.4 Test well) to visualize and analyses the distribution of probability of outcome for the ranking of ALSs regarding their total cost of ownership. All adjustable input parameter where given a uniform distribution for values +/- ten percent to ascertain the outcome. As can be seen in Figure 18, the values of total cost of ownership are generally normal-distributed. It also visualizes the difference in distribution. It can be observed that the TCO of a sucker rod pump is within a smaller margin, with a difference between lowest and highest value of 75,000 EUR, while progressive cavity pumps have a margin of 150,000 EUR. An interesting coincident is the nearly identical values of TCO for gas lifting and linear rod pumps with a slightly lower TCO for GL, showing that the given results in regard to TCO between these two ALSs is very uncertain but the sequence of the other ALSs is definite.

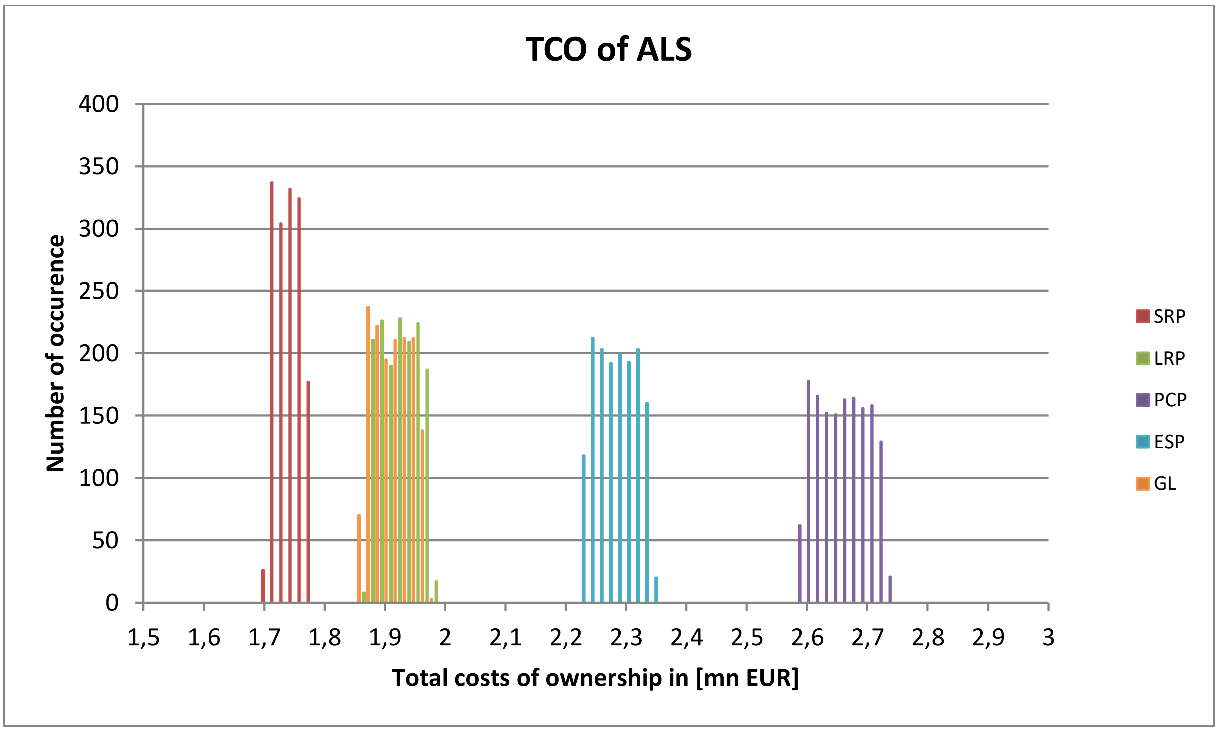


Figure 18: Probability distribution of TCO for all ALSs using values of the test well

Another Monte-Carlo simulation was performed to determine the performance of the NPV calculation as shown in Figure 19. The result of this simulation is that the outcome of the LCC in regard to the ranking of ALSs due to NPV is very uncertain. Although, the tendency of GL having a higher NPV can be noticed, due to the uncertainty of the input parameter, +/- ten percent for each, this result is not concluding. This can be explained due to the fact that the mean value of NPV for all ALSs are similar, but the standard deviation is relatively high as can be seen in Table 6.

Table 6: Mean and standard deviation of NPV calculation for all ALSs

	Mean	Standard Deviation
SRP	- 97.188,35	285.585
LRP	- 128.598,59	285.186
PCP	- 397.757,09	284.851
ESP	- 352.293,97	284.915
GL	- 76.017,71	285.186

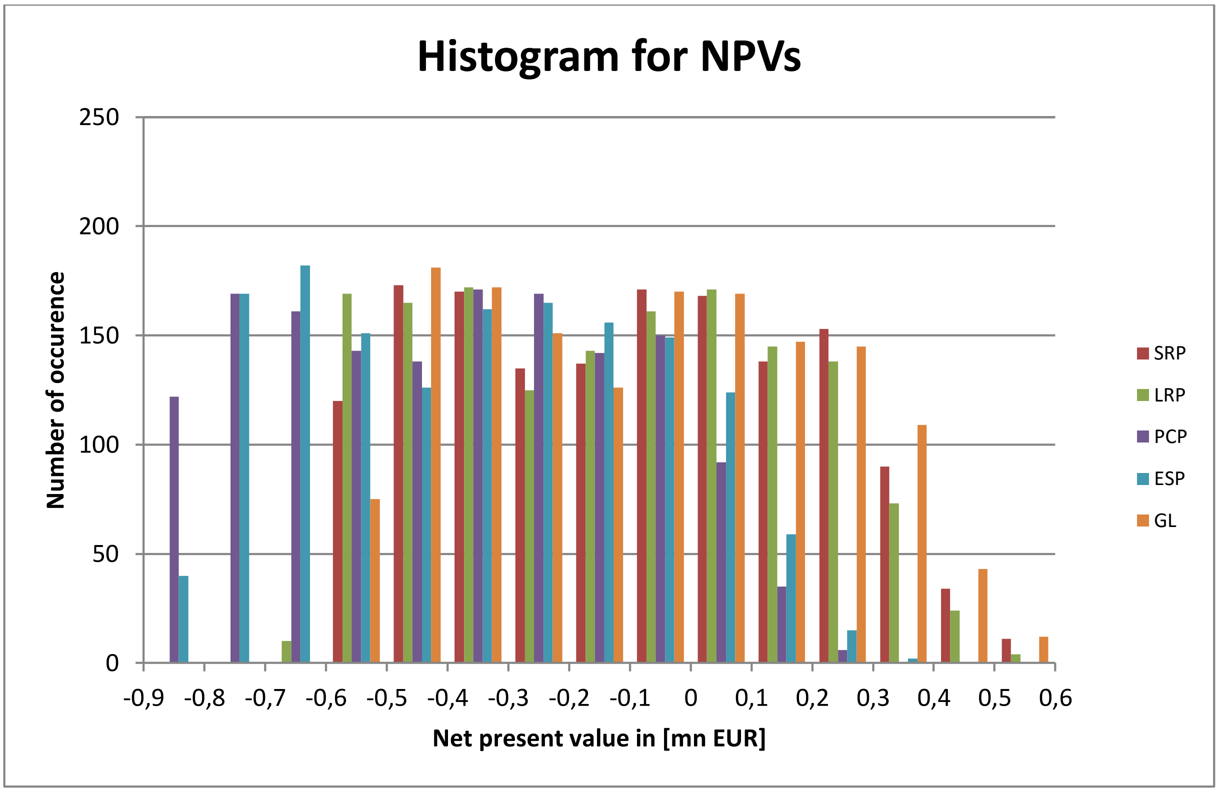


Figure 19: Probability distribution for NPV calculations

3.4 Step 4: Reporting and decision making

The general components of an LCC analysis vary from application to application. Overall, the result should show all factors that make up the cost of a particular alternative in a way that those alternatives can be compared.

The final format of the report highly depends on the audience that will be reviewing the life cycle and their understanding of LCC analysis. In general, its objective was to report all findings, establish the economic solution and to decide on a strategy for the next project phase. The following sequences of steps should be included into an LCC analysis report:

- Cover sheet
- Table of content
- Executive summary
- A project description to describe the purpose of the project, including its objective.
- Alternative description, where all alternative solutions and their differences are defined.
- Cost data, including a list of all cost items that will be used in the report and how those values were generated.
- A Calculations-Spreadsheet to show the calculation of the actual values. Due to limitation of space, it may be sufficient to show some calculations or their results for each alternative in a descriptive manner. All other calculations can be shown in the appendix.
- Interpretations and recommendations to describe how the data was analysed and interpreted and to provide a general recommendation based on the results of the analysis.
- A sensitivity analysis must be included into the report to show the influence a change of values has on certain variables. It can also show how certain and how independent from each other the results are.
- As last point an appendix can be included to show all calculations and various data sources.

The recommendation, concluding a life cycle should either include the preferred option of the alternative solutions or the decision to invest in further studies when the possibility exists to provide significant improvement over the preferred option. This recommendation of an iteration of the LCC can be due to uncertainty of the existing data or to include new options and should include a plan of succeeding activities.

Details of the conclusion for this project will be presented in chapter 5 Discussion including a general discussion as well as a presentation of results of a test well.

4 Excel tool and test well

To facilitate the application of LCC in the decision process for ALS selection, and within the scope of this master thesis a spreadsheet based on Microsoft Excel including Visual Basic Applications (VBA) and macros has been composed to calculate the life cycle costs for artificial lift systems for different well setups. The input and calculations are based on the information described in previous chapters. As a trial run for the tool, a test well already installed with a gas lifting system was selected, its specifics entered into the tool and an LCC analysis was performed.

4.1 Variable input

Different parameters were studied on their influence on the life cycle cost of an artificial lift system. The factors with the highest impacts were implemented as input into the Excel file. These parameters can be divided into two categories: “General Variable Input” and “ALS Specific Parameter”.

The following technical and economical parameters are used to calculate the LCC and have to be entered manually: Top of perforation (MD) [m], flow rate [m^3/d], initial water cut [%], duration [years], WACC [%], Risk [%], oil price either in [USD/bbl] or [EUR/m^3] and royalties [%]. They are defined as general and are valid for all ALSs.

Additionally, for identification purposes, the name of the engineer using the Excel spreadsheet and the name of the well for which the LCC is to be calculated have to be entered into the tool. The current date is programmed as a fixed entry.

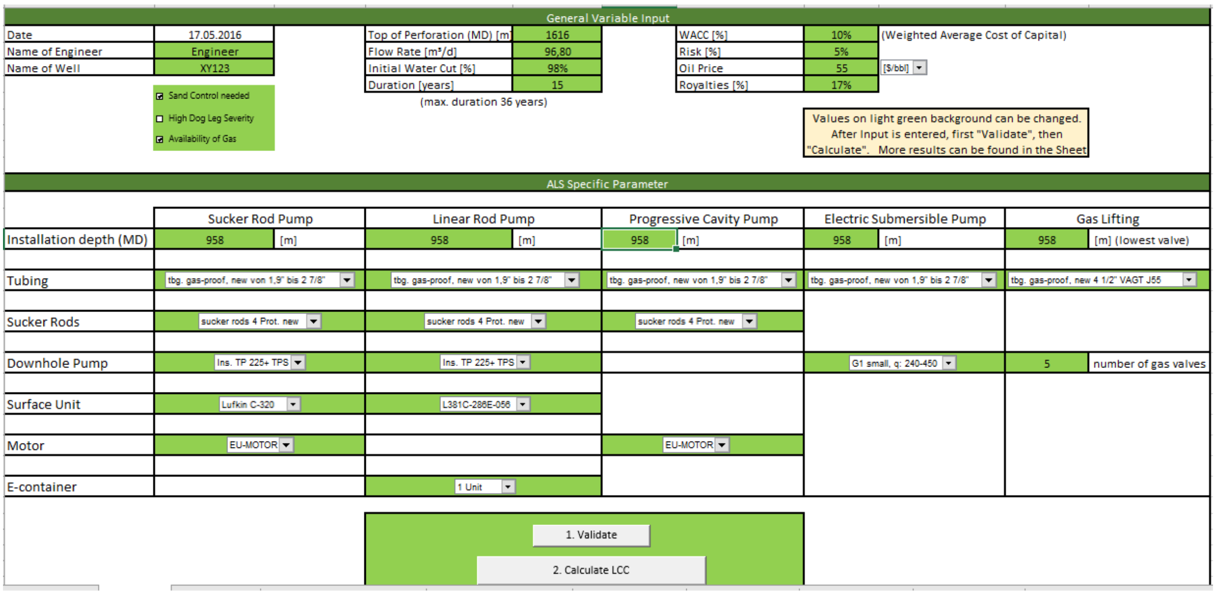
Another three conditions that can influence the outcome of the LCC were specified and can be activated via check boxes. The first one should be checked when a well exhibits a high dog leg severity which is usually expressed in degrees per 100 feet of wellbore length. A dog leg depicts a particularly crooked place in a wellbore where the trajectory of said wellbore changes rapidly. This effect is sometimes created intentionally, but more commonly it is not desired, as it can lead to detrimental side effects for the bottom hole assembly, such as an increase in the overall friction between installations and tubing wall. [30] This is especially harmful for ALSs with reciprocating up-down movements such as SRP, LRP and PCP.

Another factor are sand-control installations which prevent migration of reservoir sand into the wellbore or near-wellbore area. They are set up to maintain the structure of the reservoir around the wellbore as well as to avoid a restriction in the production stream. Sand production can erode hardware, block perforations or moving equipment, create downhole cavities, and if produced must be separated and disposed of on surface. The basic sand-control methods are gravel packs and sand consolidation. If no downhole sand control is installed, a desander has to be set up near the wellhead. [30]

The third aspect is in regard to gas availability. If no reliable gas source is available within a certain vicinity around the well, gas lifting is eliminated as a technically possible solution.

Due to the fact, that all ALSs have different installations that influence the cost calculations, the main installations can be chosen by the user of the spreadsheet. This input includes installation depth of each ALS as well as a selection of tubing, sucker rods, downhole pumps, surface units, motors, E-containers or number of gas valves, depending on the ALS.

Figure 20 shows the structure of the input sheet of the Excel tool. Cells coloured in green can be changed and should be used to enter the specifics of the well, both for general input as well as the ALS specific parameters. A validation of the values entered was included. This validation is not a technical feasibility study but rather compares the different values in order to identify and consequently allow avoidance of mistakes, like setting an installation depth much lower than the top of perforation or entering different installation depths for each ALS.


General Variable Input

Date	17.05.2016
Name of Engineer	Engineer
Name of Well	XY123

☑ Sand Control needed
☐ High Dog Leg Severity
☑ Availability of Gas

Top of Perforation (MD) [m]	1616
Flow Rate [m³/d]	96,80
Initial Water Cut [%]	98%
Duration [years]	15

(max. duration 36 years)

WACC [%]	10%	(Weighted Average Cost of Capital)
Risk [%]	5%	
Oil Price	55	[$/bbl]
Royalties [%]	17%	

Values on light green background can be changed. After Input is entered, first "Validate", then "Calculate". More results can be found in the Sheet

ALS Specific Parameter

	Sucker Rod Pump	Linear Rod Pump	Progressive Cavity Pump	Electric Submersible Pump	Gas Lifting
Installation depth (MD)	958 [m]	958 [m]	958 [m]	958 [m]	958 [m] (lowest valve)
Tubing	tbg. gas-proof, new von 1,9" bis 2 7/8"	tbg. gas-proof, new von 1,9" bis 2 7/8"	tbg. gas-proof, new von 1,9" bis 2 7/8"	tbg. gas-proof, new von 1,9" bis 2 7/8"	tbg. gas-proof, new 4 1/2" VAGT J55
Sucker Rods	sucker rods 4 Prot. new	sucker rods 4 Prot. new	sucker rods 4 Prot. new		
Downhole Pump	Ins. TP 225+ TPS	Ins. TP 225+ TPS		G1 small, q: 240-450	5 number of gas valves
Surface Unit	Lufkin C-320	L381C-286E-056			
Motor	EU-MOTOR		EU-MOTOR		
E-container		1 Unit			

Figure 20: Input Sheet of Excel based LCC calculation tool

4.2 Basis of calculation

For the Excel sheet to function actual costs and correlations for each installations and input factor, as described in chapter 3.2 and shown in Appendix C: Cost factors for Artificial Lift Systems, was researched and introduced to the program.

OMV E&P operates storages in which **replacements for installations**, equipment, tubing and sucker rods are stored, waiting to be put in use. These items are bought in advance, to reduce mean time to repair as parts of ALS may have a long delivery time. However, this can also lead to financial losses as some of these items have expiration dates. For example, the elastomer stator of an PCP is extremely sensitive to weather influences, and has many requirements for storage. Moreover, when its stored time exceeds 12 months, all elastomers must be checked for their elasticity and must be exchanged if brittle. [31] Storage staff is also responsible for the inspection of each item that is returned to them after being used in field and if necessary to repair them. If a well intervention is planned cost estimations are prepared by the completion engineer in charge of the well, which includes the costs of all replacements, equipment, working hours and materials needed. The costs for the installations used in the Excel program are the prices which are internally applied within OMV. These prices were taken from said cost estimations as well as different price lists for tubing, sucker rods and linear rod pump installations. Which installations need replacement during a well intervention, was determined by comparing cost estimates and working reports, as well as operation manuals of different ALSs and selecting the most common.

The **number of well interventions and their associated costs** over the entire life cycle are calculated over the average run life of the failed installations. As ARLF is influenced in a “real-life” application by a number of things, a basis for estimating this value for each ALS had to be found. The ARLF for sucker rod pumps is decided on by comparing four different values of run life. The correlation between ARLF and flowrate, depth, downhole pump and surface unit (pump jack) was found and is used for run life estimations. The lowest of these values is then used for further calculation. Depending on the input, this results in an average run life between 0 and 1110 days. Figure 21 depicts how the correlation between run life and flow rate is influenced by installation depth of the pump.

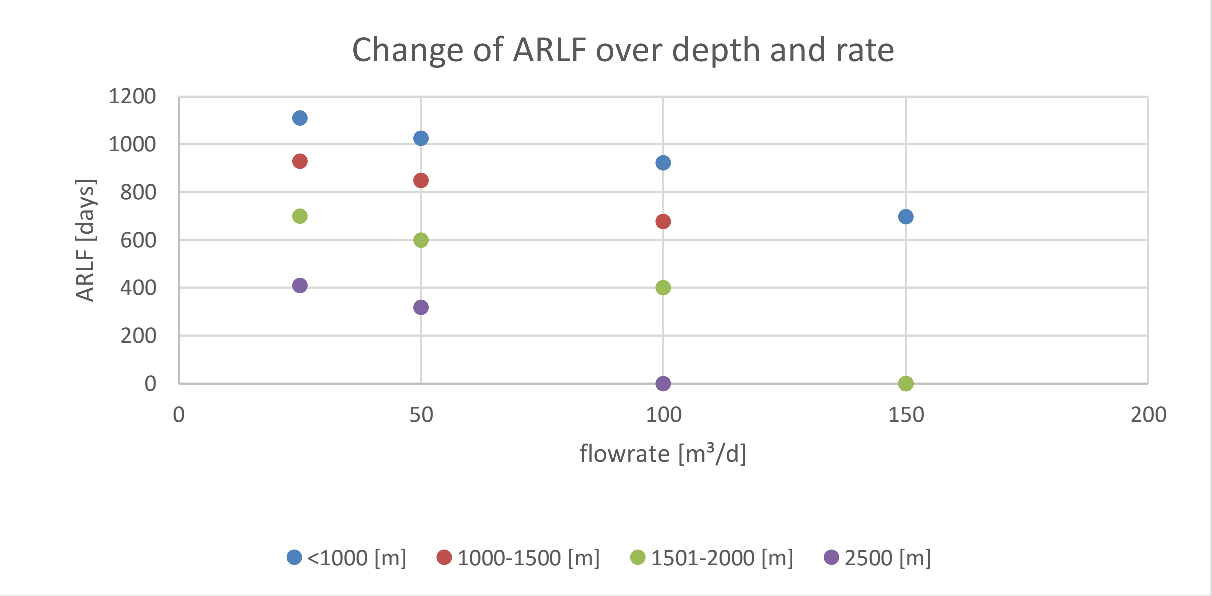


Figure 21: Correlation of average run life of SRP and flow rate influenced by depth

As there are currently no linear rod pumps installed in Austria, the values for SRP were used instead. Run life for ESP is estimated over rate and depth according to well intervention data of previous installations resulting in a run life between 600 and 1600 days, while calculations for gas lifting are based on flow rate, depth and number of gas valves installed. Generally, gas lift wells have a long run life as no moving parts are included into the installations. This is reflected in the estimates, resulting in an ARLF between 800 and 3000 days.

Another important factor which is dependent on the variable input is **mean time to repair**. The Excel sheet uses the average time needed for the different installations as provided by OMV. Evidently, failure at a well with a higher flow rate will be discovered earlier than at a well with a lower one, as the decrease in production will be noticed sooner if the volume of oil is not reached. The repair of such a well will be scheduled and performed with a higher urgency than a well with a lower flow rate, as the loss in income due to deferred production will be tried to be kept small. Also, the time discrepancy between a change of installation for a deep well and a shallow one is taken into account. For gas lifting the additional time for start-up is also regarded in the calculation of MTTR. When converting MTTR from hours into days needed for well intervention, each workday is accounted for with 16 hours, 2 working shifts of eight hours each, as is usual within OMV. This leads to a longer downtime in days and, consequently, to an increase in deferred production costs due the fact that eight hours per day are not worked in order to repair the failed ALS.

A high influence on the overall costs of an ALS are the **energy costs**. These are predicted over the flow rate. For SRP, PCP and ESP, basis for these estimations were measurements of different installations that were done for a previous project. The consumption of lift gas needed for gas lifting is continuously measured for each GL well. These values were used to correlate the amount of lift gas with the anticipated flow rate. As can be seen in Figure 22, all four ALSs show an explicit connection between energy consumption and flow rate.

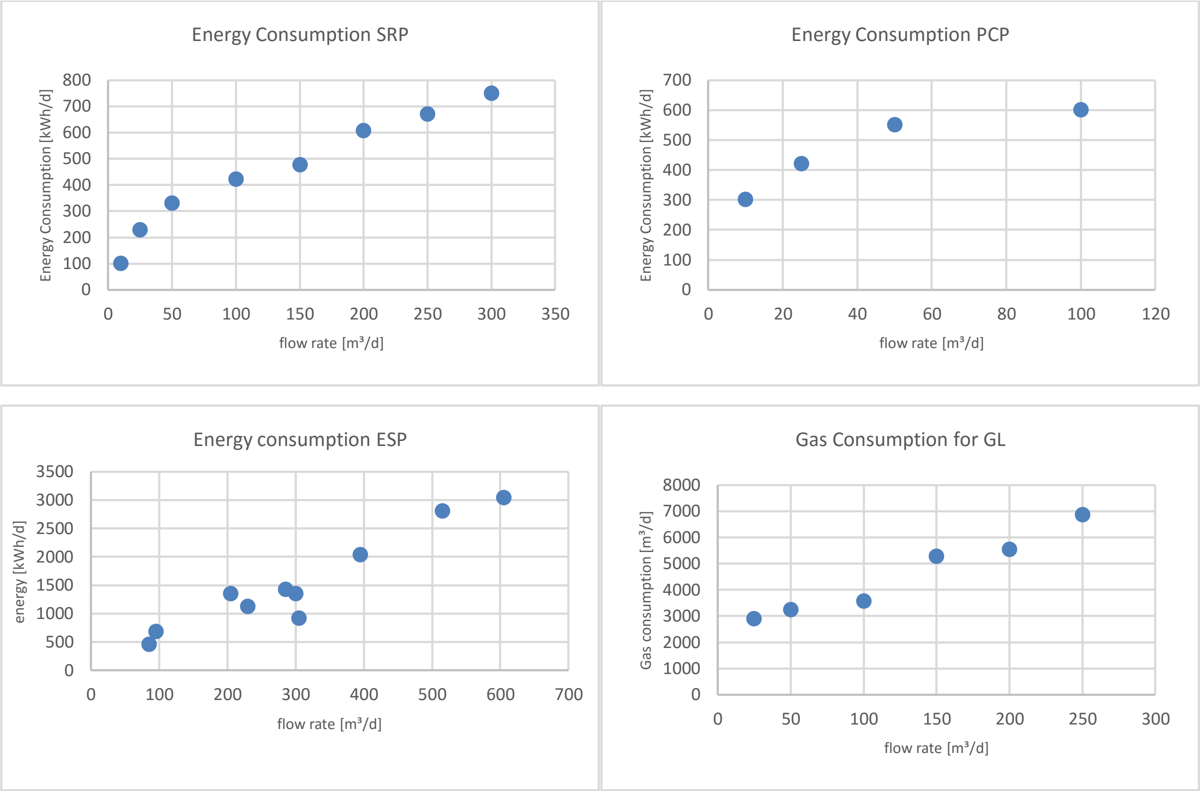


Figure 22: Estimations for energy consumption per ALS influenced by flow rate

However, in case of gas lifting additional lost revenues can occur if it is applied in a well with a high gas liquid ratio (GLR). When the gas that is produced from the well is compressed and inserted into the well again for lifting purposes, it is not available for selling and thus reducing the income. However, this factor is difficult to integrate into the calculations as the gas is reused repeatedly and the exact amount that is momentarily lost to the market depends on the prevailing gas sales price and is hard to discern.

The water cut of the reservoir increases steadily from its initial value with each year of production, leading to an increasing amount of water that needs to be treated each year. The Excel spreadsheet calculates both water and oil production for each year to generate the **water treatment costs**.

The **chemical injection costs** account for the amount of corrosion inhibitor that is injected into the well, which corresponds to the amount of fluids that are produced from the well, as shown in Figure 23.

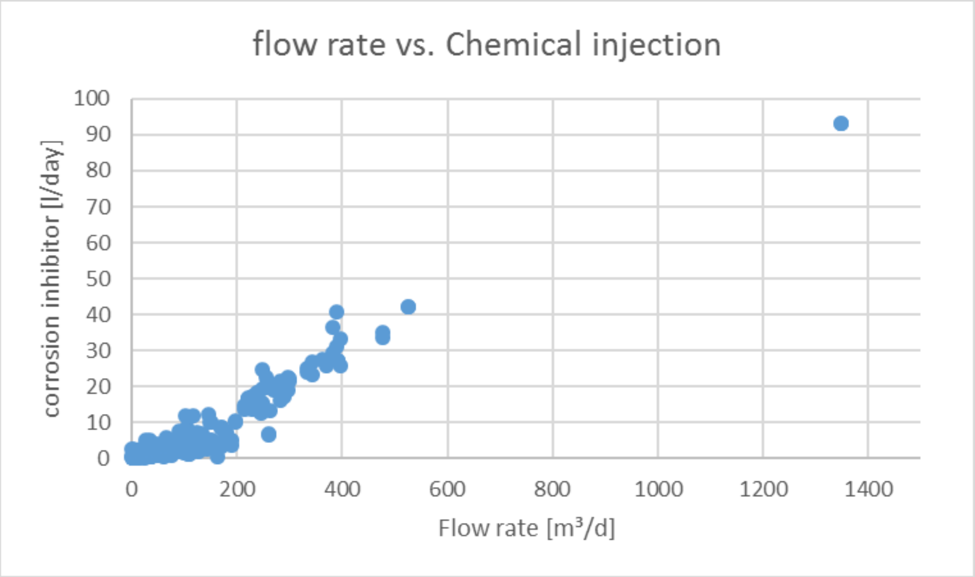


Figure 23: Correlation between flow rate and chemical injection

4.3 Output

Variable input and pre-entered costs are used to calculate the life cycle costs and various KPIs. Figure 24 and Figure 25 visualize the influence of these input parameters on the output of the Excel tool.

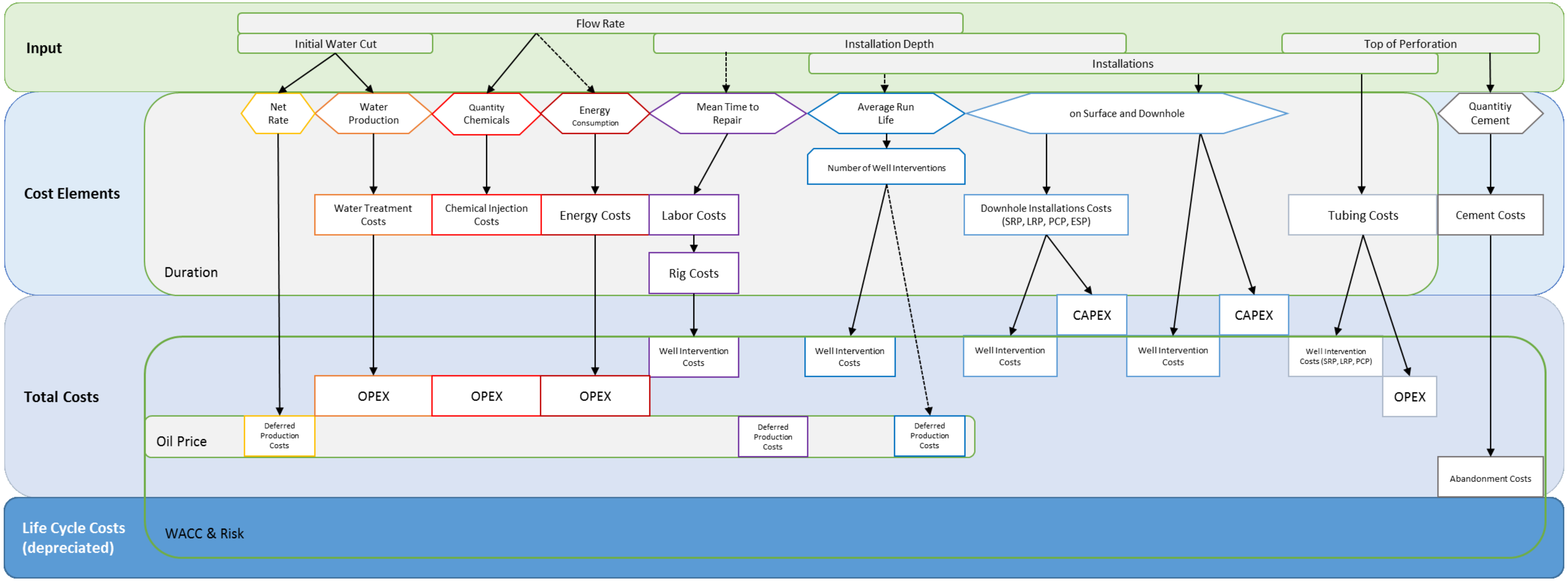
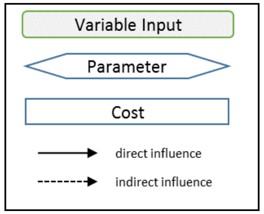


Figure 24: Flowchart of input verus output (LCC tool)



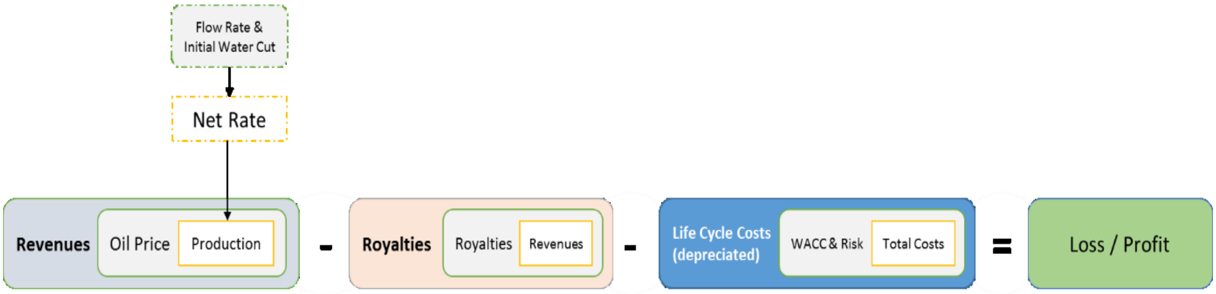


Figure 25: Flowchart for calculation of loss or profit (Excel)

As can be seen in Figure 24, most parameters and costs are influenced by flow rate as was already mentioned in previous chapters. Also most cost factors are programed in such a manner that each of them is influenced by more than one input parameter. This way they are aligned more closely to actual circumstances.

The results of the Excel sheet are accessible in a separate worksheet which also includes the input data that was entered into the program.

The outcome of the Excel worksheet are the following results for each ALS:

- An actual ranking of the artificial lift system according to their total costs as well as their costs per cubic meter of oil produced, as shown inTable 11.
- A breakdown of the discounted as well as total costs according to the five categories capital expenditures, well intervention, operational expenditures, deferred production and abandonment (Table 8 and Table 9).
- The list of KPIs as discussed in chapter 3.3.2 Key performance indicators (KPI), including ARLF, number of fails, system effectiveness, total oil production, NPV at the given discount factor, IRR, DPI, discounted payback period, as well years of oil production.
- A chart showing life cycle costs versus the calculated system efficiency (Figure 31).
- A graph each for the cumulative and the cumulative discounted cash flows comparing the ALS (Figure 26 and Figure 27).
- Charts showing the breakdown of costs as absolute number as well as in percentage, both for the discounted and total costs. (Figure 29 and Figure 30)

Additionally, to the worksheets for “Input”, where well specifications are entered into the program, and “Output” where the results are presented, the worksheets listed below are part of the Excel file:

- “NPV for all ALS” includes all NPV and most of the KPI calculations. (see 9.4 Appendix D: NPV calculations for ALS)

- “Effectiveness” shows the calculations regarding effectiveness and its factors.
- Individual worksheets listing the costs for the five ALSs (see 9.3 Appendix C: Cost factors for Artificial Lift Systems)
- Cost list, where all ALS specific installation and their costs can be found (see 9.5 Appendix E: Additional Excel Worksheets)
- “ARLF_MTTR” shows estimations and trendsetting for both run life and mean time to repair for each ALS. (see 9.5 Appendix E: Additional Excel Worksheets)
- “Parameter (WC)” includes estimations and calculations concerning water cut, chemical injection volume required, and energy consumption (described above)

As an additional feature, a print option was implemented into the program allowing the separate selection of worksheets to be saved as a pdf-file in a freely selectable memory space.

4.4 Test well

To ascertain its functionality, the specifications of a developed well, as listed in Table 7, were entered into the Excel spreadsheet. This well was chosen, as it is well documented and sufficient data is available. Furthermore, the parameters of the well are within a range without any extreme values.

Table 7: Input parameters for the test well

Top of Perforation (MD)	1616 [m]
Flow Rate	96,80 [m³/d]
Initial Water Cut	98 [%]
Duration	15 [years]
WACC	10 [%]
Risk	5 [%]
Oil Price	55 [USD/bbl]
Royalties	17[%]
Installation depth (MD)	958 [m]

The LCC was calculated and some of the results that were generated are shown below. The discussion of the results can be found in the following chapter.

Figure 26 and Figure 27 show the cumulative cash flow curves during the duration of the test well’s life cycle. As can be seen only, GL installations trumps all other ALSs, of which most do not reach values above zero. Due to an increase in costs and a decrease in revenues all ALSs register with a negative cash flow after year 14. In general, are the values of the discounted cash flow curve lower than the values not accounting for the TVoM.

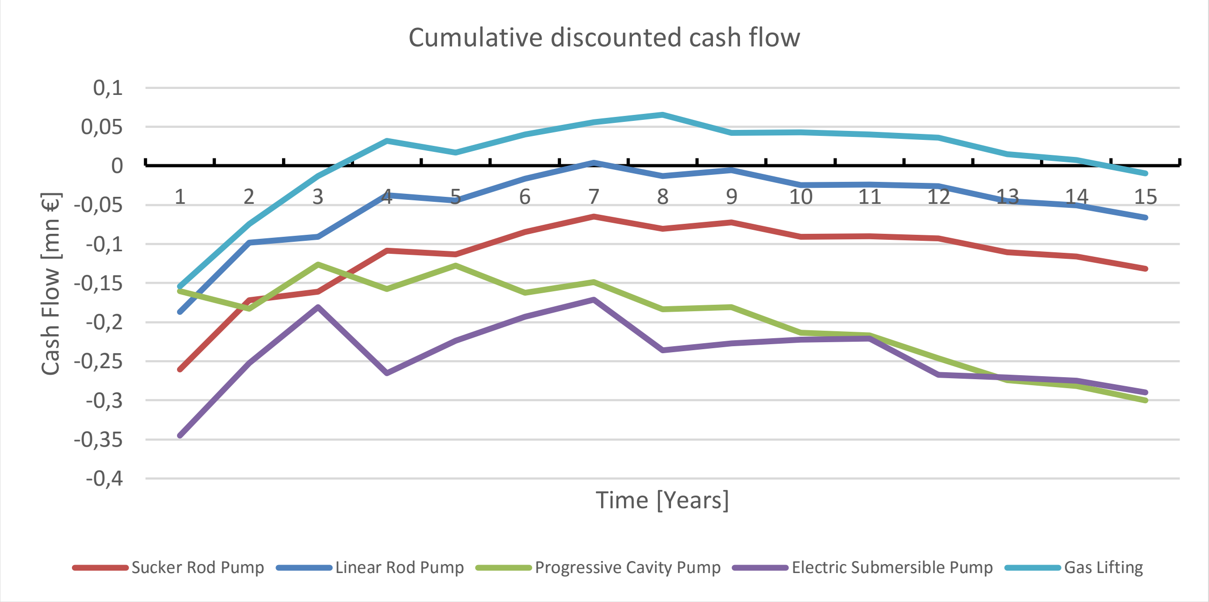


Figure 26: Cumulative discounted cash flow (Excel)

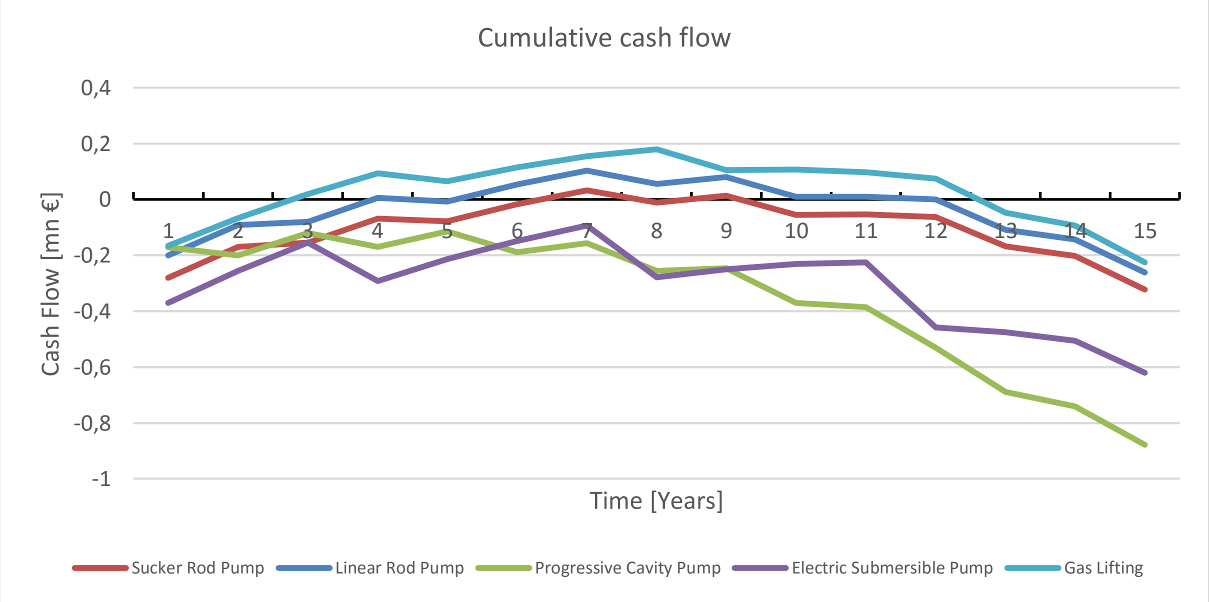
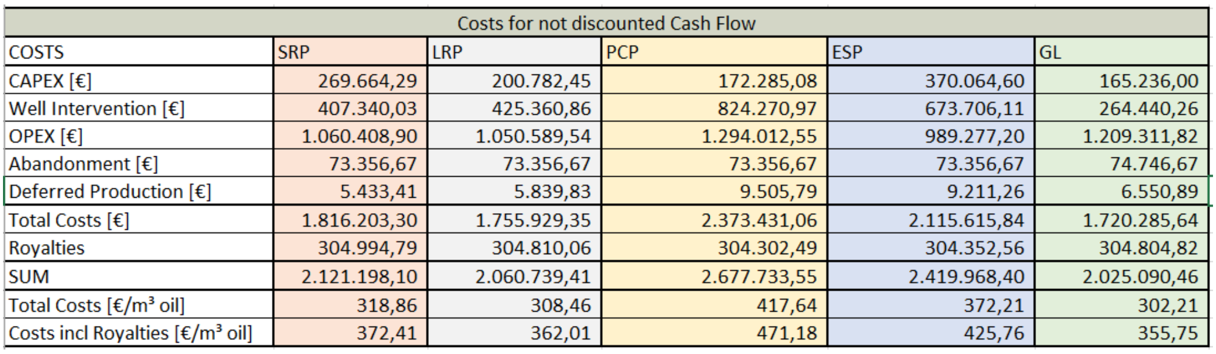


Figure 27: Cumulative cash flow (Excel)

The following three tables show the results of the LCC analysis for the specifications of the test well. Table 8 list the totalized costs of each category (capex, well intervention, opex, abandonment and deferred production) per ALS and the resulting total cost of ownership. Costs due to royalties were included into this list and the total costs per cubic meter of oil produced, both with including and excluding royalties, is calculated. A further indication to the overall result of the LCC are the costs including royalties in [EUR/m³ oil]. If they are higher than the oil price entered previously into the spreadsheet, the cash flow will be negative.

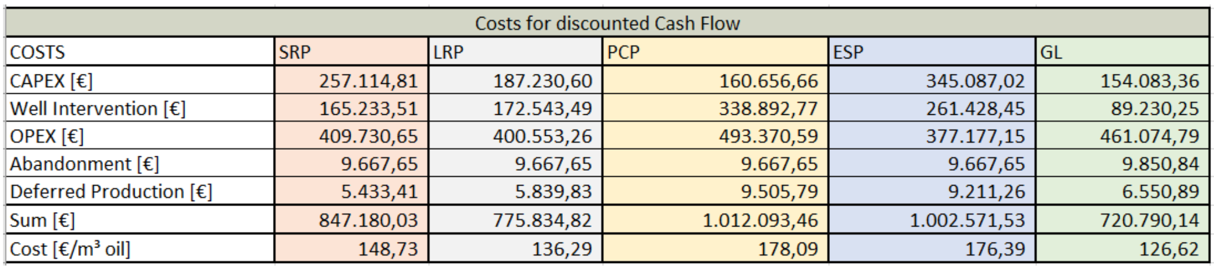
Table 8: Not discounted costs of LCC for test well (Excel)



Costs for not discounted Cash Flow					
COSTS	SRP	LRP	PCP	ESP	GL
CAPEX [€]	269.664,29	200.782,45	172.285,08	370.064,60	165.236,00
Well Intervention [€]	407.340,03	425.360,86	824.270,97	673.706,11	264.440,26
OPEX [€]	1.060.408,90	1.050.589,54	1.294.012,55	989.277,20	1.209.311,82
Abandonment [€]	73.356,67	73.356,67	73.356,67	73.356,67	74.746,67
Deferred Production [€]	5.433,41	5.839,83	9.505,79	9.211,26	6.550,89
Total Costs [€]	1.816.203,30	1.755.929,35	2.373.431,06	2.115.615,84	1.720.285,64
Royalties	304.994,79	304.810,06	304.302,49	304.352,56	304.804,82
SUM	2.121.198,10	2.060.739,41	2.677.733,55	2.419.968,40	2.025.090,46
Total Costs [€/m³ oil]	318,86	308,46	417,64	372,21	302,21
Costs incl Royalties [€/m³ oil]	372,41	362,01	471,18	425,76	355,75

Table 9 shows the discounted costs of the categories mentioned above as well as the calculated cost per cubic meter of oil produced accounting for the TVoM.

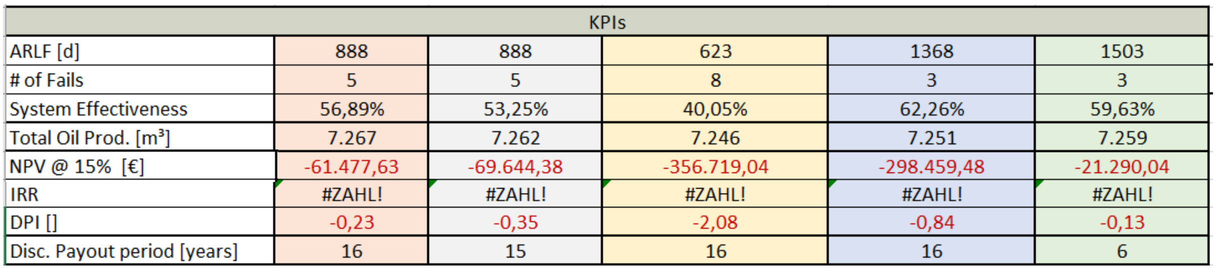
Table 9: Discounted costs of LCC for test well (Excel)



Costs for discounted Cash Flow					
COSTS	SRP	LRP	PCP	ESP	GL
CAPEX [€]	257.114,81	187.230,60	160.656,66	345.087,02	154.083,36
Well Intervention [€]	165.233,51	172.543,49	338.892,77	261.428,45	89.230,25
OPEX [€]	409.730,65	400.553,26	493.370,59	377.177,15	461.074,79
Abandonment [€]	9.667,65	9.667,65	9.667,65	9.667,65	9.850,84
Deferred Production [€]	5.433,41	5.839,83	9.505,79	9.211,26	6.550,89
Sum [€]	847.180,03	775.834,82	1.012.093,46	1.002.571,53	720.790,14
Cost [€/m³ oil]	148,73	136,29	178,09	176,39	126,62

Table 10 present the calculated KPIs (see chapter 3.3.2 Key performance indicators (KPI)) for each ALS. Due to a relatively low oil price and as was already shown in Figure 26, are all NPVs negative, leading to an IRR which cannot be calculated ('#ZAHL!' is Excel's method of indicating an invalid value). For easier visualization, all negative values are coloured red.

Table 10: KPIs sorted by ALS (Excel)



KPIs					
ARLF [d]	888	888	623	1368	1503
# of Fails	5	5	8	3	3
System Effectiveness	56,89%	53,25%	40,05%	62,26%	59,63%
Total Oil Prod. [m³]	7.267	7.262	7.246	7.251	7.259
NPV @ 15% [€]	-61.477,63	-69.644,38	-356.719,04	-298.459,48	-21.290,04
IRR	#ZAHL!	#ZAHL!	#ZAHL!	#ZAHL!	#ZAHL!
DPI []	-0,23	-0,35	-2,08	-0,84	-0,13
Disc. Payout period [years]	16	15	16	16	6

The above stated results were then used to create corresponding charts to facilitate the interpretation of the results. Figure 28 shows the total costs of ownership as well as the discounted costs for each ALS in explicit numbers according to the categories. It can be seen that the TVoM has high influence on the outcome of the LCC and the ultimate ranking of the alternatives.

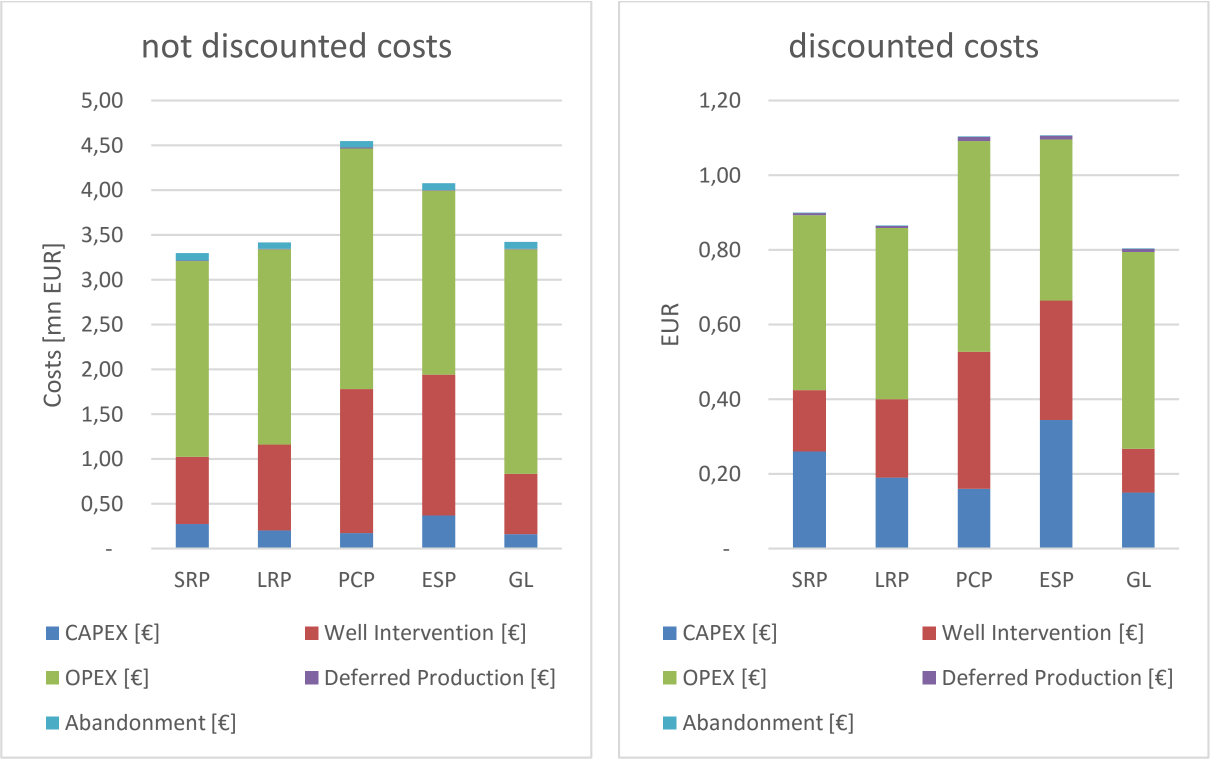


Figure 28: Not discounted and discounted costs per ALS

Figure 29 and Figure 30 visualize the above mentioned costs in percentage according to each category. In the direct comparison of both charts, the influence of the discounting can be noticed. It can be seen that the length of the life cycle influences the impact of the abandonment costs on the final decision. As the rate of percentage is reduced due to the discounting over time, so is the influence of abandonment costs on the result. Coincidently, this means that the influence of the costs due to first installation (capex) rise with a longer duration of life cycle. These charts can be used to find the category which is the highest cost contributor to overall costs and define a first point of investigation where costs may be saved in the future.

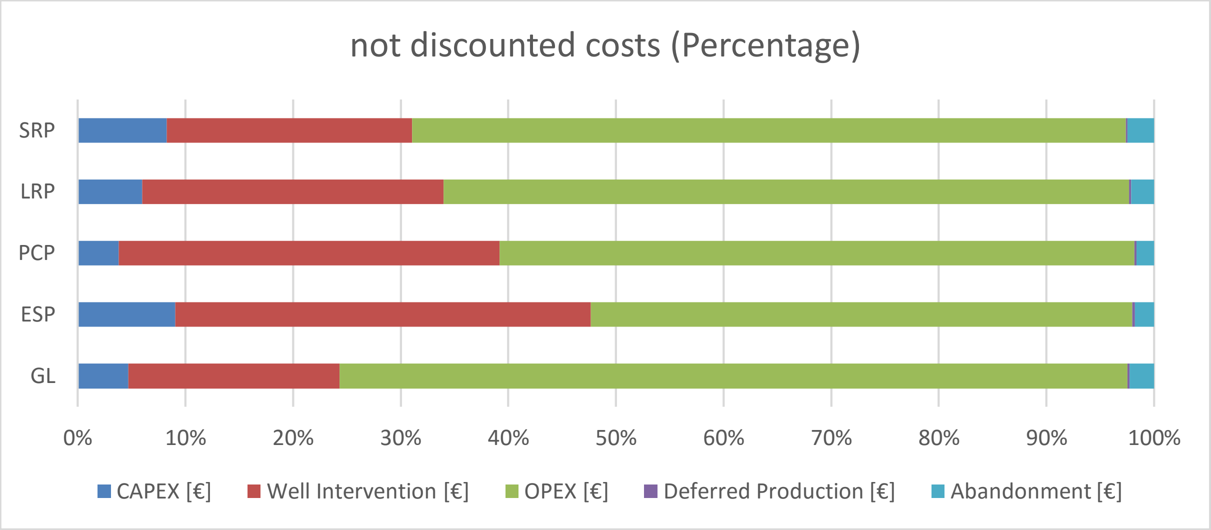


Figure 29: Allocation of total costs of ownership to 5 categories of costs in percentage

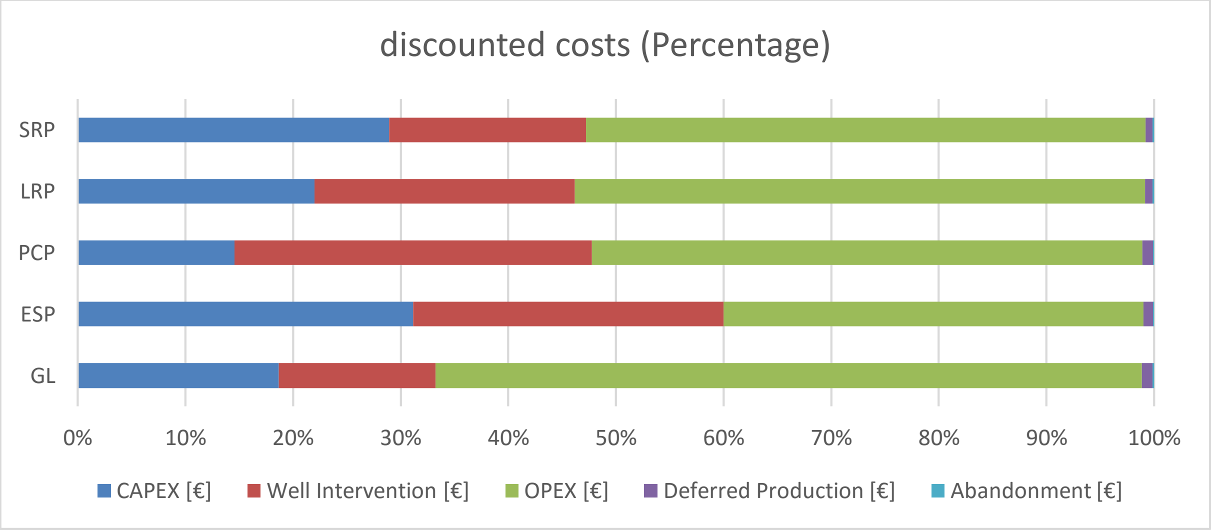


Figure 30: Allocation of discounted total costs to 5 categories of costs in percentage

5 Discussion

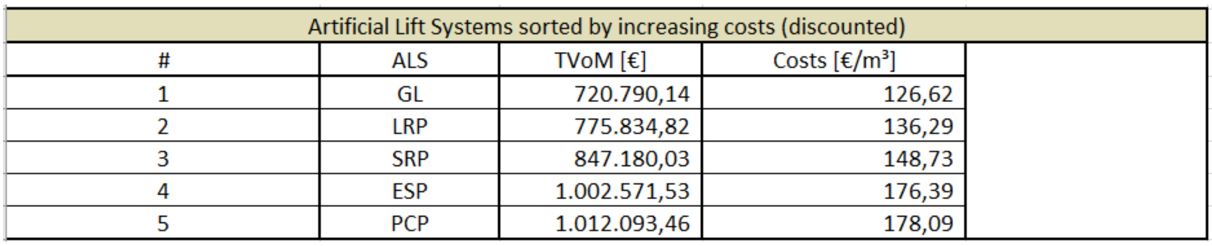
This section summarizes and interprets the findings presented in Chapter 3 and 4 including different assumptions as well as the results of the LCC of the test well.

5.1 Interpretation of results

The test well that was entered into the spreadsheet, is based on a gas lift system which is in operation since the 1960’s. The well is completed with a 2 7/8” tubing and has 4 gas lift valves installed. The calculated gas consumption correlates with the recorded amount of lift gas. For the set-up of the other ALSs, installations were chosen which can be found in wells with similar specifications.

Due to the matureness of the oil field a high initial water cut of 98% is assumed. This results in large amounts of water being produced which have to be treated, leading to overall higher water treatment costs. Initially, the life cycle costs were calculated for 30 years even though oil can probably only be produced for 17 more years from this well. This 30-years calculation further increased the costs without collecting any revenues. Thus, the **duration** was changed to 15 years.

Table 11: Ranking of the ALSs according to increasing costs (Excel)



Artificial Lift Systems sorted by increasing costs (discounted)

#	ALS	TVoM [€]	Costs [€/m³]
1	GL	720.790,14	126,62
2	LRP	775.834,82	136,29
3	SRP	847.180,03	148,73
4	ESP	1.002.571,53	176,39
5	PCP	1.012.093,46	178,09

The artificial lift system with the lowest life cycle cost according to the Excel spreadsheet is gas lifting, followed by linear rod pump, sucker rod pump, progressive cavity pump and electric submersible pump, as can be seen in Table 11.

This case visualizes very clearly the impact that time has on the cost and the difference between **total cost of ownership** and costs accounting for the TVoM. Although, the ESP has lower total costs of ownership than the PCP, due to the fact, that the majority of these costs are capital expenditures which are accounted for in the first year, ESP has slightly higher discounted costs and also a lower **NPV** than the PCP. And although GL has rather high operational expenditures, due to low capex and very low well intervention costs it is the only installation that returns a positive cash flow for 10 of the 15 years. Due to the high initial water cut of over 98% and a moderately low oil price of 55 USD/bbl none of the alternatives will return a positive NPV for the assumed WACC and risk after the duration of 15 years. Furthermore, based on the input parameters, the **DPI** for all ALSs will be negative, resulting in a loss of value if the well is operated for 15 years with either of these alternatives. Consequently, the IRR is not applicable with these ranges of costs (cf. Table 10).

Another indicator for a less favourable outcome is that the **undiscounted total costs per m³ oil produced** for the proposed 15 years for each ALS is above the oil price.

As already mentioned, the well intervention costs of GL are very low, as the **average run life** of this installation is with 1503 days by far the longest of the proposed alternatives. PCP shows with 623 days the lowest ARLF, resulting in eight well interventions over the course of 15 years. A high ARLF indicates a low number of well interventions, which can be interpreted as a reduced overall risk for accidents or injuries during the life cycle, too.

Another output of the Excel sheet and important ranking criteria is the **cost effectiveness**. As was shown in Figure 31, an ESP installation would be slightly more efficient than gas lifting for this well (62.3 % to 58,3%). Due to the facts that the life cycle costs of GL are lower compared to those of ESP, and furthermore have a positive cumulative cash flow for a period of the life cycle, GL appears to be the best solution under the given circumstances.

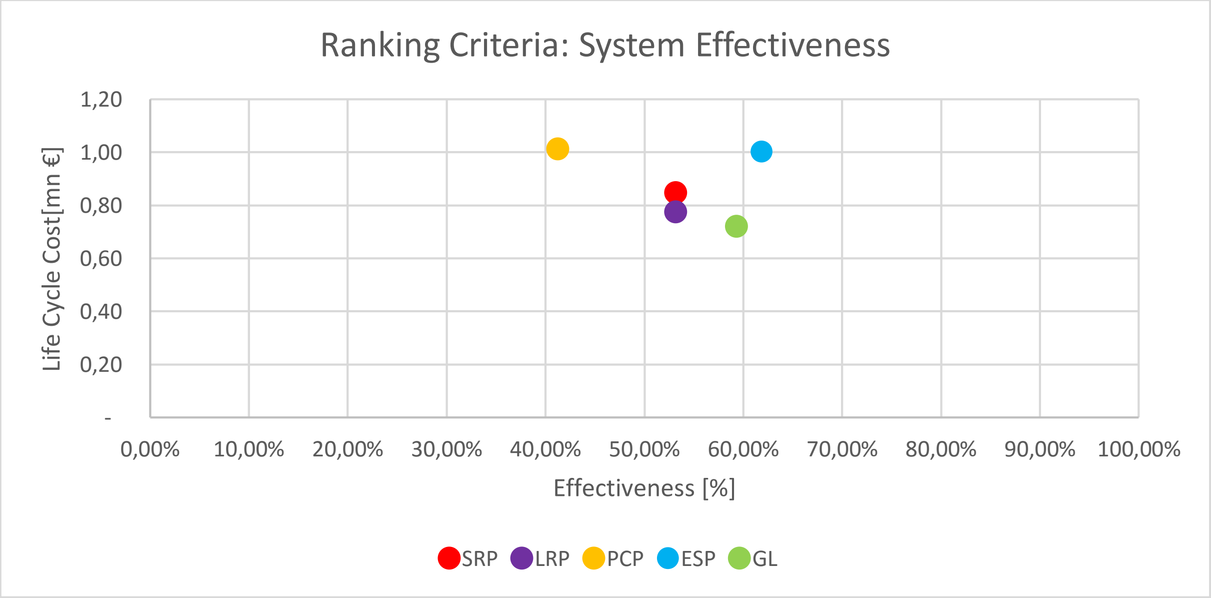


Figure 31: System effectiveness of ALSs in test well (Excel file)

However, due to the variables mostly influenced by the low oil price, the **NPV** at 15 percent is below zero for all ALSs. Consequently, almost certainly none of the alternatives as proposed in the test well would be chosen at this point.

Another important factor is that an LCC calculation is an iterating process. Therefore, when a decision is made, in this case for gas lifting, and acquisition and installation are finished, it is imperative that the costs of the chosen solution are being tracked and added to the cost structure estimated at the beginning of the project.

5.2 Framework

It is important to mention that the LCC tool was programmed based on a specific framework which influences the overall costs of the ALS. Most of this framework concerns all ALSs equally, thus the ranking should not be affected.

The yearly change of water cut is calculated based on a linear changed by a constant value. Although the lifting systems are influenced differently by the water cut, as shown in the sensitivity analysis, the overall sensitivity of the water cut is below 5% for both total cost of ownership and net present value.

With the goal to create an easily useable and understandable tool some simplifications had to be applied:

- All input factors, as listed in Table 7, other than water cut are assumed as constant values over the entire life cycle. As it was not part of this thesis to develop different oil price scenarios the Excel file also uses a constant oil price over the entire life cycle leading to a certain imprecision in the values.
- These include that no open hole completion can be taken into account, as the tubing costs are calculated by multiplying the chosen tubing with top of perforation.
- Only one kind of tubing and size can be selected for the whole completion of each ALS, although this does not reflect real completions, where tubing diameter decreases with increasing depth. For the whole life cycle, all well interventions are calculated with the same installation costs. A change in completion, either in tubing or installation is not assumed.
- It is recognized that different factors influence energy consumption of an ALS. The rates used for electricity and gas consumption are only estimated over the flow rate.
- If high dog leg severity is acknowledged the maintainability of SRP, LRP and PCP is reduced to 50%. If no gas is available in the near vicinity of the well, then gas lifting is removed as a viable option for the ALS selection. The checkbox for sand control adds costs of either a sand filter installed downhole or a desander on the surface to the installation costs, depending on the ALS.

- For programming optimization even if the ARLF is below 180 days, only one well intervention per year is charged.
- Mean time to repair is also influenced by depth and rate. It is assumed that in case of schedule conflicts of the available rigs, a higher flow rate has a positive impact on the urgency and amount of time needed until the pump is operational again. Moreover, with increasing depth the repair time is assumed to increase.
- The operational costs and well intervention costs of LRP are only estimates as OMV currently has no LRPs installed in Austria. Therefore, the corresponding data could not be analysed and verified. As alternative these parameters are derived from SRP values, due to the fact that both pumps are equipped with the same downhole installations.
- As is standard for economic calculations within OMV, the net present value is discounted mid-year, rather than at the end of the year. The calculations do not include depreciation or taxes (other than royalties).
- The following conversion factors were used for the calculations:
  1 EUR = 1.0983 USD
  1 m^3 = 6,2898 bbl
  1 year = 365 days

The framework of the Excel file is based on the assumptions described above. When analysing the LCC a user needs to be aware of these assumptions in order to create an accurate interpretation of the results.

5.3 General considerations

Internal business cases for technical solutions very often tend to base their calculations on initial acquisition costs and obvious operational costs. This is not a systematic approach which should try to include all costs associated with the decision to implement this particular business case. By performing an LCC, the influence of various additional cost drivers on the NPV can be determined.

This thesis could show that in certain cases the operating and maintenance costs can become more dominant than the initial cost of the operation phase. Performing a life cycle costs analysis helps minimizing the level of “surprise” in the operating expenditures at the later stage.

An LCC analysis can provide a better overview on economic aspects during the process of selecting the technical solutions and ensures that most of the possible costs that may occur in a later stage of the project are being included in the analysis.

The values used in this Excel sheet are kept rather straightforward and simple. Normally, a life cycle cost analysis is performed for a particular setting with all specifications known beforehand. As this sheet was generated to be generally applicable for different wells and settings, some compromises had to be made. Therefore, the results cannot be seen as universally applicable numbers, but should rather give an indication to the range of possible costs and a ranking of the ALSs based on their estimated life cycle costs.

Nevertheless, a very important fact is that although the Excel tool facilitates both the compilation of the costs and the calculation, as well as allows good visualization for easier interpretation, the end user needs to be aware of the limitations and assumptions basing these calculations.

6 Conclusion and recommendations

This thesis could show that life cycle costing can be a very helpful instrument when a decision concerning a selection between technical viable solutions has to be made. International standards were published describing the working steps and goals of life cycle costing in the oil and gas business. LCC is often used, as it not only lists the costs that occur during a project's initial phase but calculates and analyses the costs until the abandonment phase including all operational and repair costs. Moreover, it also includes the time value of money allowing for a more detailed analysis of costs and how they are going to impact a company in the future. The KPIs that are the result of the LCC help further identify limitations of the alternatives, like average run life of the installations and the amount of well interventions that need to be scheduled during the appointed time.

Nevertheless, the outcome of an LCC and thus also the Excel file, depend largely on the data used. The data currently implemented into the program has some costs and parameters that are based on estimations, as values were not available during the computation of the tool. In addition, the list of costs can and should be extended if new cost factors become known or can be identified. This is especially true for the values of the linear rod pump as there are no empirical values available, up to now. Another adjustment of costs should be done for gas lifting installations. In the current version of the Excel sheet, surface installations such as pipelines which are needed to transport the gas to the location are not included in the calculation. Moreover, the list of costs needs to be updated regularly for the tool to stay effective. With new technologies or a change in supplier the calculations may become inaccurate. As OMV operates also in different countries, and the tool might be used abroad as well, the costs should be changed to represent the local circumstances, where, e.g. labour, environmental or abandonment costs may differ to those in Austria.

In general, it is established that a large amount of data is collected by OMV concerning the installations and production of each well. However, the data available for each well does not always seem to be consistent and might require some considerations on the data acquisition and quality control processes. Data is recorded for each well and entered into an overview table, which also includes the operating time of the system between the last three well interventions, but not all changes and values are always recorded. For example, only the current set of installation is documented in this file, although the last well intervention may even have been a change in ALS.

A follow up project is considered by OMV where different scenarios concerning the oil price are calculated to further the possibility of implementing life cycle costing into the decision making process of an artificial lift system selection. It may be helpful to include some reservoir parameters into the calculation to better predict the decline curve and change in water cut.

However, as could be shown on the example of the test well, the carefully collected and selected data can be used as the basis for spreadsheet calculations of the LCC.

Life cycle costing should be developed and integrated into OMV’s standard process for decision making. Interpretation of LCC is, like most economic evaluations, subjective and open to bias, error and misinterpretation. In order to avoid those, a broad understanding of LCC, its use and objectives, as well as of the implementation of the respective tool should be encouraged by providing training and courses. This will assure that decision makers will be able to use LCC efficiently and help reduce unexpected expenditures for the company due to unplanned cost elements.

I hope that this thesis and the developed Excel spreadsheet will mark a first successful step to bring life cycle cost analysis as a supporting tool into the decision making at OMV to improve the application of ALSs.

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9 Appendices

9.1 Appendix A: ISO 15663:1-2000 - Glossary of Terms

Definitions according to ISO 15663 [17]:

- *Cost Breakdown Structure:*
  Structure related to the methods an organization employs to report costs

- *Cost Driver:*
  Major cost element which if changed will have a major impact on the life-cycle cost of an option

- *Cost Element:*
  Identifiable part of the life-cycle cost of an option which can be attributed to an activity

- *Life Cycle:*
  All development stages of an item or equipment or function, from when the study commences up to and including disposal

- *Life-Cycle Cost:*
  Discounted cumulative total of all costs incurred by a specified function or item or equipment over its life cycle

- *Life-Cycle Costing:*
  Process of evaluating the difference between the life-cycle costs of two or more alternative options

- *Net Present Value:*
  Sum of total discounted costs and revenues

- *Sensitivity Analysis:*
  Process of testing the outcome of a life-cycle costing in order to establish whether the final conclusion is sensitive to changes in assumptions

9.2 Appendix B: Graphs and Diagrams

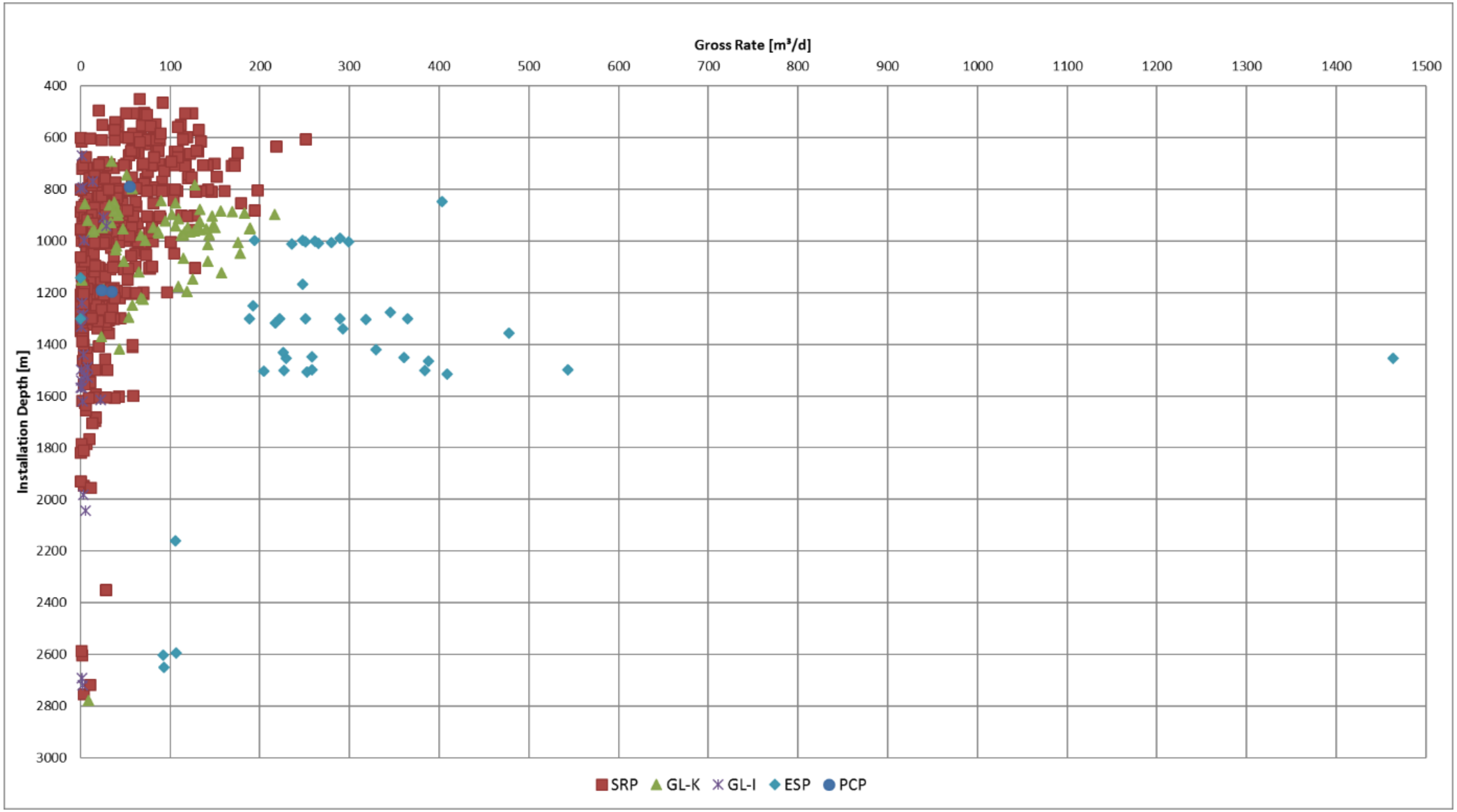


Figure 32: ALS operated by OMV in Austria gross rate [m³/d] vs. depth [m]

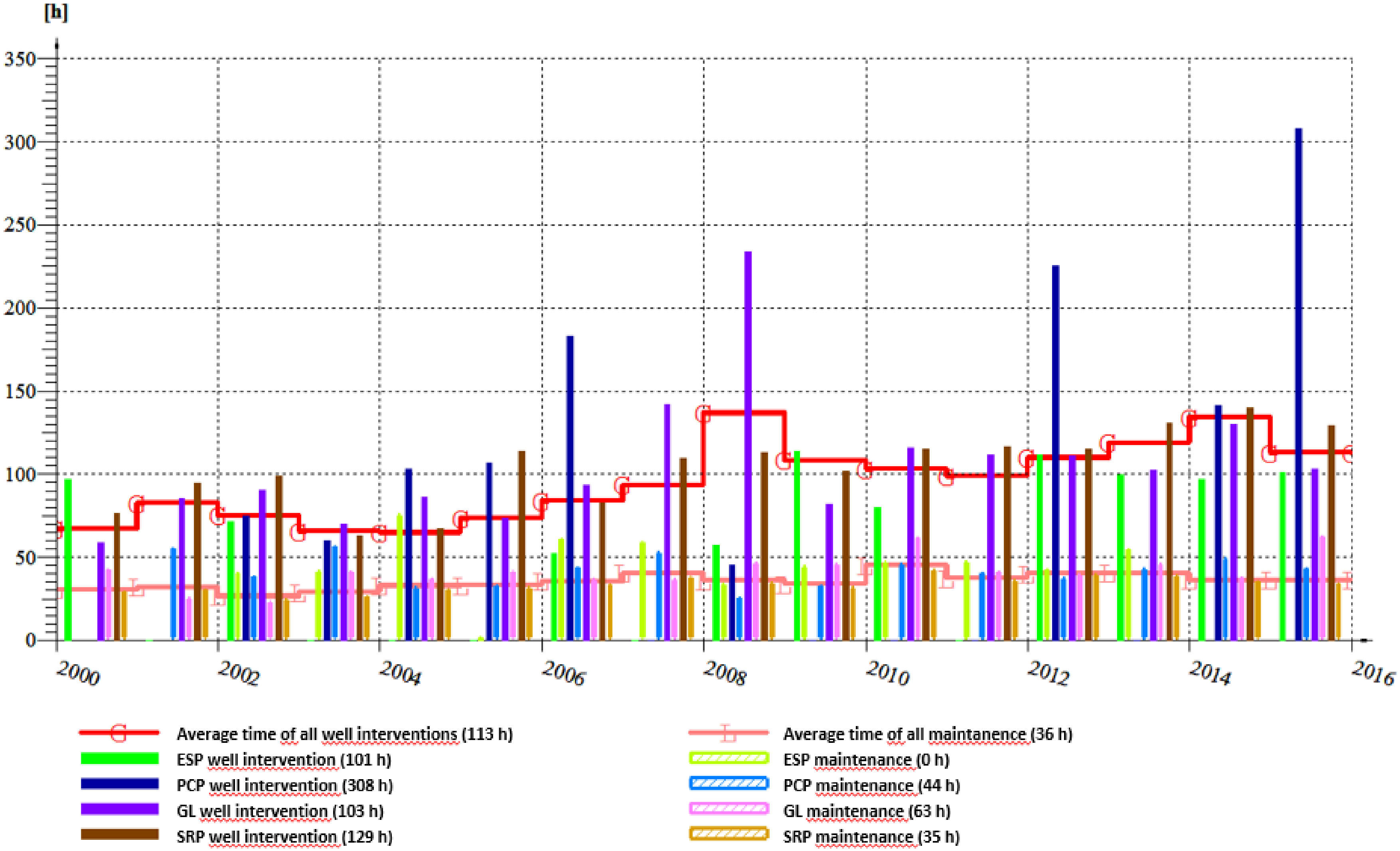


Figure 33: Average times of well intervention per ALS

9.3 Appendix C: Cost factors for Artificial Lift Systems

Table 12: Example costs for Sucker Rod Pumps

Sucker Rod Pumps							
pre installation		**Planning & Design**	**3000**	€	per installation	OMV	capex
	Rig Costs	**SUM**	**39.975,20**				
First Installation		Personnel	16.195,20	€	total	OMV	capex
			482,00	€/hour		OMV	capex
		Site Prepartation	5.000,00	€	per site	extern	capex
		Rig	3.450,00	€	total		capex
		Eqipment	3.500,00	€			capex
		Chemicals	130,00	€			capex
		Transport	4.200,00	€			capex
		Logistics	3.250,00				
		Storage	4.250,00	€		OMV	capex
	Downhole Installations	**SUM**	**50.194,44**				
		Tubing (list)	15.000,00	€	per reservoir depth	OMV	opex
		downhole pump (list)	4.300,00	€		OMV	capex
		sinkerbar	300,00	€		OMV	capex
		sucker rods	8.444,44	€	per installation depth	OMV	opex
		gas anchor		€		OMV	capex
		sand control	7.050,00	€		OMV	capex
		well monitoring equipment	12.300,00	€		OMV	capex
		packer	2.800,00	€		OMV	capex
		SSSV		€		OMV	capex
	Surface Installtions	**SUM**	**176.800,00**				
		Foundation	21.400,00	€			capex
		Polierstange	500,00	€			capex
		Well head	42.700,00	€			capex
		Pump Unit (list)	70.000,00	€			capex
		Pump Unit Installation	20.500,00	€			Capex
		Prime Mover	3.900,00	€			capex
		E-Container	10.000,00	€			capex
		Lightning Arrester	300,00	€			capex
		Chemical Injection Line	7.500,00	€			capex
	Insurance	Insurance		€			capex
	Investment Costs	Investment Costs		€			capex
Well Intervention	Replacements	installations	30.544,44	€	per well intervention		opex
	rig costs (Total)	rig costs	25.152,31	€	per well intervention	OMV	opex
		Waste Management		€	per well intervention		opex
	ARLF	calculated	948,1	[days]			opex
	MTTR	calculated	2,8	[days]	per well intervention		opex
recurring costs	Energy	**Energy Costs**	**11.785,82**	€	per year		opex
		Energy Consumption	293,54	kWh	per day		opex
		Energy Costs	0,11	€/kWh			opex
	Maintenance Costs	**Total**	**3.400,00**	€	per year		opex
		Transport	600,00		per year	extern	opex
		Workshop, Assembly	980,00		per year	omv	opex
		Maintenance	1.000,00		per year	omv	opex
		Maintenance	820,00		per year	extern	opex
	Operator Costs	**Personnel**	**27.948,00**	€	per year	intern	opex
	Environmental Costs	**Water Treatment Costs**	**1.111,41**	€	per year		opex
		Water Treatment Costs/Vol	0,05	€/m³			opex
		Water Production Volume	58,56	m³	per day		opex
	Chemical Injection	**Total costs**	**16.791,84**		per year		opex
		chemical Costs/Vol	4,14	€/l			opex
		Chemical Volume	78,00	l	per month		opex
deferred Production	pump not running	**due to MTTR**	**19.907,44**	€	per well intervention		loss of profit
Abandonment	rig costs	**SUM**	**75.225,56**	€	per abandonment		Provision
		de-installation		€	per abandonment		Provision
		cementation	9.485,56	€	per abandonment		Provision
		Cement	0,13	€/l			
		Personnel	38.560,00	€	per abandonment	OMV	Provision
			482,00	€/hour		OMV	Provision
		Personnel	3.400,00	€	per abandonment	extern	Provision
		Site Prepartation	5.000,00	€	per abandonment	extern	Provision
		Rig	3.450,00	€	per abandonment		Provision
		Eqipment	3.500,00	€	per abandonment		Provision
		Chemicals	130,00	€	per abandonment		Provision
		Transport	4.200,00	€	per abandonment		Provision
		Logistics	3.250,00				
		Storage	4.250,00	€	per abandonment		Provision
		Waste Management		€	per abandonment		Provision
	Testing	Integrity Test		€	per abandonment		Provision
	remaining value of equipment	scrap value		€	per abandonment		Provision
	restoration of surface	restoration of surface		€	per abandonment		Provision

Table 13: Example costs for Linear Rod Pumps

Linear Rod Pumps							
pre installation		**Planning & Design**	**3.200,00**	€	per installation	OMV	capex
First Installation	Rig Costs	**SUM**	**43.214,24**	€			
		Personnel	19.434,24	€		OMV	capex
			482,00	€/hour		OMV	capex
		Site Prepartation	5.000,00	€	per site	extern	capex
		Rig	3.450,00	€	total		capex
		Eqipment	3.500,00	€			capex
		Chemicals	130,00	€			capex
		Transport	4.200,00	€			capex
		Logistics	3.250,00	€			
		Storage	4.250,00	€		OMV	capex
	Downhole Installations	**SUM**	**50.394,44**	€	total	OMV	opex
		Tubing (list)	15.000,00	€	total	OMV	opex
		downhole pump (list)	4.300,00	€		OMV	capex
		sinkerbar	300,00	€		OMV	capex
		sucker rods	8.444,44	€		OMV	opex
		gas anchor		€		OMV	capex
		sand control	7.050,00	€		OMV	capex
		well monitoring equipment	12.500,00	€		OMV	capex
		packer	2.800,00	€		OMV	capex
		SSSV		€		OMV	capex
	Surface Installtions	**SUM**	**120.145,28**	€			capex
		Well head	42.700,00	€			capex
		Pump Unit (list)	35.730,00	€			capex
		E-Container	39.415,28	€			capex
		Lightning Arrester	300,00	€			capex
		Chemical Injection Line	2.000,00	€			capex
	Insurance			€			capex
	Investment Costs			€			capex
Well Intervention	Replacements	installations	30.544,44	€	per well intervention		opex
	rig costs	rig costs total	43.214,24	€	per well intervention	OMV	opex
		Waste Management		€	per well intervention		opex
	ARLF	calculated	948,08	[days]	per well intervention		opex
	MTTR	calculated	3,42	[days]	per well intervention		opex
recurring costs	Energy	**Energy Costs**	**11.785,82**	€	per year		opex
		Energy Consumption	293,54	kWh	per day		opex
		Energy Costs	0,11	€/kWh			opex
	Maintenance Costs	**Total**	**3.400,00**	€	per year		opex
		Transport	600,00	€	per year		
		Workshop, Assembly	980,00	€	per year		
		Maintenance	1.000,00	€	per year	omv	
		Maintenance	820,00	€	per year	extern	
	Operator Costs	**Personnel**	**27.948,00**	€	per year	intern	opex
	Environmental Costs	**Water Treatment Costs**	**1.111,41**	€	per year		opex
		Water Treatment Costs/Vol	0,05	€/m³			opex
		Water Volume	58,56	m³	per day		opex
	Chemical Injection	**Total costs**	**16.791,84**		per year		opex
		chemical Costs/Vol	4,14	€/m³			opex
		Chemical Volume	78,00	m³	per month		opex
deferred Production	pump not running	**due to MTTR**	**22.652,75**	€	per year		loss of profit
Abandonment	rig costs	**SUM**	**67.513,56**	€	per abandonment		Provision
		de-installation		€	per abandonment		Provision
		cementation	9.485,56	€	per abandonment		Provision
		Cement	0,13	€/l			
		Personnel	30.848,00	€	per abandonment	OMV	Provision
			482,00	€/hour		OMV	Provision
		Personnel	3.400,00	€	per abandonment	extern	Provision
		Site Prepartation	5.000,00	€	per abandonment	extern	Provision
		Rig	3.450,00	€	per abandonment		Provision
		Eqipment	3.500,00	€	per abandonment		Provision
		Chemicals	130,00	€	per abandonment		Provision
		Transport	4.200,00	€	per abandonment		Provision
		Logistics	3.250,00				
		Storage	4.250,00	€	per abandonment		Provision
		Waste Management		€	per abandonment		Provision
	Testing	**Integrity Test**		€	per abandonment		Provision
	remaining value of equipment	**scrap value**		€	per abandonment		Provision
	restoration of surface			€	per abandonment		Provision

Table 14: Example costs for progressive cavity pumps

Progressive Cavity Pump							
pre installation		**Planning & Design**	**3.100,00**	€	per installation	OMV	capex
First Installation	Rig Costs	**SUM**	**47.152,68**	€	total	OMV	
		Personnel	20.359,68	€		OMV	capex
			482,00	€/hour		OMV	capex
		Site Prepartation	5.000,00	€	per site	extern	capex
		Rig	3.450,00	€	total		capex
		Eqipment	6.513,00	€			capex
		Chemicals	130,00	€			capex
		Transport	4.200,00	€			capex
		Logistics	3.250,00	€			capex
		Storage	4.250,00	€		OMV	capex
	Downhole Installations	**SUM**	**71.214,44**				
		Tubing (list)	26.620,00	€	total	OMV	opex
		PCP	15.000,00	€		OMV	capex
		sucker rods	8.444,44	€		OMV	opex
		gas anchor		€		OMV	capex
		sand control	7.050,00	€		OMV	capex
		well monitoring equipment	12.300,00	€		OMV	capex
		packer	1.800,00	€		OMV	capex
		SSSV		€		OMV	capex
	Surface Installtions	**SUM**	**75.100,00**				
		Desander	3.500,00	€			capex
		Well head	35.400,00	€			capex
		Prime Mover	3.900,00	€			capex
		E-Container	30.000,00	€			capex
		Lightning Arrester	300,00	€			capex
		Chemical Injection Line	2.000,00	€			capex
	Insurance			€			capex
	Investment Costs			€			capex
Well Intervention	Replacements	installations	51.864,44	€	per well intervention		opex
	rig costs	Total	47.152,68	€	per well intervention	OMV	opex
		Waste Management		€	per well intervention		opex
	ARLF	calculated	623,00	[days]	per well intervention		opex
	MTTR	calculated	3,58	[days]	per well intervention		opex
recurring costs	Energy	**Energy Costs**	**20.486,17**	€	per year		opex
		Energy Consumption	510,24	kWh	per day		opex
		Energy Costs	0,11	€/kWh			opex
	Maintenance Costs	**Total**	**2.160,00**	€	per year		opex
		Transport	1.010,00			omv	opex
		Maintenance	1.150,00			omv	opex
	Operator Costs	**Personnel**	**27.948,00**	€	per year	intern	opex
	Environmental Costs	**Water Treatment Costs**	**1.111,41**	€	per year		opex
		Water Treatment Costs/Vol	0,05	€/m³			opex
		Water Volume	58,56	m³	per day		opex
	Chemical Injection	**Total costs**	**21.958,56**		per year		opex
		chemical Costs/Vol	4,14	€/m³			opex
		Chemical Volume	102,00	m³	per month		opex
deferred Production	pump not running	**due to MTTR**	**39.249,87**	€	per year		loss of profit
Abandonment	rig costs	**SUM**	**67.513,56**	€	per abandonment		Provision
		de-installation		€	per abandonment		Provision
		cementation	9.485,56	€	per abandonment		Provision
		Cement	0,13	€/l			Provision
		Personnel	30.848,00	€	per abandonment	OMV	Provision
			482,00	€/hour		OMV	Provision
		Personnel	3.400,00	€	per abandonment	extern	Provision
		Site Prepartation	5.000,00	€	per abandonment	extern	Provision
		Rig	3.450,00	€	per abandonment		Provision
		Eqipment	3.500,00	€	per abandonment		Provision
		Chemicals	130,00	€	per abandonment		Provision
		Transport	4.200,00	€	per abandonment		Provision
		Logistics	3.250,00				
		Storage	4.250,00	€	per abandonment		Provision
		Waste Management		€	per abandonment		Provision
	Testing	**Integrity Test**		€	per abandonment		Provision
	remaining value of equipment	**scrap value**		€	per abandonment		Provision
	restoration of surface			€	per abandonment		Provision

Table 15: Example costs for electrical submersible pumps

Electrical Submersible Pump							
pre installation		**Planning & Design**	**3.000,00**	€	per installation	OMV	capex
First Installation	Rig Costs	**SUM**	**69.515,72**	€			capex
		Personnel	46.734,72	€	total	OMV	capex
			482,00	€/hour		OMV	capex
		Site Prepartation	5.000,00	€	per site	extern	capex
		Rig	3.450,00	€	total		capex
		Eqipment	2.501,00	€			capex
		Chemicals	130,00	€			capex
		Transport	4.200,00	€			capex
		Logistics	3.250,00	€		OMV	capex
		Storage	4.250,00	€		OMV	capex
	Downhole Installations	**SUM**	**197.365,23**	€	25.830,37		capex
		Tubing (list)	26.620,00	€	total	OMV	opex
		ESP	110.731,51	€		OMV	capex
		cable	14.576,00	€			
		cable protector	4.919,20	€		OMV	capex
		Sensor	20.622,62	€			
		gas separator		€		OMV	capex
		sand control	7.050,00	€		OMV	capex
		well monitoring equipment	10.045,90	€		OMV	capex
		packer	2.800,00	€		OMV	capex
		SSSV		€		OMV	capex
	Surface Installtions	**SUM**	**122.600,00**	€			capex
		Well head	40.300,00	€			capex
		E-Container	80.000,00	€			capex
		Lightning Arrester	300,00	€			capex
		Chemical Injection Line	2.000,00	€			capex
	Insurance			€			capex
	Investment Costs			€			capex
Well Intervention	Replacements	installations	150.849,33	€	per well intervention		opex
	rig costs	Total	69.515,72	€	per well intervention	OMV	opex
		Waste Management		€	per well intervention		opex
	ARLF	calculated	1.387,20	[days]	per well intervention		opex
	MTTR	calculated	8,22	[days]	per well intervention		opex
recurring costs	Energy	**Energy Costs**	**13.093,84**	€	per year		opex
		Energy Consumption	326,12	kWh	per day		opex
		Energy Costs	0,11	€/kWh			opex
	Maintenance Costs	**Total**	**1.790,00**	€	per year		opex
		Transport	1.100,00			omv	opex
		Maintenance	690,00			omv	opex
	Operator Costs	**Personnel**	**27.948,00**	€	per year	intern	opex
	Environmental Costs	**Water Treatment Costs**	**1.111,41**	€	per year		opex
		Water Treatment Costs/Vol	0,05	€/m³			opex
		Water Volume	58,56	m³	per day		opex
	Chemical Injection	**Total costs**	**11.625,12**		per year		opex
		chemical Costs/Vol	4,14	€/m³			opex
		Chemical Volume	54,00	m³	per month		opex
deferred Production	pump not running	**due to MTTR**	**37.527,42**	€	per year		loss of profit
Abandonment	rig costs	**SUM**	**67.513,56**	€	per abandonment		Provision
		de-installation					
		cementation	9.485,56	€	per abandonment		Provision
		Cement	0,13	€/l		OMV	Provision
		Personnel	30.848,00	€	per abandonment	OMV	Provision
			482,00	€/hour		OMV	Provision
		Personnel	3.400,00	€	per abandonment	extern	Provision
		Site Prepartation	5.000,00	€	per abandonment	extern	Provision
		Rig	3.450,00	€	per abandonment		Provision
		Eqipment	3.500,00	€	per abandonment		Provision
		Chemicals	130,00	€	per abandonment		Provision
		Transport	4.200,00	€	per abandonment		Provision
		Logistics	3.250,00				
		Storage	4.250,00	€	per abandonment		Provision
		Waste Management		€	per abandonment		Provision
	Testing	**Integrity Test**		€	per abandonment		Provision
	remaining value of equipment	**scrap value**		€	per abandonment		Provision
	restoration of surface			€	per abandonment		Provision

Table 16: Example costs for gas lifting

Gas Lifting							
pre installation		**Planning & Design**	**3.600,00**	€	per installation	OMV	capex
First Installation	Rig Costs	**SUM**	**55.536,00**	€	total		capex
		Personnel	30.366,00	€		OMV	capex
			482,00	€/hour		OMV	capex
		Site Prepartation	5.000,00	€	per site	extern	capex
		Rig	3.450,00	€	total		capex
		Eqipment	4.600,00	€			capex
		Chemicals	220,00	€			capex
		Transport	3.450,00	€			capex
		Logisitcs	4.200,00	€			
		Storage	4.250,00	€		OMV	capex
	Downhole Installations	**SUM**	**44.020,00**	€			
		Tubing (list)	26.620,00	€	total	OMV	opex
		Gas Valves	5.100,00	€		OMV	capex
		well monitoring equipment	12.300,00	€		OMV	capex
		SSSV		€		OMV	capex
	Surface Installtions	**SUM**	**74.900,00**				
		Kick Off Compressor	9.000,00	€			capex
		Well head	45.000,00	€			capex
		Gas Injection Line	3.600,00	€			capex
		E-Container	4.000,00	€			capex
		Lightning Arrester	300,00	€			capex
		Desander	3.500,00				
		Gas Separator	7.500,00	€			capex
		Gas Processing Facility		€			capex
		Chemical Injection Line	2.000,00	€			capex
	Insurance			€			capex
	Investment Costs			€			capex
Well Intervention	Replacements	installations	21.072,00	€	per well intervention		opex
	rig costs	Total	55.536,00	€	per well intervention	OMV	opex
		Waste Management		€	per well intervention		opex
	ARLF	calculated	1.009,00	[days]	per well intervention		opex
	MTTR	calculated	6,72	[days]	per well intervention		opex
recurring costs	Energy	**Energy Costs**	**24.364,91**	€	per year		opex
		Energy Consumption (GAS)	3.337,66	m^3	per day		opex
		Energy Costs	0,02	€/m^3			opex
	Maintenance Costs	**Total**	**4.600,00**	€	per year		opex
		Transport	400,00	€		omv	opex
		Maintenance	4.200,00	€		omv	opex
	Operator Costs	**Personnel**	**27.948,00**	€	per year	intern	opex
	Environmental Costs	**Water Treatment Costs**	**1.111,41**	€	per year		opex
		Water Treatment Costs/Vol	0,05	€/m^3			opex
		Water Volume	58,56	m^3/d			opex
	Chemical Injection	**Total costs**	**14.208,48**		per year		opex
		chemical Costs/Vol	4,14	€/m^3			opex
		Chemical Volume	66,00	m^3	per month		opex
deferred Production	pump not running	**due to MTTR**	**42.704,51**	€	per year		loss of profit
Abandonment	rig costs	**SUM**	**71.403,56**	€	per abandonment		Provision
		de-installation	2.500,00	€	per abandonment		Provision
		cementation	9.485,56	€	per abandonment		Provision
		Cement	0,13	€/l		OMV	
		Personnel	30.848,00	€	per abandonment	OMV	Provision
			482,00	€/hour		OMV	Provision
		Personnel	3.400,00	€	per abandonment	extern	Provision
		Site Prepartation	5.000,00	€	per abandonment	extern	Provision
		Rig	3.450,00	€	per abandonment		Provision
		Eqipment	4.600,00	€	per abandonment		Provision
		Chemicals	220,00	€	per abandonment		Provision
		Transport	3.450,00	€	per abandonment		Provision
		Logistics	4.200,00	€	per abandonment		Provision
		Storage	4.250,00	€	per abandonment		Provision
	Testing	**Integrity Test**		€	per abandonment		Provision
	remaining value of equipment	**scrap value**		€	per abandonment		Provision
	restoration of surface			€	per abandonment		Provision

9.4 Appendix D: NPV calculations for ALS

Table 17: Example for NPV calculation for a sucker rod pump

Sucker Rod Pump																			
years	ARLF	948,08	2,60					WACC	WACC+Risk					WACC+Risk		WACC+Risk	WACC+Risk	WACC+Risk	
25	YEARS	**WI**	**net rate**	**CAPEX**	**OPEX**	**WI**	**pre tax Costs**	**disc. PT Costs**	**disc. PT Costs**	**Revenue**	**Royalties**	**Cash Flow**	**cum CF**	**disc. CF**	**cum. disc. cash flow**	**disc. CAPEX**	**disc. OPEX**	**disc. WI**	**deferred Prod.**
		[Y/n]	[m³/day]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]
1	1			261.525,20	8.444,44	-	269.969,64	257.405,96	251.747,99	-	-	- 269.969,64	- 269.969,64	- 251.747,99	- 251.747,99	249.354,49	7.874,49	-	-
2	2		3	-	61.007,52	-	61.007,52	52.880,35	49.469,39	313.545,07	53.302,66	199.234,89	- 70.734,75	161.554,34	- 90.193,65	-	49.469,39	-	-
3	3	x	2,922	-	61.009,00	55.696,75	116.705,75	91.962,45	82.290,11	303.010,74	51.511,83	134.793,16	64.058,41	95.043,68	4.850,03	-	43.017,91	39.272,21	2.382,16
4	4		2,844	-	61.010,48	-	61.010,48	43.704,89	37.407,78	297.240,73	50.530,92	185.699,33	249.757,73	113.859,14	118.709,17	-	37.407,78	-	-
5	5		2,766	-	61.011,96	-	61.011,96	39.732,68	32.529,30	289.088,55	49.145,05	178.931,54	428.689,27	95.399,62	214.108,78	-	32.529,30	-	-
6	6	x	2,688	-	61.013,44	55.696,75	116.710,19	69.095,38	54.109,14	278.744,99	47.386,65	114.648,15	543.337,42	53.153,14	267.261,92	-	28.287,03	25.822,11	2.191,39
7	7		2,61	-	61.014,92	-	61.014,92	32.838,52	24.598,02	272.784,21	46.373,32	165.395,98	708.733,40	66.678,98	333.940,91	-	24.598,02	-	-
8	8	x	2,532	-	61.016,40	55.696,75	116.713,15	57.105,07	40.915,32	262.567,82	44.636,53	101.218,14	809.951,54	35.483,34	369.424,25	-	21.390,10	19.525,23	2.064,21
9	9		2,454	-	61.017,88	-	61.017,88	27.140,59	18.600,54	256.479,87	43.601,58	151.860,41	961.811,95	46.292,74	415.717,00	-	18.600,54	-	-
10	10		2,376	-	61.019,36	-	61.019,36	24.673,86	16.174,77	248.327,70	42.215,71	145.092,63	1.106.904,57	38.460,58	454.177,58	-	16.174,77	-	-
11	11	x	2,298	-	61.020,84	55.696,75	116.717,60	42.905,52	26.903,51	238.302,08	40.511,35	81.073,13	1.187.977,70	18.687,43	472.865,01	-	14.065,36	12.838,15	1.873,45
12	12		2,22	-	61.022,32	-	61.022,32	20.392,61	12.231,04	232.023,35	39.443,97	131.557,06	1.319.534,76	26.368,72	499.233,73	-	12.231,04	-	-
13	13	x	2,142	-	61.023,80	55.696,75	116.720,56	35.460,00	20.343,44	222.124,91	37.761,24	67.643,12	1.387.177,88	11.789,64	511.023,37	-	10.635,95	9.707,49	1.746,27
14	14		2,064	-	61.025,28	-	61.025,28	16.854,22	9.248,88	215.719,01	36.672,23	118.021,49	1.505.199,38	17.887,11	528.910,48	-	9.248,88	-	-
15	15		1,986	-	61.026,76	-	61.026,76	15.322,39	8.042,70	207.566,84	35.286,36	111.253,71	1.616.453,09	14.662,09	543.572,57	-	8.042,70	-	-
16	16	x	1,908	-	61.028,24	55.696,75	116.725,00	26.642,64	13.376,65	197.859,17	33.636,06	47.498,11	1.663.951,20	5.443,27	549.015,84	-	6.993,82	6.382,83	1.555,50
17	17		1,83	-	61.029,72	-	61.029,72	12.663,74	6.081,73	191.262,49	32.514,62	97.718,15	1.761.669,35	9.737,80	558.753,64	-	6.081,73	-	-
18	18		1,752	-	61.031,20	-	61.031,20	11.512,77	5.288,59	183.110,32	31.128,75	90.950,36	1.852.619,71	7.881,20	566.634,84	-	5.288,59	-	-
19	19	x	1,674	-	61.032,68	55.696,75	116.729,44	20.017,77	8.795,70	173.593,42	29.510,88	27.353,10	1.879.972,81	2.061,09	568.695,93	-	4.598,88	4.196,82	1.364,73
20	20		1,596	-	61.034,16	-	61.034,16	9.515,15	3.999,13	166.805,98	28.357,02	77.414,80	1.957.387,61	5.072,43	573.768,36	-	3.999,13	-	-
21	21	x	1,518	-	61.035,64	55.696,75	116.732,40	16.544,03	6.650,98	157.416,25	26.760,76	13.923,09	1.971.310,70	793,29	574.561,64	-	3.477,59	3.173,40	1.237,55
22	22		1,44	-	61.037,13	-	61.037,13	7.864,14	3.024,06	150.501,63	25.585,28	63.879,23	2.035.189,93	3.164,87	577.726,51	-	3.024,06	-	-
23	23		1,362	-	61.038,61	-	61.038,61	7.149,39	2.629,68	142.349,46	24.199,41	57.111,45	2.092.301,38	2.460,49	580.187,01	-	2.629,68	-	-
24	24	x	1,284	-	61.040,09	55.696,75	116.736,84	12.430,25	4.373,29	133.150,51	22.635,59	- 6.221,92	2.086.079,46	- 233,09	579.953,92	-	2.286,74	2.086,56	1.046,78
25	25		1,206	75.225,56	61.041,57	-	136.267,13	13.190,78	4.439,09	126.045,12	21.427,67	- 31.649,68	2.054.429,77	- 1.031,03	578.922,88	2.450,58	1.988,51	-	-
26	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
27	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
28	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
29	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
30	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
31	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
32	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
33	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
34	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
35	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
36	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
SUMME		9,00	50,47	336.750,76	1.473.033,44	501.270,79	2.311.055,00	965.005,16	743.270,84	5.259.620,21	894.135,44	2.054.429,77		578.922,88		251.805,07	373.941,97	123.004,79	15.462,04
		WI	**net rate**	**CAPEX**	**OPEX**	**WI**	**pre tax Costs**	**disc. PT Costs**	**disc. PT Costs**	**Revenue**	**Royalties**	**Cash Flow**	**cum CF**	**disc. CF**	**cum. disc. cash flow**	**disc. CAPEX**	**disc. OPEX**	**disc. WI**	**deferred Prod.**
		[Y/n]	[m³/day]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]
						IRR	63%	Payout [years]	3										
						DPI []	2,299												
						Total Prod. [m³]	18368												

Table 18: Example for NPV calculation for a linear rod pump

Linear Rod Pump																			
	ARLF	948,08	2,60					WACC	WACC+Risk					WACC+Risk		WACC+Risk	WACC+Risk	WACC+Risk	
	YEARS	**WI**	**net rate**	**CAPEX**	**OPEX**	**WI**	**pre tax Costs**	**disc. PT Costs**	**disc. PT Costs**	**Revenue**	**Royalties**	**Cash Flow**	**cum CF**	**disc. CF**	**cum. disc. cash flow**	**disc. CAPEX**	**disc. OPEX**	**disc. WI**	**deferred Prod.**
		[Y/n]	[m³/day]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]
1	1		0	201.953,96	-	-	201.953,96	192.555,55	188.323,04	-	-	- 201.953,96	- 201.953,96	- 188.323,04	- 188.323,04	188.323,04	-	-	-
2	2		3	-	61.007,52	-	61.007,52	52.880,35	49.469,39	313.545,07	53.302,66	199.234,89	- 2.719,07	161.554,34	- 26.768,70	-	49.469,39	-	-
3	3	x	2,922	-	61.010,48	73.758,68	134.769,16	106.196,16	95.026,76	302.534,30	51.430,83	116.334,31	113.615,24	82.028,21	55.259,51	-	43.018,95	52.007,81	2.782,29
4	4		2,844	-	61.011,96	-	61.011,96	43.705,95	37.408,69	297.240,73	50.530,92	185.697,84	299.313,08	113.858,23	169.117,73	-	37.408,69	-	-
5	5		2,766	-	61.013,44	-	61.013,44	39.733,65	32.530,09	289.088,55	49.145,05	178.930,06	478.243,14	95.398,83	264.516,56	-	32.530,09	-	-
6	6	x	2,688	-	61.014,92	73.758,68	134.773,60	79.789,38	62.483,70	278.306,71	47.312,14	96.220,97	574.464,11	44.609,94	309.126,50	-	28.287,72	34.195,98	2.553,36
7	7		2,61	-	61.016,40	-	61.016,40	32.839,32	24.598,61	272.784,21	46.373,32	165.394,50	739.858,60	66.678,39	375.804,88	-	24.598,61	-	-
8	8	x	2,532	-	61.017,88	73.758,68	134.776,56	65.943,08	47.247,69	262.154,98	44.566,35	82.812,07	822.670,68	29.030,86	404.835,74	-	21.390,62	25.857,07	2.400,75
9	9		2,454	-	61.019,36	-	61.019,36	27.141,25	18.600,99	256.479,87	43.601,58	151.858,93	974.529,60	46.292,29	451.128,03	-	18.600,99	-	-
10	10		2,376	-	61.020,84	-	61.020,84	24.674,46	16.175,16	248.327,70	42.215,71	145.091,15	1.119.620,75	38.460,19	489.588,22	-	16.175,16	-	-
11	11	x	2,298	-	61.022,32	73.758,68	134.781,01	49.545,65	31.067,15	237.927,39	40.447,66	62.698,73	1.182.319,48	14.452,11	504.040,34	-	14.065,70	17.001,45	2.171,83
12	12		2,22	-	61.023,80	-	61.023,80	20.393,11	12.231,34	232.023,35	39.443,97	131.555,58	1.313.875,06	26.368,42	530.408,76	-	12.231,34	-	-
13	13	x	2,142	-	61.025,28	73.758,68	134.783,97	40.947,71	23.491,74	221.775,66	37.701,86	49.289,83	1.363.164,89	8.590,81	538.999,57	-	10.636,21	12.855,54	2.019,21
14	14		2,064	-	61.026,76	-	61.026,76	16.854,62	9.249,10	215.719,01	36.672,23	118.020,01	1.481.184,90	17.886,89	556.886,46	-	9.249,10	-	-
15	15		1,986	-	61.028,24	-	61.028,24	15.322,76	8.042,89	207.566,84	35.286,36	111.252,23	1.592.437,13	14.661,89	571.548,35	-	8.042,89	-	-
16	16	x	1,908	-	61.029,72	73.758,68	134.788,41	30.765,64	15.446,71	197.548,07	33.583,17	29.176,49	1.621.613,62	3.343,62	574.891,97	-	6.993,99	8.452,72	1.790,29
17	17		1,83	-	61.031,20	-	61.031,20	12.664,05	6.081,88	191.262,49	32.514,62	97.716,67	1.719.330,29	9.737,65	584.629,62	-	6.081,88	-	-
18	18		1,752	-	61.032,68	-	61.032,68	11.513,05	5.288,72	183.110,32	31.128,75	90.948,88	1.810.279,17	7.881,07	592.510,69	-	5.288,72	-	-
19	19	x	1,674	-	61.034,16	73.758,68	134.792,85	23.115,44	10.156,80	173.320,47	29.464,48	9.063,14	1.819.342,31	682,92	593.193,61	-	4.599,00	5.557,80	1.561,37
20	20		1,596	-	61.035,64	-	61.035,64	9.515,38	3.999,22	166.805,98	28.357,02	77.413,32	1.896.755,63	5.072,33	598.265,94	-	3.999,22	-	-
21	21	x	1,518	-	61.037,13	73.758,68	134.795,81	19.104,09	7.680,17	157.168,74	26.718,69	- 4.345,75	1.892.409,88	- 247,60	598.018,34	-	3.477,67	4.202,50	1.408,75
22	22		1,44	-	61.038,61	-	61.038,61	7.864,33	3.024,13	150.501,63	25.585,28	63.877,75	1.956.287,63	3.164,80	601.183,14	-	3.024,13	-	-
23	23		1,362	-	61.040,09	-	61.040,09	7.149,57	2.629,75	142.349,46	24.199,41	57.109,97	2.013.397,60	2.460,43	603.643,56	-	2.629,75	-	-
24	24	x	1,284	-	61.041,57	73.758,68	134.800,25	14.353,66	5.050,00	132.941,15	22.600,00	- 24.459,10	1.988.938,50	- 916,31	602.727,26	-	2.286,79	2.763,21	1.179,83
25	25		1,206	67.513,56	61.064,46	-	128.578,02	12.446,46	4.188,61	126.045,12	21.427,67	- 23.960,57	1.964.977,93	- 780,55	601.946,71	2.199,35	1.989,26	-	-
26	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
27	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
28	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
29	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
30	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
31	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
32	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
33	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
34	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
35	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
36	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
SUMME		9,00	50,47	269.467,53	1.464.644,46	663.828,16	2.397.940,15	957.014,66	719.492,33	5.256.527,80	893.609,73	1.964.977,93		601.946,71		190.522,39	366.075,86	162.894,07	17.867,68
			net rate	**CAPEX**	**OPEX**	**WI**	**pre tax Costs**	**disc. PT Costs**	**disc. PT Costs**	**Revenue**	**Royalties**	**Cash Flow**	**cum CF**	**disc. CF**	**cum. disc. cash flow**	**disc. CAPEX**	**disc. OPEX**	**disc. WI**	**deferred Prod.**
			[m³/day]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]
						IRR	83%	Payout [years]	3										
						DPI []	3,159												
						Total Prod. [m³]	18357												

Table 19: Example for NPV calculation for a progressive cavity pump

Progressive Cavity Pump																			
	ARLF	623,00	1,71					WACC	WACC+Risk					WACC+Risk		WACC+Risk	WACC+Risk	WACC+Risk	
	YEARS	**WI**	**net rate**	**CAPEX**	**OPEX**	**WI**	**pre tax Costs**	**disc. PT Costs**	**disc. PT Costs**	**Revenue**	**Royalties**	**Cash Flow**	**cum CF**	**disc. CF**	**cum. disc. cash flow**	**disc. CAPEX**	**disc. OPEX**	**disc. WI**	**deferred Prod.**
		[Y/n]	[m³/day]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]
1	1		0	169.947,12		-	169.947,12	162.038,23	158.476,51	-	-	- 169.947,12	- 169.947,12	- 158.476,51	- 158.476,51	158.476,51	-	-	-
2	2	x	3	-	73.634,59	99.017,12	172.651,72	149.651,78	139.998,75	310.470,41	52.779,97	85.038,72	- 84.908,40	68.955,67	- 89.520,84	-	59.708,36	80.290,39	3.074,66
3	3		2,922	-	73.636,08	-	73.636,08	58.024,17	51.921,36	305.392,90	51.916,79	179.840,03	94.931,63	126.806,57	37.285,73	-	51.921,36	-	-
4	4	x	2,844	-	73.637,56	99.017,12	172.654,68	123.681,28	105.860,98	294.325,95	50.035,41	71.635,86	166.567,48	43.922,60	81.208,33	-	45.149,91	60.711,07	2.914,78
5	5		2,766	-	73.639,04	-	73.639,04	47.955,79	39.261,58	289.088,55	49.145,05	166.304,46	332.871,95	88.667,33	169.875,66	-	39.261,58	-	-
6	6	x	2,688	-	73.640,52	99.017,12	172.657,64	102.217,68	80.047,48	278.181,49	47.290,85	58.232,99	391.104,94	26.997,96	196.873,62	-	34.141,19	45.906,29	2.754,89
7	7	x	2,61	-	73.642,00	99.017,12	172.659,12	92.925,96	69.607,10	270.109,26	45.918,57	51.531,56	442.636,50	20.774,82	217.648,44	-	29.688,59	39.918,51	2.674,95
8	8		2,532	-	73.643,48	-	73.643,48	36.032,06	25.816,69	264.632,04	44.987,45	146.001,11	588.637,62	51.182,60	268.831,05	-	25.816,69	-	-
9	9	x	2,454	-	73.644,96	99.017,12	172.662,08	76.799,63	52.633,87	253.964,80	43.174,02	38.128,70	626.766,32	11.623,06	280.454,10	-	22.449,74	30.184,13	2.515,07
10	10		2,376	-	73.646,44	-	73.646,44	29.779,76	19.521,91	248.327,70	42.215,71	132.465,55	759.231,87	35.113,45	315.567,55	-	19.521,91	-	-
11	11	x	2,298	-	73.647,92	99.017,12	172.665,04	63.471,86	39.799,45	237.820,33	40.429,46	24.725,83	783.957,70	5.699,33	321.266,88	-	16.975,91	22.823,54	2.355,19
12	12	x	2,22	-	73.649,40	99.017,12	172.666,52	57.702,19	34.608,52	229.748,10	39.057,18	18.024,40	801.982,10	3.612,73	324.879,61	-	14.761,96	19.846,56	2.275,25
13	13		2,142	-	73.650,88	-	73.650,88	22.375,33	12.836,75	223.871,18	38.058,10	112.162,20	914.144,30	19.548,95	344.428,56	-	12.836,75	-	-
14	14	x	2,064	-	73.652,36	99.017,12	172.669,48	47.688,57	26.169,46	213.603,64	36.312,62	4.621,54	918.765,84	700,43	345.128,99	-	11.162,61	15.006,85	2.115,37
15	15		1,986	-	73.653,84	-	73.653,84	18.492,75	9.706,81	207.566,84	35.286,36	98.626,63	1.017.392,47	12.997,97	358.126,96	-	9.706,81	-	-
16	16	x	1,908	-	73.655,32	99.017,12	172.672,45	39.412,72	19.788,21	197.459,18	33.568,06	- 8.781,33	1.008.611,15	- 1.006,34	357.120,62	-	8.440,88	11.347,33	1.955,48
17	17		1,83	-	73.656,80	-	73.656,80	15.283,88	7.340,04	191.262,49	32.514,62	85.091,07	1.093.702,22	8.479,49	365.600,11	-	7.340,04	-	-
18	18	x	1,752	-	73.658,28	99.017,12	172.675,41	32.573,06	14.962,99	181.314,72	30.823,50	- 22.184,19	1.071.518,03	- 1.922,35	363.677,77	-	6.382,77	8.580,21	1.795,60
19	19	x	1,674	-	73.659,76	99.017,12	172.676,89	29.612,12	13.011,40	173.242,49	29.451,22	- 28.885,62	1.042.632,41	- 2.176,57	361.501,20	-	5.550,35	7.461,06	1.715,66
20	20		1,596	-	73.661,24	-	73.661,24	11.483,70	4.826,49	166.805,98	28.357,02	64.787,72	1.107.420,12	4.245,07	365.746,27	-	4.826,49	-	-
21	21	x	1,518	-	73.662,72	99.017,12	172.679,85	24.473,25	9.838,66	157.098,03	26.706,66	- 42.288,48	1.065.131,64	- 2.409,44	363.336,83	-	4.197,03	5.641,63	1.555,78
22	22		1,44	-	73.664,20	-	73.664,20	9.491,04	3.649,66	150.501,63	25.585,28	51.252,15	1.116.383,79	2.539,27	365.876,10	-	3.649,66	-	-
23	23	x	1,362	-	73.665,68	99.017,12	172.682,81	20.226,17	7.439,57	140.953,57	23.962,11	- 55.691,35	1.060.692,44	- 2.399,31	363.476,79	-	3.173,68	4.265,88	1.395,90
24	24	x	1,284	-	73.667,16	99.017,12	172.684,29	18.387,59	6.469,24	132.881,34	22.589,83	- 62.392,78	998.299,66	- 2.337,41	361.139,38	-	2.759,78	3.709,46	1.315,95
25	25		1,206	67.513,56	73.668,64	-	141.182,21	13.666,56	4.599,21	126.045,12	21.427,67	- 36.564,76	961.734,90	- 1.191,15	359.948,23	2.199,35	2.399,86	-	-
26	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
27	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
28	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
29	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
30	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
31	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
32	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
33	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
34	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
35	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
36	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
SUMME		14	50,47	237.460,69	1.767.638,87	1.386.239,74	3.391.339,30	1.303.447,11	958.192,69	5.244.667,72	891.593,51	961.734,90		359.948,23		160.675,86	441.823,93	355.692,90	30.414,53
			net rate	CAPEX	OPEX	WI	pre tax Costs	disc. PT Costs	disc. PT Costs	Revenue	**Royalties**	Cash Flow	cum CF	disc. CF	cum. disc. cash flow	disc. CAPEX	disc. OPEX	disc. WI	deferred Prod.
			[m³/day]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]
						IRR	65%	Payout [years]	3										
						DPI []	2,240												
						Total Prod. [m³]	18316												

Table 20: Example for NPV calculation for an electric submersible pump

Electric Submersible Pump																			
	ARLF	1.387,20	3,80					WACC	WACC+Risk					WACC+Risk		WACC+Risk	WACC+Risk	WACC+Risk	
	YEARS	WI	net rate	CAPEX	OPEX	WI	pre tax Costs	disc. PT Costs	disc. PT Costs	Revenue	Royalties	Cash Flow	cum CF	disc. CF	cum. disc. cash flow	disc. CAPEX	disc. OPEX	disc. WI	deferred Prod.
		[Y/n]	[m^3/day]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]
1	1		0	365.860,95		-	365.860,95	348.834,73	341.167,10	-	-	- 365.860,95	- 365.860,95	- 341.167,10	- 341.167,10	341.167,10	-	-	-
2	2		3	-	55.538,82	-	55.538,82	48.140,17	45.034,97	313.545,07	53.302,66	204.703,59	- 161.157,36	165.988,77	- 175.178,33	-	45.034,97	-	-
3	3		2,922	-	55.540,30	-	55.540,30	43.764,96	39.161,89	305.392,90	51.916,79	197.935,81	36.778,45	139.566,04	- 35.612,28	-	39.161,89	-	-
4	4	x	2,844	-	55.541,78	220.365,05	275.906,83	197.646,01	169.168,70	290.549,99	49.393,50	- 34.750,34	2.028,11	- 21.306,72	- 56.919,00	-	34.054,72	135.113,98	6.690,74
5	5		2,766	-	55.543,26	-	55.543,26	36.171,31	29.613,59	289.088,55	49.145,05	184.400,24	186.428,35	98.315,32	41.396,32	-	29.613,59	-	-
6	6		2,688	-	55.544,74	-	55.544,74	32.883,89	25.751,64	280.936,38	47.759,19	177.632,46	364.060,81	82.353,91	123.750,22	-	25.751,64	-	-
7	7		2,61	-	55.546,22	-	55.546,22	29.895,24	22.393,32	272.784,21	46.373,32	170.864,68	534.925,48	68.883,68	192.633,90	-	22.393,32	-	-
8	8	x	2,532	-	55.547,70	220.365,05	275.912,75	134.997,78	96.724,83	258.675,31	43.974,80	- 61.212,25	473.713,24	- 21.458,75	171.175,15	-	19.472,97	77.251,85	5.956,73
9	9		2,454	-	55.549,18	-	55.549,18	24.708,13	16.933,47	256.479,87	43.601,58	157.329,11	631.042,35	47.959,81	219.134,95	-	16.933,47	-	-
10	10		2,376	-	55.550,66	-	55.550,66	22.462,53	14.725,15	248.327,70	42.215,71	150.561,33	781.603,67	39.910,20	259.045,16	-	14.725,15	-	-
11	11		2,298	-	55.552,14	-	55.552,14	20.421,03	12.804,82	240.175,52	40.829,84	143.793,54	925.397,22	33.144,54	292.189,70	-	12.804,82	-	-
12	12	x	2,22	-	55.553,62	220.365,05	275.918,67	92.207,28	55.303,92	226.800,62	38.556,11	- 87.674,15	837.723,06	- 17.573,02	274.616,68	-	11.134,92	44.169,00	5.222,73
13	13		2,142	-	55.555,10	-	55.555,10	16.877,78	9.682,80	223.871,18	38.058,10	130.257,98	967.981,04	22.702,90	297.319,58	-	9.682,80	-	-
14	14		2,064	-	55.556,58	-	55.556,58	15.343,85	8.420,05	215.719,01	36.672,23	123.490,19	1.091.471,23	18.715,94	316.035,52	-	8.420,05	-	-
15	15		1,986	-	55.558,06	-	55.558,06	13.949,32	7.321,98	207.566,84	35.286,36	116.722,41	1.208.193,64	15.382,81	331.418,33	-	7.321,98	-	-
16	16	x	1,908	-	55.559,54	220.365,05	275.924,59	62.980,16	31.620,88	194.925,94	33.137,41	- 114.136,06	1.094.057,58	- 13.079,96	318.338,37	-	6.367,11	25.253,77	4.488,72
17	17		1,83	-	55.561,02	-	55.561,02	11.528,98	5.536,76	191.262,49	32.514,62	103.186,84	1.197.244,42	10.282,77	328.621,13	-	5.536,76	-	-
18	18		1,752	-	55.562,50	-	55.562,50	10.481,17	4.814,70	183.110,32	31.128,75	96.419,06	1.293.663,49	8.355,08	336.976,22	-	4.814,70	-	-
19	19		1,674	-	55.563,98	-	55.563,98	9.528,59	4.186,81	174.958,15	29.742,89	89.651,28	1.383.314,76	6.755,33	343.731,54	-	4.186,81	-	-
20	20	x	1,596	-	55.565,47	220.365,05	275.930,52	43.017,22	18.079,73	163.051,26	27.718,71	- 140.597,97	1.242.716,79	- 9.212,37	334.519,18	-	3.640,80	14.438,92	3.754,72
21	21		1,518	-	55.566,95	-	55.566,95	7.875,29	3.166,00	158.653,81	26.971,15	76.115,71	1.318.832,51	4.336,79	338.855,97	-	3.166,00	-	-
22	22		1,44	-	55.568,43	-	55.568,43	7.159,54	2.753,12	150.501,63	25.585,28	69.347,93	1.388.180,44	3.435,82	342.291,79	-	2.753,12	-	-
23	23	x	1,362	-	55.569,91	220.365,05	275.934,96	32.320,00	11.887,90	139.145,25	23.654,69	- 160.444,40	1.227.736,04	- 6.912,31	335.379,48	-	2.394,08	9.493,83	3.204,21
24	24		1,284	-	55.571,39	-	55.571,39	5.917,29	2.081,86	134.197,29	22.813,54	55.812,36	1.283.548,40	2.090,89	337.470,37	-	2.081,86	-	-
25	25		1,206	67.513,56	55.572,87	-	123.086,43	11.914,87	4.009,71	126.045,12	21.427,67	- 18.468,98	1.265.079,41	- 601,65	336.868,71	2.199,35	1.810,36	-	-
26	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
27	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
28	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
29	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
30	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
31	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
32	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
33	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
34	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
35	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
36	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
SUMME		6	50,47	433.374,51	1.333.340,22	1.322.190,30	3.088.905,03	1.281.027,14	982.345,69	5.245.764,40	891.779,95	1.265.079,41		336.868,71		343.366,44	333.257,90	305.721,35	29.317,86
			net rate	CAPEX	OPEX	WI	pre tax Costs	disc. PT Costs	disc. PT Costs	Revenue	Royalties	Cash Flow	cum CF	disc. CF	cum. disc. cash flow	disc. CAPEX	disc. OPEX	disc. WI	deferred Prod.
			[m^3/day]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]
						IRR	39%	Payout [years]	5										
						DPI []	0,981												
						Total Prod. [m^3]	18320												

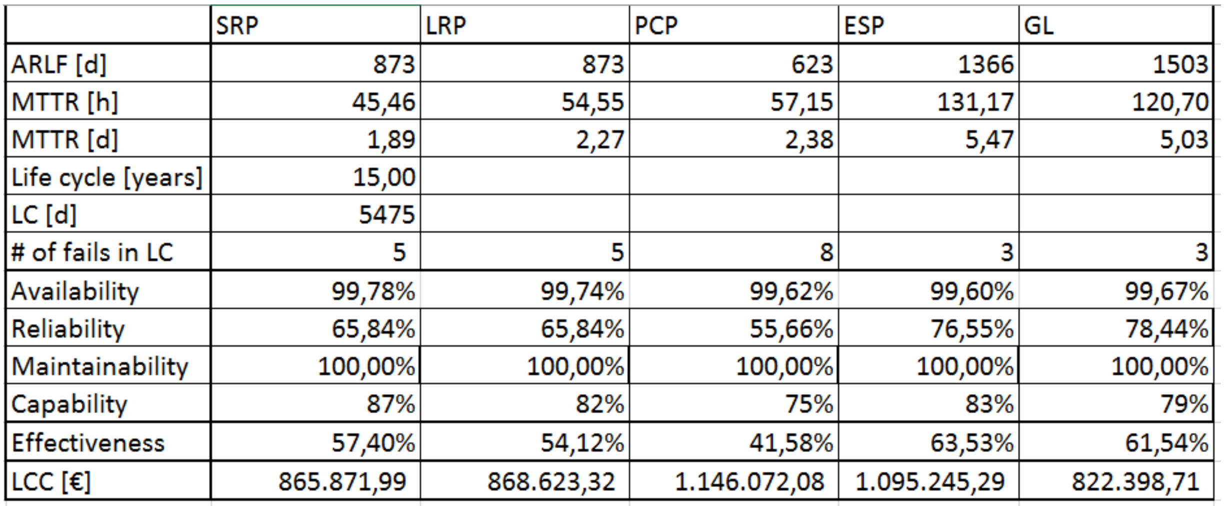
Table 21: Example for NPV calculation for gas lifting

Gas Lifting

	ARLF	1.009,00	2,76					WACC	WACC+Risk					WACC+Risk		WACC+Risk	WACC+Risk	WACC+Risk	
	YEARS	**WI**	**net rate**	**CAPEX**	**OPEX**	**WI**	**pre tax Costs**	**disc. PT Costs**	**disc. PT Costs**	**Revenue**	**Royalties**	**Cash Flow**	**cum CF**	**disc. CF**	**cum. disc. cash flow**	**disc. CAPEX**	**disc. OPEX**	**disc. WI**	**deferred Prod.**
		[Y/n]	[m³/day]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]	[€]
1	1		0	151.436,00		-	151.436,00	144.388,56	141.214,80	-	-	- 151.436,00	- 151.436,00	- 141.214,80	- 141.214,80	141.214,80	-	-	-
2	2		3	-	72.203,25	-	72.203,25	62.584,64	58.547,72	313.545,07	53.302,66	188.039,16	36.603,16	152.476,01	11.261,22	-	58.547,72	-	-
3	3	x	2,922	-	72.204,73	76.608,00	148.812,73	117.262,29	104.928,99	299.773,28	50.961,46	99.999,09	136.602,24	70.510,12	81.771,33	-	50.912,11	54.016,88	5.619,62
4	4		2,844	-	72.206,21	-	72.206,21	51.724,96	44.272,30	297.240,73	50.530,92	174.503,59	311.105,83	106.994,62	188.765,95	-	44.272,30	-	-
5	5		2,766	-	72.207,69	-	72.207,69	47.023,66	38.498,45	289.088,55	49.145,05	167.735,81	478.841,64	89.430,47	278.196,42	-	38.498,45	-	-
6	6	x	2,688	-	72.209,17	76.608,00	148.817,17	88.103,52	68.994,57	275.766,79	46.880,35	80.069,26	558.910,90	37.121,69	315.318,10	-	33.477,60	35.516,98	5.169,59
7	7		2,61	-	72.210,65	-	72.210,65	38.864,12	29.111,55	272.784,21	46.373,32	154.200,24	713.111,14	62.165,45	377.483,56	-	29.111,55	-	-
8	8		2,532	-	72.212,13	-	72.212,13	35.331,74	25.314,91	264.632,04	44.987,45	147.432,46	860.543,60	51.684,38	429.167,93	-	25.314,91	-	-
9	9	x	2,454	-	72.213,62	76.608,00	148.821,62	66.195,46	45.366,41	251.760,31	42.799,25	60.139,44	920.683,04	18.332,76	447.500,69	-	22.013,42	23.352,99	4.719,56
10	10		2,376	-	72.215,10	-	72.215,10	29.200,98	19.142,49	248.327,70	42.215,71	133.896,89	1.054.579,93	35.492,86	482.993,55	-	19.142,49	-	-
11	11		2,298	-	72.216,58	-	72.216,58	26.546,89	16.645,99	240.175,52	40.829,84	127.129,11	1.181.709,04	29.303,38	512.296,93	-	16.645,99	-	-
12	12	x	2,22	-	72.218,06	76.608,00	148.826,06	49.735,11	29.830,04	227.753,82	38.718,15	40.209,62	1.221.918,66	8.059,44	520.356,37	-	14.475,07	15.354,97	4.269,53
13	13		2,142	-	72.219,54	-	72.219,54	21.940,48	12.587,27	223.871,18	38.058,10	113.593,54	1.335.512,20	19.798,42	540.154,79	-	12.587,27	-	-
14	14	x	2,064	-	72.221,02	76.608,00	148.829,02	41.104,22	22.556,24	211.749,50	35.997,42	26.923,07	1.362.435,27	4.080,41	544.235,20	-	10.945,68	11.610,56	3.969,51
15	15		1,986	-	72.222,50	-	72.222,50	18.133,37	9.518,18	207.566,84	35.286,36	100.057,98	1.462.493,25	13.186,61	557.421,81	-	9.518,18	-	-
16	16		1,908	-	72.223,98	-	72.223,98	16.485,22	8.276,85	199.414,66	33.900,49	93.290,19	1.555.783,44	10.691,03	568.112,83	-	8.276,85	-	-
17	17	x	1,83	-	72.225,46	76.608,00	148.833,46	30.883,13	14.831,54	187.743,02	31.916,31	6.993,25	1.562.776,68	696,89	568.809,72	-	7.197,41	7.634,13	3.519,48
18	18		1,752	-	72.226,94	-	72.226,94	13.624,71	6.258,74	183.110,32	31.128,75	79.754,63	1.642.531,31	6.911,04	575.720,77	-	6.258,74	-	-
19	19		1,674	-	72.228,42	-	72.228,42	12.386,35	5.442,50	174.958,15	29.742,89	72.986,84	1.715.518,16	5.499,64	581.220,41	-	5.442,50	-	-
20	20	x	1,596	-	72.229,90	76.608,00	148.837,90	23.203,64	9.752,27	163.736,53	27.835,21	- 12.936,58	1.702.581,58	- 847,64	580.372,77	-	4.732,70	5.019,57	3.069,44
21	21		1,518	-	72.231,38	-	72.231,38	10.237,07	4.115,48	158.653,81	26.971,15	59.451,28	1.762.032,86	3.387,31	583.760,09	-	4.115,48	-	-
22	22		1,44	-	72.232,86	-	72.232,86	9.306,62	3.578,75	150.501,63	25.585,28	52.683,49	1.814.716,35	2.610,18	586.370,27	-	3.578,75	-	-
23	23	x	1,362	-	72.234,34	76.608,00	148.842,34	17.433,76	6.412,47	139.730,05	23.754,11	- 32.866,40	1.781.849,95	- 1.415,96	584.954,31	-	3.112,02	3.300,45	2.619,41
24	24		1,284	-	72.235,82	-	72.235,82	7.691,74	2.706,16	134.197,29	22.813,54	39.147,93	1.820.997,88	1.466,59	586.420,90	-	2.706,16	-	-
25	25		1,206	71.403,56	72.237,30	-	143.640,87	13.904,56	4.679,30	126.045,12	21.427,67	- 39.023,42	1.781.974,46	- 1.271,24	585.149,66	2.326,07	2.353,23	-	-
26	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
27	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
28	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
29	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
30	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
31	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
32	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
33	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
34	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
35	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
36	0		0	-	-	-	-	-	-	-	-	-	#NV	-	#NV	-	-	-	-
SUMME		8	50,47	222.839,56	1.733.286,65	612.864,00	2.568.990,21	993.296,81	732.583,95	5.242.126,11	891.161,44	1.781.974,46		585.149,66		143.540,87	433.236,55	155.806,53	32.956,14
			net rate	**CAPEX**	**OPEX**	**WI**	**pre tax Costs**	**disc. PT Costs**	**disc. PT Costs**	**Revenue**	**Royalties**	**Cash Flow**	**cum CF**	**disc. CF**	**cum. disc. cash flow**	**disc. CAPEX**	**disc. OPEX**	**disc. WI**	**deferred Prod.**
			[m³/day]	**[€]**	**[€]**	**[€]**	**[€]**	**[€]**	**[€]**	**[€]**	[€]	**[€]**	**[€]**	**[€]**	**[€]**	**[€]**	**[€]**	**[€]**	**[€]**
						IRR	105%	Payout [years]	2										
						DPI []	4,077												
						Total Prod. [m³]	18307												

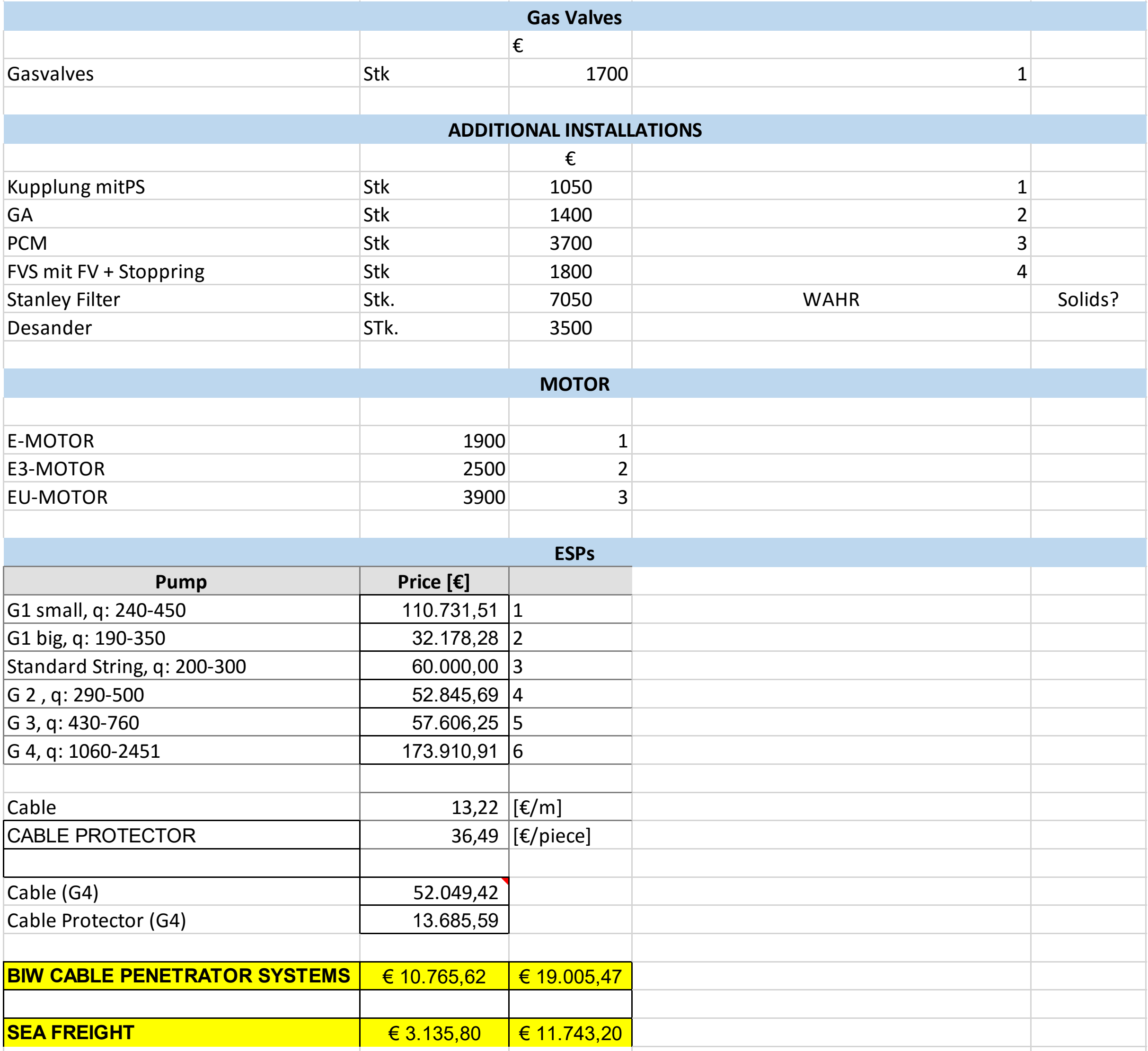
9.5 Appendix E: Additional Excel Worksheets

Table 22: Effectiveness Calculation (Excel)



	SRP	LRP	PCP	ESP	GL
ARLF [d]	873	873	623	1366	1503
MTTR [h]	45,46	54,55	57,15	131,17	120,70
MTTR [d]	1,89	2,27	2,38	5,47	5,03
Life cycle [years]	15,00				
LC [d]	5475				
# of fails in LC	5	5	8	3	3
Availability	99,78%	99,74%	99,62%	99,60%	99,67%
Reliability	65,84%	65,84%	55,66%	76,55%	78,44%
Maintainability	100,00%	100,00%	100,00%	100,00%	100,00%
Capability	87%	82%	75%	83%	79%
Effectiveness	57,40%	54,12%	41,58%	63,53%	61,54%
LCC [€]	865.871,99	868.623,32	1.146.072,08	1.095.245,29	822.398,71

Table 23: Cost list of installations (Excel)



Gas Valves				
		€		
Gasvalves	Stk	1700	1	
ADDITIONAL INSTALLATIONS				
		€		
Kupplung mitPS	Stk	1050	1	
GA	Stk	1400	2	
PCM	Stk	3700	3	
FVS mit FV + Stoppring	Stk	1800	4	
Stanley Filter	Stk.	7050	WAHR	Solids?
Desander	STk.	3500		
MOTOR				
E-MOTOR	1900	1		
E3-MOTOR	2500	2		
EU-MOTOR	3900	3		
ESPs				
Pump	**Price [€]**			
G1 small, q: 240-450	110.731,51	1		
G1 big, q: 190-350	32.178,28	2		
Standard String, q: 200-300	60.000,00	3		
G 2 , q: 290-500	52.845,69	4		
G 3, q: 430-760	57.606,25	5		
G 4, q: 1060-2451	173.910,91	6		
Cable	13,22	[€/m]		
CABLE PROTECTOR	36,49	[€/piece]		
Cable (G4)	52.049,42			
Cable Protector (G4)	13.685,59			
BIW CABLE PENETRATOR SYSTEMS	€ 10.765,62	€ 19.005,47		
SEA FREIGHT	€ 3.135,80	€ 11.743,20		

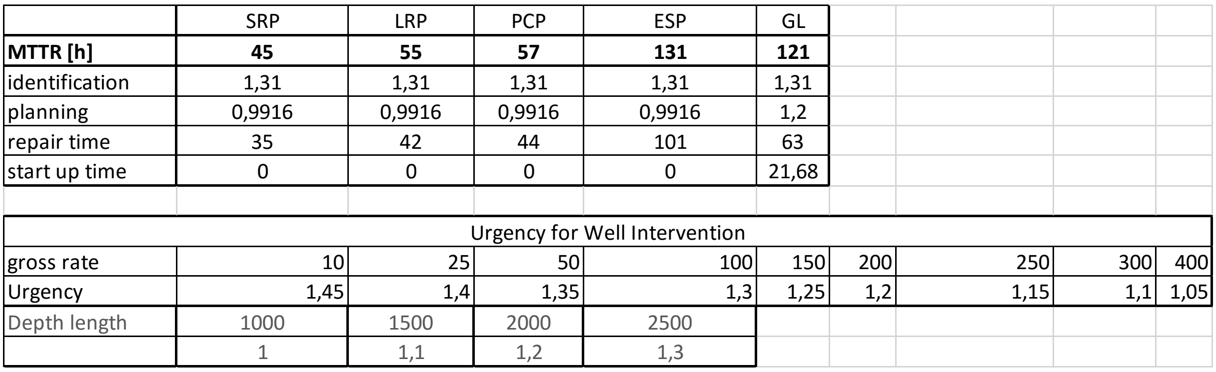
			TUBINGS				
Bezeichnung	**ME**	**LA**	**Bezeichnung**	**€/m**			
STGR	M	BJ0	tbg. blanc new, bis 3 1/2"	15	1		
	M	BJ1	tbg. Coated + relined, new bis 3 1/2 "	25	2		
	M	VN0E	tbg. Coated new 4"	49,4	3		
	M	BJ2	tbg. Coated + relined or GFK used	7	4		
	M	BJ3	tbg. bl. used white EUE	7	5		
	M	BJ4	tbg. bl. used blue EUE	3	6		
	M	BJ5	tbg. gas-proof, new von 1,9" bis 2 7/8"	16	7		
	M	**VN0E**	tbg. gas-proof, new 3 1/2" VAGT J55	20,96	8		
	M	**VN0E**	tbg. gas-proof, new 3 1/2" VAGT L80	28,33	9		
	M	**VN0E**	tbg. gas-proof, new 3 1/2" VAGT VA-SS C-90	31,16	10		
	M	**VN0E**	tbg. gas-proof, new 4 1/2" VAGT J55	26,62	11		
	M	**VN0E**	tbg. gas-proof, new 4 1/2" VAGT L80	27,46	12		
	M	**VN0E**	tbg. gas-proof, new 4 1/2" VAGT VA-SS C-90	48,62	13		
	M	**VN0E**	tbg. gas-proof, new 5 1/2" VAGT J55	49,52	14		
	M	BJ6	tbg. gas-proof, used alle Dimensionen	8	15		
	M	BJ7	tbg. bl. used white NUE	5	16		
	M	BJ9	tbg. bl. used blue NUE, coated	2	17	€/piece	m/piece
	Stk.	BJA	tbg. short piece, new	400	18	**600**	1,5
	Stk.	BJB	tbg. short piece, used	100	19	**150**	1,5
			SUCKER RODS				
PG	Stk.	BT1	sucker rods used	3,3	1	**23**	7
	Stk.	BT4	sucker rods w/o Prot. new	8,4	2	**59**	7
	Stk.	BT2	sucker rods 4 Prot. new	10,6	3	**95**	9
	Stk.	BT3	sucker rods 2 Prot. new	10,3	4	**72**	7
	Stk.		sinkerbar			**300**	
	Stk		polished rod			**500**	
			DOWNHOLE PUMPS				
pump	Stk.		Ins. TP 150+ TPS	2750	1		
			Ins. TP 175+ TPS	3200	2		
			Ins. TP 225+ TPS	4300	3		
			TP TH 225	2450	4		
			TP TH 275	3500	5		
			TP TH 375	9400	6		
			SURFACE PUMP JACK				
			Lufkin C-320	70000	1		
			Lufkin C-640	91000	2		
			Lufkin C-1280	91000	3		

Linear Rod Pumps

LRP	max. structural			Price		
Type	Loading, [to]	HP	stroke length,m	400V	600V	
L239C-254E-044	5,4	15	1,1	27.378,00	28.314,00	1
L239C-258E-044	5,4	20	1,1	28.548,00	29.475,00	2
L381F-215E-032	6,8	10	0,8	27.918,00	29.178,00	3
L381B-256E-056	6,8	20	1,4	33.084,00	34.101,00	4
L381B-284E-056	6,8	25	1,4	34.074,00	34.758,00	5
L381C-286E-056	6,8	30	1,4	34.605,00	35.730,00	6
L381B-324E-056	6,8	40	1,4	39.645,00	40.896,00	7
L381B-256E-064	6,8	20	1,6	36.558,00	37.818,00	8
L381B-324E-086				56.950,00	58.510,00	9
L472B-2578-100	10,7	50	2,5	76.488,00	78.041,00	10
L767B-2587-100	13,6	75	2,5	86.775,00	87.377,00	11

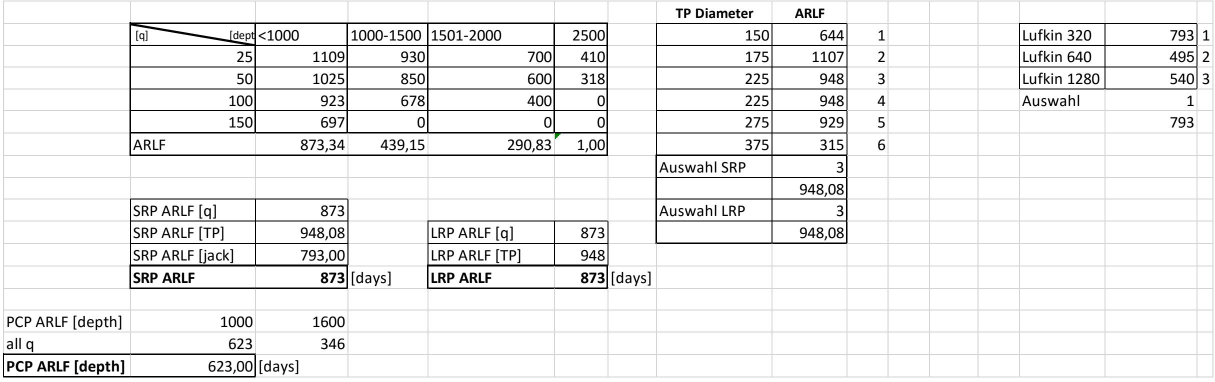
E-Container	max kW			Price
1 Unit	15	1		39.415,28
2 Units	30	2		40.965,28
3 Units	45	3		44.795,28
4 Units	60	4		49.345,28
5 Units	75	5		50.055,28
6 Units	90	6		56.325,28

Table 24: MTTR Calculation (Excel)



	SRP	LRP	PCP	ESP	GL				
MTTR [h]	**45**	**55**	**57**	**131**	**121**				
identification	1,31	1,31	1,31	1,31	1,31				
planning	0,9916	0,9916	0,9916	0,9916	1,2				
repair time	35	42	44	101	63				
start up time	0	0	0	0	21,68				
Urgency for Well Intervention									
gross rate	10	25	50	100	150	200	250	300	400
Urgency	1,45	1,4	1,35	1,3	1,25	1,2	1,15	1,1	1,05
Depth length	1000	1500	2000	2500					
	1	1,1	1,2	1,3					

Table 25: ARLF calculation SRP/LRP/PCP (Excel)



[q] [dept	<1000	1000-1500	1501-2000	2500
25	1109	930	700	410
50	1025	850	600	318
100	923	678	400	0
150	697	0	0	0
ARLF	873,34	439,15	290,83	1,00

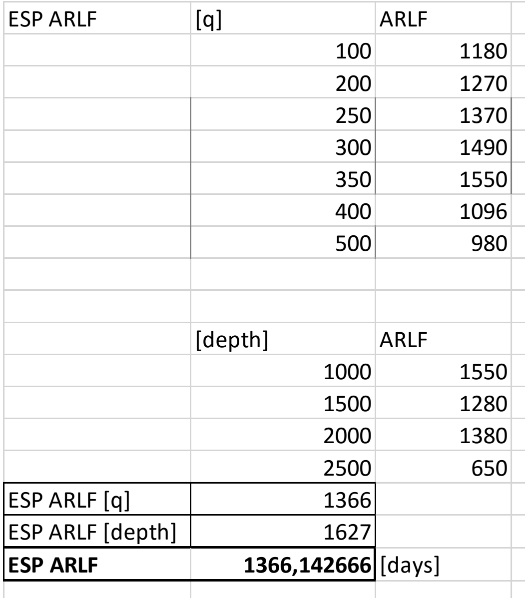
SRP ARLF [q]	873				
SRP ARLF [TP]	948,08		LRP ARLF [q]	873	
SRP ARLF [jack]	793,00		LRP ARLF [TP]	948	
SRP ARLF	**873**	[days]	**LRP ARLF**	**873**	[days]

PCP ARLF [depth]	1000	1600	
all q	623	346	
PCP ARLF [depth]	623,00	[days]	

TP Diameter	ARLF	
150	644	1
175	1107	2
225	948	3
225	948	4
275	929	5
375	315	6
Auswahl SRP	3	
	948,08	
Auswahl LRP	3	
	948,08	

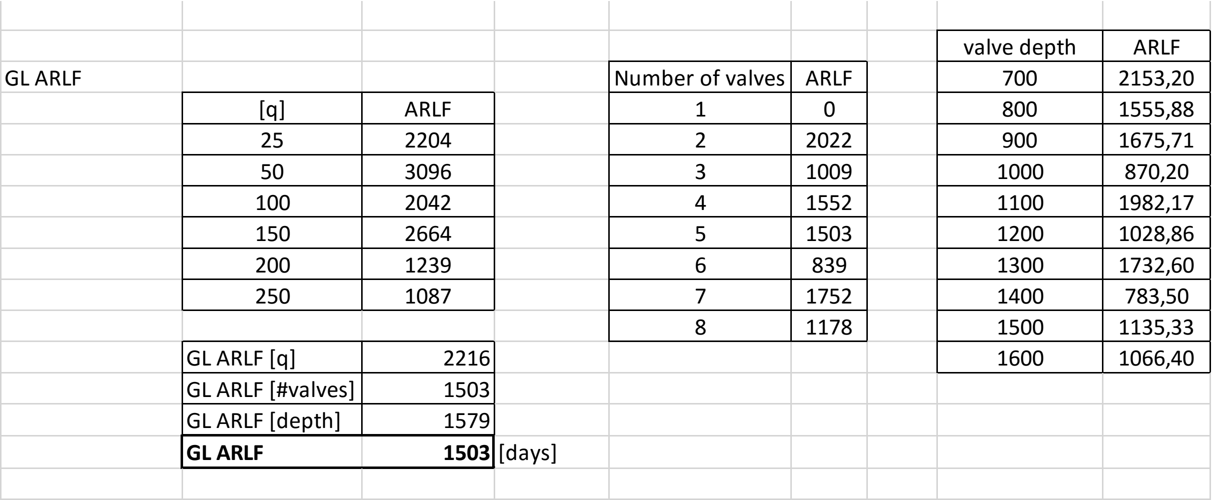
Lufkin 320	793	1
Lufkin 640	495	2
Lufkin 1280	540	3
Auswahl	1	
	793	

Table 26: ARLF calculation ESP (Excel)



ESP ARLF	[q]	ARLF
	100	1180
	200	1270
	250	1370
	300	1490
	350	1550
	400	1096
	500	980
	[depth]	ARLF
	1000	1550
	1500	1280
	2000	1380
	2500	650
ESP ARLF [q]	1366	
ESP ARLF [depth]	1627	
ESP ARLF	**1366,142666**	[days]

Table 27:ARLF calculation GL (Excel)



GL ARLF

[q]	ARLF
25	2204
50	3096
100	2042
150	2664
200	1239
250	1087

Number of valves	ARLF
1	0
2	2022
3	1009
4	1552
5	1503
6	839
7	1752
8	1178

valve depth	ARLF
700	2153,20
800	1555,88
900	1675,71
1000	870,20
1100	1982,17
1200	1028,86
1300	1732,60
1400	783,50
1500	1135,33
1600	1066,40

GL ARLF [q]	2216	
GL ARLF [#valves]	1503	
GL ARLF [depth]	1579	
GL ARLF	**1503**	[days]