Master Thesis

Identification of potential candidates for Linear Rod Pump (LRP) applications in OMV PETROM and definition of standard LRP types

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Wien, 25.11.2013

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AFFIDAVIT

I hereby declare that the content of this work is my own composition and has not been submitted previously for any higher degree. All extracts have been distinguished using quoted references and all information sources have been acknowledged.

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Kurzfassung

Bei der Auswahl von Fördersystemantrieben, ist besonderes Augenmerk auf den Produktionsbereich, die Lage der Produktionsstätte, die Untergrundbeschaffenheiten, die Quellproduktivität, die Lebenserwartung des Pumpsystems und die Produktionskosten zu legen.

OMV PETROM betreut ungefähr 7500 Bohrstellen, von denen circa 163 mit dem Linear Rod Pump (LRP) System ausgestattet sind. Dieses LRP System ist ein relativ neuer Fördersystemantrieb, welcher sich seiner zahlreichen Vorteile wegen, zu einer innovativen Alternative zur konventionellen Gestängetiefpumpe entwickeln könnte. Schon in naher Zukunft könnte die Verwendung des LRP Systems in Rumänien erweitert werden, unter der Annahme, dass die spezifischen LRP Eigenschaften speziellen Quellgegebenheiten am besten entsprechen.

Daher ist es Thema dieser Arbeit, alle PETROM Ölquellen auf die mögliche Anwendung eines LRP Systems zu untersuchen und Empfehlungen abzugeben, bei welchen Bohrungen das LRP System wirklich angewandt werden soll. Nach Abschluss dieser Untersuchung besteht der letzte Schritt dieser Arbeit in einem Standardisierungsvorschlag, welche LRP Modelle zur Verwendung empfohlen werden.

Die Diplomarbeit beginnt mit der Zusammenfassung der Vor und Nachteile der LRP Technik und vergleicht diese mit anderen Pumpsystemen, um zu definieren, unter welchen Konditionen dieses LRP System verwendet werden soll und unter welchen Kriterien PETROM diese Technik anwenden soll.

Ein anderer wichtiger Teil dieser Arbeit behandelt die Anwendung von Daten von Pumpsystemen unter der Verwendung von QROD, einem auf die Praxis bezogenen Gestängetiefpumpensimulator, um Grenzwerte für jedes Pumpsystem zu errechnen, um, auf Tiefen und Fließraten basierende Pumpmodelle zu erarbeiten.

Darüber hinaus wurde eine Quelldatenuntersuchung von speziellen Beispielen, geeignet für LRP Anwendung durchgeführt, basierend auf die soeben erwähnten Kriterien, um einen Überblick aller LRP Anwendungen und einen Vorschlag für die LRP Standardisierung dieser Quellen zu ermöglichen.

Dieses Projekt wurde durchgeführt in Zusammenarbeit mit dem Production System Optimization Department of the E&P division bei OMV PETROM SA in Bukarest, welches mir auch ermöglichte, die verwendete Software, wertvolle Informationen und den Zugang zu PETROMs „best practices“ Dokumentationen zu verwenden. Zusätzliche Informationen wurden aus SPE Artikeln, technischen Büchern, Fachzeitschriften und dem Internet zusammengetragen. Diese Quellen wurden unter Anwendung der IEEE 2006 Art zitiert.

Wann immer der Begriff PETROM erwähnt wird, bezieht es sich auf OMV PETROM SA.

Abstract

When selecting an artificial lift system (ALS), special emphasis has to be given to operating range, well location, subsurface conditions, productivity of the well, run life of the pump and production costs.

OMV PETROM operates approximately 7500 wells of which about 163 wells are produced with the Linear Rod Pump (LRP). The LRP is a relatively new artificial lift technology which could become an innovative alternative to the conventional beam pumping unit due to its numerous benefits. In the near future application of LRP could be extended in Romania assuming that LRP characteristics suit specific well features.

Therefore the objective of this thesis is to screen all PETROM Oil Wells for potential LRP application and to recommend in which wells the LRP should be utilized in the future. Having done that, the final step of the thesis consists of a standardization proposal for LRP types that are recommended to be used.

The thesis begins with outlining the benefits and limitations of the LRP, the linear rod pump is compared to other pumping unit systems in order to define under which conditions the LRP should be utilized and which are the selection criteria of LRP application in PETROM.

Another important part of the thesis deals with input of data for pumping unit systems into QROD, which is a practical beam pumping design simulator, in order to create boundary conditions based on depth and pump displacement for each pumping unit system model.

Moreover, a well data screening of defined cases suitable for LRP application, based on the criteria mentioned above, was performed in order to first screen all wells for LRP application and secondly to propose an LRP standardization for these wells.

This project has been carried out in cooperation with the Production System Optimization Department of the E&P division in OMV PETROM SA in Bucharest which provided me the employed software, valuable input, and access to PETROMs “best practices” documentation. Further information has been taken from SPE papers, technical books, journals and the internet. The used sources have been stated using the IEEE 2006 style for citation.

When referring to PETROM in this thesis the reference is made to OMV PETROM SA.

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List of abbreviations

ALS	Artificial Lift System
API	American Petroleum Institute
Ap	Plunger area
Avg.	Average
bbl.	Barrel
L x W x H	Length x Width x Height
BPD	Barrels per day
CAPEX	Capital expenditures
cP	Centipoise
CPU	Conventional Pumping Unit
Dp	Plunger diameter
e.g.	Exampli gratia
ESP	Electric Submersible Pump
fpm	Feet per minute
GL	Gas lift
HP	Horsepower
HPU	Hydraulic pumping unit
HRP	Hydraulic Rod Pumps
lb.	Pounds
In.	inch
In-lbf	Inch pound force
IPR	Inflow Performance relationship
LRP	Linear Rod Pump
Max.	Maximum
Min.	Minimum
mmmm	Motor
MTBF	Mean Time Between Failure
MTBI	Mean Time Between Intervention
MPUL	Maximum Pumping Unit Load
NF	Natural Flow
NPV	Net Present Value
OPEX	Operation expenditures
PCP	Progressive Cavity Pump
pcs.	Pieces
to.	Tons
m	meter
PLC	Programmable Logic Controller
POC	Pump off Controller
PPRL	peak polished rod loading
Prod.rate	Production rate
q	Flowrate
RRP	Reciprocating Rod Pump
SPM	Strokes per minute
TEFC	Totally Enclosed, Fan Cooled
TEBC	Totally Enclosed, Blower Cooled
UWI	Unique Well Identifier
vs.	versus
VSD	Variable speed drive
w/	with
w/o	without

1 Introduction

When an oil well is first discovered, the oil usually flows naturally because of sufficient reservoir energy. This energy is provided by the reservoir pressure. As the production continues, the reservoir pressure decreases until production based on natural flow is not possible anymore and an Artificial Lift Systems (ALS) has to be taken into consideration in order to resume production from the well. Artificial lift is defined as a technique used for increasing the well productivity with low reservoir pressure adding the energy to the fluid column in a wellbore so that to be able to flow from reservoir to surface.

The proper selection of the artificial lift method based on specific operating conditions, has an important long term impact of well profitability reflected in lower production and higher operating costs. In other words, an artificial lift method which fits best to the environment, costs and subsurface conditions has to be chosen. In order to provide optimal production the following factors should be considered: the operating range of the ALS, well location, subsurface conditions, the productivity of the well, capital expenditures (CAPEX), expected operation expenditures (OPEX) as well as the life expectancy of the artificial lift system.

There are various factors affecting the selection of a particular artificial lift method. One of the main factors in artificial lift selection is the ability of a well to produce fluids (Inflow performance). For the optimum lift methods not only present time production, but also future production must be considered. Produced solids such as paraffin, asphaltene or sand must be thought of when choosing an ALS not to mention its equipment as scrapers or guides may help paraffin removal. Gas liquid ratios limit the selection of lifting methods *and "as a rule of thumb, all methods of lift have reduced efficiency with increasing gas-liquid ratio."* [1, p. 570] As the chosen ALS has to be able to provide the most economical production rate with respect to the reservoir also the reservoir characteristics have to be thought about. The reservoir type will have influence to the inflow production rate, gas liquid ratio and depth of lift.

There is a variety of different pumping systems and the relevant ones for this thesis will be described, discussed and compared in detail in chapter 3 "LRP and Comparison with other Pumping Systems".

1.1 Objectives

The aim of this work is to perform a production optimization study for Romanian wells with the LRP unit as an alternative to other pumping systems which are widely utilized. In order to have a successful optimization established and potential Linear Rod Pump (LRP) candidates approved, the following points will be discussed in detail in the following chapters:

- Background information about Romania's oil history and the artificial lift system usage in general
- Application and description of the system and working principle of LRP
- Comparison with other pumping unit types as "classical pumping units", "Rotaflex" Long-Stroke Pumping Unit and Hydraulic Rod Pump in respect of footprint and civil work requirements, operation range and limitations, power requirements and consumption, cost and maintenance requirements
- LRP application criteria with the goal of clear selection rules for LRP
- Well screening to find out which well candidates suit LRP criteria
- Flowrate vs. depth ranges
- Statistics of the existing wells with LRP installation and possible failure analysis
- Screening of approximately 7500 wells, based on established application criteria and a list of all wells where LRP can be utilized
- Standardization of all existing and potential LRP applications in PETROM by suggesting standard LRP types which should be used in the future to meet PETROM´s needs

2 Background

PETROM operates 7391 production wells (PETROM data base June 2012) out of which around 5369 wells are produced with the Conventional beam pumping Unit and 163 of them are operated by the Linear Rod Pumps (LRP). 1710 wells are produced by Progressive Cavity Pumps (PCP), 92 with Gas Lift (GL), 206 with natural flow (NF) and 14 are run with the Electric Submersible Pump (ESP)[I]. For a more detailed description see *Table 6* and *Figure 17.*

PETROM wants to expand the application of LRP and, for this reason, the application of the LRP will be analysed in more detail within this thesis.

In order to get a better understanding the country´s close link to oil industry, the following chapter is dealing with Romanian oil history and the crucial historical facts. Furthermore, a short introduction on the use of Artificial Lift Systems will be presented and, further on, this will be completed by a detailed description of the relevant pumps.

2.1 Romanian Oil History

The Romanian Petroleum industry starts back in 1769 with the extraction of crude oil in Moldavia. However, the first oil exploration was documented in the Roman province of Dacia, now in Romania. Extrapolation of crude oil consisted of collecting oil from the shallow pits and ditches by using a simple technique of digging small holes in the ground, collecting crude oil and then channeling it through ditches towards a collecting pit. Industrial distillation of oil started with the Mehedinteanu brothers, who built a refinery in the periphery area of Ploiesti City, not far from Bucharest, in the south of Romania. At that time the refinery installations were rather simple and built primitively meaning that the equipment was built of iron or raw iron cylindrical vessels, heated directly with wood fire. [2]

Bucharest was the first city in the world illuminated with lamps fired by kerosene. This combustible hydrocarbon liquid was first offered by the Mehedinteanu brothers for the purpose of lightening the streets. The kerosene had uncontestable properties. In an interesting article about 150 years of oil in Romania, the circumstances and growing importance of the oil industry in Romania is expressed in the following citation.

> *"Colorless and with no smell, burning with a light flame, with a constant intensity and shape, without smoke and without ash or resinous compounds in the wick. This important properties of the product as well as the offer of 335 lei per year for each street lamp had practically excluded all the competition, the other offers which proposed as a fuel the rape or nut oil were taking the costs up to 600 lei per year. Teodor Mehedinteanu's offer was approved on the 8th October 1856 and so Bucharest would have been illuminated with 1000 street lamps. At 1st April 1857-*

[I] *Information provided by PETROM (July 2012)*

> *the date for coming into operation of the contract for the capital illumination - everything was ready and working perfectly.”* [3]

Figure 1 shows the oil production in 1900 and the harsh circumstances people had to live in. [2]

Figure 1: Oil production in 1900 in Romania

Table 1: Romanian Oil History essential dates

1875: The first country to produce 257 tons of crude oil [2]
1861: The first well drilled in Romania , at a depth of 150 meters by using wooden rods and auger type bits [4]
1896: Setup of the Romanian Company Steaua Romana. Their refinery was considered as the largest and modest in Europe with a processing capacity of1200 tons/day [2]
1900: Oil production at 250.000 tones. Romania was the third largest oil producer in the world with annual production of 1.9 million barrels [2]
1900: Romania was the first country in the world to export gasoline [2]
1903: The setup of Romanian - American Company STANDARD OIL [4]
1907: The Romanian - American company drilled the first well in Moreni by using the Rotary system, the first International Oil Conference was held in Bucharest and the first air system extraction by STEAUA ROMANIA in Campina was tested [4]
1909: In Romania, methane gas was discovered at Sarmasel, Mures County [2]

1910: Start of the ASTRA ROMANA Company
1912: The first use of tacit type valve, the first blow-out preventer system [5]
1913: The first natural gas production [5]
1921: Testing of gas-lift extraction system, by ASTRA ROMANA [5]
1925: The first crude oil production of the Sarata Monteoru mine [5]
1927: The execution of the first mechanical core and the first casing perforation with a perforation gun [5]
1931: First electrical well logging execution [5]
1938: The deepest well in Romania, 13 Astra Romana(at Boldesti) reaches the depth of 3644 m [2]
1940: The first gas storage at Levantin Boldesti reservoir established, performed by Astra Romana Company [2]
1951:The first water injection operation on an industrial scale is carried out at Sarmatian Boldesti oil field, at a 2600 m depth [4]
1975: The first offshore drilling platform is set in position on the continental platform of the Black Sea [5]
1984: 7000 Baicoi well reaches a depth of 7025 m [5]
1987: The first offshore oil production starts and the first offshore water injection process is initiated [5]
1993: The SPE Romanian section is set up [5]
1993: PETROM becomes member of the Petroleum Recovery Institute [4]
1997: Setup of the National Oil Company PETROM S.A. [4]

1999: PETROM discovered the biggest Romanian oil field in the last 25 years on the Black Sea platform through Pescarus 60 well [4]

2004: PETROM becomes a member of the OMV Group [5]

Figure 2: PETROM becomes a member of the OMV Group[II]

Since 2004: Restructuring and modernization process at PETROM [6]

- Romanian reserves replacement rate increased to 70% in 2011 from 11% in 2004
- Well modernization program (over 5,000 wells) finalized in 2008; additional 3,000 wells modernized by end of 2011
- Extended reach drilling and multi-stage fracturing new technologies successfully applied offshore
- Joint venture with Exxon Mobil company for deep-water offshore exploration

Highlights of 2011 PETROM [6]

- PETROM Group production increased by 1% compared to 2010
- Group reserve replacement rate increased to 70% from 67% in 2010; reserve replacement rate in Romania maintained at 70% for the fourth consecutive year
- Redevelopment of major fields significantly progressed
- Exploration licenses successfully extended

Key observations 2012/2013 [6]

- 300 days well MTBF (Mean Time Between Failure) targeted in 2013 (260 days in 2012)
- 2400 wells equipped with Pump off Controller (POC) until end of 2012
- 850 wells to be equipped with POC’s in 2013
- More than 1,550 workover jobs planned for 2013

[II] *Internally provided by OMV PETROM S.A. on 28.11.2012*

- 350 acidizing jobs and 30 frac jobs planned to stimulate the wells
- Identification of LRP potential candidates and installation, which is part of this thesis

2.2 Artificial Lift System Usage

ALS must be constructed in order to provide the necessary drawdown to produce the fluid from the bottom of the well up to the surface at an aimed rate and pressure. Each artificial lift method may be classified from poor to excellent according to the well behavior and the surface/subsurface conditions.

> A drawdown is defined as *"the difference in height between the static level and the dynamic level in a pumping well, expressed as hydrostatic fluid pressure."* [7]

During the wells natural flowing life no artificial method is needed, but as the well dies due to the decrease in reservoir pressure, a suitable artificial lift system must be found and installed in order to maintain the flowing bottom hole pressure. Keeping the required flowing bottom hole pressure is the very basis for any artificial lift installation design. [8, p. 2]. The artificial lift design and analysis can be divided into two main components which are the reservoir component and artificial lift system. The reservoir component represents the well´s ability to produce fluids and is also called Inflow performance relationship (IPR). The artificial lift system includes for instance the separator, flow line, flow line restrictions such as chokes, tubing string and the artificial lift mechanism itself. Tubing intake pressures can be determined for changing flow rates and when this tubing intake curve is arranged on the same plot as the IPR curve, the rate for a distinct lift method can be determined. [9]

A method for analyzing a well which will allow determination of production capacity for any combination of components is called Nodal^{TM} Analysis. This method can be used to determine pressure drops or flow resistance in any part of the system. The method is applicable in many aspects like electrical circuits and complex pipeline systems. All the components upstream of the node are called the inflow section, whereas the outflow section consists of all the components downstream of the node. In *Figure 3*, if the node is considered at point 6 (p_{wf}) the outflow section would be at the node points 1 till 5 and the inflow section would be labeled with the numbers 7 and 8. Some basic assumptions have to be satisfied, so that the flow rate through the system can be determined. [10]

- Outflow and the Inflow at the node must be equal
- Only one pressure can exist at a node
- A relationship between flow rate and pressure drop must be available

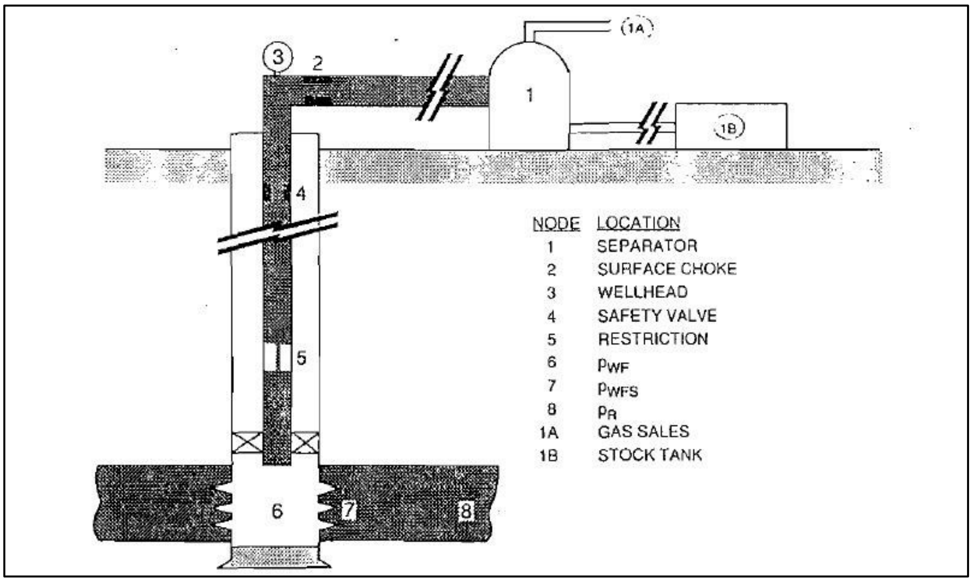


Figure 3: Location of various nodes [10]

There are always two fixed pressures in the well, which do not vary with the changing flow rates. One of these pressures that remain fixed is the average reservoir pressure p_r (in *Figure 3* labeled as 8) and the other is system outlet pressure, usually the separator pressure p_{sep}, and in systems with a choke the pressure at the wellhead p_{wh}. Afterwards, a specific node may be selected, usually located at the intake of the well or at the wellhead. [10]

The pressure at the node, called p_{node} can be calculated as follows:

Inflow to the node: $p_r - \Delta p$ (upstream) = p_{node}

Outflow from the node: $p_{sep} + \Delta p$ (downstream) = p_{node}

The pressure drop, Δp_r, in any component is related to the flow rate through the system including frictional, gravitational and elevation terms. Finding the flow rate and pressure that fulfill the basic assumptions summarized above can be shown graphically in *Figure 4* by plotting node pressure versus flow rate. At the intersection of the two curves the argument that the inflow must be equal to outflow is valid. This is the flow rate which shows the producing capacity of the system with the current configuration. The effect of any change in well configuration can be shown graphically by recalculating node pressure versus flow rate. If a change was made in an upstream component, the outflow curve will remain unchanged. If either curve is changed, the intersection point will be shifted and there will be a new intersection point, meaning that there will be a new flow capacity and node pressure. If the reservoir pressure is depleted the curves will also shift as the pressures are changed. The nodal system analysis can be used to interpret the production of oil and gas wells, naturally flowing or equipped with artificial lift systems. Through modification of the inflow and outflow expressions the method can also be used for injection wells furthermore. [10]

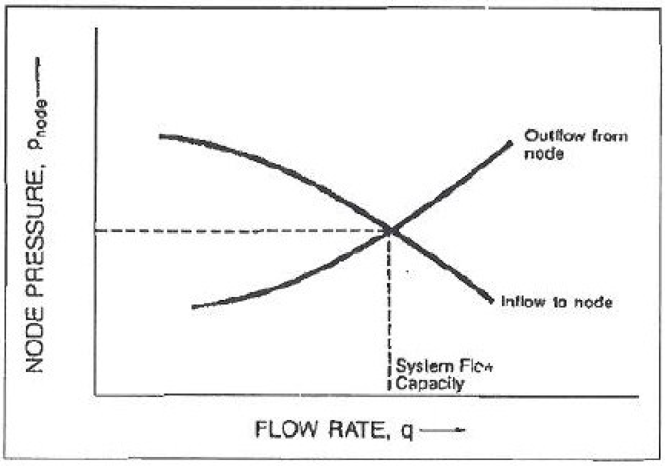


Figure 4: Node pressure versus flow rate [10]

Figure 5 shows a typical flow rate vs. pressure graph with possible rates by different artificial lift methods. Note that the intersection point of IPR (Inflow to node) and tubing intake (outflow from node) show the actual flowrate for the individual ALS.

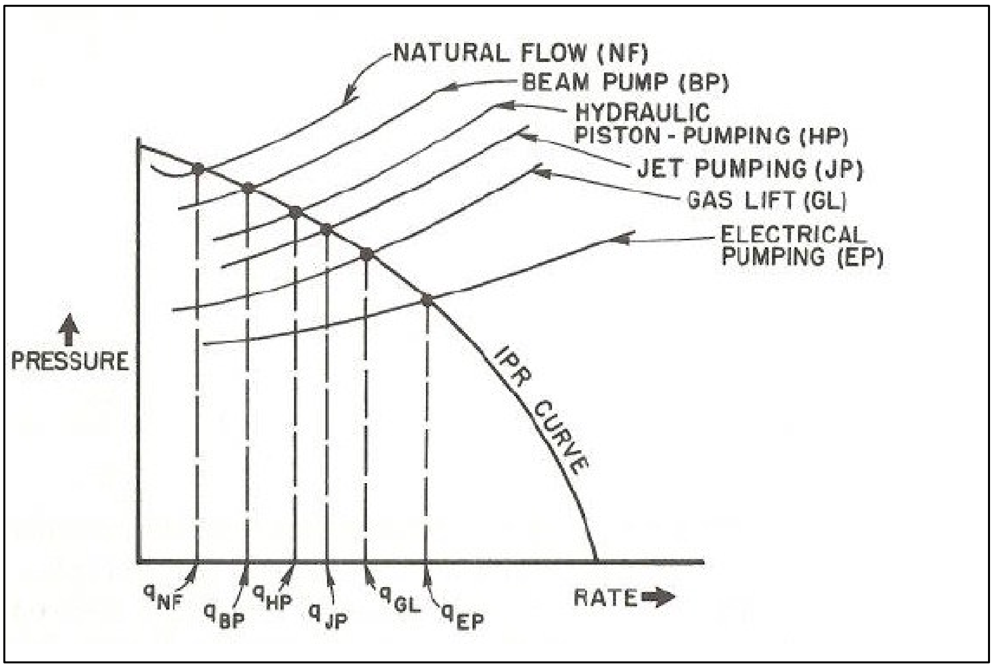


Figure 5: Tubing Intake Curves for ALS [9]

Figure 6 illustrates a dead well where the tubing intake curve does not intersect the IPR curve meaning that the flowing bottomhole pressure is too low for the well to flow for a particular tubing size, depth and wellhead pressure. This well must be provided with some type of ALS. It is to be mentioned that even though a well may be able of flowing naturally it does not mean that no ALS is needed or should not be considered at all. Many wells are able of producing higher rates when equipped with an ALS, and this is done for example for rate acceleration projects. [9]

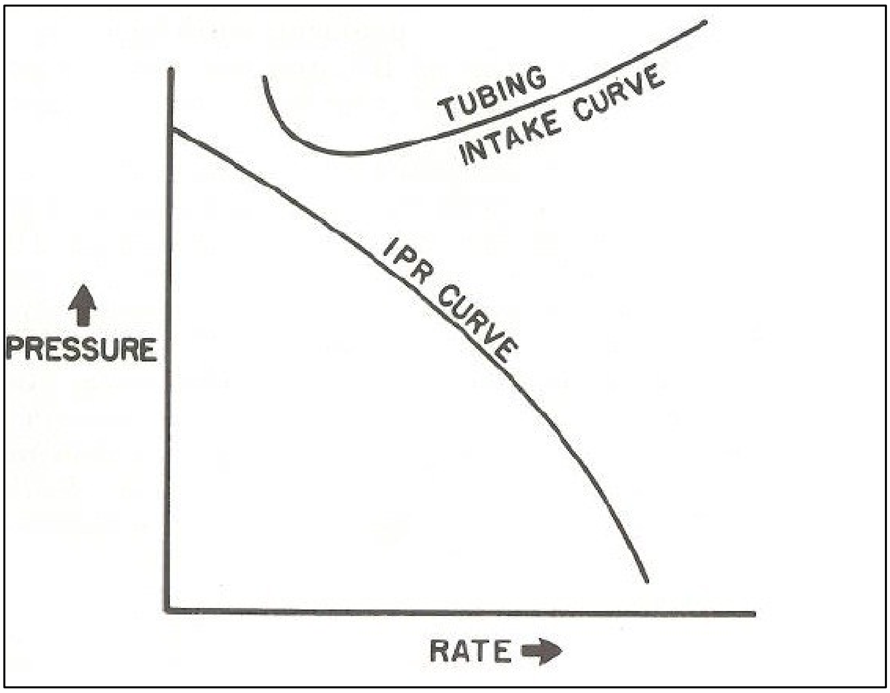


Figure 6: Dead Well [9]

The two major techniques of artificial lift systems are split into Pumping systems and Gas lift, which can be split in either continuous Gas lift or intermittent Gas lift. Usually the main decision whether to use the one artificial method or another depends on many factors such as geographical location, the availability of electricity on location or gas, sand, scale or paraffin problems in the well, well deviation, costs of equipment, MTBF or production rate. This thesis will deal with the application and selection criteria of several pumping systems mentioned in Chapter 3 “LRP and Comparison with other Pumping Systems”, with a special focus on the Linear Rod Pump.

Figure 7 demonstrates the main methods for Artificial Lift. [11, p. 434]

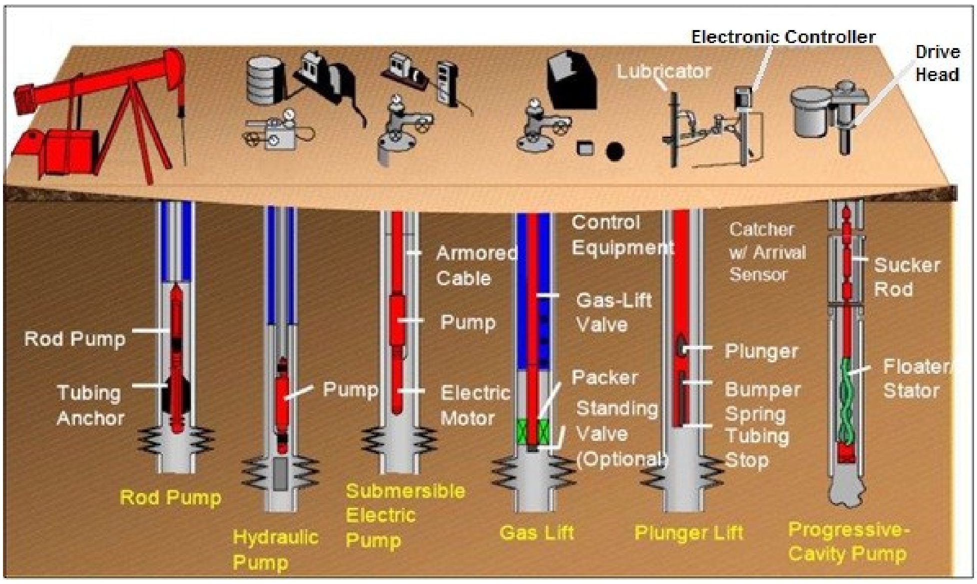


Figure 7: Main methods of Artificial Lift

Not included in the list of the main methods of Artificial Lift in *Figure 7* is the Jet pump. Jet pumping is a hydraulically driven method of fluid lifting. The Jet pump does not contain a rod string or moving parts as the key components are the nozzle and throat. The Jet pump´s downhole equipment converts the energy of a high velocity jet stream (high pressure liquid passes through the nozzle where this liquid is converted from low velocity and high static pressure flow to high velocity and low static pressure flow) into useful work to lift the fluids of the well. [12] [13]

In order to choose the right ALS, different reservoir behaviors have to be taken into account, because the ALS design is based on the anticipated performance of current reservoir conditions.

According with Lea James, two main philosophies are taken into consideration in artificial lift design:

- If future reservoir performance can be predicted, the artificial lift selected method can provide up to the largest rate anticipated over the life of the well. Following this way, the artificial lift equipment will be oversized increasing the energy or operational costs.
- The second philosophy is to design the artificial lift method only for current reservoir conditions neglecting the future production profile. Consequently, large amount of capital expenditures will be required later. [14]

The operator should consider the long and the short term aspects for an artificial lift plan. If operational costs are significantly higher for a particular method which assures higher production, it should be replaced by a method that can produce with lower rate but more reliable. This may be more economical. [15]

In order to choose a specific form of artificial lift the following factors have to be considered:

- **Well characteristics**
  Reservoir characteristics and the well depletion plan should be considered as well as a possibility of a fast production decline of the well before choosing an appropriate lift system [15]. It is a bad choice choosing a high volume method, e.g. Electrical Submersible Pump or the Jet Pump that will only be required for a short period of time. If economics do not justify the change into ALS, the better and more economically efficient method will be choosing a lower capacity method even though production will not be as high at the beginning [16].
- **Field location**
  Location is another important point in selecting which pump can be used. For instance, if the necessary electrical power cannot be provided to the well site, some ALS simply cannot be used and this would disqualify the ESP or any ALS requiring electrical power. If the production location is situated in urban areas this also shortens the list of artificial pumps that can be utilized for production, because of the necessity of a relatively small footprint and low noise generation. Not only urban areas, but also remote areas like for example somewhere in a desert, arctic or offshore locations decrease the list of ALS choices.
- **Economics**
  Other important selection criteria are the costs that an ALS causes for the company. Items like energy cost, maintenance cost, personnel cost, oil and water treatment costs and replacement of capital items, because of wear or failure, are economic factors that one has to bear in mind.
    - CAPEX (capital expenditures) are onetime costs and accrue usually at the beginning of a project. By definition CAPEX is *“an expenditure that creates future benefits. Companies use CAPEX to acquire or upgrade physical assets such as equipment or property.”* [12, p. 520]. Potentially, CAPEX also emerge during the economic life of e.g. projects or facilities. These CAPEX have to then be differentiated from ongoing operating costs. An example for later arising capital expenditures is secondary recovery like waterflooding or cyclic steam injection. These methods have to be adopted, if artificial lift systems are not sufficient anymore.
    - OPEX (operating expense) are ongoing frequently occurring costs of running a business, product, or system like for instance operation man hours, fuel or energy consumption and are formed due to day-today business. [12]

  Other than the costs that ALS causes for the company, savings can be generated by for instance producing electricity from flare gas. Microturbines enable producers to utilize flare gas to generate electricity which can provide power needed to operate on location facilities. Microturbine´s produced electricity may operate compressors, valves and ALS. Furthermore tougher environmental regulations make the power generator an efficient and on site source of electricity. [17]

- **Depth and Volume**

  The volume of the liquid that has to be lifted and the well depth will have a strong influence on the final selection of the pump. To illustrate, if the pump needs to lift 50 BPD from 1829 meters (6000 feet), the selection can be minimized to the conventional sucker rod pumping system and Plunger Lift. When 10.000 BPD have to be lifted from the same depth, only ESP, GL or Jet Pump remain as an option. [III]

  It can be stated that in most cases, lifting depth goes hand in hand with liquid volume lifted as well rates rapidly decrease in deeper wells.

  Figure 8 below partly proves the mentioned statement. The chart shows artificial lift methods of moderate liquid capacity like for instance Plunger Lift, Progressive Cavity Pumping or Rod Pumping. In the case of the PCP a rather sharp decrease in liquid production rate is seen over the depth. This is due to the increasing torque development of the rotating sucker rod string. This torque development can be limited by utilizing an ESPCP, which is a PCP combined with a downhole motor like with the ESP. As already mentioned the usage of PCPs is limited to a certain depth. According to the lift capacity of the pump the setting depth of the rotor/stator system therefore is restricted. It has to be mentioned at this point that some disadvantages like for instance elastomer swelling in the stator with some well fluids or windup and afterspin of rods with increasing depth also come along with the PCP Pump [13]. In an advanced stage of the thesis the pumping unit selection due to depth vs. production rate will be discussed in detail.

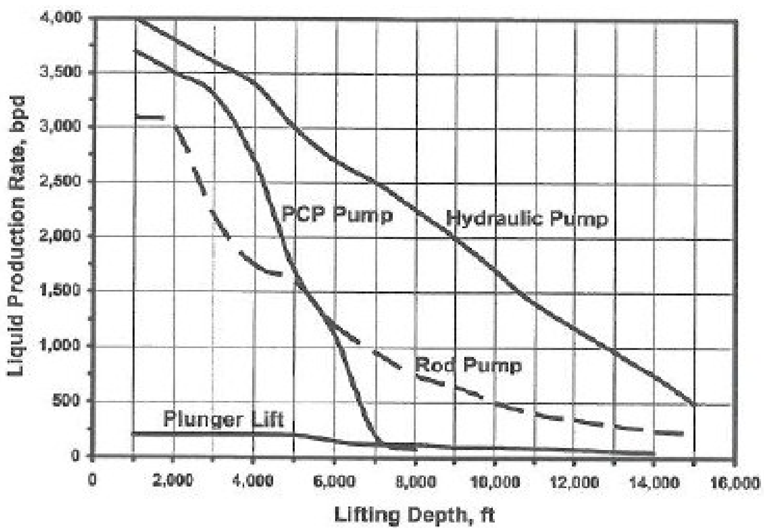


Figure 8: Liquid Production Rate vs. Lifting Depth for ALS [18]

III *Data from technical discussion with PETROM's Production System Optimization Department on 18.10.2012*

3 LRP and Comparison with other Pumping Systems

In this chapter a detailed overview and application criteria will be described in order to compare the LRP with other pumping systems and, in addition, to examine which system optimally fits for PETROM's needs. It will be shown if the LRP is a suitable substitute for the classical pump jack.

3.1 Overview on the LRP

The LRP is a stroking unit that combines simple mechanics in a compact, low profile solution with economic advantages over traditional pumping systems which can be read in detail in the subchapter 3.1.1.1 "Benefits" and to a further extend in chapter 3.2 "Comparison with other Pumping Unit Systems".

Description of the LRP:

As pictured in *Figure 9* a schematic illustration of the LRP is presented. The unit itself is mounted on the well head and has a linear mechanical actuator arrangement and is screwed on a stand as illustrated in *Figure 10*.

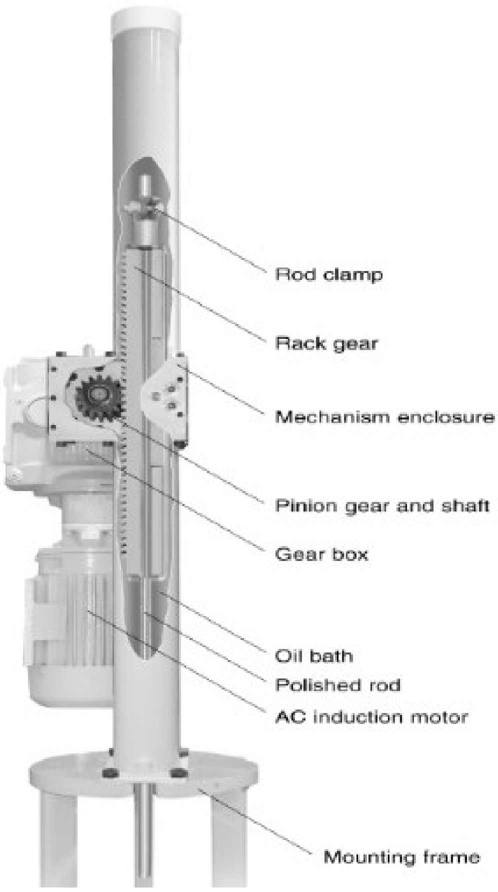


Figure 9: LRP system [19]

Figure 10: Installed LRP from Asset 9 Moldava Sud

The linear actuator arrangement is a moving system that creates motion in a straight line. As depicted in *Figure 9* the circular gear (pinion gear) engages teeth on a linear bar (rack gear). The rotational movement applied to the pinion causes the rack to move upwards and downwards, therefore translating the rotational motion of the pinion gear into linear motion of the rack gear. The rack gear is attached to the polished rod of the sucker rod pump to transmit and control vertical motion of the sucker rod string. The Linear Rod Pump's reversible totally enclosed and fan cooled (TEFC) motor has a reversibly rotatable element which is attached to the linear mechanical actuator arrangement. This relationship between the rotational position of the motor and the linear position of the pinion gear control the polished rod motion. In order to master the up and down reciprocating motion of the sucker rod by reversing the motor, the above described simple rack and pinion mechanism is applied and is connected through a gearbox. [20, p. 3] The polished rod, having a shiny smooth surface, runs through a channel inside the rack and is suspended from the upper end of the same by a securing rod clamp. This device is the only moving part that is visible at the surface and prevents wear of the stuffing box packing, which is designed to stop fluid leakage by creating a seal around the polished rod. Should it come to the incident that the rod or pump gets stuck, the rod is still able to float inside the rack. The rack is lubricated each stroke in an oil sump which is also illustrated in *Figure 9*. The LRP also includes a position sensor which shows the position of the rack along the pump axis. [20, p. 5]

Description of pump cycle:

The actuator rod is in a fully lowered position and attached to the upper end of the polished rod. The motor is then energized and accelerates the rod to a predetermined UP SPEED. The motor drives the rack upward and so the actuator rod is in upward motion. The detection of the desired top of stroke position is done and checked via an upper sensor and several independent calculations. [20] *Figure 11* demonstrates such an upstroke cycle with the sensor mounted next to the pinion and rack assembly.[iv]

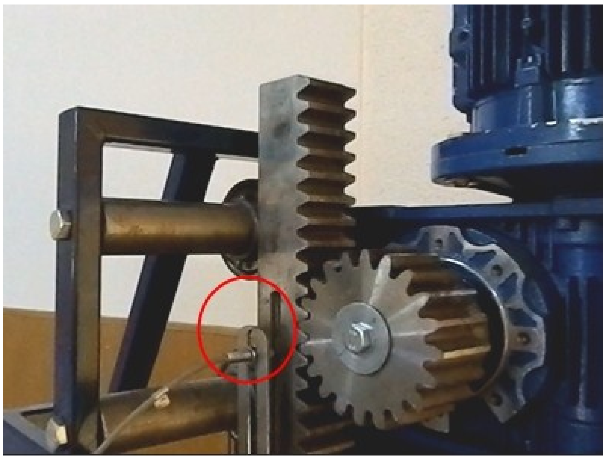


Figure 11: LRP upstroke cycle with sensor

As the actuator rod approaches a desired top of stroke position, the motor is operated in a way that the upward speed of the rod decreases so that the upward velocity is reduced to zero at the desired top of stroke position. From the top of stroke position, the motor is operated in a way that the actuator rod accelerates to a DOWN SLOW SPEED. It has to be mentioned that during downward motion the motor is operated in braking mode and not just with the downward forces on the rack caused by for instance weight of the rod string and any fluid loads acting on the subsurface installation. Due to braking mode of the motor net braking torque is applied to the pinion and the pumping unit achieves slower rotational speeds. As the actuator rod is lowered, load on the downhole pump is determined by e.g. monitoring motor torque. When the load on the downhole pump drops to a very low level or predetermined level, which indicates the travelling valve has opened and the pump is submersed into the fluid, the motor is operated such that the actuator rod can accelerate to a DOWN FAST SPEED. The end of the downstroke is detected similarly to the end of upstroke. [20]

[iv] *Provided by Nicolae Stanciu (Senior Artificial Lift Engineer at Production Operations Department Romania)*

The DOWN SLOW SPEED has the advantage of diminishing fluid pound. When the downstroke occurs, the plunger is going to hit the fluid level in the barrel, producing the phenomenon known as such. Please refer to subchapter 3.2.1.2 “Usage of Automation” for details. [20]

The LRP can be driven by different kinds of motors, including electric, hydraulic or pneumatic. If needed, a pneumatic counterbalance may be added to the system. The air balance provides greater lifting force by storing energy during a portion of each downstroke and releasing it again during the subsequent upstroke [21].

At PETROM in Romania the standard electric reversible motor is applied at the moment. Use of a hydraulic system in combination with the LRP is currently supervised and will be examined, if switching from electrical to hydraulic system will be more efficient in terms of economics and maintenance.

3.1.1 General Application of Linear Rod Pumps

The LRP comes in variety of models which differ from each other generally speaking by rod stroke length (in.), polished rod load (lb.) and pump speed in strokes per minute (SPM).

The LRP is still relatively unknown in comparison to other classic pumping methods, but gradually is making itself a name in the ALS sector with several advantages that are discussed in detail in the following chapter. The most popular LRP manufacturer is UNICO Inc. and their Linear Rod Pumps are widely used by PETROM.

Figure 12 lists a selection of different Linear Rod Pumps with different stroke length and consequently different heights [19, p. 50].

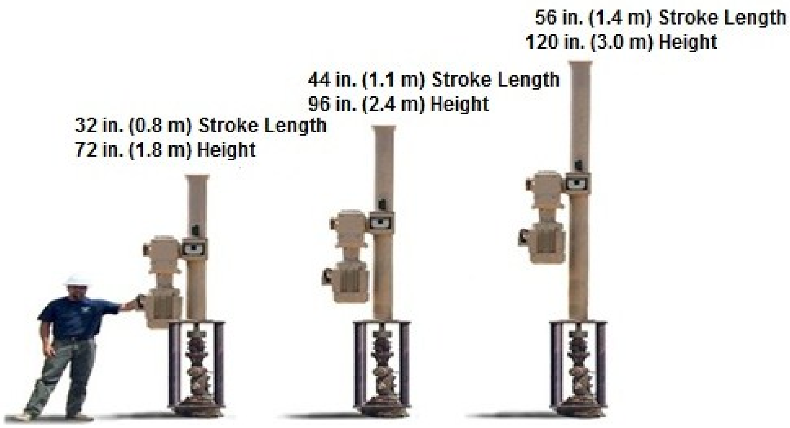


Figure 12: Different Linear Rod Pump types with electric motor

Linear Rod Pump models range from a 20 in. stroke with 4,000 lb. polished rod capacity, to a 144 in. stroke with 30,000 lb. maximum capacity. One of the main tasks of this thesis is to find standardization of all existing and potential LRP applications in PETROM by proposing standard LRP types which should be used in the future in order to meet PETROM´s necessity.

In regard to the LRP model description, an example of the pumping unit designations is shown in *Figure 13* on the next page. *Figure 14* gives a model number explanation in detail.

Figure 13: LRP model number example from Asset 9 Moldava Sud

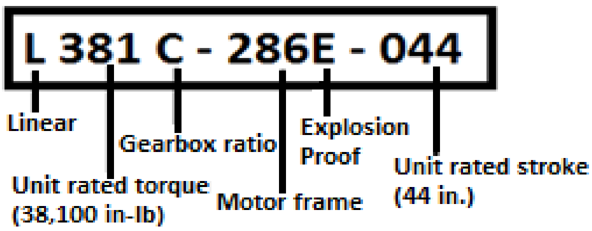


Figure 14 : LRP model number explanation in detail

For different gear box sizes, there are different gear box ratios which are then put in ratings described by letters A to J seen in the model number explanation. In case of *Figure 14* the gearbox ratio is C.

For detailed information about the motor frame number, the motor power explanation and the gear box ratios refer to Appendix F.

Listed on the following page is

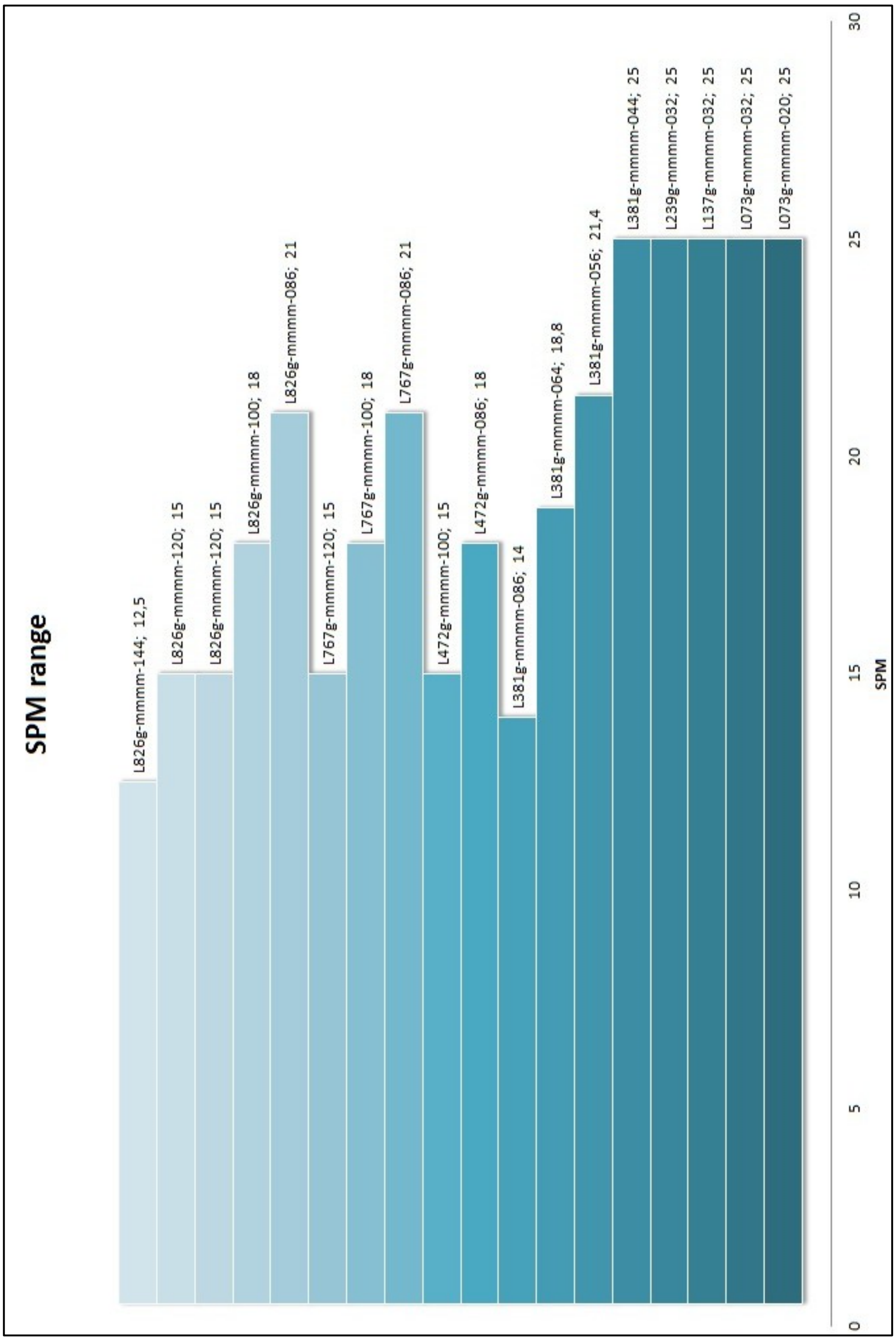
Table 2, which illustrates different kinds of LRP models, provided by UNICO including the model number, rod stroke, polished rod load and pump speed. Depending on the customer's input well production data, individual LRP models are able to be designed by the producer UNICO. By joining different rack lengths, gear boxes (g), motors (mmmm), and drives, the LRP system supports maximum flexibility with minimum spare parts.

Table 2: LRP Model characteristics from LRP catalogue [22]

Model Number	Rod Stroke Length [in.]	Polished Rod Load [lb.]	Pump Speed [SPM]
L073g-mmmm-020	20	4,000	0.5-25.0
L073g-mmmm-032	32	4,000	0.5-25.0
L137g-mmmm-032	32	7,000	0.5-25.0
L239g-mmmm-032	32	12,000	0.5-25.0
L381g-mmmm-044	44	20,000	0.5-25.0
L381g-mmmm-056	56	20,000	0.5-21.4
L381g-mmmm-064	64	20,000	0.5-18.8
L381g-mmmm-086	86	20,000	0.5-14.0
L472g-mmmm-086	86	23,600	0.5-18.0
L472g-mmmm-100	100	23,600	0.5-15.0
L767g-mmmm-086	86	30,000	0.5-21.0
L767g-mmmm-100	100	30,000	0.5-18.0
L767g-mmmm-120	120	30,000	0.5-15.0
L826g-mmmm-086	86	30,000	0.5-21.0
L826g-mmmm-100	100	30,000	0.5-18.0
L826g-mmmm-120	120	30,000	0.5-15.0
L826g-mmmm-120	120	30,000	0.5-15.0
L826g-mmmm-144	144	30,000	0.5-12.5

Documented in *Table 3* are different kinds of LRP models and their maximum SPM rate. It can be noted that the smaller units with a Rod Stroke Length of 44 in. and below can be monitored up to 25 SPM, whereas the bigger units depending on the motor power and therefore the motor rated torque with a Rod Stroke Length of 56 in. and above can only be monitored till a SPM range which is demonstrated in *Table 2 and Table 3.*

Table 3: SPM range of different LRPs



3.1.1.1 Benefits

Portability and design

The LRP is a relatively small pumping unit, easy to transport and install and is in no need of complex transportation operations. The LRP is transported in three main parts which fit in one transportation box. The motor, including the gear box, rack and pinion mechanism, the stand or mounting frame and the cylinder which protects the rack gear from adverse weather conditions. The full installation of the unit can be executed within a couple of hours. Since the transportation is manageable without any problems the LRP is a good candidate when it comes to well to well move for temporary installations and the installation in remote locations. There are no visible movable parts, except for the polished rod, to attract unwanted attention and maybe harm and injure wildlife or humans.

Economical

Installation costs are relatively low, because of the short time of the installation and simple transportation requirements [22]. The purchase price usually ranges depending on the pump model from 20,000 EURO for a 20 in. stroke length unit till 38,000 EURO for a 56 in. stroke length unit. The surface pumps with a stroke length of 100 in. and above cost beyond 80,000 EURO, because of the expensive material selection of the pinion and rack and the motor with gear box. [v] Since the unit is mounted directly on the wellhead, concrete pads are unnecessary and other site preparations are no longer needed. The low inertia design of the LRP permits it to utilize a smaller motor and gearbox other than the conventional pumping unit.

Automation

The LRP system contains patented Sucker Rod Pump control software that optimizes production while protecting the pumping system. An independently adjusting upstroke and downstroke speed regulator known as the Pump Off Controller (POC) which controls the VSD helps to optimize subsurface pump charge. This regulator maintains a target pump fill set point by modifying the pump speed based on downhole dynamometer data. The VSD receives both electrical and other production data like from dynamometer data and can use this information to change or maintain pump speed to optimize ALS performance or prevent it from damage [12]. The VSD has several advantages compared to the Fixed Speed Drive (FSD), like the capability to change the voltage frequency to the motor, which results in less rotations per minute (rpm) generated by the motor. The software also includes a Soft Landing speed control, as UNICO calls it, for a reduced fluid impact force and so, the

[v] *Technical interview and discussion about approx. LRP costs with AlferaTrade SLR (UNICO LRP distributor in Romania) on 08.10.2012*

pumping speed is continuously set to adjust well inflow. For details refer to subchapter 3.1 “Overview on the LRP“, description of pump cycle.

The system control of the LRP also includes data reporting, automated fault restarting and an automated valve check that controls if there are any leakages at the standing/traveling valve of the downhole pump. In an event of stuck pump, a sensitive position tracking and gearbox overload protection algorithm ensure an automatic shutdown of the unit. In the event of power loss, the unit electronically detects that there has been a power outage and parks itself in regeneration.

Rod load and position sensors are not required. The only external sensor is a single proximity reference sensor which is mounted directly on the pumping unit at the surface. This sensor reads the position of the rack (end of upstroke and end of downstroke). The dynamometer card is calculated based on current consumptions and does not contain a load cell like the conventional pumping unit has.[vi]

Low Speed Operation

As already observed in the model characteristics (

Table 2*)*, the LRP can operate at very low speeds. Depending on the model, the LRP operates at speeds as low as 0.5 SPM [22, pp. 1-4].

3.1.1.2 Limitations and Failure Analysis

Size

UNICO’s LRPs are designed to pump till a maximum surface stroke length of 144 in. (3.67 m) which can be a limitation, because the production limitation using subsurface pumps suitable for this stroke length and pumping from greater depths is restricted due to maximum pumping unit load. In theory the maximum polished rod load for a LRP lies at a maximum of 30,000 lbs. (13.6 tons). Until today (October 2012) 180 LRP units have been ordered by PETROM of which 163 are already installed. The average pumping unit load range average is at 4.5 tons (approx.10,000 lb.) and the average surface stroke length used is 1.3 meters. (51.2 in.)

Logistics

One disadvantage for PETROM is related to logistics. The repair of faulty equipment like for instance a faulty gearbox, control panel failure or pinion and rack failures cannot be repaired in PETROM’s own maintenance workshops. Faulty equipment must be sent to the

[vi] *Technical discussion with AlferaTrade SRL (UNICO LRP distributor in Romania)*

manufacturer's workshop, in this case to Germany. (UNICO GERMANY GmbH) and the whole process lasts approximately 100 days.

A LRP standardization, which means selecting an assortment of LRP models, would enable more spare parts in the long term and would reduce the waiting process for important spare parts needed in order to precede production.

Realistic Stroke Range

Even though the LRP can operate at speed as low as 0.5 SPM, in most PETROM cases the pump is not run much slower than 2 SPM which is a realistic stroke range in real life operations. After all PETROM's target is to produce the well in an economic range and the flowrate is dependent on the pumping speed and in fact the speed of 0.5 SPM is not common anywhere in the world. At speed as low as 0.5 SPM there will not be sufficient flow at the surface, because of the slippage of the subsurface pump.

> *"Proper pump slippage is a balance between proper lubrication to extend the life of the pump and pump volumetric efficiency."* [23, p. 34]

Check subchapter 3.2.1.6 "General Selection Methodology" for more details about volumetric efficiency and pump off control. The fluid leakage between the pump barrel and pump plunger is called pump slippage and affects pump lubrication and efficiency. The clearance between the barrel and plunger must be large enough to allow a befitting amount of slippage to sufficiently lubricate the plunger. Only in case of a very high viscosity fluid (between 30, 000 cP- 100, 000 cP) it is indicated to run with speeds lower than 2 SPM, and these conditions do not exist in Romania.

It's better to pump at higher speeds until the pump charge decreases and then stop the unit for a while, if the pump fill is less than 40%, instead of pumping at very low SPM (<=2 SPM) continuously due to bad gear lubrication. The unit will restart automatically after a certain amount of time that was established.

Wasted Energy

Another disadvantage is that the energy produced during the downstroke is converted into heat, because there is no counter balance existing like for the conventional pumping unit. In a conventional pumping unit the energy of the downstroke is converted to potential energy by lifting the counterweights. Future plans to save energy that is created during the downstroke and converted to heat are to install a generator to feed the local power grid with energy that otherwise gets lost or another option is to store the energy in a capacitor bank section of the drive and to assist in a future pump cycle. This future energy process will further enhance the overall pumping efficiency of a LRP. [vii]

Failure Incidents

The first trial operations with the LRP started in 2009 with just a few units. After this initial pilot LRP installation phase, PETROM installed more than 100 units in 2011. Failures mainly occurred in that particular year because of the broad implementation of a variety of LRP models. Depicted in *Table 4* all the LRP failure incidents that have taken place in PETROM Romania since the LRP was first introduced by PETROM in the year 2009 can be observed. The two parts of the table refer to the 7 assets shown in the table. All in all 7 failures took place and every case has been split into assets, well, UWI, the type of LRP, the resulted failure, start-up date and the runlife until the failure occurred.

Table 4: LRP failure incidents

	Asset	Well	UWI	Type LRP
1	Asset VII - Muntenia Est	481 MP Baicoi	RO53487552	L381B-256E-056
2	Asset VII - Muntenia Est	946 MP Mislea	RO23687910	L472B-2587-100
3	Asset VIII - Moldova Nord	519 Moinesti	RO04870033	L472C-2578-100
4	Asset VIII - Moldova Nord	571 Moinesti	RO96807684	L381C-286E-056
5	Asset VIII - Moldova Nord	189 Moinesti	RO42103066	L381B-324E-056
6	Asset VIII - Moldova Nord	649 Foale	RO80412406	L381C-286E-056
7	Asset V - Moesia Nord	1294 Cartojani	RO20423588	L381B-324E-056

	Failures	Start-up date	Failure date
1	Motor failure	Apr.11	Oct.11
2	Burned VSD	Apr.11	Sep.11
3	Broken rack	Mar.11	Aug.11
4	Broken rack	Feb.11	Dec.11
5	Broken rack	Feb.12	Feb.12
6	Broken rack	Mar.11	Nov.11
7	Cracked flange between motor/gearbox	Crack detected after inspection	Was not put into function

[vii] *Technical discussion with AlferaTrade SRL (UNICO LRP distributor in Romania) during a well site visit in Buzau on 10.10.2012*

Motor failure occurred due to problems with the electrical lines in the field and the power supply and corresponding voltage fluctuation. The motor was rated for a maximum of 500 V, voltage peaks greater than 500 V caused the motor to burn. There are 4 units with broken racks and these are half of all the LRP failures in Romania. The reasons of these failures were detected and the conclusion was that most of the 56 in. racks were made by the same manufacturer and the failure was caused by insufficient heat treatment to achieve desired steel hardness. Due to the fact that all units were delivered at the same time, they all had the same problem. As Alfera Trade SRL[viii], the UNICO company representative, describes in a discussion, they had the same problems in other countries with the units of the same rack size and steel treatment failure. The failure occurred within the warranty period of 2 years. The corrective action was replacing broken racks by new ones. The heat treatment has been adjusted and the rack problem was solved. Another incident was that the VSD got burned due to high peak voltages as the LRP distributor Alfera claims. The VSD failure also occurred within the warranty period and was replaced free of charge. The corrective action of this incident was to increase the voltage range, so the system can withstand higher electricity ranges. Another incident was a cracked motor/gearbox flange that was detected after the final inspection before installation. The exact failure cause could not be detected, but the crack might have come from transportation handling.

3.1.1.3 Space, Civil Works and Maintenance

As already depicted in *Figure 9 and Figure 10* the LRP is a compact pumping unit which is mounted on a mounting stand that is supported by a casing flange. The length, width, and height are unit model dependent. The picture from a field installation (*Figure 15)* provides a rough idea about the size of a typical LRP. The LRP dimensions are small sized in comparison to other pumping unit systems. LRP and stand are designed to couple to the polished rod at about 1 to 2 feet above the stuffing box [24]. The equipment weighs as much as 2,500 lbs., therefore an appropriate lift or hoist equipment has to be used to install the unit. In the case of the installation in Moldova Sud illustrated in *Figure 15*, a crane was used and the LRP stand was lifted over the flange. The stand has to be orientated to align the bolt holes in the flange and the stand. The next step is to connect the LRP assembly and stand with the stuffing box rod.

> *"The LRP rod should be aligned and concentric with the rod in the stuffing box as much as possible."* [24, p. 12]

[viii] *When referring to Alfera in this thesis the reference is made to Alfera Trade SRL*

Figure 15: Installation of LRP in Moldova Sud

PETROM's Linear Rod Pumps receive planned maintenance service and the main goal of this service aid is to maintain and repair the LRPs´ conduct to maximize the running time and decrease LRPs´ failures and down times.

For safe and continuous operation following services are to be performed **every six months or after approximately 4.000 operating hours.**

The stated task lists below were provided by Alfera Trade SRL, UNICO's supplier in Romania, in a maintenance concept for the delivered LRPs:

- First assure, that all materials, spare parts , tools and equipment are available
- Isolate the work area according to PETROM rules
- Visualize inspection of running LRP for signs of leakage, abnormal noise or vibrations
- Isolation of LRP/shutdown activities
- Replace rack and pinion oil
- Grease gearbox pinion
- Check the electronic panel components and cleaning
- Upgrade software, if necessary
- Test run, including reset maintenance time schedule, faults and events history check
- Adjust parameters for operating conditions agreed with production department

- Final inspection

At least every twelve months or after approximately 8,000 operating hours

- Replace the gearbox oil
- Check the teeth of the rack and pinion assembly

Every 30 days

- Inspect system for leaks
- Inspection of external wire cables
- VSD maintenance
    - Check heat sink fans for any dust, or debris
    - Check the circulation fans inside the VSD cabinet

Health, Safety and Environment (HSE)

- The priority is safety in respect of staff and workflow
- Conform to all relevant environmental standards
- Observe noise protection regulations

A brief comparison of the LRP in terms of footprint, civil work, costs and maintenance with other pumping unit systems is found under 3.2.4 ”Comparison of the Described Pumping Units in Brief”.

3.1.1.4 LRPs Worldwide

LRPs are internationally distributed and they also find a certain amount of demand from PETROM in Romania. UNICO is an international company with operations worldwide as the following citation states.

> *"Headquartered in Franksville, Wisconsin, UNICO has operations in Canada, Mexico, Venezuela, Colombia, England, Germany, China, and Japan, in addition to those in the United States."* [25]

Figure 16 on the next page shows the LRP model on the y-axis and the provided number of pieces on the x-axis. All in all UNICO distributed 1153 units (status 28.11.2012) worldwide[ix]. PETROM owns 180 LRP units, meaning that PETROM possesses approximately 15% of the LRP units provided worldwide. The top three LRP types in terms of unit selling worldwide and within PETROM are illustrated in the *Table 5*.

Table 5: Top three LRP model numbers purchased worldwide

Model Number	Purchased Worldwide [Pieces]	Purchased PETROM [Pieces]
L239 44 in. LRP	361	76
L381 56 in. LRP	326	40
L137 44 in. LRP	119	40

The reason why mostly the L239 44 in. LRP with a maximum polished rod rating of 5to. and the L381 56 in. LRP with a maximum polished rod rating of 7 to. are purchased worldwide is due to the fact that the production and depth range of these 2 pumping units are filling the gap between small sized and bigger sized pumping units. Furthermore Alfera claims that for the production range of these 2 pumping units (approximately 40 - 70 m^3/d) is the cheapest system with an integrated Pump Off Control System available. This argument is approved by the comparison of the LRP with other pumping unit systems in the following chapter. For higher production requirements operators tend to use bigger pumping units like for instance the in Chapter 3.2 "Comparison with other Pumping Unit Systems" explained conventional pumping unit, the long stroke pumping unit or the hydraulic pumping unit, which are generally more expensive.

[ix] *Technical discussion with Nicolae Manea, representative from Alfera via Email ,Romania on 26.11.2012*

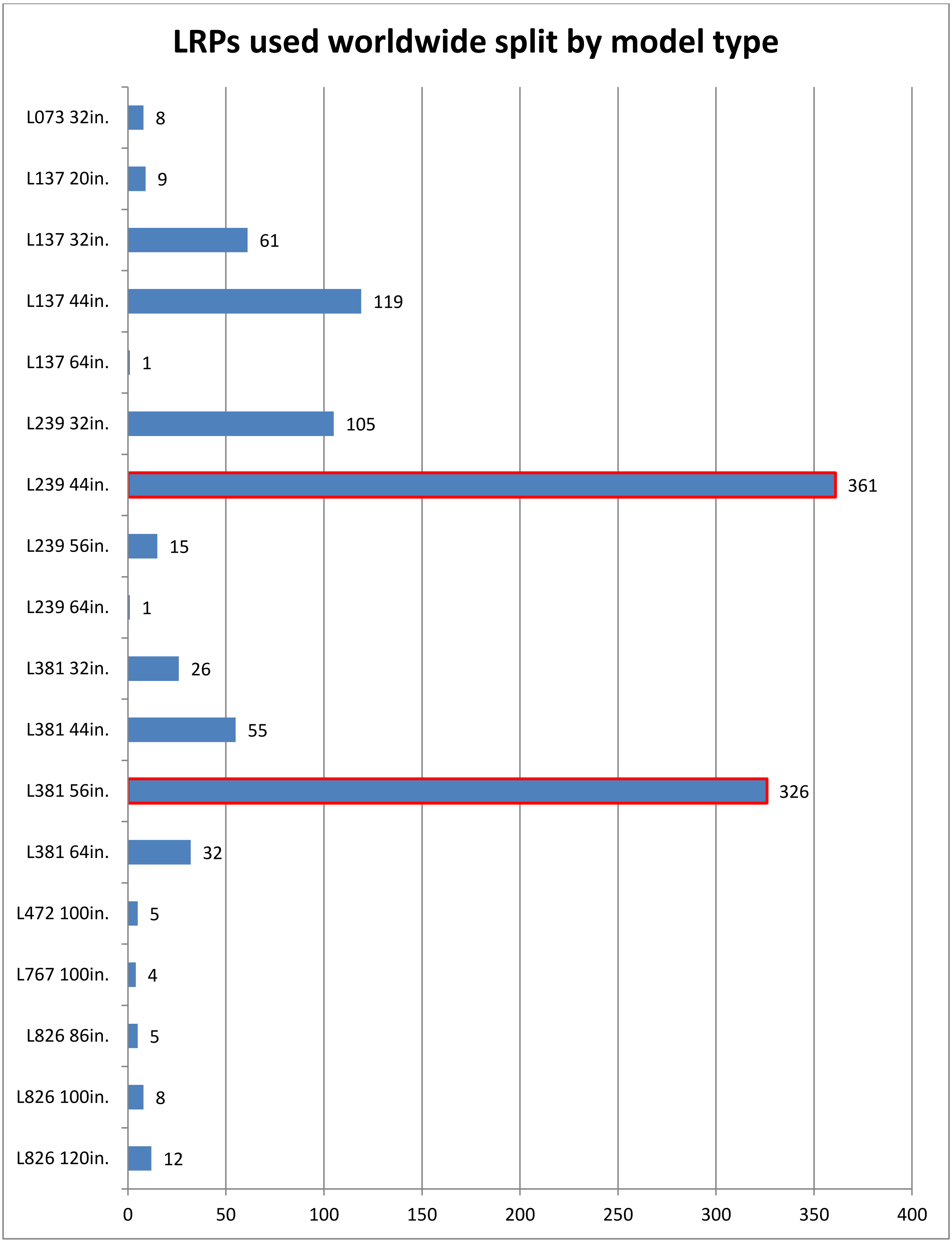


Figure 16: Quantities of LRPs used worldwide split by type

3.2 Comparison with other Pumping Unit Systems

The first artificial lift method was the conventional sucker rod pumping technique. This pumping system is the oldest and most widely spread type in the oil industry. The importance of this technique is shown in the amount of existing installations all over the world, which make up more than two thirds of the producing oil wells. At PETROM approximately 73% of all the wells use the RRP (Reciprocating Rod Pump) technique making it also in Romania the primary ALS. Other ALS applied are the Progressive Cavity Pump (PCP) with 23.14%, Gas lift (1%) and Electric Submersible Pump (ESP) with approximately 2% and out of the 97% ALS, 3% of wells are naturally flowing (*Table 6*).[x] A graphical illustration presents these data in a clearer way (*Figure 17*):

Table 6: Pump types and percentage used in Romania

Lifting method	Number of applications (7391 wells)	Percentage of types used in Romania (100%)
RRP(conventional pump + LRP)	5369	73%
PCP	1710	23%
GL	92	1%
NF	206	3%
ESP	14	0,2%

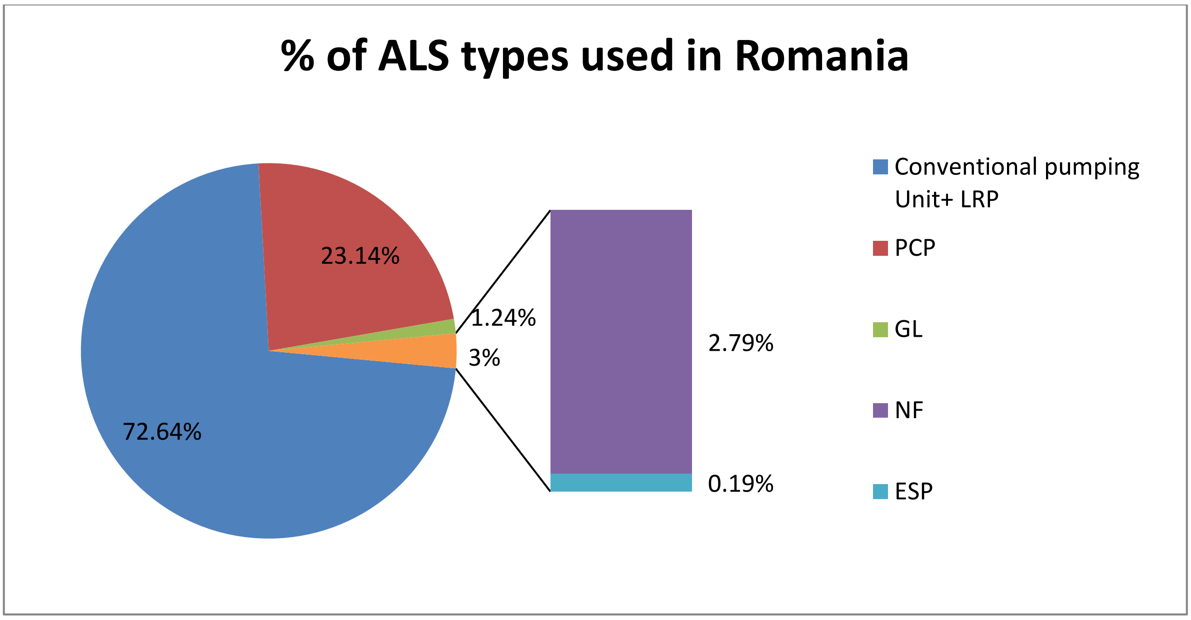


Figure 17: Percentage of ALS types used in Romania

[x] *Information taken from PETROM database (June 2012)*

3.2.1 Description of the Conventional Beam Pumping Unit System

Before starting the description of the beam pumping unit, it must be said that the individual components of the conventional pumping system can be split into two major groups, surface equipment and subsurface equipment. Special emphasis is given to the surface equipment, as one of the tasks of this thesis is to compare the LRP with other pumping systems, the main difference being the pumping technique itself. Attention is given to the subsurface equipment too, as a beam pump can be swapped by a LRP with the same subsurface equipment in place.

A properly sized pumping unit has the right size gearbox, the correct stroke length required to produce the target production and a maximum load that the polished rod can handle. (Pictured in *Figure 18* [23])

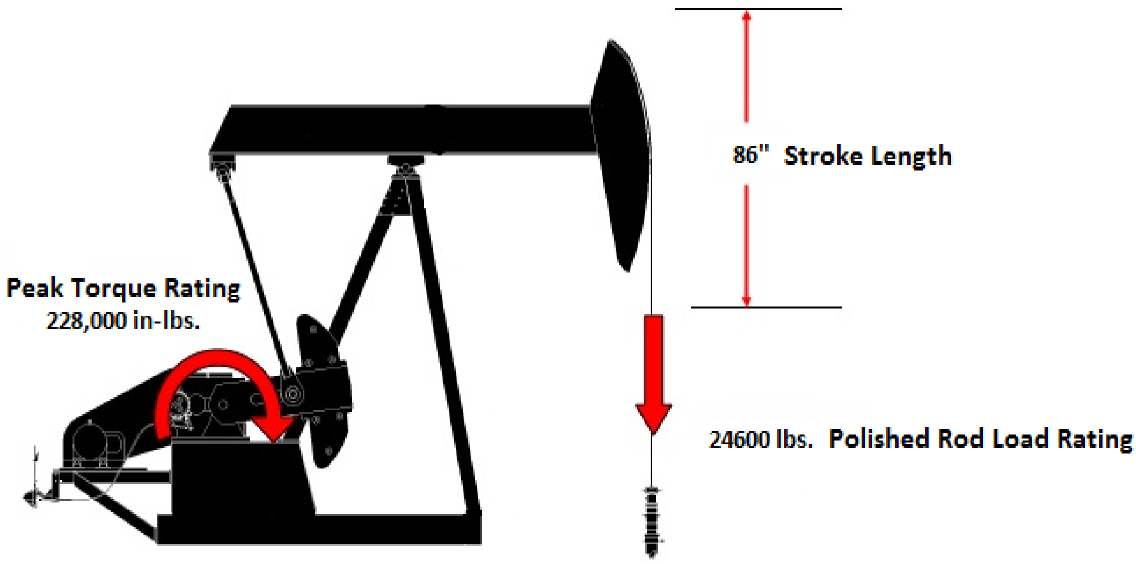


Figure 18: Conventional pumping unit designations

3.2.1.1 Pumping Unit Designations

The “American Petroleum Institute” (API) is the leading authority when it comes to publishing safety standards for the petroleum industry and these safety guidelines are the starting point for every company´s specific safety standard.

> *“All Lufkin Pumping Units with the API monogram signify that they meet or exceed the latest API standards for the design of sucker rod pumping units.”* [26, p. 2]

API developed a standard method of describing pumping units with a code with letters and numbers as illustrated in *Figure 19* as follows [26]:

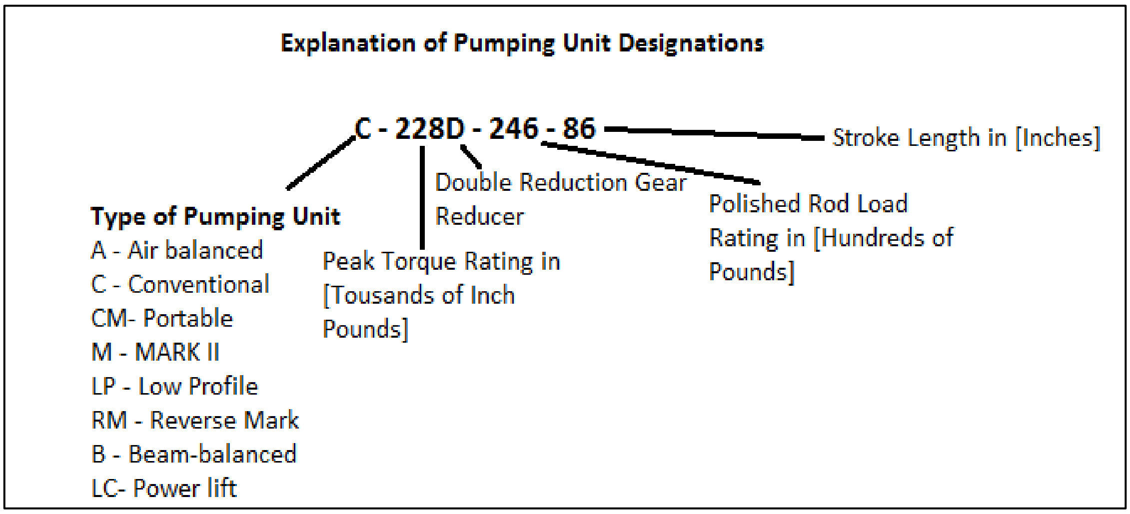


Figure 19: Pumping unit designations

The first character in the API code designates the pumping unit type.

A	Air-balanced
C	Conventional
CM	Portable/Trailer Mount
M	MARK II
RM	Reverse Mark
B	Beam-balanced
LC	Power Lift

The next four characters designate the peak torque rating, in thousands of inch-pounds, and the type of gear reducer. In many cases, a double reduction gear reducer is used, indicated by the letter “D”.
The next three characters define the peak polished rod load rating, in hundreds of pounds.
The last two characters are the stroke length, in inches.

3.2.1.2 Usage of Automation

The usage of automation and pumping control is recommended in terms of proper operation and monitoring to obtain optimum production from producing oil wells. The failure reduction and the solving of occurring problems during an operation should be the result of automation. A type of pump cycle controller should be installed; being either a time clock, a more technological rod pump controller or pump off. The purpose of the clock is to adjust the pumping time to the current well capacity. [15] *Figure 20* shows a schematic of a Conventional Beam Pumping Unit System equipped with Automation.

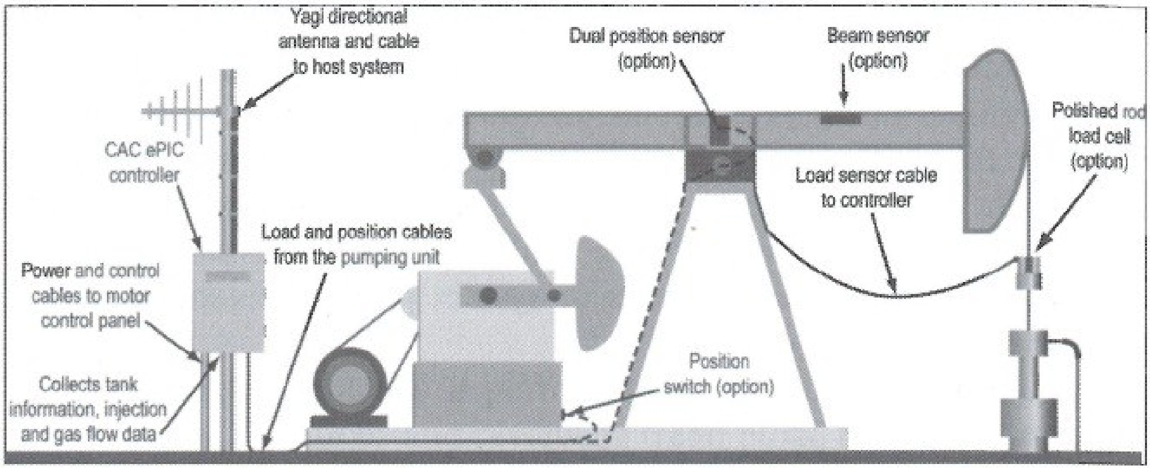


Figure 20: Schematic of Conventional Beam Pumping Unit System equipped with Automation [12]

"The POC enables the conventional beam pumping unit to operate with sufficient fluid levels to prevent damage while operating the pump at a high efficiency." [12, p. 289] The POC stops the pumping when the well is pumped off. POC monitors the pump speed automatically to increase pump efficiency. POC provides the rod string load versus polished rod position which can be seen and interpreted in dynamometer cards. The load is measured with a polished rod load cell which is mounted on top of the polished rod seen in *Figure 20*. The position is measured with a position switch (*Figure 20*) mounted on the A-frame or with an angular position transducer. [12]

A detailed investigation of the dynamometer and record data is beyond the scope of work of this thesis and only a brief introduction into dynamometers can be expected. To start with, the dynamograph is a tool for measuring polished rod load, peak torque, peak load, and horsepower requirements depending on the pumping unit and design. The dynamograph is a continuous record of all forces acting on the polished rod at any time during a pumping cycle and is recorded with respect of the polished rod position. The record is analysing the loads through the rod string to the pump and through the pumping unit to the prime mover. The recorded load diagram is shown with the rod position in inch on the x- axis and the loads in pounds on the y-axis. [8, p. 61]

A theoretical dynamometer card for elastic rods is illustrated in *Figure 21* [8].

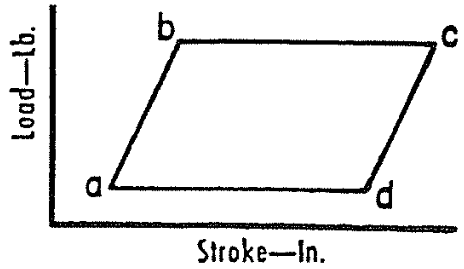


Figure 21: Theoretical dynamometer card

At the upstroke (a) the load begins to increase, because of the stretch of the rods. At point (b) the maximum polished rod load is reached and remains constant till point (c). At that point the downstroke starts and the rods begin to contract. At point (d) the fluid load got transferred to the standing valve and this indicates the minimum polished rod load. The minimum polished rod load remains constant till point (a), where the cycle is repeated. [8, pp. 63,64]

The basic goal of any control principle is to lower the fluid level in the well to the pump intake by the end of an operational period. Maximum production from the well is achieved by ensuring the lowest possible flowing bottomhole pressure. If the fluid level is at the pump intake, and the capacity of the pump in excess of well inflow, the pump barrel does not fill properly up with fluids during the upstroke. When the downstroke occurs, the plunger is going to hit the fluid level in the barrel, producing the phenomenon known as fluid pound. In this case it is said that the well is pumped off and therefore a POC is needed to detect this condition. [13] The sudden impact force is transmitted to surface along the rod string. The dynamic loads that occur during fluid pounding have negative impact on the downhole equipment. For instance the rod sting can experience buckling which can lead to rod breaks, rod to tubing wear is increasing and the occurred shock loads contribute to coupling failure due to unscrewing. On the surface the occurred shock waves can damage bearing of the pumping unit and can lead to instantaneous torques that may overload the speed reducer. [27]

Figure 22 demonstrates a shape of a fluid pound. The fluid pound profile is very characteristic and fluid pound can be identified by the very steep drop in polished rod load after the start of the downstroke.

Figure 22: Dynamometer card shape of a fluid pound [27, p. 342]

Another pumping problem which can be detected from visual analysis of dynamometer cards is the gas pound.

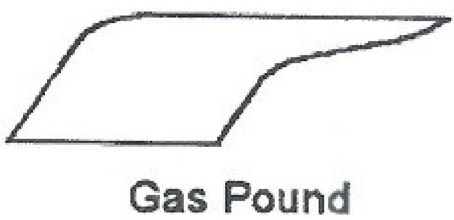


Figure 23: Dynamometer card shape of a gas pound [27, p. 342]

Figure 23 shows a gas pound card shape. Seen by the look, if free gas enters the pump, the barrel is filled with gas liquid mixture during the upstroke and when downstroke begins, the compressible mixture prevents the prompt opening of the travelling valve, because it must first be compressed to overcome the fluid load on the travelling valve. At the moment where the gas liquid mixture in the pump barrel has been compressed, the valve suddenly opens which gives rise to a shock wave similarly to that of the explained fluid pound. Gas pound brings along similar mechanical problems to the pumping equipment as fluid pound do. Furthermore gas locking can occur. [27] The phenomena of gas locking occurs when there is just too much gas in the compression chamber for the pump to manage, meaning that the traveling valve inside the bottomhole plunger fails to open to reload the pump, due to absence of fluid below the plunger. The compression ratio of the pump instructs how much pressure can be built up below the plunger to help with operating the traveling valve [23, p. 70]. A schematic of the gas lock effect is illustrated graphically in *Figure 24* .

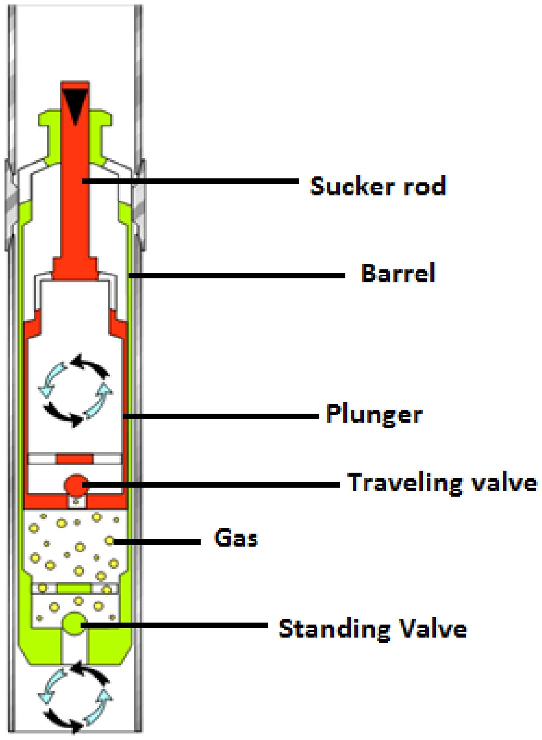


Figure 24: Schematic of a gaslock[xi]

The remedial actions that decrease gas occupying space within the barrel and therefore reduce the space available for fluids is to separate as much free gas as possible before the gas can enter the downhole pump. This is achieved by a gas separator (See Chapter 3.2.1.4 "The Main Elements of the Subsurface Equipment" for more details).

In shallow wells a surface dynamograph card is used to determine the loads and the position of the rod. *"In shallow wells rods and fluid loads behave like a concentrated mass* [8, p. 63]*"*, so the elongation of the rod string can be neglected to a certain extend. But in deep wells the rod string, due to its length, is elongated and compressed and shows a more complex load pattern, so a visual correct diagnosis of possible downhole problems for surface dynamometer cards are rarely possible. Therefore, POC is beneficial in this case as it calculates the downhole dynamograms and allows proper diagnosis of the pump behaviour.

When no Pump off condition is present and no data transmission is required, there is no reason to install well automation on the pumping unit. In this case the unit price becomes reasonable and in terms of costs more competitive than the LRP. See subchapter 3.2.1.7 "Conventional Beam Pumping Unit vs. LRP" for more information.

[xi] *Provided by Mr. Firu Liviu (Production System Optimization asset team leader) during a technical discussion about Sucker Rod Pumping on 19.12.2012*

Selection criteria for pump off controller (POC) in PETROM operations[xii]:

- Wells with low pump charge (volumetric efficiency less than 50%, also called pump off conditions)
- Wells with production >0.5 to/day (to justify investment)
- Wells with paraffin / asphaltene
- Wells with high amount of associated gas
- Wells with high frequency of interventions (more than three incidents in a year)
- Remote wells or with difficult access in adverse environmental conditions
- New wells

System benefits:

- Increased production
  - Minimize production losses with early detection of gas lock, pump intake restrictions, holes or splits in tubing and valve leaks
  - Increase system uptime by decreasing mechanical failures (tubing damage, rod parts, etc.)
- Reduced lifting costs
  - Reduction of electrical consumption
  - Reduce equipment repair costs caused by excessive wear and fluid pound

[xii] *Technical interview and discussion with Ms. Florina Dogaru, Senior Production Engineer from PETROM (in charge of well automation) on 06.12.2012*

3.2.1.3 The Main Elements of the Surface Equipment

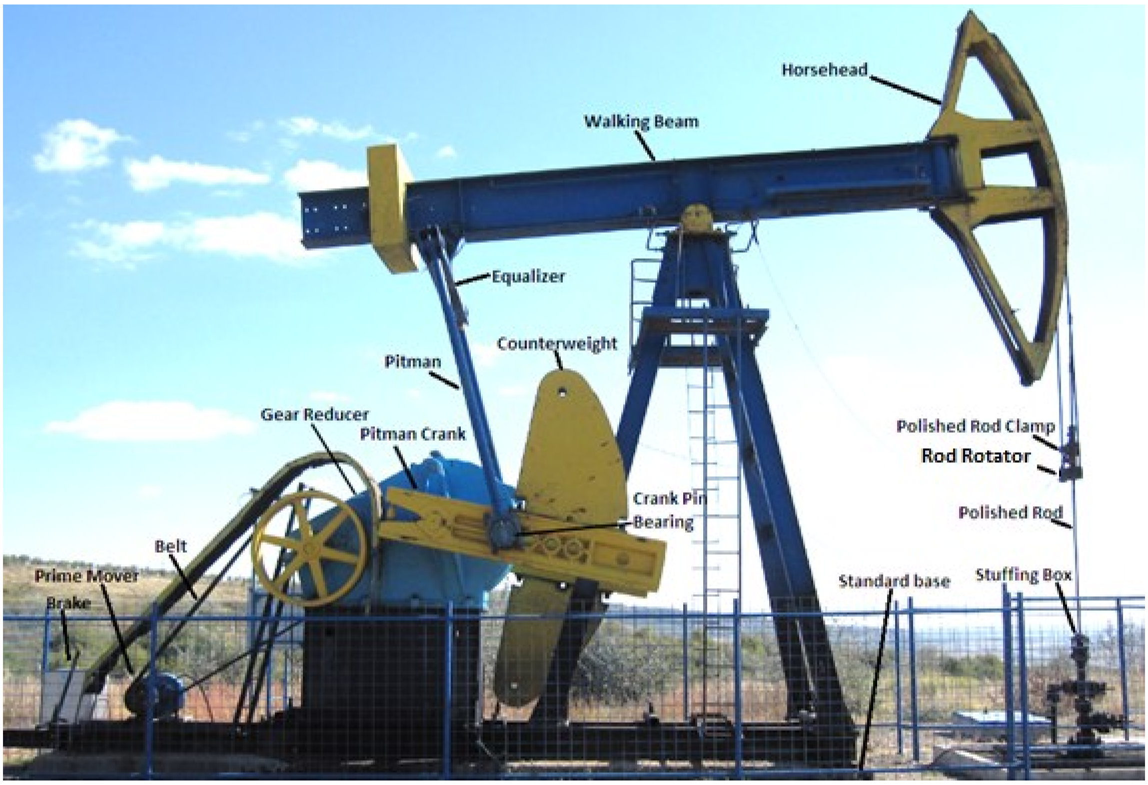


Figure 25: Conventional Pumping Unit by Vulcan in Moldova Sud (Asset 9)

The schematic (*Figure 25*) shows a conventional pumping unit being used in Asset 9 Moldova Sud distributed by manufacturer Vulcan S.A. from Bucharest.

The main elements of the surface equipment include:

- **The prime mover** is typically driven by an electric motor or a gas engine. Most prime movers are driven by electric motors. Gas engines are used in locations with no electricity. The function of the prime mover is to supply the movement the pumping system needs. The prime mover affects energy consumption and gearbox loading. Motor horsepower depends on pump depth, fluid level, pumping speed and unit balancing. Prime mover sizing shall be considered when designing the artificial lift system. However, it is important to point out that prime mover size can have a significant impact on system efficiency. In many oil fields, prime movers are usually oversized. This guarantees that enough horsepower is available to the system but at a price of lower efficiency if the prime mover used is significantly larger than the size required. Electric motors achieve their highest efficiency when loaded close to name plate horsepower. When a motor is lightly loaded its efficiency is lower. Electric motors and gas engines are low torque, but high RPM (rotations per minute) devices. Prime mover speed variation affects gearbox and rod loading and also pumping speed. High prime mover speed variation usually reduces net gearbox torque. For example, on the upstroke where polished rod load is higher, the motor slows down.

Because of this speed reduction, counterweight rotational inertia (resistance to change in speed) helps reduce gearbox torque by releasing stored kinetic energy to help the gearbox. This also reduces peak polished rod load by reducing polished rod acceleration. On the downstroke the unit speeds up resulting in higher minimum polished rod load. Therefore, high prime mover speed variation "flattens" the dynamometer card as compared to a prime mover with small speed variation. This results in a lower stress range and therefore less fatigue on the rods. [23]

- **The gear reducer** or gearbox, which reduces the high rotational speed of the prime mover to the required pumping speed and at the same time, increases the torque available at its slow speed shaft. [28]
- **The equalizer** is a rigid construction that assures uniform load by each Pitman arm.
- **The horsehead** is a solid welded construction which can be folded without effort to the right or to the left side of the walking beam by means of the worn gear device. The construction promotes an easy access to the wellhead. [29]
- **The standard base** is available in three different sorts The standard base is used for pumping units mounted on a concrete foundation, the portabable base, which permits the unit to be set on the ground directly and the two point base, which is installed on two concrete blocks.
- **The pumping unit**, which is a mechanical linkage that transforms the rotary motion of the above discussed gear reducer into a reciprocating motion which is needed to operate the downhole pump. The main component of the pumping unit is the walking beam and can be seen in the graphic (*Figure 25*: Conventional Pumping Unit by Vulcan in Moldova Sud (Asset 9)).
- **The polished rod**, which is the upper most part of the string, acts as an efficient hydraulic seal and also connects the walking beam of the pumping unit to the sucker rod string.
- **The wellhead assembly** contains a stuffing box which is situated below the polished rod and basically isolates the tubing from the rest of the system and also seals the polished rod to lead well fluids into the flowline.
- **The stuffing box** is a device which seals fluids in the tubing by forming a tight seal with the polished rod. It diverts the produced fluids out of the pumping tee, which need to be installed properly meaning that its threads need to be fitted with the tubing when screwed on, into the flowline. As the polished rod has to be lubricated, some stuffing boxes have a container attached with oil. [15, p. 506]

At this point, it should be also mentioned, that the electrical equipment should be protected against nature's interference with the operation, meaning that lightning protection and guarding against heat or cold have to be considered.

3.2.1.4 The Main Elements of the Subsurface Equipment

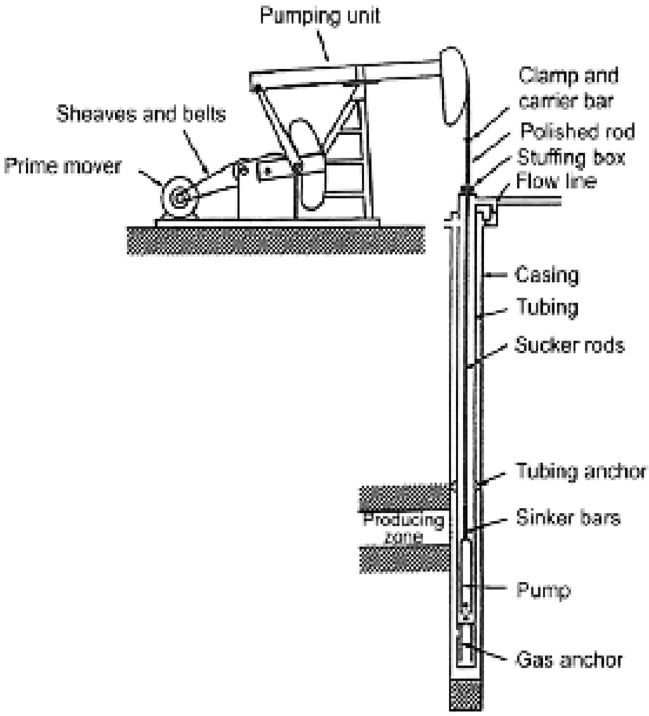


Figure 26: Conventional Pumping Unit's including subsurface equipment [15, p. 415]

The main elements of the subsurface equipment are:

- **Tubing:** Usually 2 7/8 in. or 3 ½ in. size tubing is used, depending on the volume to be produced. As far as material is concerned best practices related to downhole equipment provided by PETROM recommend using *"grade J-55 steel for normal working environments with depths no greater than 2590 meters. For deeper wells, calculations and considerations must be made with regard to pressure and corrosive environment. Couplings of the same grade as the tubings must be used."* [23, p. 60] If tubing wear exists which is typical in deviated wells, in many cases rod rotators are installed to spread wear on the whole tubing.
- **The sucker rods** are round bars made of rolled steel and threaded at the end. They transmit the movement from surface to the subsurface pump and are used to make up the mechanical assembly between the surface and downhole components of a rod pumping system. [23, p. 73]. The rods come in different API sizes available from 1/2 in. to 1 1/4 in. body diameter and are 25 to. 30 ft long and threaded to connect the downhole equipment. [30] Fiberglass sucker rods are utilized in wells with relatively high fluid levels so that excessive rod stretch which is a result of high elasticity does not demolish the efficiency of the installation. It has to be said that fiberglass rods are

lighter in weight than steel rods and also have a lower modulus of elasticity. A typical fiberglass rod string contains about 50 to 70% fiberglass rods at the top of the rod string and 50 to 30% steel rods at the bottom. Sometimes sinker bars replace steel rods. The steel at the bottom of the rod string assist the fiberglass rods to be in tension and helps the fiberglass rod to achieve overtravel. [31] Overtravel is a condition in downhole pumping operations that arises when the stroke length which is at the subsurface sucker rod pump is longer than the stroke length on surface. It comes to an overtravel, because of the elongation of the rod string because of dynamic loads imposed by the pumping cycle. In other words when the upstroke begins at the surface, the downhole pump is still in motion and moving downwards and the same vice versa. When the downstroke begins, the subsurface pump is still moving upward. [7]

- **Rod guides** are commonly used to minimize the effects of wear on the metal parts and to minimize rod loads due to mechanical friction which can be excessive in for instance crooked wells, in rod buckling or in tubing situations. There are several rod guide types. Whether the rod guides are factory mounted guides, which are molded permanently to the rod or wheeled guides, which have several wheels placed vertically in a special coupling, they all provide a centralized, low friction movement of the rod string. [32]
- **Sinker bars** are used above the pump to help the rods straighten on the downstroke and to skip buckling problems. *“Sinker bars are recommended if the load at the top of the rod section is less than 2000 lb. (910 kg)”* [23, p. 59].
- Generally said a **downhole pump** should be selected on the basis of different well criteria and operating conditions. Fluid viscosity, well depth, bottomhole temperature, gas liquid ratio, pump intake pressure and tubing size are only a few parameters that have to be mentioned at this point. These parameters influence the pump requirements like pump type, metallurgy, pump size and stresses on the pump. [15, p. 470] The downhole reciprocating pumps can be split into two types. The insert pump and the tubing pump
  - Main characteristics of the Insert pump:
    Complete pump attached to and inserted into well tubing with sucker rod string. The pump can be pulled out without pulling tubing.
  - Main characteristics of the Tubing pump:
    “The Barrel assembly of this type of pump is screwed onto and becomes part of the tubing” [23, p. 27]. The tubing pump has a larger bore than an insert rod pump and produces a greater volume of fluid in any given diameter and tubing. Rods and tubing must be pulled for service.
- The presence of gas can cause problems if the amount of free gas that enters the downhole pump is not decreased. This can cause lower pump efficiency and lower oil production so a **gas anchor** or **gas separator** is installed which is pointed out graphically in *Figure 26* below the pump.

3.2.1.5 Application Criteria

In many producing countries worldwide the conventional pumping unit is considered the premium choice for most onshore installations.

However, this ALS also has some limits that have to be considered before making the final ALS choice. In *Table 7 and Table 8*, advantages and disadvantages of the Sucker Rod Artificial Lift Method are listed. As referred to at the beginning of the chapter 3.2.1 ”Description of the Conventional Beam Pumping Unit System”, it is important to distinguish between surface equipment and the subsurface equipment. This thesis will only cover the subsurface equipment to that extend that it is clear how production per day is affected not only by the unit itself, but also by stroke length and pumping speed. The pumping speed is an important design parameter that influences the efficiency of the entire pumping system. Higher pumping speeds result in more equipment wear and lower system efficiency.

> *“Very high pumping speeds can cause the polished rod to separate from the carrier bar causing rod flotation on the downstroke. This means that the pumping unit is moving faster than the rods on the downstroke. When the polished rod and carrier bar come together again on the downstroke, the impact loading can cause damage which can result in premature failures.”* [23, p. 23]

The maximum SPM depends on the pumping unit type, polished rod stroke length, rod string material and design, pump plunger size, rod tubing friction and rod buckling or compression.

Table 7: Advantages and limitations of Conventional Pumping Units (Surface equipment) [15, pp. 438,443,459]

Advantages	**Disadvantages**
Easy for personnel to operate	Surface system takes a lot of space, because of its large size which include massive parts like the counterweights or the walking beam
Simple mechanical structure	The conventional pumping units in Romania, which are manufactured by Vulcan S.A. have a SPM interval from 5.7 to 20 SPM depending on the unit [33]
Surface unit is able to be relocated to other wells	Surface stuffing box leaks can cause pollution. Good operations are mandatory such as not to over tighten the stuffing box[xiii]
Can pump a well down to very low pressure	Noise level high and therefore insufficient for urban areas
Allows analysis on the basis of well tests, fluid level and dynamometer charts	
Good prime mover flexibility	
Availability of different sizes	

[xiii] *On field technical discussion with Nicolae Manea, representative from Alfera on 10.10.2012*

Table 8: Advantages and limits of Conventional rod pumps (Subsurface equipment) [15, pp. 438,443,459]

Advantages	Limitations
Corrosion and scale treatments are easily performed with a chemical injection line (injection of chemicals between annulus and tubing)	May cause solids formation(paraffin, scale deposits)
High temperature and viscous fluids are able to be lifted(550 °F~288 °C)	Gassy wells usually have lower volumetric efficiency and needs downhole separation
Good high viscosity fluid handling capability up to 700 cP viscosity fluids@ 40°C after applying steam injection. Before adopting steam injection the viscosity is about 3000 cP @ 20°C[xiv]	Downhole tool may become gas locked and pumping efficiency therefore is reduced
System allows gas separator installation	Crooked holes are a problem and require special operating equipment
Handles rates from 5 to1500 BPD	High volume lift capacity restricted to shallow depths with the use of large plungers
	"Another disadvantage of walking beam-type pumping apparatuses is that they cannot typically operate at pumping speeds much below 5 strokes per minute" [20, p. 1], [34, p. 7][xv]
	Solids production from the well is a problem May be able to handle 0.1% sand

[xiv] *Applied in Asset 1(Suplac) in Romania*

[xv] *Also see the Vulcan catalogue* [33] *for detailed information*

3.2.1.6 General Selection Methodology

From the beam pumping units for oil extraction in Romania at PETROM, the main pumping unit utilized is the conventional pumping unit as well. Off course this pump type comes in different unit sizes which also reflect the polished rod capacity and the different stroke lengths which are dependent on the shifting of the crank pin bearing.

The conventional beam pumping units in PETROM went through an API unit standardization process and have the API monogram since 2012, out of many different beam pumping units and manufacturers, only eleven API standard surface unit types from one company (Vulcan S.A.) have been chosen from PETROM to operate in future which makes the selection of the unit much easier and categorized. Attached to Appendix B is a detailed catalogue of the beam pumping unit standardization where the old unit types are gathered to form a specific API unit standardization type. Lufkin units are still operated as backup for the Vulcan units. In the API standardization depicted in *Table 9* eleven candidates are listed and depending on the unit peak torque rating, load at the polished rod, the stroke length and stroke per minute desired a pumping unit model is favoured.

Table 9: API standardization for conventional beam pumping units [35, p. 17]

Pumping Unit class 1 API Specification	**Max.Load at the polished rod**		**Max.stroke length**		**Maximum stroke/min**	**Peak Torque Ratings**	
Manufacturer: Vulcan S.A.	**[lb.]**	**[to.]**	**[in.]**	**[mm]**	**[SPM]**	**[lbs.in]**	**[Nm]**
C 57D-76-42	7600	3.5	42	1067	28	57000	657
C 80D-119-64	11900	5.4	64	1626	24	80000	922
C 160D-143-74	14300	6.5	74	1880	22	160000	1880
C 228D-173-74	17300	7.9	74	1880	22	160000	1880
C 228D-173-100	17300	7.9	100	2540	19	228000	2627
C 320D-213-120	21300	9.7	120	3050	17	320000	3687
C 456D-256-144	25600	11.6	144	3658	15	456000	5254
C 640D-256-144	25600	11.6	144	3658	15	640000	7374
C 640D-305-168	30500	13.8	168	4270	14	640000	7374
C 912D-305-168	30500	13.8	168	4270	14	912000	10508
C 912D-365-192	36500	16.6	192	4877	14	912000	10508

In order to compare different pumping units with each other, certain assumptions in terms of peak polished rod load, pumping unit size, SPM, well depth, reservoir pressure and volume per stroke have to be considered and determined in a scenario. The thesis will not discuss the pump displacement parameters in full detail as the focus is on selecting potential LRP candidates and defining standard LRP types, but basic approaches have to be made for a better general understanding. The flowrate that a pumping unit can achieve depends on the pump displacement, which is dependent on the strokes that a unit can make per minute, the downhole pump stroke length and the pump plunger diameter calculated as listed in **eq.1** [23, p. 31]. In case of 100% pump filling efficiency the pump displacement equals the actual flowrate. However, 100% efficiency is practically not possible; therefore the surface production has to be calculated considering less % pump efficiency. (See **eq.2**)

$$Pd=0.1166\times Dp^2\times Sp\times SPM \qquad (1)$$

The following abbreviations stand for:

$Pd=$ Pump displacement, [BPD]
$Dp=$ Pump plunger diameter, [in.]
$Sp=$ Downhole pump stroke length, [in.]
$SPM=$ Strokes per minute

For a pumping depth and volume of fluid produced, an optimum plunger diameter for the operation is assumed. If the plunger is too large, high loads are put in contact with the equipment and the plunger could get harmed or get an effect of undertravel which is not efficient for the operation. On the other side, if the plunger is too small, the pumping speed becomes too high, which results in increased peak load of the equipment. [8, p. 15]

The actual flow rate at the surface is less than the calculated theoretical pump displacement because of factors like for example pump wear, gas interference or pump slippage and these factors are difficult properties to determine. As already mentioned in the subchapter 3.1.1.2 “Limitations and Failure Analysis” the slippage, which is by definition the fluid leakage between pump barrel and pump plunger affects pump lubrication and efficiency. Slippage is the result of part of the produced liquid slipping back through the clearance of pump barrel and pump plunger. An important parameter is the fluid that is travelling though the subsurface pump due to the fact that with increasing liquid viscosity slippage losses decrease. There are also other sources that cause slippage like for instance in the pump itself. The ball to seat contacts of the traveling and standing valves can wear and therefore allow liquids to leak. [13].

The ratio of fluid production at the surface (BPD surface) to pump displacement rate (see **eq.1**) is called pump efficiency (%P_{eff})[xvi] and can be calculated like in **eq.2** [23, p. 31]

$$\%P_{eff} = \frac{BPD\ surface}{Pd \times 100} \qquad (2)$$

"Volumetric efficiencies can vary over a wide range but are in ideal case 70-80%." [8, p. 17]

If pump off conditions are present, the pump efficiency decreases and the range reduces. For the screening of wells with pump off conditions, which is part of the thesis´ objectives, a volumetric efficiency of up to 50% is the considerable range.

As water is omnipresent in produced fluid this factor must be considered when choosing a pump. Since water is heavier than oil and provides more friction and less lubrication within the pump, a high water cut (water in the fluid) will affect the plunger in a way that it prevents the plunger from falling fast enough. This can cause the sucker rods to travel faster than the plunger itself and this results in the tubing to buckle and reasons wear to the tubing wall and sucker rods, because of friction. [23, p. 33]

A pumping unit should be designed to manage to pump down the fluid level in the annulus to the minimum value consistent with efficient pump operation and prohibit for example fluid pound. To accomplish this design objective, a rate for a pump should be designed with **eq.3**. [12, p. 289]

$$Design\ Rate = \frac{Maximum\ Inflow\ Capacity \times 24\ hrs/day}{Pump\ Volumetric\ Efficiency \times hrs\ pumped/day} \qquad (3)$$

For the pumped hours per day a good value for an effective pump off control is 20 hours. For the maximum inflow capacity, the reservoir inflow capacity should be utilized for the desired daily rate.

[xvi] *Note: Pump efficiency is also called volumetric efficiency*

3.2.1.7 Conventional Beam Pumping Unit vs. LRP

Overview

In general the LRP with its lightweight and simple structure is an innovative alternative to a conventional beam pumping unit [36].

Power consumption comparison

Before talking about the power consumption comparison, the conventional beam pumping unit is put in a direct comparison with the LRP seen in *Table 10*. It has to be stated that these 2 particular models are compared with each other, because of the fact that the LRP has been installed at the same well where the CPU was standing previously.

Table 10: LRP/Conventional Beam pump model comparison

Model	**Vulcan 15-4000-10000**[xvii]	**L 767A-2587-100**
Peak polished load [to.]	15	13.6
Stroke length [in.] ([mm])	157 (4000)	100
Peak torque rating [in-lbs] ([Nm])	88,500 (10000)	76,700

Regarding the model characteristics, it can be noticed that the two models are not identical in all of the three features seen in *Table 10*.

With the LRP the rotational movement applied to the pinion causes the rack to move upwards and downwards, therefore translating the rotational motion of the pinion gear into linear motion of the rack gear. With the conventional beam pumping unit the rotary motion from the prime mover is converted to reciprocating motion. Pumping unit systems generally are high efficiency devices which make good use of electrical energy.

[xvii] *Note: Old pumping unit designations without beam pumping standardization (for more information refer to Appendix B)*

A general formula for the overall electrical efficiency of a pumping unit is given [12, p. 285]. See **eq. 4**

$$\eta = \frac{.00000736\gamma QH}{\frac{kW}{.736}} \qquad (4)$$

The following abbreviations stand for:

η= the overall electrical efficiency of the pumping unit
γ= specific gravity of the fluid
Q= the additional production from pumping the well, [BPD]
H=the vertical lift of the fluid from approximately the fluid level in the casing to the surface, [ft.]
kW= the electrical power input to the motor at the surface, [kilo-Watts]

A reasonable electrical efficiency would be of more than 50% for a pumping unit installation. Factors like for instance gas interference into the downhole pump could reduce the overall electrical efficiency to much less than 50%. [12]

A comparison of the conventional beam pumping unit and the LRP at the same well (532 SNP in Bucsani Asset 6) was calculated with the “Total Well Management “software provided by PETROM to show the power consumption of both units.

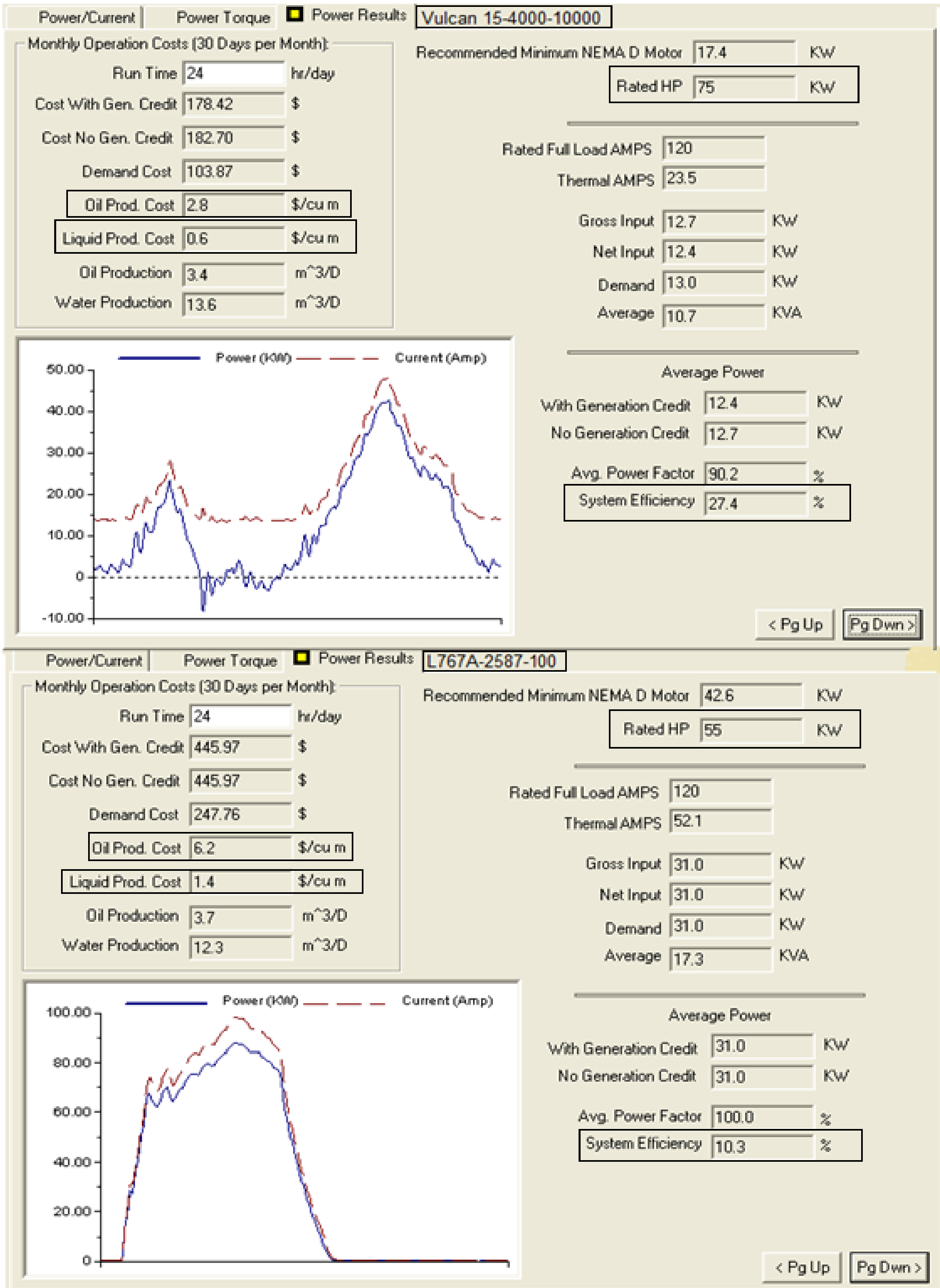


Figure 27: Power consumption and system efficiency of LRP & Conventional Beam pump

In *Figure 27* the electrical characteristics of the two pumps (see *Table 10*: LRP/Conventional Beam pump model comparison) are put in straight comparison. The graph shows the power [kW]/current [Amp.] consumption on the y-axis vs. time [sec.] on the x-axis.

Figure 27 portrays the monthly operation costs (30 days per month); the different power consumption curves and as an important figure the system efficiency.

The overall system efficiency is reached if individual efficiencies in the entire system components are combined being the lifting efficiency, the mechanical efficiency of the pumping unit and the speed reducer and the overall efficiency of the electrical motor.

In order to describe the lifting efficiency, the sources of downhole energy losses have to be mentioned. Energy losses are generated in the pump due to the frictional and hydraulic losses as well as leakages. The reciprocating rod string which is placed inside the tubing rubs against the tubing wall and causes mechanical friction, which increases the energy losses and causes dramatic energy losses in e.g. deviated wells. All energy losses and hydraulic power required for fluid lifting must be overcome by mechanical work, which is performed by the polished rod. The energy required for operating the polished rod at the surface is the sum of work performed by the pump plus the described energy losses. Thus, the total energy is directly proportional to the power required at the polished rod which is called polished rod power. The lifting efficiency is the energy efficiency of the downhole components of the pumping system. Pointed out in **eq.5** is the formula for lifting efficiency and is defined as the quotient of hydraulic power and the power required at the polished rod. [13, p. 99]

$$\eta\ lift = \frac{P\ hydr}{PRHP} \qquad (5)$$

The following abbreviations stand for:

η lift= lifting efficiency
P hydr= hydraulic power used for fluid lifting [HP]
PRHP= polished rod power required at the surface [HP]

The mechanical energy losses occur at a couple of places on the surface starting from the polished rod to the prime mover. The losses e.g. include friction in the stuffing box, the unit´s structural bearings or the speed reducer. [13]

The energy losses in an electrical motor are classified in mechanical and electrical losses. Mechanical losses occur in e.g. bearings due to friction. The electrical losses include iron and copper losses, which result in heating. Usually an overall efficiency is used to represent all losses in the motor. For average electrical motors the range is 85% to 93%. [13] (See **eq.6**)

Consequently the formula for the overall system efficiency is reached [13, p. 102]

$$\eta\ system = \eta\ lift \times \eta\ mech \times \eta\ mot \qquad (6)$$

The following abbreviations stand for:
η system= overall system efficiency
η lift= lifting efficiency
η mech= mechanical efficiency of pumping unit and speed reducer
η mot= overall efficiency of the electrical motor

The oil production costs of the LRP are with 6.2 $\$/m^3$ (39 \$/bbl.) as shown in *Figure 27* higher than the conventional beam pump with 2.8 $\$/m^3$ (17.6 \$/bbl.). This is due to the lower system efficiency of approximately 10% for the LRP compared to the 27% for the conventional beam pump. As the motor power losses and gearbox power losses are higher with the LRP the overall system efficiency is lower than the system efficiency of the conventional pumping unit.

It cannot generally be assumed, that the LRP is the higher power consumer, because till now only this comparison in terms of energy consumption has been carried out. Nevertheless, it can be stated that at least the bigger units (86 in. stroke length and bigger) are prone to higher energy consumption. This statement will be considered in the LRP Standardization Recommendation6.1

Costs

In terms of costs, *Table 11* gives an approximate price range for the pumps. In particular conventional beam pumping units were chosen from Suplac, where also LRPs are frequently installed. The unit price depends on the peak polished rod load, the maximum stroke length of the rod and automation, if any installations are utilized.[xviii] Highlighted in bold italic letters are the most similar ratings in terms of polished rod load and stroke length. The CPU has the advantage of changing the position of the crank shaft and therefore reduce the stroke length so that an actual CPU (e.g. C-80-119-64) with a stroke length of 64 in. can get to a stroke length of 42,5 in. by using the third out of 3 crank hole numbers.[xix] Generally speaking the LRP is the more economic unit with its lower price for smaller sizes up to approximately 7 tons, but more expensive for bigger units. If automation is not required (no pump off conditions present), the conventional pumping unit is the cheaper option for the following sizes.

[xviii] *See 3.2.1 (description of the conventional beam pumping unit) for detailed information about automation*

[xix] *Units were chosen from Vulcan S.A. Pumping Units for Oil Extraction Catalogue*

Table 11: Cost comparison LRP and Conventional Beam Pump

Unit	**Relevant Model Type**	**Max polish rod rating [to.] / Max stroke length [m]**	**Cost [€]**	**Automation [€]**	**Total cost [€]**
Conventional Pumping Unit	80D-109-48	4.9 / 1.2	18,000	15,000	33,000
Conventional Pumping Unit	***80D-119-64***	***5.4 / 1.6***	***20,000***	***15,000***	***35,000***
Conventional Pumping Unit	***114D-133-54***	***6.0 / 1.4***	***26,000***	***15,000***	***41,000***
Conventional Pumping Unit	228D-173-100	7.8 / 2.5	44,000	15,000	59,000
LRP	L137H-184E-020	3.1 / 0.5	20,000	In cost included	20,000
LRP	L239C-254E-044	5.4 / 1.1	29,000	In cost included	29,000
LRP	***L381C-286E-044***	***6.8 / 1.1***	***35,000***	***In cost included***	***35,000***
LRP	***L381B-286E-056***	***6.8 /1.4***	***38,000***	***In cost included***	***38,000***
LRP	L472B-2586-100	10.7 / 2.5	77,000	In cost included	77,000

Design Comparison

In order to try to analyse two pumping unit systems with each other certain recommended input data has to be obtained which was provided by company Alfera. The design sheet includes input parameters such as target production, tubing and pump information, fluid properties, recommended unit type selection etc. and on the other hand calculated output parameters like SPM, system efficiency, required prime mover size, electricity consumption or rod string stress analysis for a particular well in Asset 3 in the Babeni field. The task here was to create a design sheet (done with RODSTAR-V 3.4.0) with similar input parameters and to compare the outcome data with the present LRP data. For a complete overview of the Input and output parameters, consult the original sources in Appendix C. As the Alfera LRP design for the Babeni field is confidential only a part of the calculated parameters can be viewed.

In *Table 12* recommended input data is presented. Note that not all parameters are listed in the table.

Table 12: Recommended input data

Input Design Data		Input Design Data	
Target Prod [BPD]	79	Plunger Diameter [in.]	1.750
Run Time [hrs/day]	24	Tubing Diameter [in.]	2.875
Rod String Length [ft.]	2,875	Pump Friction [lb.]	200
Fluid over Pump[ft.]	100	Pump Efficiency[%]	85
Upper Rod Diameter [in.]	0.875	Water Cut[%]	75
Lower Rod Diameter [in.]	0.875	API Oil Grade	23
Rod String Grade	D	Water Specific Gravity	1.050
Electrical Power Cost [$/Kwh]	0.100		

Table 13 demonstrates the recommended unit type for the input design data.

Table 13: Recommended unit type selection

Recommended unit type selection LRP		Recommended unit type selection CPU	
Unit Stroke Length [in.]	44.0	Calculated Stroke Length [in.] (3. Crank Hole Number)	42.5
Unit Model	L381C-286E-044	Unit Model	C-80D-119-64

Table 14 presents the calculated Output results for the LRP and the calculated results for the CPU

Table 14: Calculated Output Results

Calculated Output Results LRP		Calculated Output Results CPU
Prod.Rate [BPD]	79.1	80
Oil Production [BPD]	19.8	20
SPM	6.92	7.38
System Efficiency[%]	18.6	47.38

Motor rated Power [HP]	30	5
Gearbox Peak Load [%]	64.1	61
Monthly electrical Bill [$]	492	193
Upper Rod service factor [%]	56	38
Lower Rod service factor [%]	32	30

By comparing the two implemented pumping unit system output results with each other major, differences in for instance power consumption and system efficiency are observed.

As the motor power losses and gearbox power losses are higher with the LRP the overall system efficiency is lower than the system efficiency of the conventional pumping unit. This is due to the in subchapter 3.1 “Overview on the LRP” mentioned fact that during downward motion the motor is operated in braking mode (more electricity is consumed) and not just with the downward forces on the rack caused by for instance weight of the rod string and any fluid loads acting on the subsurface installation. For the LRP more HP is needed in order to lift the sucker rod string at the upstroke and because no counter weights are present.

Economic Assessment

For an economic comparison between the LRP L381C-286E-044 and the CPU C-80-119-64 economic assessment factors like OPEX, CAPEX, Net Present Value and Cumulative Discounted Cash Flow are used. The Net Present Value of an amount to be received at a future date equals the amount that would have to be put on compound interest (in this case 10% discount factor) at the reference date to give the given amount of a future date. [37]

“The Discounted cash flow method takes each future cash flow and reduces the amount by how much of that cash flow represents interest earned if its principal portion were invested at the time investment originated. Then, once all future cash flows have been discounted, to arrive at the net present value you then sum all discounted cash flows and subtract that amount from the original amount invested” [38]. The Cumulative Discounted Cash Flow is the sum of the Discounted Cash Flows till a certain year.

In the implemented scenario displayed in *Table 15* the Cumulative Discounted Cash Flows have been calculated for 7 years.

Based on assumed data OPEX and CAPEX were calculated for every year. The unit cost was implemented from *Table 11*. As it is an LRP installation no concrete pads are needed. For the installation of the unit onsite it was assumed that 4 workers with 7 hours each are necessary. Furthermore it was assumed that an hour would cost 70$ each. In addition power costs were implemented from the calculated design output for the LRP L381C-286E-044 for each year with an increase of 5% annually. Maintenance costs were assumed to rise 5% per year. For maintenance, subchapter 3.1.1.3 “Space, Civil Works and Maintenance” for the LRP was considered. As lack of data from PETROM, economic data for oil and water treatment was taken from OMV Austria being approximately 4.5 $/t for oil and approximately 1.2 $/m^3 for water which subsequently brings along operation costs of 0,86 $/bbl.

For the revenues a daily production rate of 20 bbl./d was assumed with a yearly decline of 20%. For the income in $ the royalty was already subtracted from the oil price (87 $) and the runtime for the pump was set to 350 days/year. For the cash flow the calculated yearly income was subtracted by the yearly occurring OPEX and CAPEX. As the last step the already mentioned Cumulative Discounted Cash Flows have been calculated for 7 years.

Table 15: Economic Parameters of the LRP L381C-286E-044

Year	0	1	2	3	4	5	6	7
Daily Production bbl./d (20%)	0	20	16	13	10	8	7	5
Income [US $]		609.000	487.200	389.760	311.808	249.446	199.557	159.646
OPEX [US $]								
Maintenance (5%)	350	368	386	405	425	447	469	492
Power Cost (5%)	5.904	6.199	6.509	6.835	7.176	7.535	7.912	8.308
Treatment Cost	0	6.020	4.816	3.853	3.082	2.466	1.973	1.578
CAPEX [US $]								
Cost unit	35.000	0	0	0	0	0	0	0
Concrete pads	0	0	0	0	0	0	0	0
Deploy and install unit	1,960	0	0	0	0	0	0	0
CAPEX	36.960	0	0	0	0	0	0	0
OPEX	6.254	12.587	11.711	11.093	10.684	10.448	10.354	10.378
Cash Flow	-43.214	596.413	475.489	378.667	301.124	238.999	189.204	149.268
Cumulative CF	-43.214	553.199	1.028.688	1.407.356	1.708.480	1.947.478	2.136.682	2.285.950
Discount Factor	1,00	0,91	0,83	0,75	0,68	0,62	0,56	0,51
DCF	-43.214	542.194	392.966	284.498	205.672	148.399	106.800	76.598
Cumulative DCF	-43.214	498.980	891.946	1.176.444	1.382.116	1.530.516	1.637.316	1.713.914
discount factor [%]	10							

Table 16 outlines the Cumulative Discounted Cash Flows for 7 years. For this calculation a similar progression to the LRP Cumulative Discounted Cash Flow calculation has been implemented. The unit cost of the CPU C-80-119-64 was taken from *Table 11* and is equal to the one of the described LRP. Furthermore the CPU is in need of concrete pads and the installation costs of the unit onsite clearly outline a higher CAPEX than the LRP due to the longer time duration of the installation and the workers needed onsite. Due to the fact that for every pumping unit different maintenance procedures may be prosecuted (e.g. spare part change) a general value for spare parts change per year of 1350 $ was estimated plus the aligned disassemble/ reassemble time. In addition power costs were implemented from the calculated design output for the CPU C-80-119-64 for each year with an increase of 5% annually. Treatment costs, daily production and income were handled similarly to the LRP economic assessment described earlier.

Table 16: Economic Parameters of the CPU C-80-119-64

Year	0	1	2	3	4	5	6	7
Daily Production bbl./d (20%)		20	16	13	10	8	7	5
Income		609.000	487.200	389.760	311.808	249.446	199.557	159.646
OPEX [US $]								
Maintenance(5%)	1.700	1.785	1.874	1.968	2.066	2.170	2.278	2.392
Power Cost (5%)	2.316	2.432	2.553	2.681	2.815	2.956	3.104	3.259
Treatment Cost	0	6,020	4,816	3,853	3,082	2,466	1,973	1,578
CAPEX [US $]								
Cost unit	35.000	0	0	0	0	0	0	0
Concrete pads	10.000	0	0	0	0	0	0	0
Deploy and install unit	6.720	0	0	0	0	0	0	0
CAPEX	51.720	0	0	0	0	0	0	0
OPEX	4.016	10.237	9.244	8.502	7.964	7.591	7.354	7.229
Cash Flow	-55.736	598.763	477.956	381.258	303.844	241.855	192.203	152.417
Cumulative CF	-55.736	543.027	1.020.984	1.402.242	1.706.086	1.947.941	2.140.144	2.292.560
Discount Factor	1,00	0,91	0,83	0,75	0,68	0,62	0,56	0,51
DCF	-55.736	544.330	395.005	286.445	207.530	150.173	108.493	78.214
Cumulative DCF	-55.736	488.594	883.599	1.170.044	1.377.574	1.527.747	1.636.240	1.714.454

Economic Assessment Results

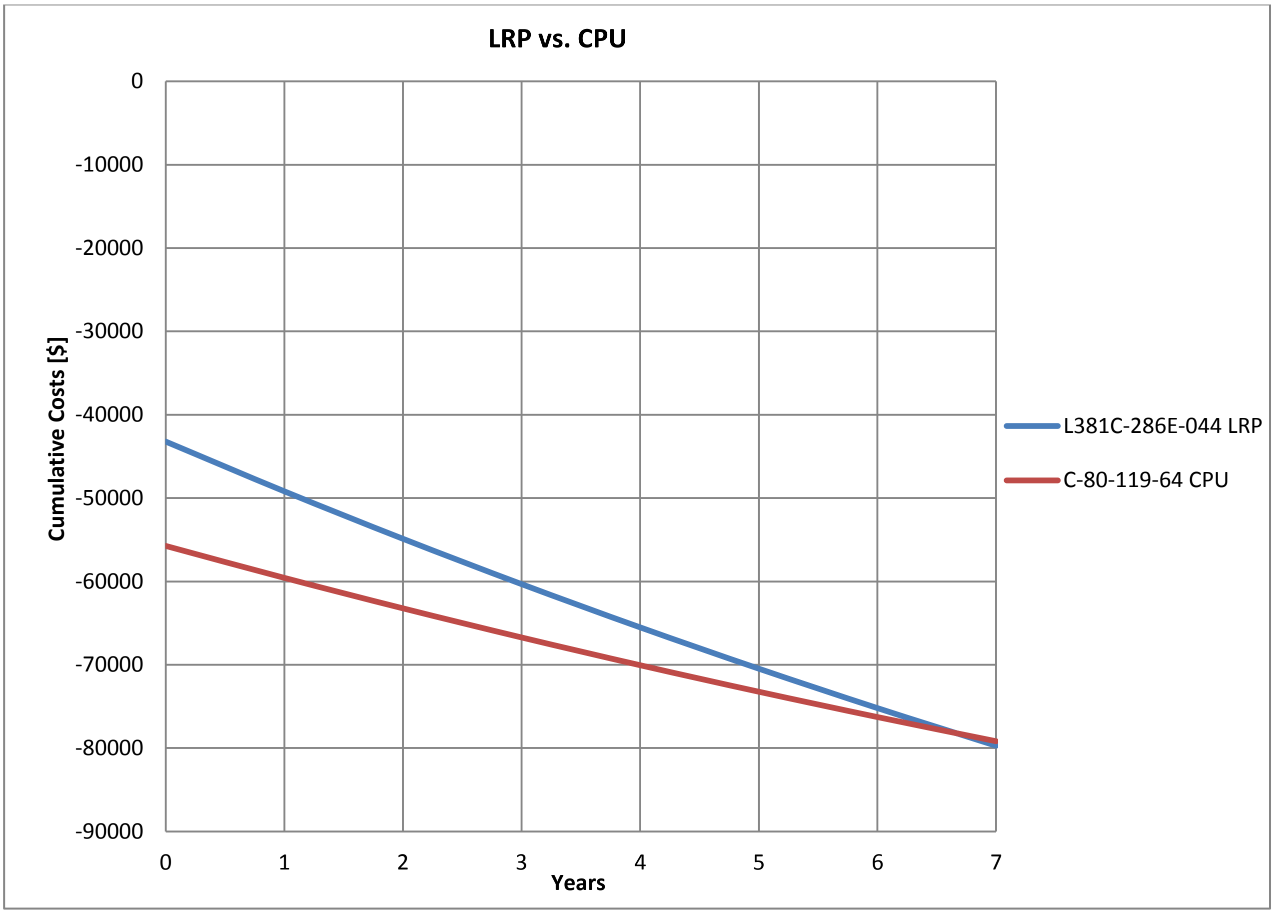


Figure 28: Cumulative Costs for particular LRP and CPU

For better visualization the income was excluded, because daily production, oil price, treatment costs and pump run time of the two pumping units are equal. *Figure 28* outlines the cumulative cost trend line after each year. The LRP is presented in the blue line, whereas the CPU is recognized in red. This graphical representation of the cumulative costs after each year displays that after a period of 7 years the described LRP model would be less economic and the portrayed CPU would be the more profitable choice in terms of costs. To sum up, the recommended implementation of this particularly described LRP in this scenario is economic up to a period of 6 years. This makes this LRP a good candidate for wells with limited life expectancy which are in many cases Pump Off Condition wells. In addition the utilization of an LRP becomes relevant when it comes to well to well move for temporary installations and the installation in remote locations. Moreover, since the full installation of the unit can be executed within a couple of hours (unit is mounted directly on the wellhead, no concrete pads), this strengthens the argument which was mentioned above.

3.2.1.8 Space, Civil Works and Maintenance

The size of a conventional pumping unit is bigger than any LRP model. In terms of obtrusiveness the conventional pumping unit's size is a drawback in populated and farming areas. The average foot print (pumping units from 7to.-15to.) of a conventional pumping unit comes with a 9 m length and 3 m width. [33, pp. 8-10] The noise level is categorised as fair and the noise level for urban areas is moderately high. [13]

To grease and maintain an oil well pumping unit, a person (or more than one person) is required to service ten (10) greasing nipples as seen on the left diagram below (*Figure 29*). The unit is stopped and a ladder or other device is used to climb the unit and grease. [39]

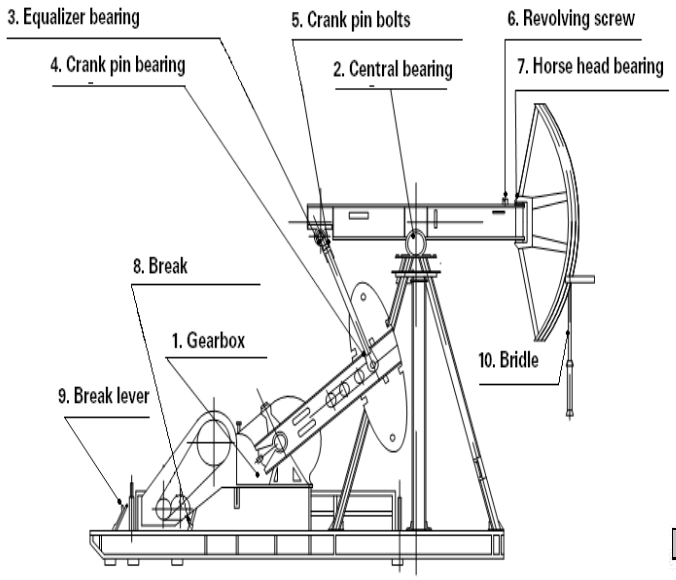


Figure 29: Multiple greasing points for conventional PU

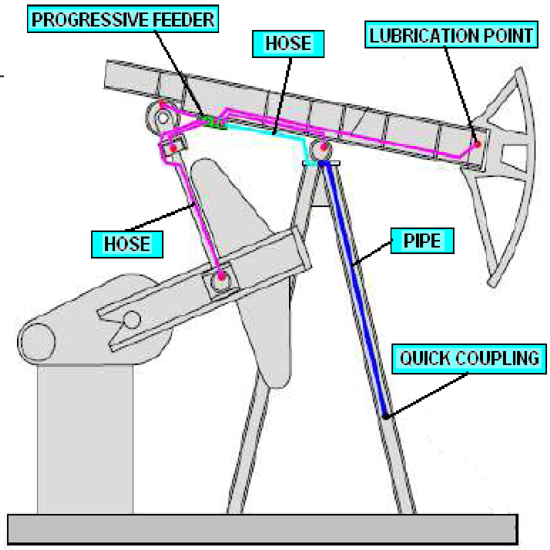


Figure 30: Single injection point greasing system

For a safe and continuous operation following parts are to be **greased every six months or after approximately 4.000 operating hours**

- Center bearing
- Equalizer bearing
- Gear reducer
- Crank pin bearing

At least every twelve months or after approximately 8.000 operating hours

- Horse head bearing
- Break lever
- Revolting screw

As an alternative a centralized greasing system has been designed to distribute grease from a single, easy accessible, injection point to all greasing points of the pumping unit. This is done by using a quick coupling, a progressive feeder and multiple hoses connected to greasing points. For a better visual understanding see *Figure 30* on the right. The grease is injected using a pneumatic high pressure pump. The system can be easily installed by two trained specialists (OMV PETROM maintenance people) in four hours. The centralized greasing system affects only bearing greasing and not gear box lubrication. Gear box lubrication was and is a separate maintenance procedure which may or may not take place at the same time as the automatic greasing procedure. No additional maintenance is required on the pumping unit after the system is installed. Pumping units use all season oil so there is no need to change the oil according to the seasons. [39]

3.2.2 The Long Stroke Pumping Unit

The long stroke pumping unit for sucker rod pumps and its construction is completely different from the conventional beam pump mechanism and any other pump. What makes this unit unique is the long polished rod stroke length. Here, the “Rotaflex” unit manufactured by Weatherford is used to describe this type of pump system.

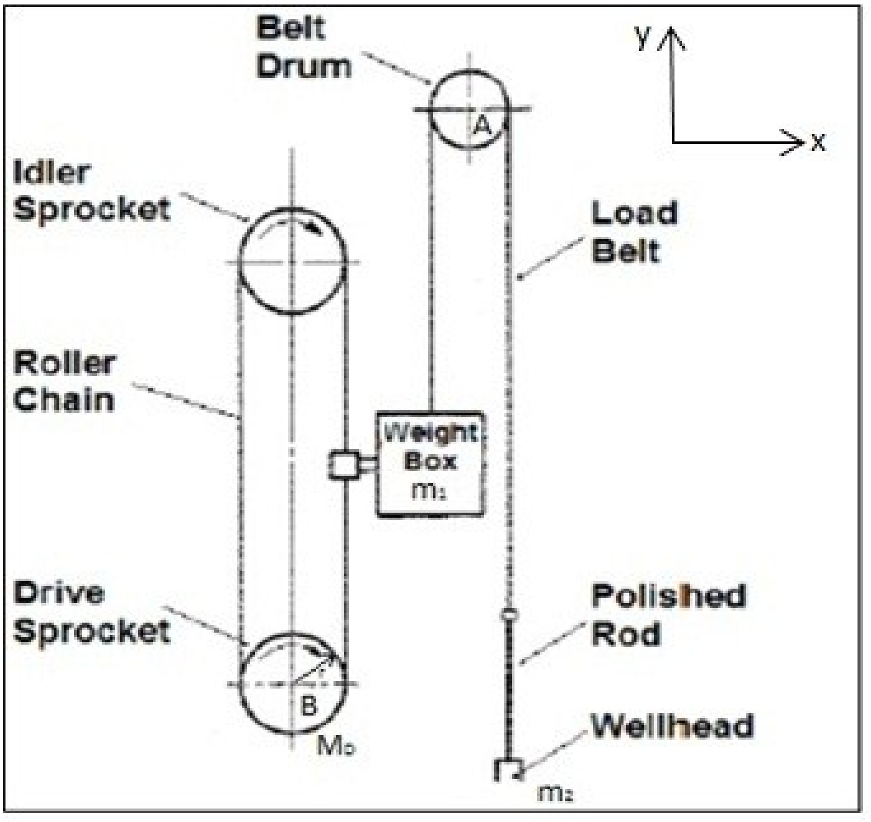


Figure 31: Main parts of “Rotaflex” unit

The following abbreviations stand for:

m_1= Mass Weight box

m_2= Mass Pump + Liquid column

r= radius

M_D= Drive Moment

$F_1 = m_1 \times g$	$\sum F_x = 0 \qquad 0=0$
$F_2 = m_2 \times g$	$\sum F_y(A) = 0 \qquad F_A = F_1 + F_2 + F_D$
$F_D = M_D/r$	$\sum F_y(B) = 0 \qquad F_B = F_2 - (F_D + F_1)$
	$\sum M(B) = 0 \qquad M_D + F_1 \times r - F_2 \times r$

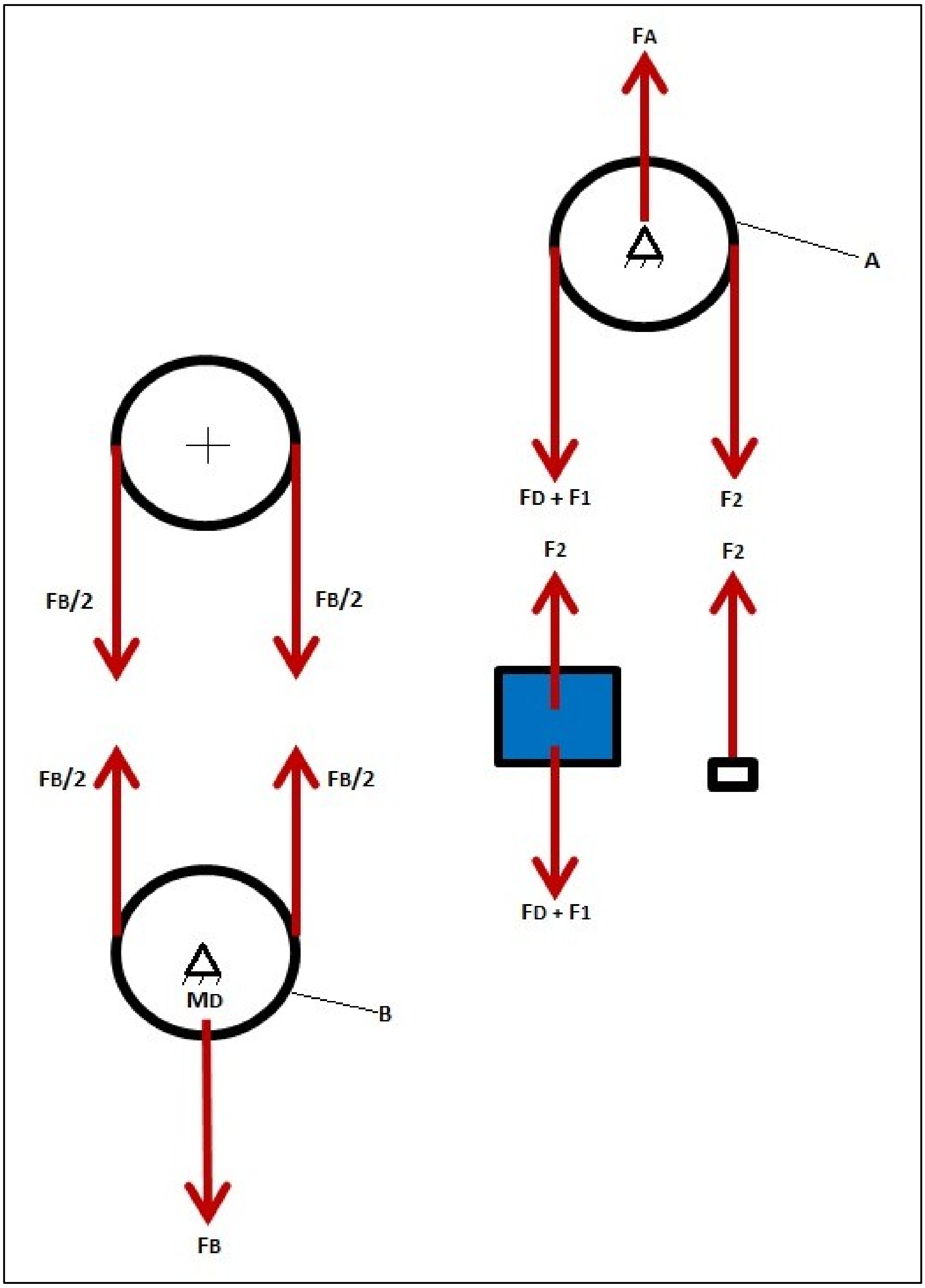


Figure 32: Forces acting on the “Rotaflex” pumping unit

Figure 31 demonstrates a schematic drawing of the main parts of the “Rotaflex” unit and its function [28, p. 1] and *Figure 32* shows the forces acting on the pumping unit.

> *“The unit is driven by a pumping unit gearbox via the drive sprocket of a vertically arranged chain assembly with an idler sprocket situated vertically above the drive sprocket.”* [28, p. 1]

The roller chain, which is driven by the drive sprocket, moves the weight box which is connected to one of the links of the chain. The weight box can only progress vertically. The polished rod is connected to an elastic load belt that runs on a belt drum that is located higher than the Idler Sprocket, so that the polished rod loads produce vertical forces in the belt. The second vertical end of the load belt is connected to the weight box. The weight box holds *“the pumping load on the polished rod as well as the counterbalance load, because it contains the counterweights of the unit”* [28, p. 1]. The mechanism of the “Rotaflex” is fully mechanical and the prime mover helps the unit to get a constant direction of rotation, while as the reversal of polished rod up or downstroke happens automatically.

3.2.2.1 Specifications and Application Criteria

In *Table 17*, provided by the oilfield service and equipment company Weatherford, “Rotaflex” specifications, relevant for useful comparisons with the LRP are listed. With the recorded features it is easier to compare the “Rotaflex” with the LRP in the next subchapter to come. For a complete overview of the “Rotaflex” models, consult the original source in Appendix D.

Due to the immense stroke length difference, it is not possible to have a 1:1 comparison between a LRP and a “Rotaflex” pump. As already mentioned the “Rotaflex” has different operation areas, meaning deep wells with high volume production whereas the LRP is mostly used in relatively shallow wells in PETROM where a big stroke length is not needed.

Table 17: “Rotaflex” specifications [40, p. 3]

Model Number	**Max.stroke length [in.] ([mm])**	**Max.Load at the polished rod [lbs.] ([to.])**	**Pump Speed [SPM]**
900	288 (7315)	36,000 (16)	4.50
1100	306 (7772)	50,000 (22.6)	4.30
1150	366 (9296)	50,000 (22.6)	3.64
1151	366 (9296)	50,000 (22.6)	3.75

The “Rotaflex” is very well suited for:

- Deep wells
- Wells with high volume production potential

3.2.2.2 "Rotaflex" vs. LRP

Figure 33: Image of "Rotaflex" Long Stroke Pumping Unit [40, p. 1]

Depending on the "Rotaflex" model (example in *Table 17*), the stoke length goes from 7.3 m (288 in.) to 9.3 m (366 in.) for sucker rod pumps and has the capacity to pump from greater depths. Stable velocity and few SPM increase the unit life including the rod string and the downhole pump. The long stoke length (*Figure 33*) admits less cycles and reversals than the LRP, ensuring an increased service life due to less cycles per time unit. As the stroke lengths are long, the large downhole stroke provides a better compression ratio to help eliminate gas lock problems. [40] [41] See subchapter 3.2.1.2 "Usage of Automation3.2.1.2" for the occurrence of phenomena of gas locking.

In terms of costs there is a drastic difference in purchasing expenses. Depending on the model type, the specifications differ from each other.

Table 18:"Rotaflex"/ LRP cost comparison

Unit	Relevant Model Type	Max polish rod rating [to.] / Max stroke length [m]	Cost [€]
"Rotaflex"	900	16 / 7.3	100,000
LRP	L767B-2587-100	13.6 / 2.54	81,000

A "Rotaflex" 900 model with a 42 in. heavy duty load belt, 36,000 lbs. (16 to.) polished rod load, 9400 lbs. counterweight and maximum stroke length of 288 in. (7.3 m) costs about

100,000 Euros. The most costly LRP that has been purchased by PETROM had a surface stroke length of 100 in. (2.5 m) and a polished rod load of 30,000 lbs. (13.6 to.) [xx] and cost close to 81,000 Euros.

3.2.2.3 Space, Civil Works and Maintenance

The "Rotaflex" pumping units are constructed of large and heavy moving parts. Therefore a hoisting system is needed during installation of the pumping unit. A hoisting supervisor should give directions for all hoisting operations. Furthermore, a 3 man crew with truck and tools are needed for the installation. Due to the geometry of the "Rotaflex" pumping unit, it must be placed so that the load belt is directly over the center of the well. The concrete base should be of suitable material to carry a minimum of 125,000 pounds for the 900 type and 175,000 pounds for the 1100, 1150 and 1151 type. [42, pp. 5,8] The average footprint is 7 m length and 2.5 m width.

With periodical maintenance according to the recommended schedule, the life of the unit can be extended and costly down time can be prevented. Visual inspections are to be made routinely.

For the gearbox:

- Inspect the fluid level at the sight glass regularly. A sample of the lubrication is taken and a visual inspection is performed every 6 months.
- Check gear tooth condition for abnormal wear.
- Change the lubrication in the gear reducer after the first 1,000 hours and then every year.
- Routinely check for leaks. Seal replacement is required if a leak develops that exceeds one cup per week [42, p. 18].

Chain and Sprockets:

- The chain and sprockets are pre-lubricated at the factory. The chain reservoir is fitted with a drain plug to be emptied when needed.
- It is recommended to change the lubrication in the sump once a year [42, p. 18].

The periodic maintenance service requirements are:

- Grease every six months until old grease is disposed out of the grease relief fitting. This is to insure that an amount of new grease has entered the bearing cavity.
- Inspect the seals every 6 months to insure no loss of grease and these seals have not lost their sealing capability [42, p. 18].

[xx] *See Table 24: LRP delivered until 1st of Nov.2012"*

3.2.3 Hydraulic Pumping Unit

Another type of artificial lift system is the Hydraulic pumping unit. This type of pumping unit is being produced by different manufacturers (e.g. Weatherford, Cameron, HRP International, Lufkin or Sivam) based on the same principle. Sivam´s[xxi] "Powerlift" has been chosen here as a comparison to the LRP and it could be used in PETROM production operations in the future as well.

3.2.3.1 Overview and Working Principle

The Powerlift contains two major components seen in *Figure 34* on the following page:[xxii]

- **The tower**, as the first component, which is attached above the wellhead. The tower features a hydraulic cylinder and the rod string is connected to the hydraulic cylinder with an actuator. Limit switches control the lift and decent speed of this actuator.
- **The power unit** as the second major component includes the prime mover, hydraulic system and controllers. The two components are connected by hydraulic lines.

The Powerlift Unit is easy to rig up and is, in comparison to a conventional beam pump, much lighter, but can produce the amount of force essentially needed in the well without peak torque limitation as no gearbox is installed. The Powerlift comes in different sizes and therefore in different maximum stroke lengths, which are bigger compared to the classical pumping unit, so if a conventional beam pumping unit is run at a standard speed with a certain production volume, the Powerlift Unit can produce the same production volume with less SPM at half of the speed with a bigger stroke length. Due to the lower SPM and the long stroke length a high lifetime is expected [43]. The pump is able to lift larger pump plungers, which means higher volume rate capacities for the whole system [44].

[xxi] *http://www.sivam.com/*

[xxii] *Gathered photo from Marco Antonacci,Sivam s.r.l. Sales& Service Representative, on 07.12.2012*

Figure 34: Powerlift Unit

The “Powerlift” working principle is outlined best for a full pump cycle. The unit does not contain any mechanical switches and only the position of the piston regulates the change of directions of the flow, meaning the opening and closing of the hydraulic circuits, at position A and B (see *Figure 35*) [43, p. 2].In order to understand the principal function of the Powerlift Unit, the down and upstroke movement of the piston is described as follows.

During the downstroke the rod string and the piston are travelling downwards into the cylinder due to gravity. The hydraulic oil below the piston, which is pictured in yellow in *Figure 35* on the next page, is forced back to the hydraulic pump under a pressure P1. The electrically driven hydraulic pump raises the oil under a differential pressure P2 to the accumulators. There, the oil is deposited under a total pressure P1+P2. [43]

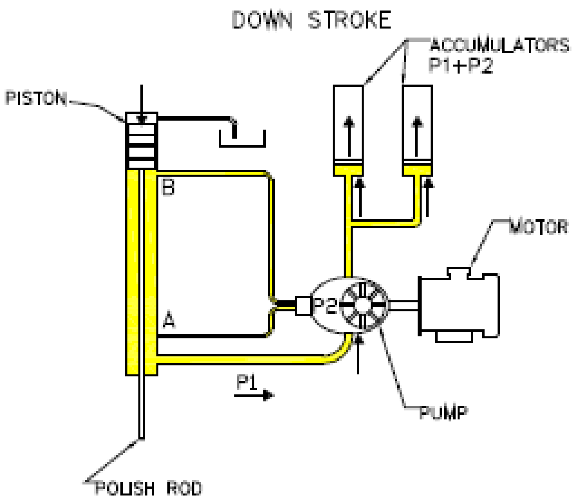


Figure 35: Downstroke of a Powerlift Unit [45]

When the rod string including the piston travels down during the downstroke, it shuts the hole which is shown in *Figure 36* at (A). After the downstroke is completed the oil stored in the accumulators flows in the opposite direction into the hydraulic pump and so the pump boosts the oil under a differential pressure P3. The oil now lifts the piston through the cylinder under a total pressure of P1+P2+P3. During upstroke the piston shuts the hole which is illustrated as (B) in *Figure 36* below. The pressure increase controls a reverse motion of the hydraulic pump and the whole cycle is repeated with the rod string going downwards again. [43]

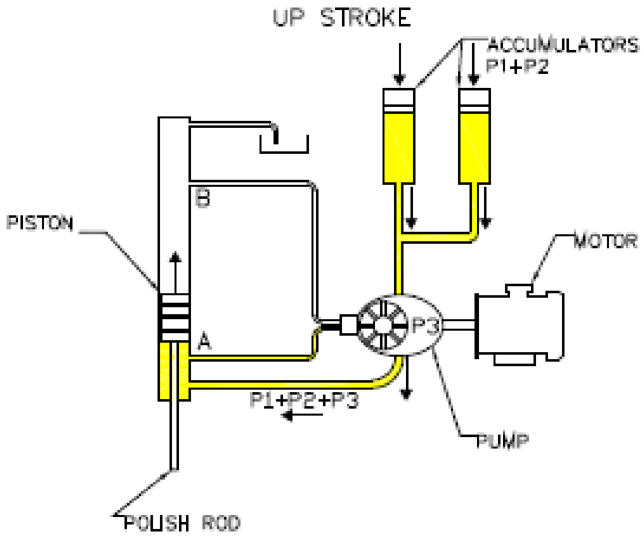


Figure 36: Upstroke of a Powerlift Unit [45]

Generally speaking, Hydraulic Rod Pumps (HRP) are equipped with a tower mounted hydraulic cylinder and is moved with a non-counterbalanced power unit. The HRP comes in different stroke length ranges and categories of stroke length.

A 120 in. stroke length is considered as short stroke where as a 240 in. is noted to be a long stroke length unit. An ultra-long stroke length is given when the stroke is at 336 in.. No more leaks can occur at the surface, because there is no stuffing box anymore and requires no special wellhead or adapters (see *Figure 37*). The rod string fatigue is reduced, because of the slower traveling speeds and because of the slower strokes per minute the traveling and standing valves of the subsurface pump reduce wear. Due to the longer stroke length, the subsurface pump gets higher compression ratios which help to reduce gas locking.

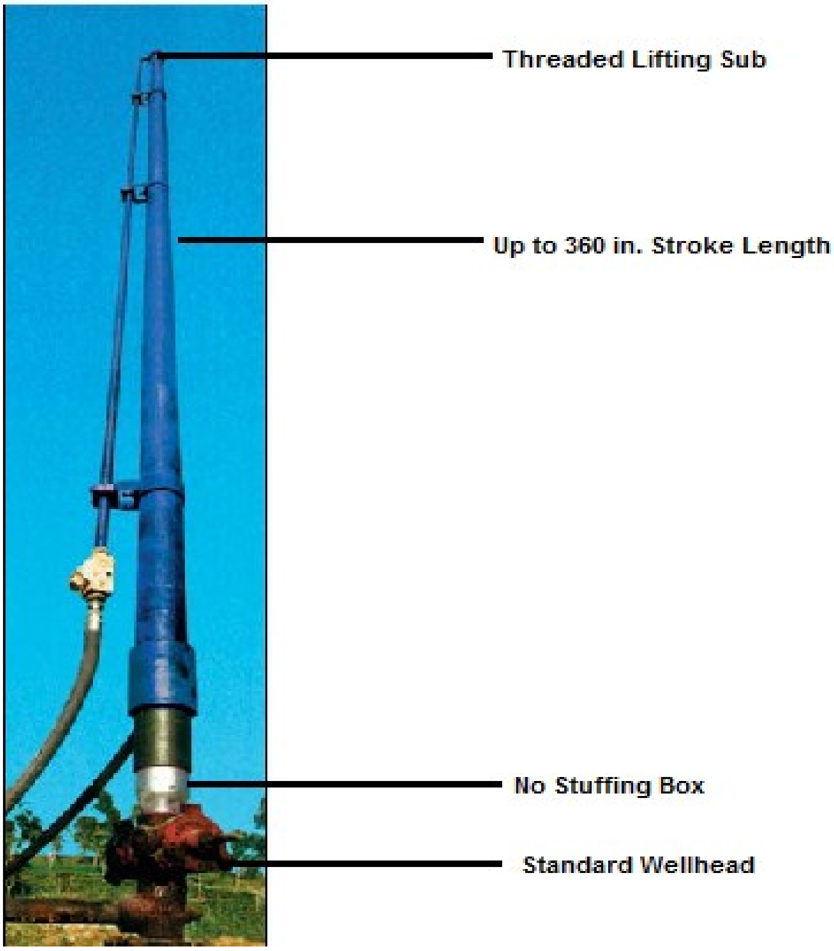


Figure 37: Hydraulic Rod pump, surface equipment [44]

The Powerlift Unit is split into three different categories, which are called either small unit, medium unit or large unit depending on the maximum stroke length. Each model has its own individual maximum stroke length, maximum polished rod load and pump speed. (*Table 19*)

Table 19: Powerlift Unit technical data [43]

Model	**Max.stroke length [in.] ([mm])**	**Max.Load at the polished rod [lbs.] ([to.])**	**Pump Speed [SPM]**
Small Unit (PL 165)	240 (6096)	24250 (11)	3
Medium Unit (PL 270)	240 (6096)	24250 (11)	4
Medium Unit (PL 300)	256 (6500)	24250 (11)	4
Large unit (PL645)	360 (9144)	30865 (14)	4
Large unit (PL1020)	360 (9144)	39680 (18)	6

In order to operate the hydraulic cylinder, a hydraulic power unit is needed. Hydramold, a Romanian hydraulic power equipment producer, presented to PETROM its hydraulic power unit with electric, hydraulic and automation features, but this thesis will not examine it further in detail. For information about the Power Unit, consult the original source in Appendix E.

3.2.3.2 Application Criteria

Main advantages and limitations of the Powerlift Unit are discussed point by point below. After analyzing the pros and cons of the pump it is up to the production engineering department to weigh the odds for the Powerlift Unit to be chosen as the ideal ALS for a particular well.

- The Powerlift Unit is one of the ideal solutions for heavy and viscous oils. The unit can make long strokes, can go at low SPM and keep the same production. Upstroke and downstroke can be different and the unit offers a progressive speed starting, which, in other words, means, it starts with low speed and by time reaches gradually a progressive increase.
- The length of action for assembling a Powerlift Unit is done in a couple of hours.
- As already mentioned in the working principle, because of the long strokes that HRP makes, it causes less wear to the system.
- The unit does not possess a gear box and therefore is not exposed to torque forces and is applicable for deep wells [43, p. 4].
- The main disadvantage is the high price of the unit (*Table 20*), where the Powerlift Unit is compared with the LRP.

3.2.3.3 Hydraulic Pumping Unit vs. LRP

The most significant difference that can be observed at first sight are costs of the two units and the stroke length disparity the Powerlift Unit has compared to any LRP unit. Other than the price, it is not possible to measure polished rod load versus stroke position with the hydraulic pumping unit, because no stuffing box is placed in order to install a pump off controller. Pump off conditions are only measured with volumetric production measurements.

Both the LRP and the hydraulic pumping unit don’t require a concrete base, but the hydraulic pumping unit needs additional space for the power unit.

Table 20 lists a general comparison of the two pumping unit types. In the example LRPs are compared with the (PL 300) Powerlift Unit from Sivam.

The Powerlift Unit shows following pump characteristics:

- 11 tons(24640 lbs.) peak polished rod load (with 90 mm ID cylinder)
- 6.5 meters max stroke (256 in.). Can be adjustable
- 4.1 stroke per minute maximum speed (at maximum capacity and maximum stroke).
- 90 KW electric Engine, 380V, 50-60Hz 3 phase.

Table 20: Cost comparison of the LRP vs. Powerlift Unit[xxiii]

Unit	Model Type	Max polish rod rating [to.] / Max stroke length [m]	Cost [€]
Powerlift	Medium Unit (PL 300)	11 / 6.5	100,000
LRP	L381C-286E-044	6.8 / 1.1	36,000
LRP	L381B-286E-056	6.8 / 1.4	37,000
LRP	L472B-2586-100	10.7 / 2.5	77,000

Another hydraulic pumping unit with the same working principle as the Powerlift Unit is Weatherford's VSH-2 Hydraulic pumping unit, which could be also alternatively used for PETROM's necessity. The hydraulic pumping unit has various model specifications. Its surface stroke length ranges from 1.5 m to 3.8 m and its peak polished rod load lies between 9 to. till 18 to. depending on the model type. [46, p. 15] A price comparison of the LRP vs. the Powerlift Unit vs. the "VSH-2" is depicted graphically in *Table 21*.

Table 21: LRP /"VSH-2" /" Powerlift Unit" cost comparison

Unit	Relevant Model Type	Max polish rod rating [to.] / Max stroke length [m]	Cost [€]
LRP	L381B-286E-056	6.8 / 1.4	38,000
LRP	L472B-2586-100	10.7 / 2.5	77,000
Weatherford	Mini-VSH (Mini-V)	9 / 1.5	49,000
Weatherford	VSH-2 120	18 / 3	85,000
Weatherford	VSH-2 150	18 / 3.8	86,000
Powerlift	Medium Unit (PL 300)	11 / 6.5	100,000

Similarly to the earlier discussed "Rotaflex" pumping unit in Chapter 3.2.2 "The Long Stroke Pumping Unit", the hydraulic pumping unit is made for deep wells and because of the long stroke length the hydraulic pumping units are mostly used for high oil producing wells and it is not possible to have a 1:1 comparison with the LRP.

xxiii *Note: The costs are approximate numbers related to the offer*

3.2.3.4 Space, Civil Works and Maintenance

The cylindrical tower of the unit is mounted directly on the wellhead, while the hydraulic power supply unit is positioned on site at a distance from the wellhead appropriate for the operating conditions. However, this depends on the available space and other operational requirements (e.g. required space and place of rig during well interventions).

> *"In any case, all handling operations must be performed by skilled personnel and in safe conditions. The operators involved must always keep a safe distance and pay particular attention to the operations".* [47, p. 11]

The internal cylinder of the tower is 90mm and the hydraulic power unit dimensions are 2.7 m length x 1.9 m width x 1.95 m height.
For the correct functioning of the Sivam Powerlift Unit, the following operations and maintenance checks must be carried out:[xxiv] (See *Table 22*)

Table 22: Sivam Powerlift Unit maintenance checks

Description	Visual Check	Replace
Aspiration Cartridge Filter	350h	2000h
Return Cartridge Filters	350h	1000h
Stuffing Box Gasket	350h	1500h
Oil Level	750h	4000h-7000h
Ventilation Cap	2000h	4000h

The oil has to be emptied completely out of the system every 1 to 1.5 years. Check the conditions of the oil in the system every 2000 hours of operation, through specific chemical-physical tests that ensure that the oil maintains its initial characteristics in time.

For Weatherford's VSH-2 Hydraulic Pumping Unit: [48]

- The hydraulic filter has to be changed every five to six months
- Inspect and tighten up wiring every month
- Inspect general wear every week
- Ensure proper manuals are in panels at all times
- Hydraulic oil samples at least once a year
- When in manual turn speed to a low setting
- Do everything slow and easy
- On new units, the hydraulic filter should be changed the 1st month

[xxiv] *Technical Discussion with Mr. Mario Di Berto from Sivam on 07.12.2012*

- Maintenance schedule calls for changing filter every 5-6 months, depending on operating conditions
- Hydraulic fluid should be sampled annually

3.2.4 Comparison of the Described Pumping Units in Brief

A comprehensive summary of the pumping unit systems are listed for the given field of interest. According to the value of the individual fields of interest a color is added for the respective pumping unit.

The following color abbreviations stand for:

Green	LOW	L
Orange	MODERATE	M
Red	HIGH	H

Table 23: General comparison of discussed Pumping Units

Field Of Interest	LRP	CPU	"Rotaflex"	Sivam HPU
Cost	M	M	H	H
Maintenance	L	M	H	H
Footprint	L	H	H	M
Depth	L	M	H	H
Volume	L	M	H	H
SPM	L	H	L	L
Civil work requirements	L	M	M	M
Power consumption	M	M	H	H

For a more comprehensive overview a few field of interest values have been put into a graph and compared between the different pumping unit types.

In *Figure 38*, 1 stands for LOW [L], whereas 3 stands for HIGH [H].

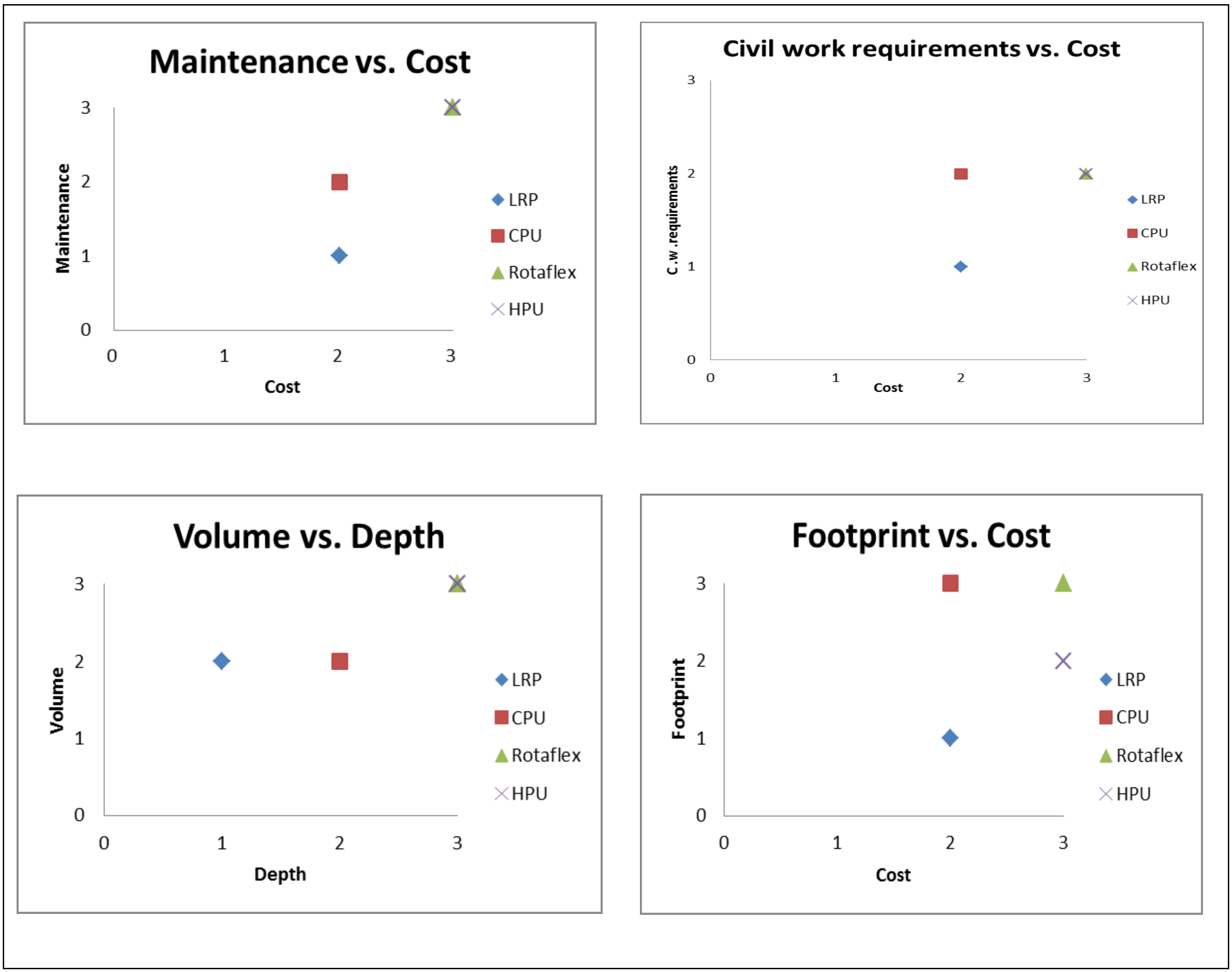


Figure 38 Overview of field of interest values between discussed Pumping Unit Systems

4 Selection Criteria of potential LRP candidates

Based on the standardization process of the conventional beam pumping units discussed in the subchapter 3.2.1.6 “General Selection Methodology” suitable selection criteria for LRPs need to be applied and in further steps data screening for selecting available well candidates has to be performed.

4.1 Selection Criteria of LRP´s Application in PETROM

Until the 1st of November 2012, 180 Linear Rod Pumps were delivered to PETROM. Most of the ordered units came with a stroke length of 44 in. (see *Table 24*)

Table 24: LRP delivered until 1st of Nov.2012

Nr	LRP name	pcs.
1	L137C-215S-044	30
2	L239C-254E-044	65
3	L381F-215E-032	2
4	L137H-184E-020	4
5	L239D-254E-044	1
6	L239B-256E-044	2
7	L239C-256E-044	3
8	L239C-215E-044	5
9	L137B-254E-044	10
10	L381C-286E-044	11
11	L381A-256E-056	11
12	L381B-256E-056	1
13	L381B-284E-056	1
14	L381B-286E-056	17
15	L381C-286E-056	4
16	L381D-286E-056	1
17	L381B-324E-056	4
18	L381C-324E-056	1
19	L472B-2586-100	3
20	L767A-2587-100	2
21	L472B-2578-100	2
	Total	180

In future, LRP model standardization has to be performed with the aim of reducing different LRP models used. When the depth and the production potential of the well are known an LRP model, which fits best according to the standardization, will be chosen.

In order to start a successful standardization process, the following LRP parameters have to be considered:

- Polished rod load
- Peak Torque rating
- Motor Power
- Stroke length
- Depth of the well
- Expected production
- SPM

Starting with the polished rod load, the peak polished rod load is dependent on the gearbox size and unit rated torque. Summarized in *Table 25* below is a list of model number and peak polished rod load.

Table 25: Peak polished rod force for LRP model numbers

Model Number	**Peak polished rod load in [to.] and ([lbs])**	
L073g-mmmm-032	1.7	(3750)
L137g-mmmm-(032 or 044)	3.1	(7000)
L239g-mmmm-(032 or 044)	5.4	(11900)
L381g-mmmm-(044 or 056 or 64 or 86)	7	(15430)
L472g-mmmm-(086 or 100 or 120)	10.7	(23590)
L767g-mmmm-(086 or 100 or 120)	13.6	(29980)

The individual Linear Rod Pump unit has only a certain polished rod force available, depending on the available torque specified by the supplier.

In *Table 26* below, the variety of LRP units used in PETROM with corresponding motor power ratings in HP can be seen.

Table 26: LRP Motor Power

Nr	LRP name	Motor Power
1	L137H-184E-020	25 HP
2	L381F-215E-032	10 HP
3	L137C-215S-044	10 HP
4	L239C-254E-044	15 HP
5	L239D-254E-044	15 HP
6	L239B-256E-044	20 HP
7	L239C-256E-044	20 HP
8	L239C-215E-044	10 HP
9	L137B-254E-044	15 HP
10	L381C-286E-044	30 HP
11	L381A-256E-056	20 HP
12	L381B-256E-056	20 HP
13	L381B-284E-056	25 HP
14	L381B-286E-056	30 HP
15	L381C-286E-056	30 HP
16	L381D-286E-056	30 HP
17	L381B-324E-056	40 HP
18	L381C-324E-056	40 HP
19	L472B-2586-100	60 HP
20	L767A-2587-100	60 HP
21	L472B-2578-100	50 HP

As an example, a well has been chosen and well data have been compared to see the difference between the calculated HP by RODSTAR-V 3.4.0 (see Appendix G for complete design) with a conventional beam pump and the recommended HP and LRP model selection by UNICO for the same well. With the input parameters of the conventional beam pump, UNICO's recommendations for the same well are seen in the *Table 27* below.

Table 27: RODSTAR design vs. UNICO's recommended design

Input parameters	**RODSTAR design for Beam pump**	**UNICO's recommended data**
Pump setting depth [m]	596	596
Recommended Pump model	Vulcan C-173-110-59	L239C-254E-044
SPM	5	6
Peak polished rod load [to.]	2.12	5.4
Stroke length [in.]	59	44
Pump volume efficiency [%]	85	85
System Efficiency [%]	22	15.9
Production rate [m3/d]	7	6.3
Motor rated power [HP]	10	15

As a result it can be said from the design comparison, that the peak polished rod load for the conventional pumping unit is set lower than the recommended LRP by UNICO. Furthermore, the LRP in the recommended UNICO design is equipped with a stronger motor and the system efficiency is lower than the conventional pumping unit. A similar example is illustrated in subchapter 3.2.1.7 "Conventional Beam Pumping Unit vs. LRP".

Practical approaches in choosing the right HP rating were done by picking the installed LRPs and by investigating the well candidates. In order to compare the calculated values with the real ones in the field, where each LRP was designed and ordered specifically for each well, an overview was created considering:

- LRP type
- Production rate [m^3/d]
- Well depth [m]
- SPM

Table 28: Overview of most commonly used LRP types

LRP type	Min. Depth	Max. Depth	Avg. Depth	Min.Prod	Max.Prod	Avg.Prod	Min.spm	Max.spm	Avg.spm	Horsepower
Model Number	(m)	(m)	(m)	(m3/D)	(m3/D)	(m3/D)	spm	spm	spm	HP
L239C-254E-044	120	380	190	2	27	13	3	8	5	15
L137C-215S-044	196	210	200	8	10	9	3	7	5	10
L381A-256E-056	150	540	215	6	27	17	4	6	5	20
L381B-286E-056	170	880	430	8	15	11	5	6	5	30
L137B-254E-044	140	220	191	5	30	19	3	10	6	10
L381B-324E-056	700	1000	900	3	10	7	3	7	4	40
L381C-286E-056	517	1230	910	5	16	8	5	8	7	30

After choosing the most significant LRP models and comparing them with the PETROM well data base (based on October 2012), certain HP trends depicted in *Table 28* are observed. The deeper the well and the bigger the stroke length, the higher the motor power [HP] has to be. Depending on the maximum depth, the production rate and maximum stroke length, a motor with its HP rating is designed by the supplier and delivered to PETROM.

To illustrate the above graphically, please refer to *Figure 39*. It shows a fluid flow [BPD] on the y-axis vs. well depth in [ft] on the x- axis. As already mentioned above, the deeper the well is and the higher the fluid flow, the more motor rated power is required by the pumping unit in order to lift the reservoir fluids to surface.

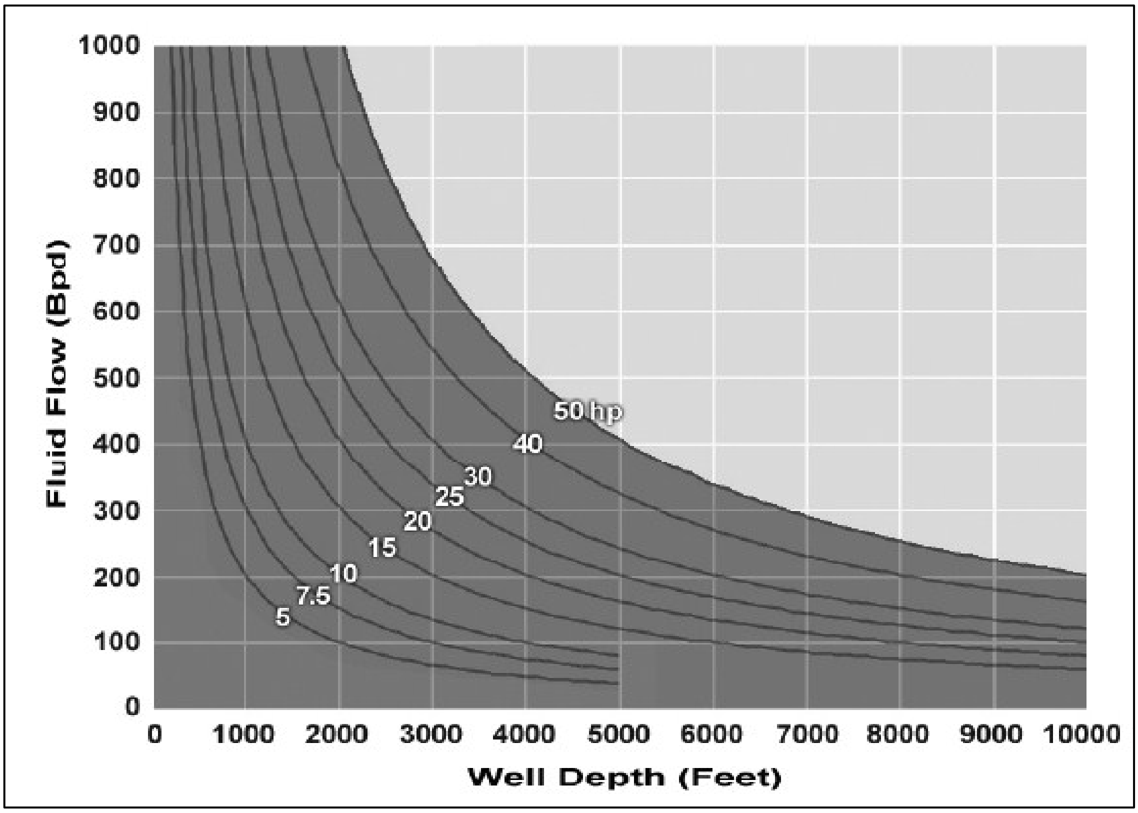


Figure 39: Fluid Flow vs. Pump Depth for various models [21, p. 12]

4.2 Selection Criteria Steps for Discussed Pumping Unit Systems

In order to select pumping units, the LRP in particular, it is important to take a closer look at the pump design which was developed by the American Petroleum Institute (API). A pump description key is explained in the *Figure 40* for designing downhole pumps [23, p. 26]. The biggest downhole pump diameter in terms of inch used by PETROM is 2.750 in. and this is also being considered in designing the individual flowrate versus depths charts for the different kinds of pumping units in the following steps to come.

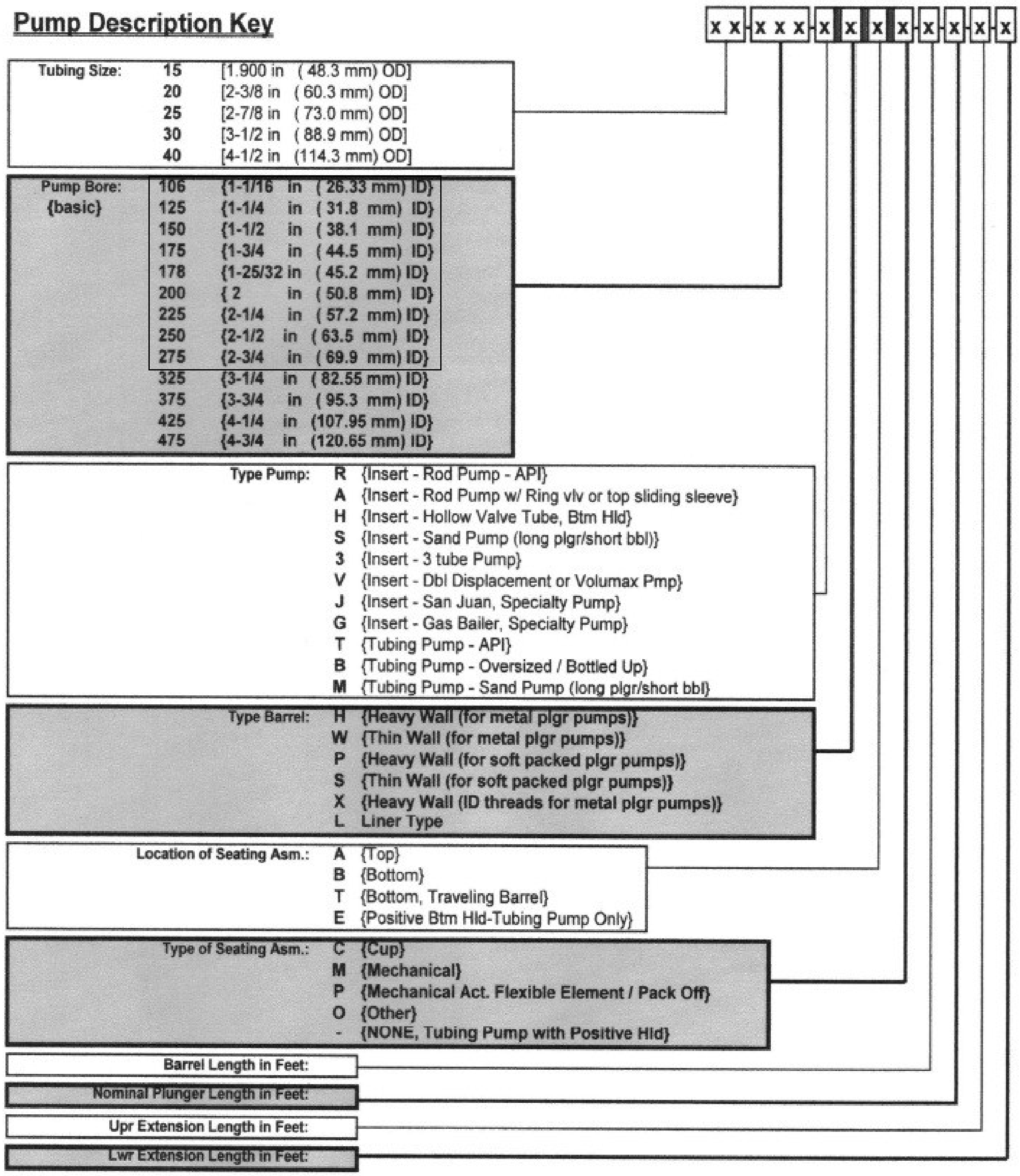


Figure 40: API Pump Description

4.2.1 Explanation how Graphs are developed to assess LRP Type Operating Range with an Example

Taking **eq.1**" $Pd=0.1166 \times Dp^2 \times Sp \times SPM$" into account, which describes the pump displacement, a pump displacement [BPD] vs. plunger size [in.] for a stroke length of 56 in. was created. Different SPM were chosen to comprehend the variation of pump displacement and the plunger size. 5 SPM is assumed to be a SPM minimum value and 12 SPM is adopted as the maximum value for SPM. With a bigger plunger diameter a downhole pump is able to lift more fluid and consequently the flowrate rises.

Table 29 shows the calculated results for different plunger diameters and different SPM, which are then plotted in *Figure 41* on the next page.

For a graphical depiction of flowrate vs. plunger size for a 32 in. and 44in. stroke length go to Appendix H.

Table 29: Flowrate vs. Plunger size for 56 in. stroke length data

Plunger diameter [in.]	Ap [in.]	Q Unit [BPD]	Q [BPD]; 5 SPM	Q [BPD]; 7 SPM	Q [BPD]; 9 SPM	Q [BPD]; 12 SPM
1,06	0,88	5,75	28,76	40,27	51,77	69,03
1,25	1,23	8,00	40,00	55,99	71,99	95,99
1,5	1,77	11,52	57,59	80,63	103,67	138,23
1,75	2,41	15,68	78,39	109,75	141,11	188,14
2	3,14	20,48	102,39	143,35	184,30	245,74
2,25	3,98	25,92	129,59	181,42	233,26	311,01
2,5	4,91	32,00	159,99	223,98	287,97	383,96
2,75	5,94	38,72	193,58	271,02	348,45	464,60

The plunger area is defined as follows: **eq.7**

$$Ap = \frac{Dp^2 \times \pi}{4} \qquad (7)$$

Where:

Ap= Plunger area, [in.^{2}]
Dp= Plunger diameter, [in.]

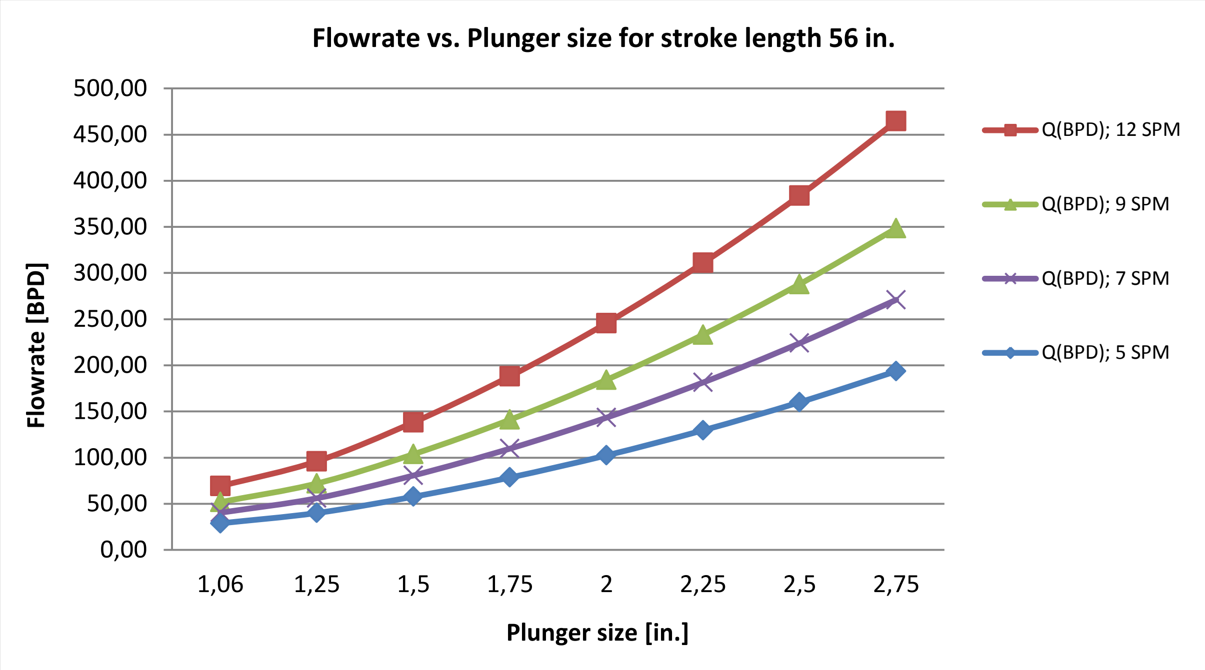


Figure 41: Flowrate vs. Plunger size for 56 in. stroke length

Generally speaking, PETROM's intention is to focus on detecting a flow rate vs. depth range for LRPs and examining the LRP range with other pumping units discussed in chapter 3.2 "Comparison with other Pumping Unit Systems".

It is furthermore beneficial to define the peak polished rod load to form a "Pump displacement vs. depth" diagram and to take notice of the general recommended LRP application area for PETROM and establish the application areas of the in chapter 3.2 mentioned pumping units.

For the minimum polished rod load (*F min*) following formula is defined: **eq.8** [30]

$$Fmin = L \times wr(2 - f) \qquad (8)$$

L= Length of the taper section, [ft]; taper section is the length of each sucker rod type in terms of size

wr= Average weight of the taper section, [lb/ft]

f= Mills acceleration factor, [-]

In the following equation the peak polished rod load (*F max*) is defined: **eq.9** [30, p. 21]

$$Fmax = Fo + L \times wr \times f \qquad (9)$$

Where:

L= Length of the taper section, [ft]
wr= Average weight of the taper section, [lb/ft]; see *Table 30* as an example
Fo= Fluid load on plunger, [lb]
f= Mills acceleration factor, [-]
The Mills acceleration factor gives reasonable load values for small pumps and medium pumping depths as in the case of the LRP illustrated in **eq.10** [30, p. 21]

$$f = 1 + \frac{Sp \times SPM^2}{70{,}500} \qquad (10)$$

Where:

Sp= Polished rod stroke length, [in.]
SPM= Pumping speed, [SPM]

The Fluid load on the plunger seen in eq.4 is calculated on the gross area of the plunger: **eq.11** [30, pp. 41,42]

$$Fo = 0.34 \times L \times Dp^2 \times SpGr \qquad (11)$$

Where:

Fo= Fluid load on the plunger, [lbs]
L= Dynamic fluid level, [ft]
Dp= Plunger diameter, [in.]
SpGr= Specific gravity of the produced fluid, [-]

Dp can be extracted from **eq.1**

$$Pd = 0.1166 \times Dp^2 \times Sp \times SPM \qquad (1)$$

After rearranging the Pump displacement equation following **eq.12** is gathered:

$$\mathrm{Dp} = \sqrt{\frac{\mathrm{Pd}}{0.1166 \times \mathrm{Sp} \times \mathrm{SPM}}} \qquad (12)$$

The buoyant rod string weight is described as follows: **eq.13** [30, p. 42]

$$Wrf = Wr(1 - 0.128 \times SPGr) \qquad (13)$$

Where:

Wrf= Rod string weight including buoyancy, [lbs]
Wr= Total rodstring weight in air, [lbs]
SpGr= Specific gravity of the produced fluid [-]

The rodstring weight in air (*Wr*) is dependent on the rod size and *Wr* values can be read from *Table 30* below. [30, p. 4]

Table 30: Rodstring weight in air

Rod Size (in.)	1/2	5/8	3/4	7/8	1	1 1/8	1 1/4
Weight in Air (lb/ft)	0.726	1.135	1.634	2.224	2.904	3.676	4.538

In order to get a peak polished rod load (*F max*) value, eq. 10, 11 and 12 have to be combined and added in eq.9 in order get the final expression *F max* from **eq.14**

$$Fmax = 0.34 \times L \times \left(\frac{Pd}{0.1166 \times Sp \times SPM}\right) \times SpGr + L \times Wr \times (1 + \frac{Sp \times SPM^2}{70{,}500}) \qquad (14)$$

4.3 Implementation Method for Pumping Unit Systems

Implementing the equations in chapter 4.2 “Selection Criteria Steps for Discussed Pumping Unit Systems”, in particular **eq.14,** into a meaningful method of obtaining pump displacement rates and peak polished rod loads *(F max)* by for instance pump depth, surface stroke length, SPM and pump diameter input, means establishing a system that allows the user to simulate the above described. In our case, QROD 2.4 provides the required steps for running a design of a pumping unit and constitutes the result outcomes.

In the following subchapters, a detailed description of the mentioned simulator shall be given and the design outcome will be presented in combination with pump displacement vs. depth plot depending on the pumping unit system in order so see the different pumping unit depth ranges [m] dependent on the pump displacement [m^3/d].

4.3.1 Description of Employed Simulator

QROD is a practical beam pumping design simulator. If a pumping unit including peak polished rod load and surface stroke length, rods or a pump size for a well is needed, the QROD design tool is useful.

> *“After the input data has been supplied appropriately for the problem at hand, the program mathematically simulates the motion of the surface unit.”* [49]

There are three primary design variables for a beam pumping system:

- The stroke length
- The pump diameter
- The stroke rate

The user has to change these three variables to achieve the desired design outcome. [49] The thesis objective is to minimize the peak polished rod loading of the chosen pumping unit in a matter, that the maximum pumping unit load with certain pump efficiency (0.90-0.95) is less than the already mentioned peak polished rod loading (PPRL) for a selected depth [m] and pump displacement [m^3/d]. If, for instance, the area of the downhole pump is reduced, meaning that another downhole pump is installed, the PPRL is also decreased. QROD also obtains a number of secondary design variables including unit type, rod string type or fluid specific gravity (0.891) that were implemented into the simulation.

It is practical to use the AutoCalc option, where the results are immediately updated and the changing effects are instantly seen in the outcome information. All modified input data and output information are depicted on a window for fast review by the user. Furthermore, the output can be enhanced by for instance dynamometer cards displayed in the same window. [49]

To understand the exact logic of the simulation process, a decision flow schematic describing how QROD was used is shown below

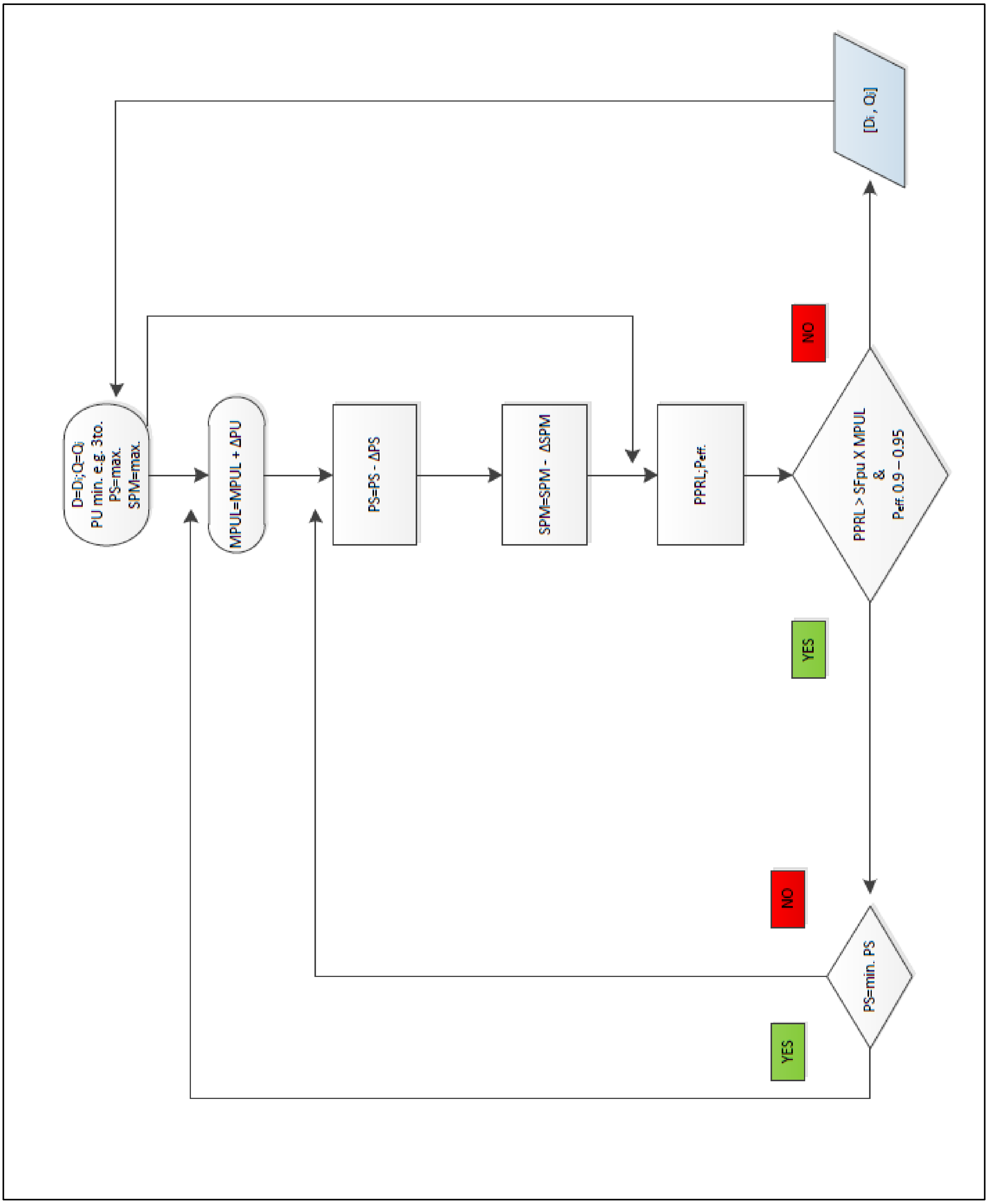


Figure 42: Decision tree schematic of QROD

The abbreviations from the decision tree schematic of QROD stand for:

max.=maximum
min.=minimum
D=Depth (predefined)
Q=Flowrate
PU=Pumping Unit: depending on the PU, the min. pumping unit load is applied, till MPUL for this PU is reached. Furthermore PU has to be changed to a bigger PU in order to continue the cycle
PS=Pumping Size
SPM=Strokes per minute
MPUL=Max. PU Load
PPRL=Peak Polished Rod Load
Peff.=Pump efficiency
SFpu=PU Safety Factor; 0.9
ΔPU=Incremental PU
ΔPS=Incremental PS
ΔSPM=Incremental SPM

In the following problem, the principle of how a pumping unit has been chosen for a certain depth and pump displacement (here flowrate) is described:

To make the procedure more logic the following details are given.

First the desired pump depth (D) is entered[xxv] and a intended target flowrate (Q) is selected. To start with, the smallest possible LRP size (PU min) with its appropriate stroke length is evaluated. Moreover the maximum plunger size (PS=max) is picked and the stroke rate is set to a maximum (in this thesis design the SPM is set to 10 SPM)[xxvi].

> *The starting depth is chosen to be 200 m. The LRP with a pumping unit load of 3 to. and the minimum surface stroke length of 32 in. is picked. A pump diameter of 2.750 in. is selected and the SPM set to 10.*

The next step is to evaluate if the peak polished rod load (PPRL) has been reached and sufficient pump efficiency is given.

> *The polished rod load is 3.281 lbs (approx. 1.5 to.), so there is still a buffer to reach the PPRL of 3 to.*

[xxv] *Note: The same depth intervals are chosen for every pumping unit system, in order to compare the entire pumping unit system outcome in one pump displacement vs. depth plot (200 m, 300 m, 500 m, 700 m, etc.)*

[xxvi] *Note: The SPM are pumping unit system dependent, meaning that the LRP and the conventional pumping unit had been set to maximum SPM=10. The HPU and the "Rotaflex" both have a maximum SPM=4 due to the long surface stroke length*

Furthermore the reached polished rod load has to be smaller than the maximum pumping unit load times a safety factor of 0.9 (PPRL>SFpu X MPUL), so the system is not overloaded.

In terms of the practical example, this is the case. The polished rod load of 1.5 to. is smaller than 2.7 to. and the pump efficiency is between 0.9 – 0.95, so this prediction is valid.

Here, the last step is to read out the 95% pump efficiency flowrate for the given predetermined depth

If the previous step is wrong (meaning that PPRL>SFpu X MPUL) the depth and its given 95% pump efficiency flowrate of 261 bbl/d or 41.5 m^3/d are valid and the two points may be created on a pump displacement vs. depth plot and the next pump depth can be evaluated for the same unit.

The last pump depth that can be selected and handled by this particular pumping unit (3to. 32 in.) is 1640 ft (500 m).

The starting depth for this phase is chosen to be 500 m as has been stressed before. A pump diameter of 2.750 in. is selected and the SPM set to 10. Unfortunately the MPUL for this pumping unit of 6613 lbs (3to.) has been exceeded, because the calculated PPRL is 7943 lbs (3.6 to.).

As PPRL>SFpu X MPUL is true, the user has still the option of decreasing the variables which are pump diameter and SPM in order to decrease the PPRL.

A pump diameter of 2.250 in. has been picked and the stroke rate has been reduced to 8.3 SPM. As a result, reached PPRL has been calculated to be 6194 lbs, which is below the MPUL and two new points for the 95% pump efficiency flowrate of 134 bbl/d or ~22 m^3/d have been created.

For a detailed view of the design inputs and the results, please look up Appendix I

As the next step a new pumping unit would have to be chosen and the whole process would start over again in a circle.

Note that every pumping unit system is able to cover a wider depth range as simulated in this example by for instance further decreasing pump diameter or stroke rate.

4.3.2 QROD Design Output

The QROD data is gathered in MS Excel and a diagram, showing depth in [m] vs. pump displacement in [m^3/d] is plotted for every pumping unit system. When taking a look at *Figure 43, Figure 44, Figure 45* and *Figure 46* in this subchapter, the implemented simulator steps, which were described in the previous subchapter, become evident.

As illustrated in *Figure 43,* all the LRP model types with their MPUL and various surface stroke lengths are depicted. As a logical consequence it can be said that every individual pumping unit covers a certain area consisting of a depth range in combination with the accompanying pump displacement range. Additionally, each coloured line defines the maximum area range the specific pumping unit, LRP in this case, is able to reach.

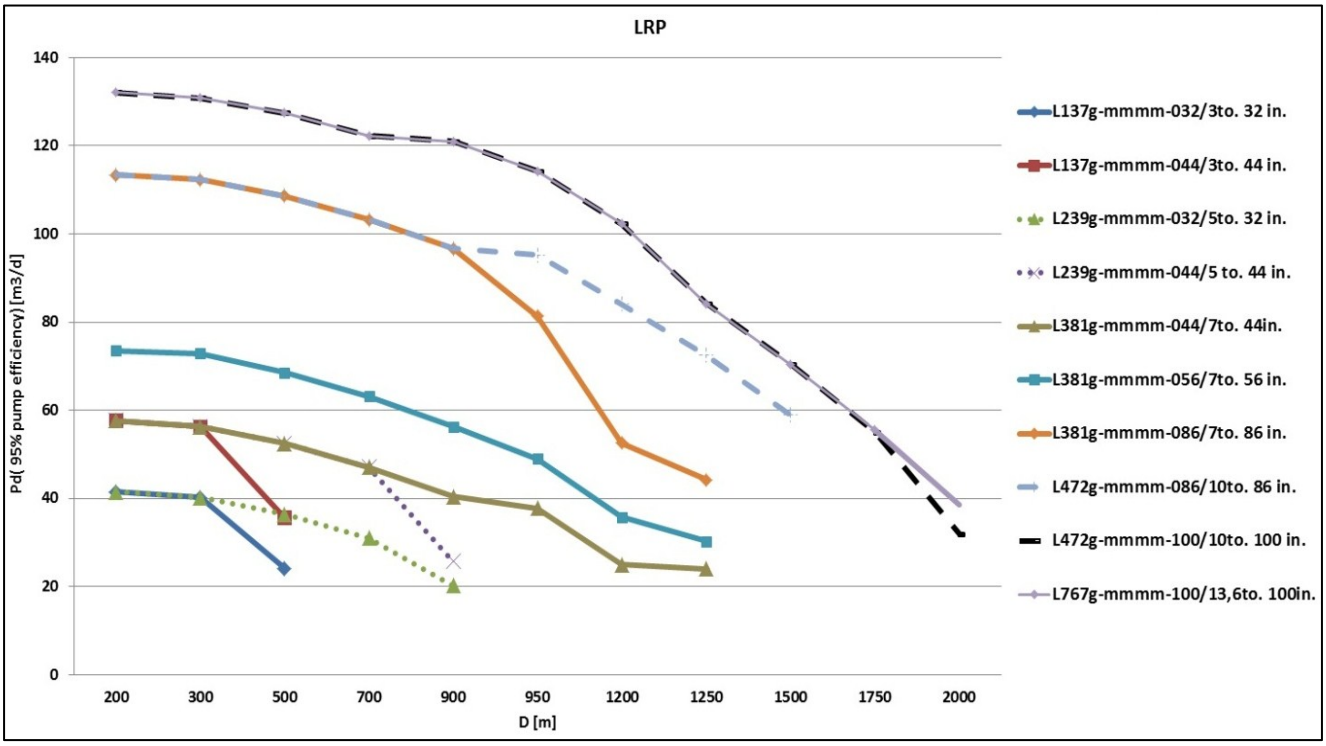


Figure 43: LRP application areas

Displayed in *Figure 44* is the plot for the conventional pumping units. As some of the unit models are bigger, meaning that the MPUL is higher and the surface stroke length is greater than the LRP, wider depth and accordingly pump displacement ranges may be covered.

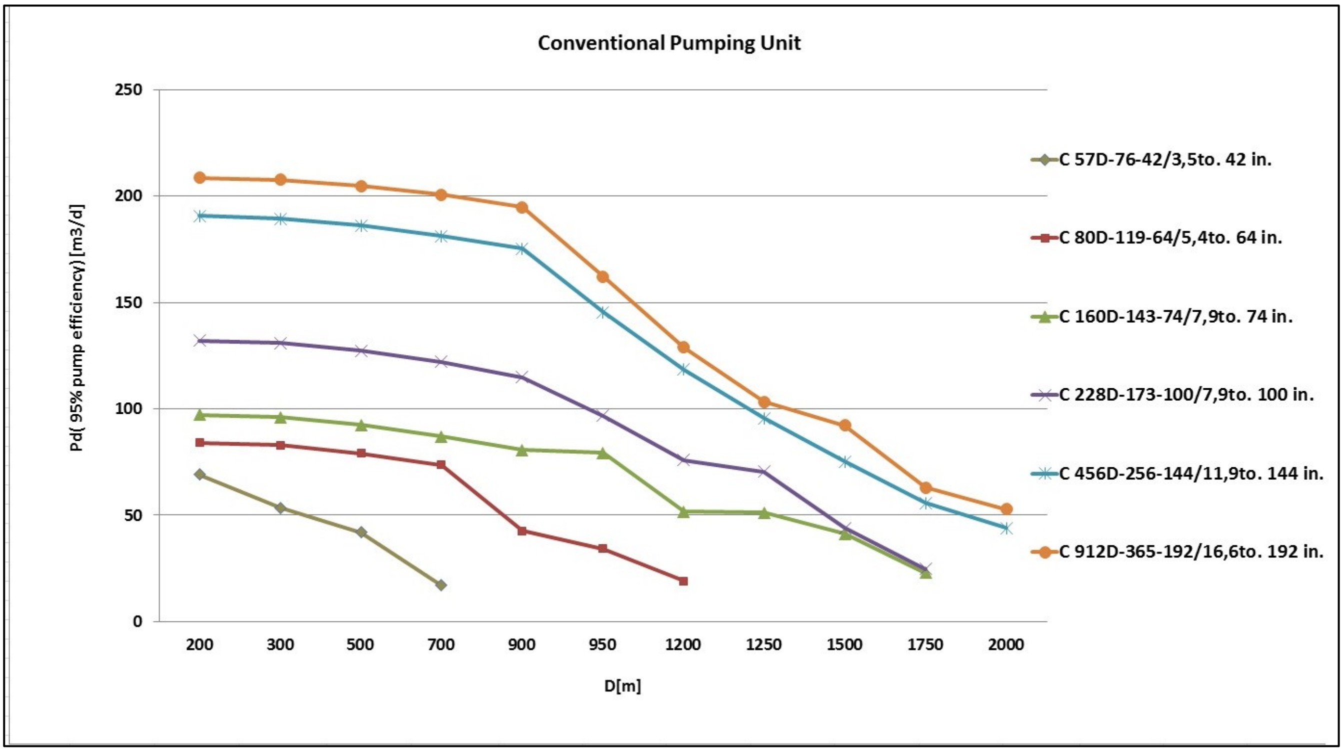


Figure 44: Conventional pumping unit application areas

As represented in *Figure 45* below, the “Rotaflex” covers a much wider area range than in case of the LRP and verifies that the “Rotaflex” is perfectly designed for high volume production and deep wells, also due to the broad MPUL and the large surface stroke lengths.

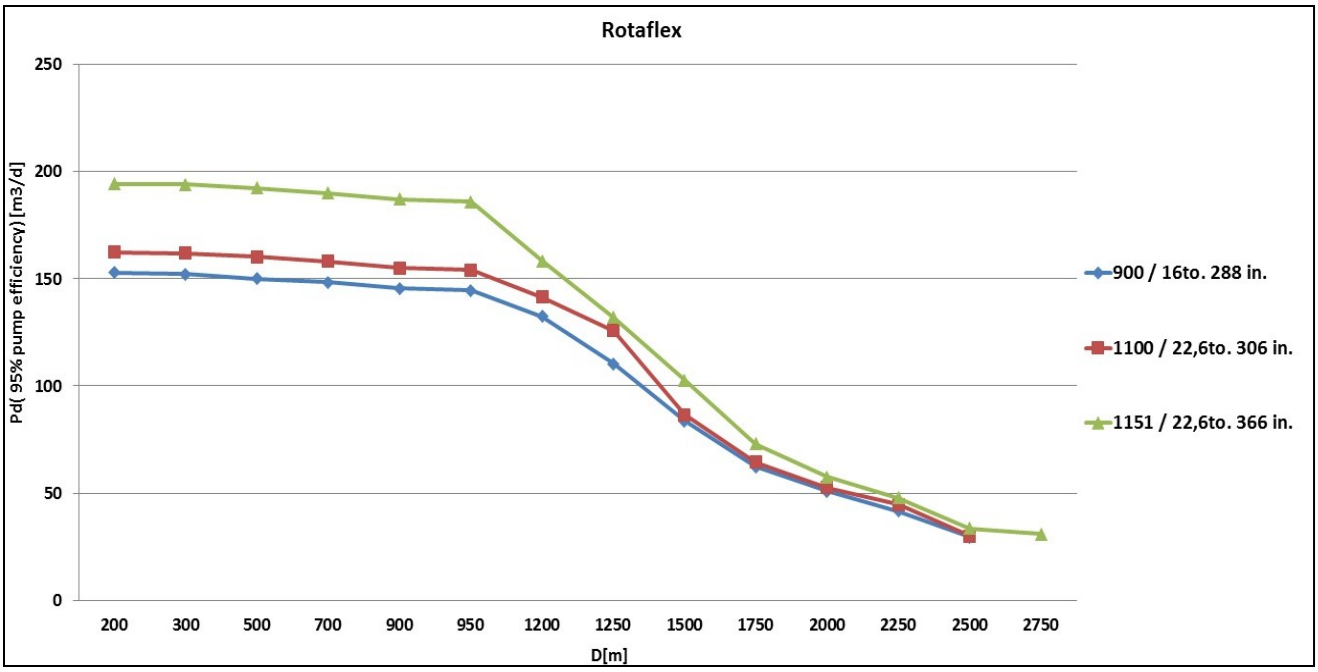


Figure 45: “Rotaflex” application areas

Displayed in *Figure 46* similarly to the “Rotaflex”, the hydraulic pumping unit (HPU) is able to cover a wide area range with a MPUL of 11 or 18 tons and large surface stroke lengths ranging from 240 in. to 360 in.

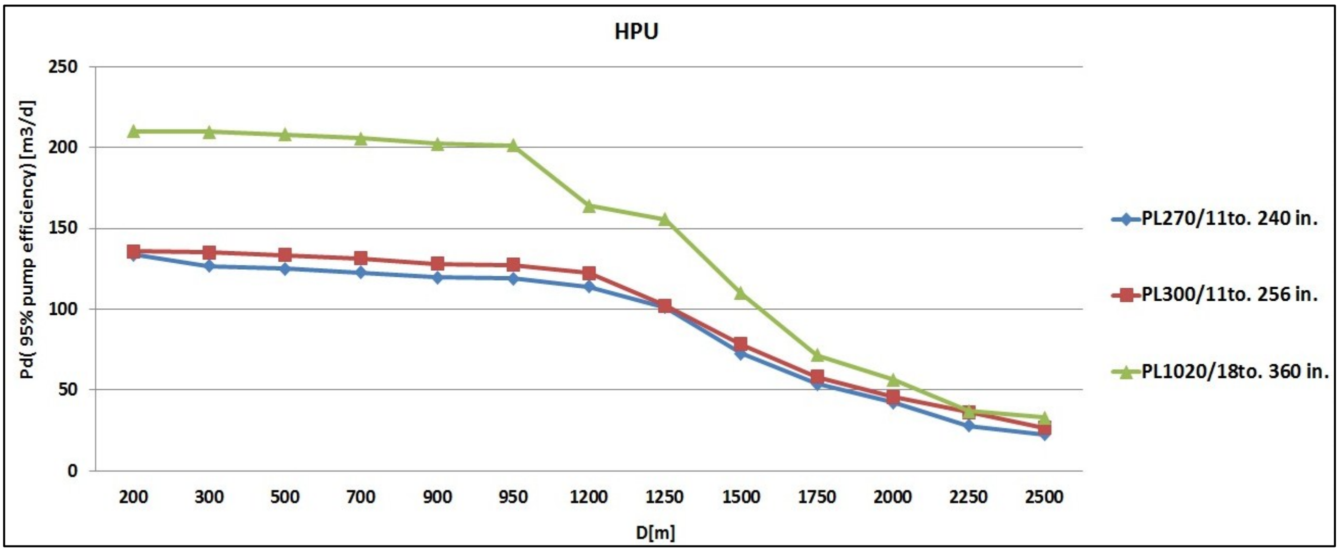


Figure 46: Hydraulic pumping unit application areas

5 LRP Candidate Screening based on Well Requirements

The aim of this section is to screen all the wells for potential LRP application.

> Screening is basically *"evaluating a large number of subjects to identify those with a particular set of attributes or characteristics."* [50]

In this thesis a screening of all PETROM oil wells equipped with downhole reciprocating rod pumps was performed in order to discover wells where the LRP can be utilized in the future.

> *Note:* Data screening and analyzing is based on PIMMS (Production Information Management Monitoring System) data from October 2012. It is a tool for data collection and monitoring of production. The application allows recording, reporting of information related to the quantification of production throughout the production system and is a web application, developed and tailored according to PETROM requirements.[xxvii]

- **PIMMS is a modern and flexible system for:**
    - Data acquisition
    - Production monitoring
    - Reporting
    - Allocation and
    - Hydrocarbon accounting

As data screening is performed in all fields it is an advantage to know where the fields are located in Romania.

[xxvii] *See Monitoring and Reporting Production Systems of PETROM*

PETROM field operations have been organized in 10 assets distributed all over Romania. The position of all assets is illustrated as an asset map overview in *Figure 47*.[xxviii]

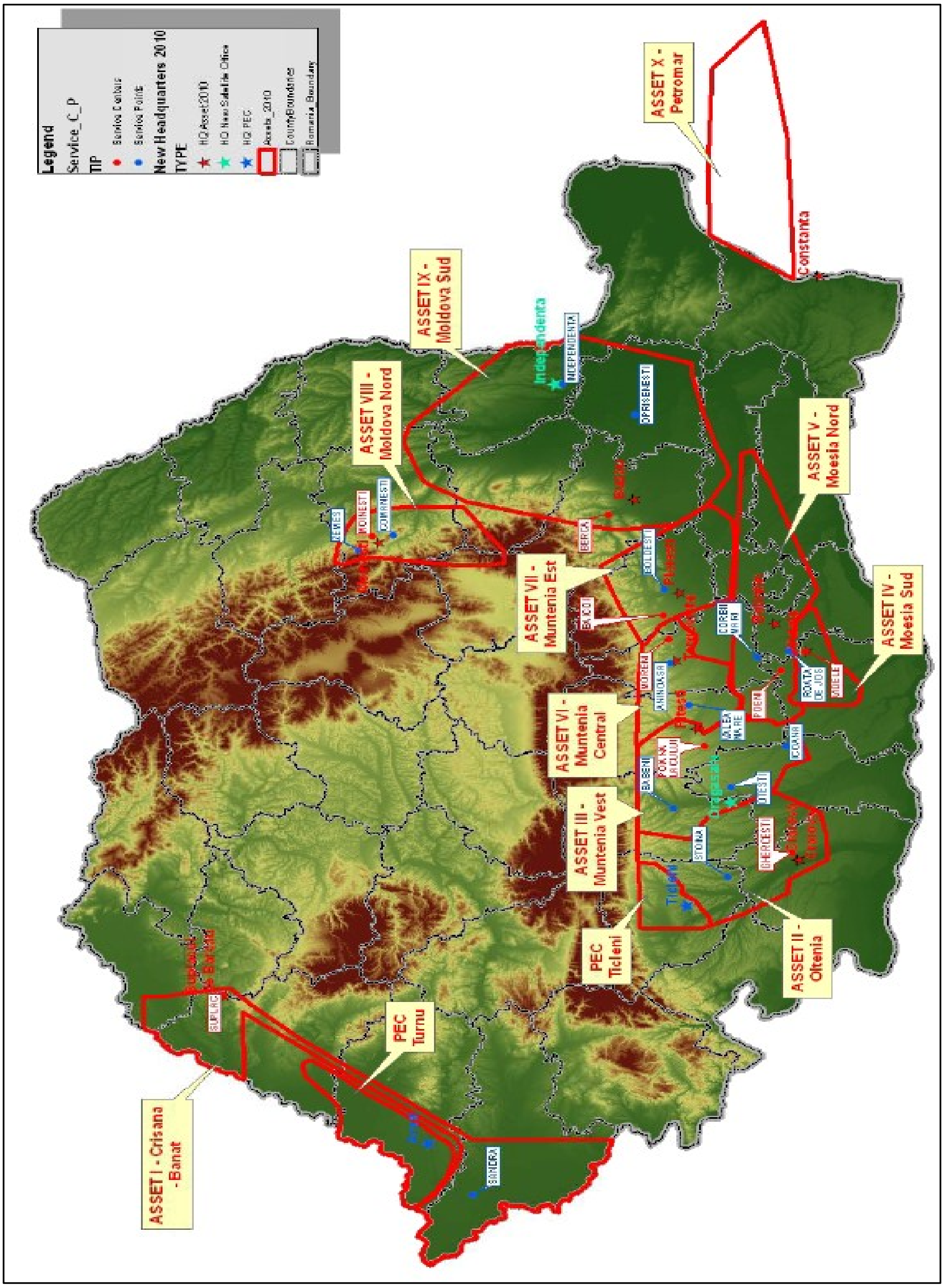


Figure 47: Asset map overview of Romania

[xxviii] *Distributed by PETROM E&P Domestic Assets Department on 21.01.2013*

The following subchapter will screen and analyze LRP based on the following logic:

- LRP shows more flexibility than the conventional pumping unit system in terms of low strokes per minute. In heavy oil reservoirs it is important to run the surface pump at low SPM at the downstroke so that the downhole pump will fill properly with reservoir fluids. This feature is an advantage when it comes to heavy oil wells with pump off conditions and cyclic steam injection, because they both possess viscous fluids and they are difficult to transport to surface.
- The remaining pump off condition wells are compared with the LRP in terms of costs with other available pumping unit systems when equipped with well automation (pump off controller) considering each pumping systems´ pump displacement vs. depth coverage.
- All other wells without pump off conditions are compared with the LRP in terms of costs with other available pumping unit systems without well automation (no pump off controller) based on the same logic as above. Considering the fact that no pump off conditions are present in these wells, no automation is required for them which makes the conventional pumping unit economically attractive for these applications.
- After the screening based on all criteria mentioned above, LRP candidate wells are recognized and displayed on a flowrate vs. depth plot.
- The impact of the GLR was assumed to have a negligible effect on wells with pump off conditions.

5.1 Heavy Oil Wells with Pump Off Conditions (Excluding Wells with Cyclic Steam Injection)

Petroleum is not a uniform material as on a molecular basis, but a complex mixture of organic compounds of for instance sulfur, oxygen and nitrogen plus hydrocarbons, as well as metallic constituents like iron or copper. The most widely used classification of petroleum distinguishes between oils either on an asphalt base or on a paraffin base. [51]

- Asphalt- base crude oils include very little paraffin wax and a residue primarily asphaltic. Here sulfur, oxygen or nitrogen contents are relatively high. Light and intermediate fractions have high percentages of naphtalenes. These oil crudes are applicable for making high quality gasoline, machine lubricating oils, and asphalt. [51]
- Paraffin- base crude contains hardly any asphaltic material and is a good source of paraffin wax, quality motor lubricating oils, and high grade kerosene [51]. Paraffin waxes are mixtures of long chained hydrocarbons. They are crystalline in nature and tend to precipitate from crude oils at and below the WAT (Wax appearance temperature) [52]. *"The WAT is the temperature at which, on a cooling cycle, the crude oil first precipitates solid wax"* [53]. As the temperature of the liquid solution is lowered to its WAT, the energy of the molecular motion is slowed down, and the randomly tangled molecules in the melt move closer together and form clusters. The

paraffin molecules continue to attach and detach until the clusters reach a critical size and become stable. [51] The deposition of paraffin wax results in several problems for instance in reduction of production and pipeline blockage. There are some options for removing the waxes like for example thermal techniques, where the temperature of the oil can be maintained or increased above the WAT by increasing the flow rate. The wax deposits will either not be laid down or will be softened and detached. Wax deposition can also be removed by launching a cleaning pig into a pipe where the pig mechanically scrapes wax from the wall of the pipe. Wax inhibitors are another option to discharge the deposits. [53]

The difference to conventional oil is that the heavy oil components occur at different amounts than for instance conventional oil. Heavy oils contain less lights hydrocarbons, but more resins and asphaltenes.

To understand the composition of petroleum it is necessary to define diverse fractions. Petroleum or heavy oil can be defined in term of four general fractions: saturates, aromatics, resins and asphaltene, which are also seen in common oil analysis. [51]

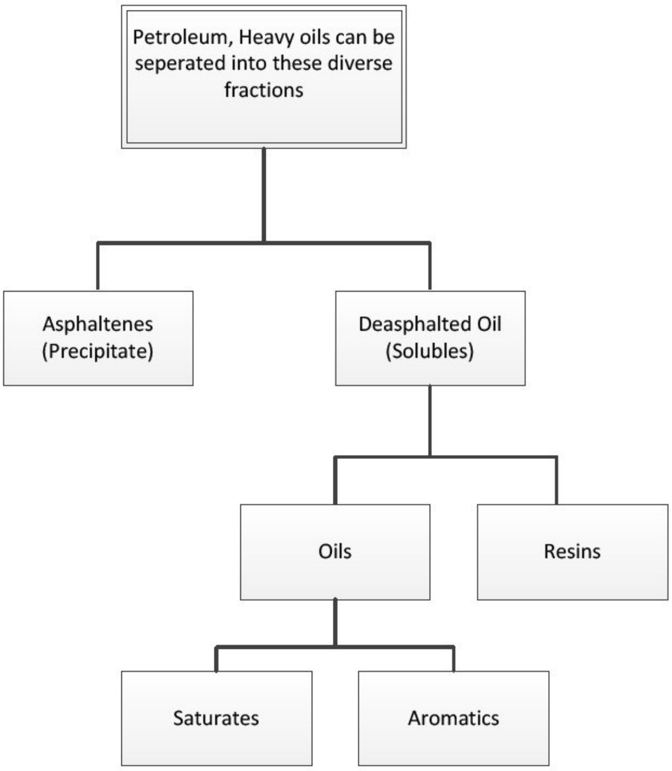


Figure 48: The separation of a petroleum feedstock into four major fractions [51]

Normal crude oil, heavy crude oil and tar sands are naturally occurring in petroleum substances which are distinguished by their high specific gravity. Heavy oils are different from conventional petroleum as they have a higher viscosity and lower API gravity. Viscosity is the principal single fluid characteristic influencing the motion of crude oil or other material and is a measure of the internal resistance to motion of a fluid. [51]

> *"Viscosity may be defined as the force in dynes required to move a plane of 1 cm^2 area at a distance of 1 cm from another plane of 1cm^2 area through a distance of 1 cm in 1s."* [51, p. 259]

In the centimeter gram second (cgs) system the unit of viscosity is poise. Other terms commonly used are for instance "kinematic viscosity" and "fluidity". The "kinematic viscosity" is the viscosity in centipoises divided by the specific gravity. The unit is stoke (cm^2/s) and fluidity is the reciprocal of viscosity. [51]

The American Petroleum Institute created the API Gravity Scale to measure the specific gravity of liquids with lower density than water, particularly petroleum. API gravity is graduated in degrees (API°) and the formula used to obtain the API gravity of petroleum liquids is defined as follows: **eq.15** [54]

$$API\ gravity = \left(\frac{141.5}{SG}\right) - 131.5 \qquad (15)$$

Where:

SG= Specific Gravity

The smaller the API gravity, the heavier the fluid is according to the API scale. With the help of *Figure 49* different types of oil are defined. [55]

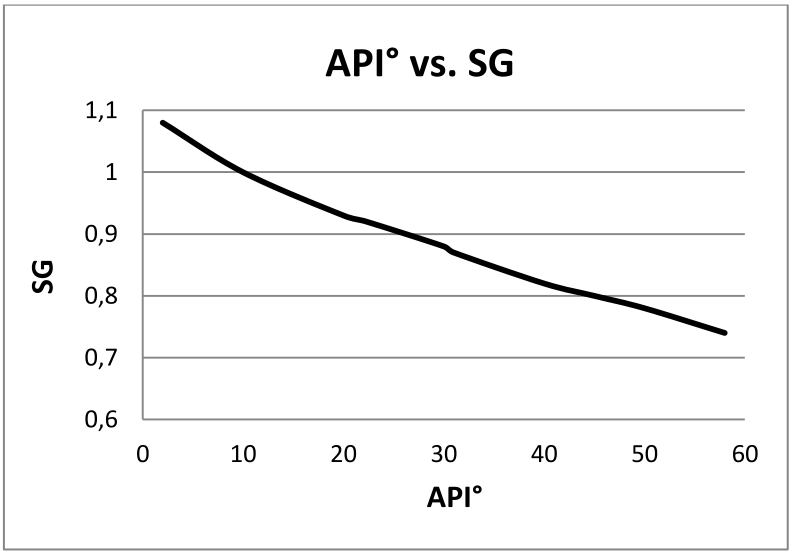


Figure 49: API gravity vs. Specific gravity

Specific gravities of petroleum range go from 0.8 (45.3° API) for lighter crude oils to over 1.0 (10°API) for heavier asphaltic oils [51].

Figure 50 shows a variation in API gravity with the viscosity of crude oil. The more viscous the oil gets, the smaller the API gravity is. *Figure 50* also illustrates where heavy oil is situated and where light petroleum is located in terms of viscosity and API gravity.

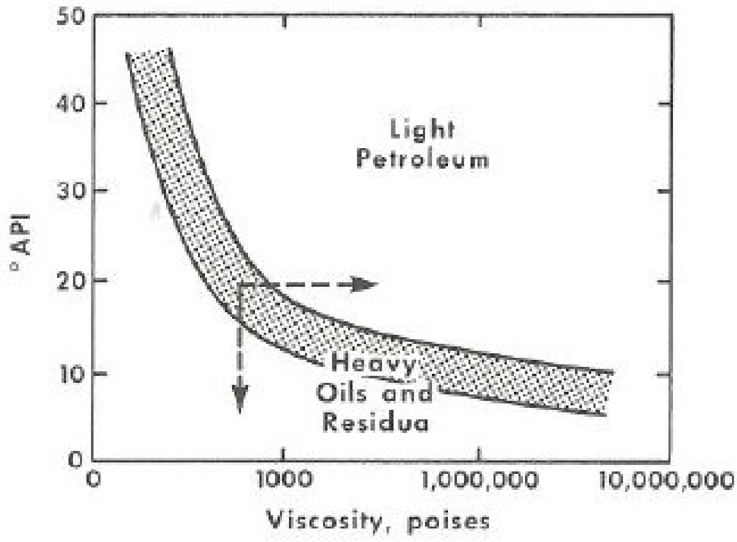


Figure 50: Variation in API gravity with viscosity of crude oil [51, p. 266]

Light oil: The API gravity is greater than 31.1° API, which has for example a specific gravity of less than 0.87 [54].

Medium crude: By definition medium crude has an API degree between 22.3° and 31.1°API with a specific gravity between 0.87 and 0.92 [54].

Heavy crude: Defined as having an API gravity less than 22.3°API with for instance a specific gravity greater than 0.92. Its viscosity is less than 10,000 cP (10 Pa.s), which means it has mobility at reservoir conditions [54, p. 12]. Moreover heavy oils are usually found at relatively shallow depth and present pump off conditions at PETROM in Romania. [xxix] A good example for a heavy oil environment in Romania is Asset 1, more precisely the Suplac field. The relationship between API gravity and depth can be seen in *Figure 51*, where the API gravity is low with shallow depth and is gradually increasing with rising depth. It has to be mentioned that the specific gravity of oil is an approximate measure of its asphaltene content. Therefore *Figure 52* describes the relationship of the asphaltene content of crude oil to API gravity. Generally, the higher the asphaltene percentage in oil is, the lower the API gravity must become.

[xxix] *For detailed information about pump off conditions, proceed to “Selection criteria for pump off controller (POC) in PETROM operations” in subchapter 3.2.1.2 “Usage of Automation3.2.1.2”*

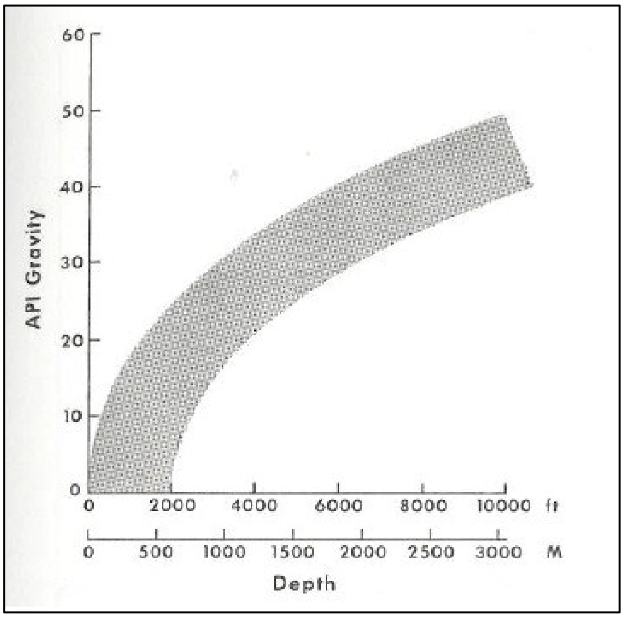


Figure 51: Relationship of crude oil API gravity to reservoir depth [51, p. 61]

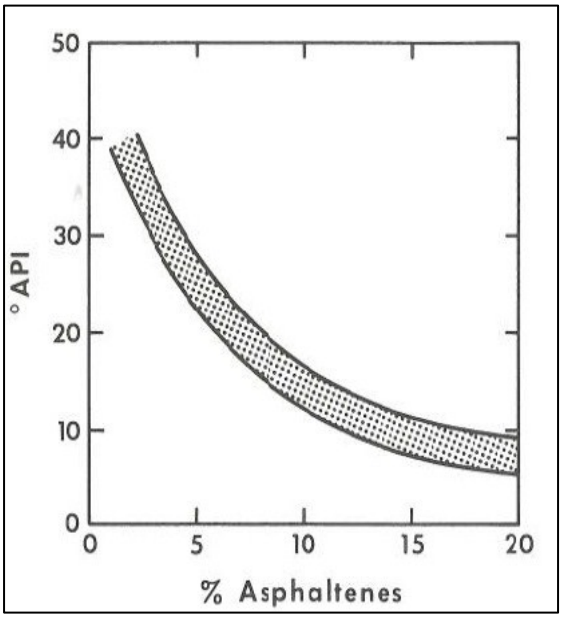


Figure 52: Relationship of asphaltene content of a crude oil to API gravity [51, p. 54]

PETROM uses four categories based on the depth interval as follows: [23, p. 4]

- “Suplac” category with depth less than 300 m /approx.868 wells
- Shallow wells with depth less than 1500 m /approx.6077 wells
- Medium wells with depth between 1500 m /approx.1106 wells
- Deep wells with depth more than 3000 m /approx. 45 wells

To make the example for a heavy oil environment in Romania in the Suplac field more demonstrative, a sample from Suplac field was picked which was analysed in a laboratory in Campina from the fluids department.

OMV Petrom SA-ICPT Campina

PETROM
Membru OMV Grup

ICPT are sistemul de management al calității conform ISO 9001:2000- Certificat SRAC nr. 670/2 din 05.09.2008 (IQNet nr. RO-0670).

SECȚIA FLUIDE- LABORATOR ANALIZE ȚIȚEI

RAPORT DE ÎNCERCARE

Nr. raport **41/04.03.2010**

I. DATE GENERALE

Tip matrice (probă) analizată: Țiței
Denumire sondă: **Depozit Suplac** Denumire zăcământ:
Identificator sondă: RO Identificator zăcământ RO
Cod probă: **10TIT00065**
Beneficiar: Grup Zăcăminte Suplac
Comanda: 860/28.01.2010
II. CONDIȚII DE PRELEVARE: Proba prelevată de beneficiar

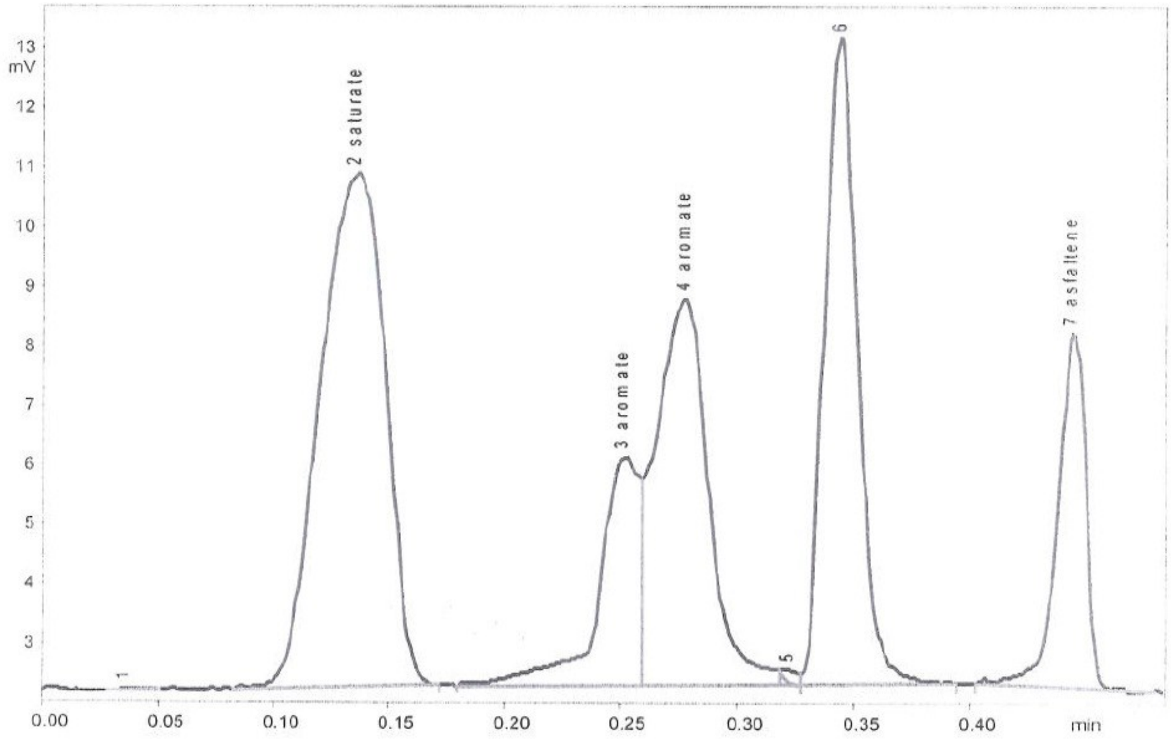
Nr. crt.	Caracteristica	U.M.	Valoarea	Metoda de analiză	Observații
1	Densitatea la 20°C	kg/m³	963.2	STAS 35-81	
2	Conținut de impurități prin centrifugare, din care:	% vol		SR ISO 9030/1995	
	- mecanice	% vol			
	- apă	% vol			
	- emulsie	% vol			
3	Conținut apă prin distilare	% vol		SR EN ISO 9029/2002	
4	Conținut în cloruri	% gr		STAS 1166/89	
5	Punct congelare	°C	6	STAS 39/80	
6	Viscozitate cinematică	m²/Sx10⁻⁶		STAS 117/87	
	- la 20°C				
	- la 30°C				
	- la 40°C		728.9		
	- la 50°C		341.2		
	- la 60°C		179		
7.	Distilare - punct inițial	°C	221	SR EN ISO 3405/2003	
	10% vol	°C	257		
	20% vol	°C	300		
	30% vol	°C	324		
	40% vol	°C	346		
	50% vol	°C	353		
	60% vol	°C			
	70% vol	°C			
	80% vol	°C			
	90% vol	°C			
	- punct final	% vol./°C	58/360		
	- până la 100°C	% vol.			
	- până la 200°C	% vol.			
	- până la 300°C	% vol.	20		
8.	Conținut în sulf total	% gr.	0.22	SREN ISO 8754/2004	
9.	Conținut în parafină	% gr.		Metoda I.C.P.T.	
10.	Conținut în asfaltene	% gr		Metoda I.C.P.T.	
11.	Conținut în rășini	% gr		Metoda I.C.P.T.	

Data executării: 17.02.-03.03.2010

Figure 53: Suplac labor oil analysis

With a calculated API gravity of 15.4°API (963.2 kg/m^3) and a viscosity of 728.9 m^2/sx10^{-6}, it can be proclaimed to be heavy oil as seen in *Figure 53*. In *Figure 54*, different peaks on a chromatogram are illustrated which correspond to different components in the sample mixture. The chromatogram shows diverse fractions of oil in percent and as asphaltenes as one of the components with the peak number 7 shows a percentage of approximately 10.4 % and with 22,7% rasins it can be concluded that the sample mixture is heavy oil.

Data Handling File: Titei   Calculation-File: Titei



Calculation Method : Percent

Peak No	Win No.	Ret.Time (min)	Area	Resp.-Fact.	Area%	Name
2	1	0.136	8807	1.000	35.492	saturate
3	2	0.252	2455	1.000	9.892	aromate
4	2	0.278	5331	1.000	21.486	aromate
6		0.345	5636	1.000	22.713	răşini
7	3	0.444	2585	1.000	10.418	asfaltene
			24814		100.000	

Figure 54: Different component in a Suplac sample oil mixture

Generally speaking, with heavy oil and existing pump off conditions PETROM recommends running a pumping unit with low SPM (5 SPM or lower) for the downhole pump to fill completely with reservoir fluids.

Resuming that heavy oil reservoirs with pump off conditions are comparatively shallow wells with a low average production rate in Romania of approx.6 m^3/d and a suggested SPM rate of 5 or lower, the LRP is suitable for these conditions. Taking the other pumping unit systems into account, the conventional pumping unit is usually restricted to higher SPM and with more SPM rates the downhole pump would not have enough time to fill completely. The other two pumping systems, being the “Rotaflex” and the “HPU”, are not regarded as economic for heavy oil and existing pump off conditions and aside from that are utilized for deeper wells and high volume production.

A total number of 456 wells with the above described characteristics have been screened and implemented in flowrate [m^3/d] vs. depth [m] plots till a predefined depth range to be seen in the following graphs for heavy oil wells with pump off conditions. The wells themselves are recognizable as black small triangles, whereas the pumping units with their MPUL and surface stroke length are described in the legend of the figures. A cumulative well count till a predefined depth range is highlighted in grey and also depicted in the figure legend. All the wells have a production rate of less than 50 m^3/d. As a result only a few pumping units cover the screened wells and are qualified to become potential candidates. As the rest of the pumping units are ineligible due to being oversized and not economic for this case, they are not pictured in the figures to come.

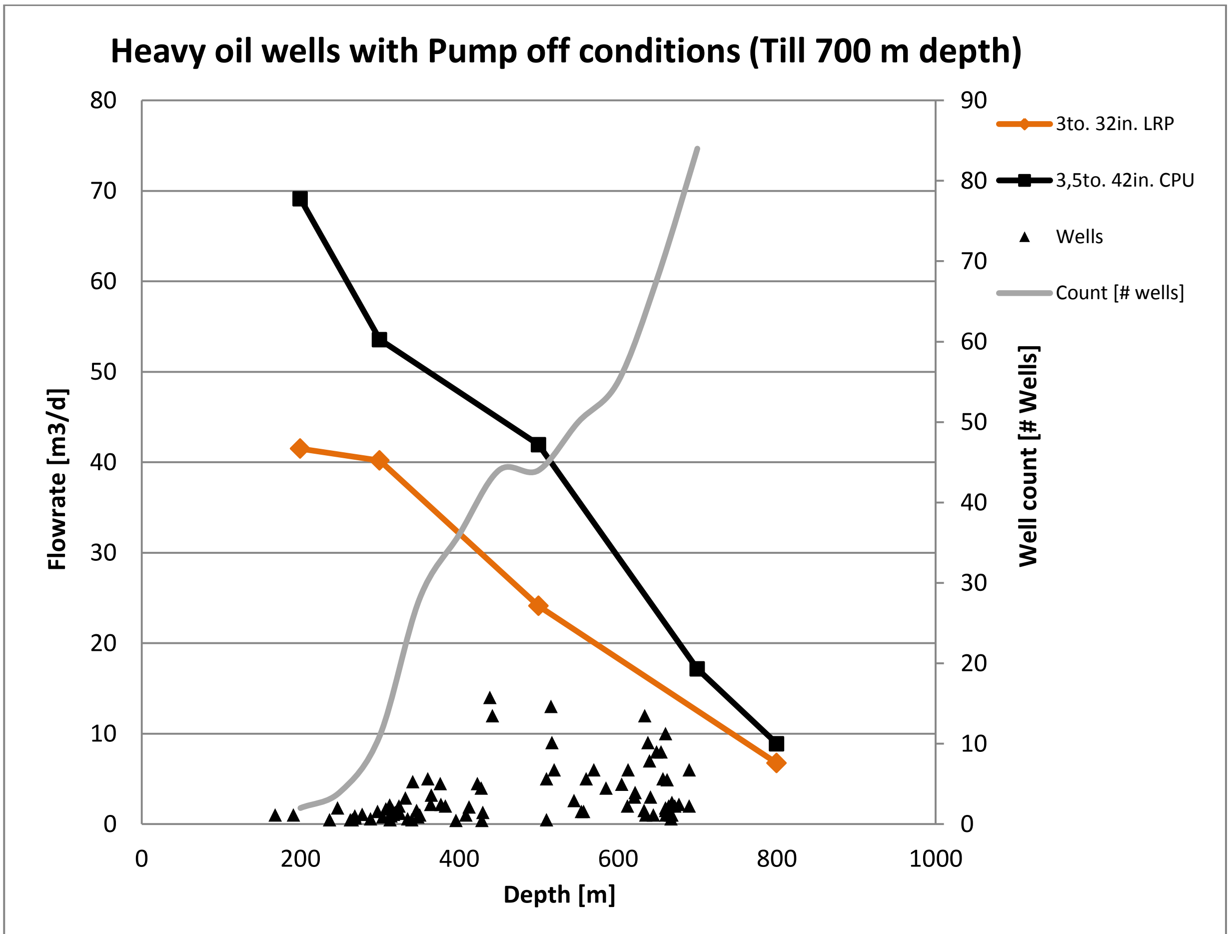


Figure 55: Heavy oil wells with pump off conditions (Till 700 m depth)

As seen in *Figure 55*, a total number of 84 heavy oil screened wells with pump off conditions (see well count) have been implemented till a depth of 700 m. The pumping unit which covers these wells most satisfyingly without being overdesigned is the LRP with a MPUL of 3 to. and a surface stroke length of 32 in. (L137-g-mmmm-032) highlighted in orange in *Figure 55*.

The conventional pumping unit with the model C 57D-76-42 on the other hand, also covers the screened wells. It is depicted as a black line in the same figure. When the costs with automation are taken into consideration, the conventional pumping unit is not as economic as the LRP with a MPUL of 3 to. and 32 in. surface stroke length as listed in *Table 31.* It has to be mentioned at this point, that pumping with lower speeds with an LRP (<=5SPM) is of advantage in comparison to a conventional pumping unit with pump off controller in heavy oil environments, because of the better pump charge (pump efficiency) during the downstroke. In order to guarantee good pump charge with classical pumping unit equipped with a pump off controller the pumping is sometimes stopped by the pump off controller which might result in plugging of the pump by sands/fines settling on top of the pump when stopped. While using a LRP which allows lower pumping speeds and the DOWN SLOW SPEED method (see Chapter 3.1 “Overview on the LRP” for a detailed description) a continuous flow is guaranteed and pump plugging can be avoided.

Table 31: Heavy oil well screened potential pumping unit candidates till 700 m depth

Pumping unit model	**Approximate cost w/o automation [€]**	**Costs w/ automation [€]**
C 57D-76-42	20,000	29,000
L137-g-mmmm-032		***22,000***

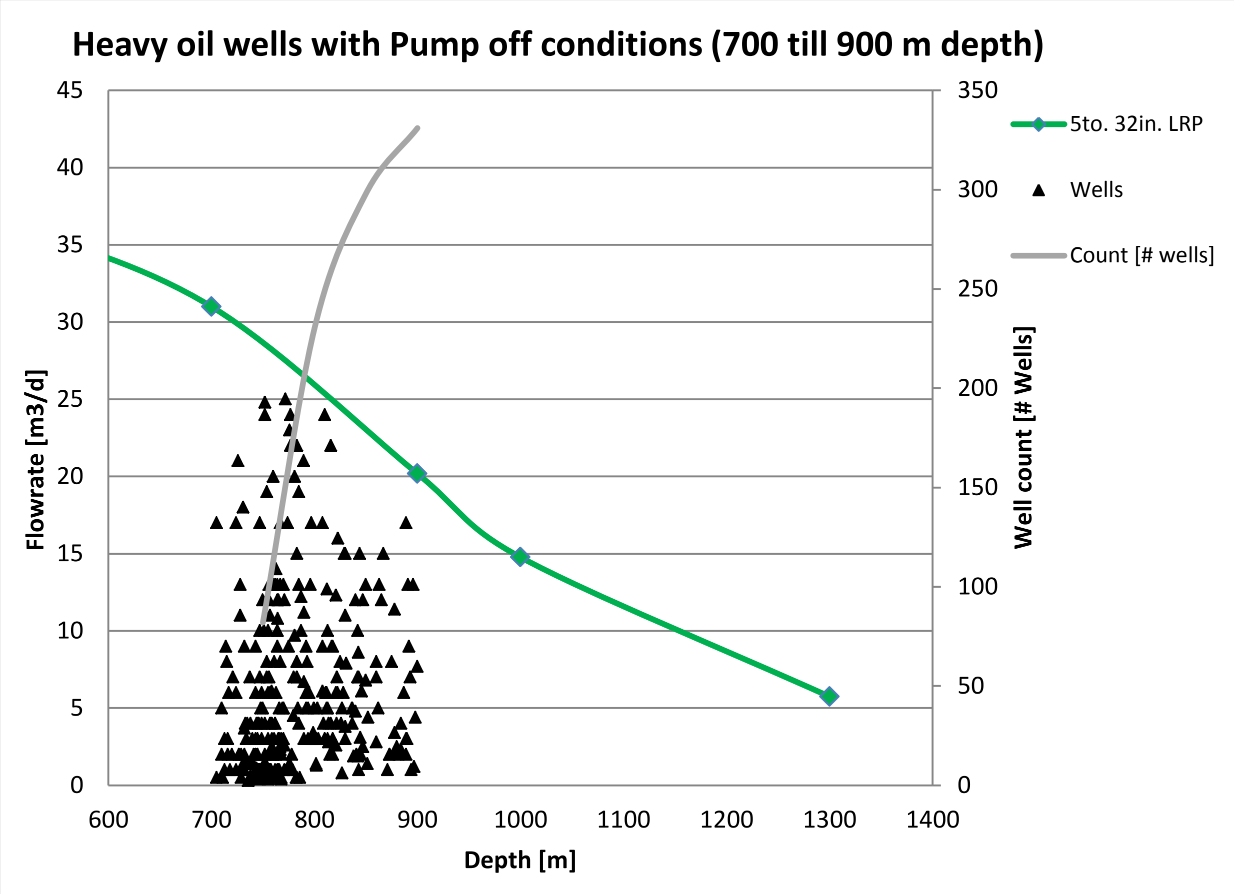


Figure 56: Heavy oil wells with pump off conditions (700 till 900m depth)

Illustrated in *Figure 56* are a total of 331 heavy oil wells with pump off conditions from 700 till 900 m depth (recognizable as black small triangles). As the screened wells in this depth interval reach a flowrate of up to 25 m^3/d the most suitable pumping unit to cover the screened wells most satisfyingly without being overdesigned is the 5to. 32in. LRP represented in green.

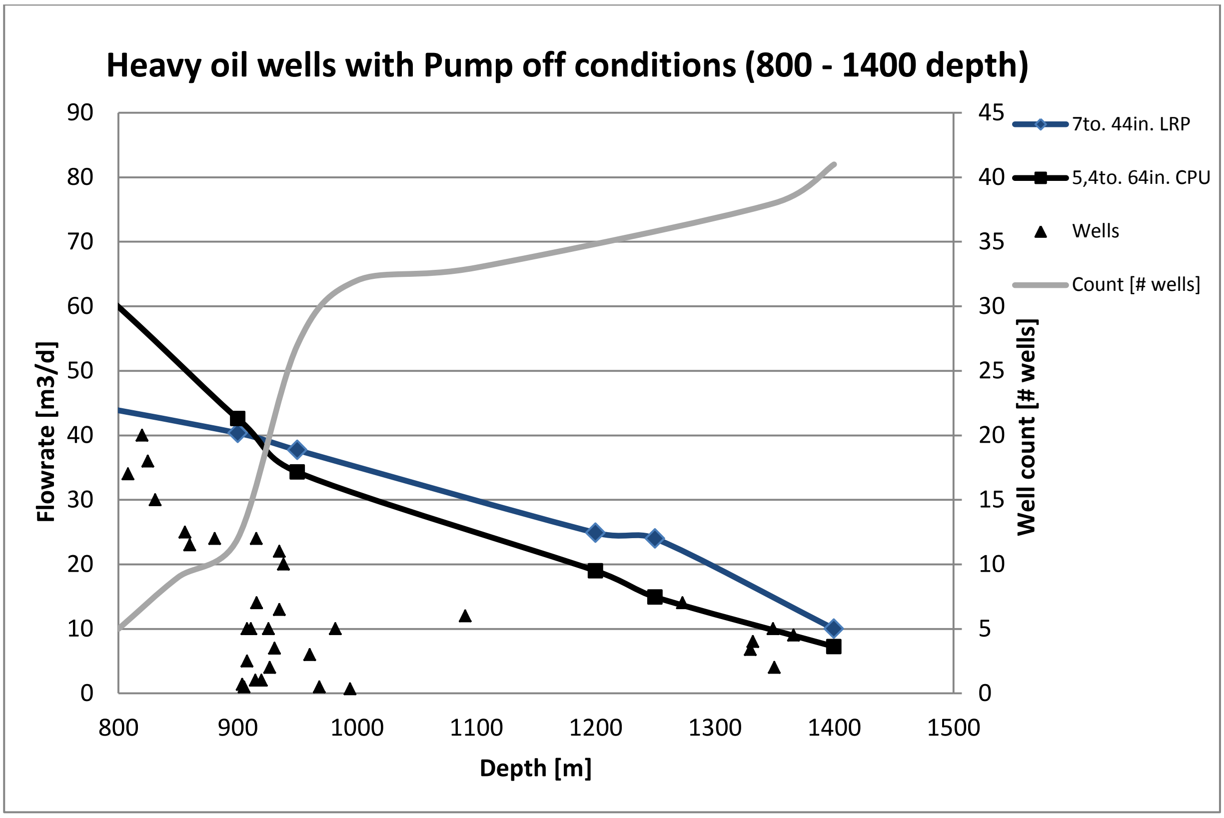


Figure 57: Heavy oil wells with pump off conditions (800 till 1400m depth)

All the wells that possess a flowrate of more than 25 m^3/d and are in this depth interval of 700 till 900m may be covered by a bigger pumping unit in terms of MPUL and stroke length as for instance described in *Figure 57*. Similarly to the other two screened heavy oil well intervals a well examination for the 800 till 1400 m depth was performed. Depicted in *Figure 57* are the remaining 41 wells which fall into the criteria of heavy oil wells with pump off conditions and may be covered by the 7to. 44in. LRP marked in blue. Identical to the procedure for the heavy oil wells till 700 m depth also in this case the conventional pumping unit with 5,4to. 64in. with the model C-80D-119-64 covers these particular screened wells represented in black in the graph.

For a detailed design comparison of these two unit models with a representative economic assessment, refer to subchapter 3.2.1.7 “Conventional Beam Pumping Unit vs. LRP” under the point Design Comparison.

An approximate cost comparison of the two unit models is seen in *Table 32.*

Table 32: Heavy oil well screened potential pumping unit candidates from 800 till 1400 m depth

Pumping unit model	**Approximate cost w/o automation [€]**	**Costs w/ automation [€]**
C-80D-119-64	20,000	***35,000***
L381-g-mmmm-044		***35,000***

5.2 High Viscous Oil Wells with Cyclic Steam Injection

As has been stressed earlier, different scenarios are analyzed. Up next all cyclic steam injection wells have been reviewed in order to find LRP candidates.

Due to their low gravity (less than 22.3 °API) and high viscosity (2,400 cP – 4,000 cP at 30°C - 40°C)[xxx], the thermal recovery technique has been employed to enhance oil production from this field.

Predominantly steam is injected down injection wells to heat the oil to reduce its viscosity and make it mobile. The steam also produces drive to push the oil toward producing wells. Main surface equipment consists of water treatment plants and boilers that produce high pressure steam above reservoir pressure. [56]

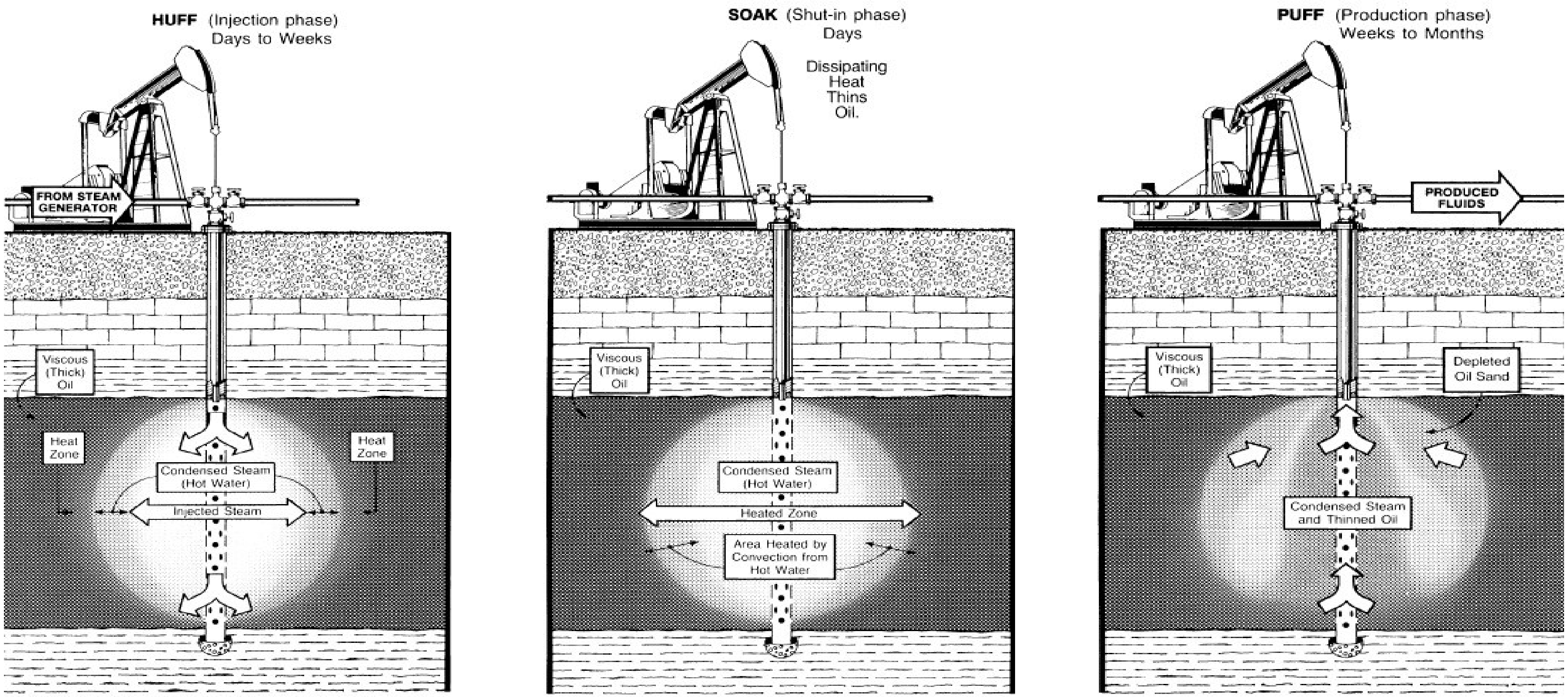
Cyclic Steam injection works best for heavy oils, because the heavier the oil, the higher the viscosity reduction. It must be stated that a part of the produced heat cannot be used to heat the oil in the formation and make it mobile, because heat is lost during its way downhole. Wellbore heat losses are the most significant ones. The deeper the well, the more energy is lost and the less the oil can be treated at that point. Due to heat losses steam injection is limited to shallow deposits.

The visual representation of the cyclic steam stimulation is shown in the schematic and depicts a typical cyclic steam injection cycle as described in the three phases (*Figure 58*). This method is applied to boost recovery during the primary production phase.

The beginning of the next injection starts when oil is not mobile enough to flow anymore, because of temperature reduction and consequently production falls to a level where it is no longer economic to produce. [57]

[xxx] *Approx. reservoir data form PETROM report " Sectia fluide – laborator analyze titei" with report number 6 from 06.01.2012*

Figure 58: Cyclic Steam Injection divided into three phases [58, p. 19]



The **first phase** of cyclic steam injection is the injection phase which is used to heat the crude to the point where it is mobile enough to flow.

The **second phase** starts at the point when the steam injection is turned off and also is called shut in phase. This phase lasts days where the dissipating heat thins the oil.

The **third phase** is the production phase where pumping of the well begins through the same wellbore. The injection and production phase represent one complete cycle of the operation.

Predominantly cyclic steam injection is performed in Asset 1 (Suplac) and Asset 6 (Moreni). Currently there are 602 wells that are stimulated with this stimulation method. As already stated earlier cyclic steam injection wells are principally not found in deep wells (deeper than 400m). For wells up to a production rate of 40 m^3/d, the 3to.MPUL and 32 in. surface stroke length LRP is preferable and is highlighted in orange as pictured in *Figure 59*. This LRP is practically able to cover the majority of the cyclic steam injection wells (586 wells). Illustrated in grey is the cumulative well count. Most of the cyclic steam injected wells are found between 100 to 350 m.

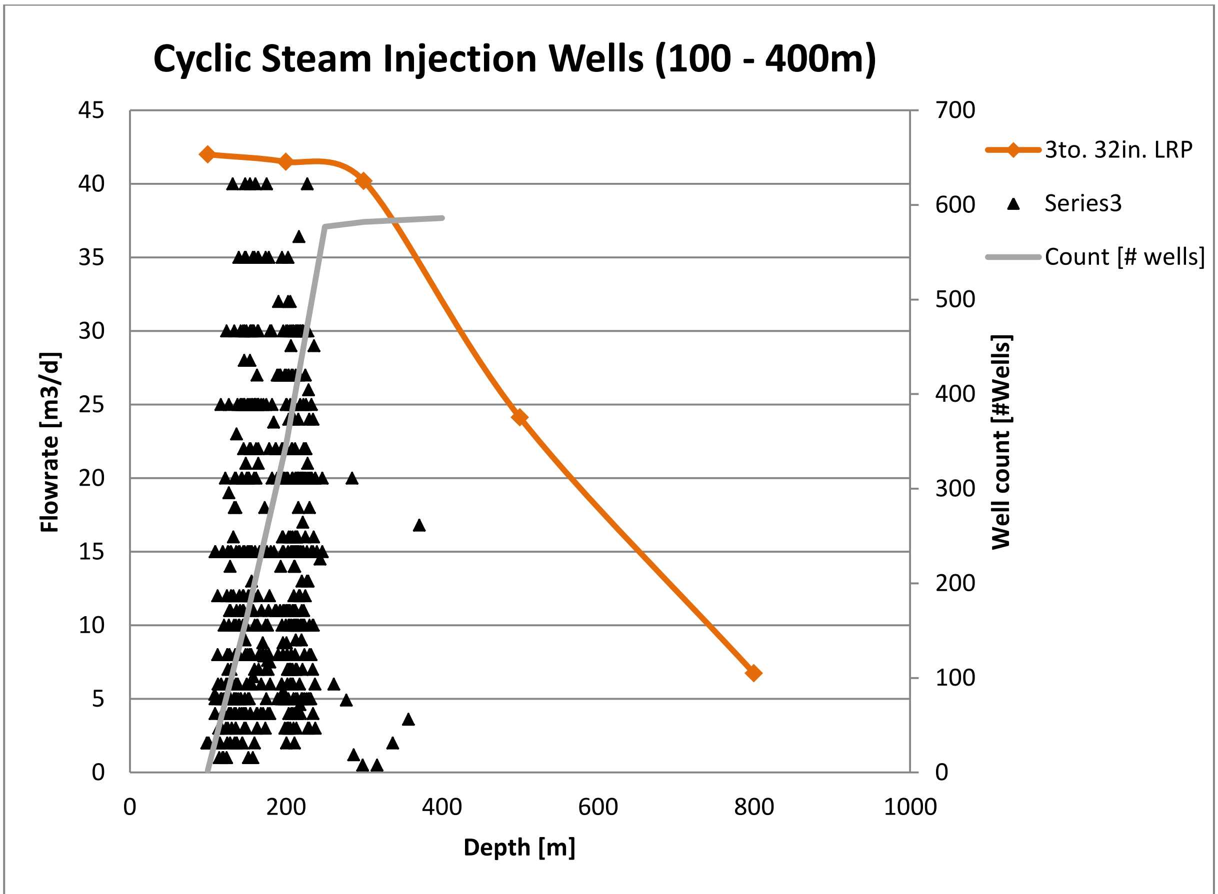


Figure 59: Cyclic Steam Injection Wells (100 till 400m)

Similarly to the heavy oil wells with pump off conditions (800 till 1400m depth) the next biggest LRP model (7to. 44in.) to cover the remaining cyclic steam injection wells had to be chosen. Represented in *Figure 60* are the majority of remaining wells (8 wells) seen as a black triangle and the two types of pumping units that are eligible to cover them.

The 7 leftover wells unfortunately do not match the cyclic stream injection well output, as their flowrate is far beyond this scenario range.

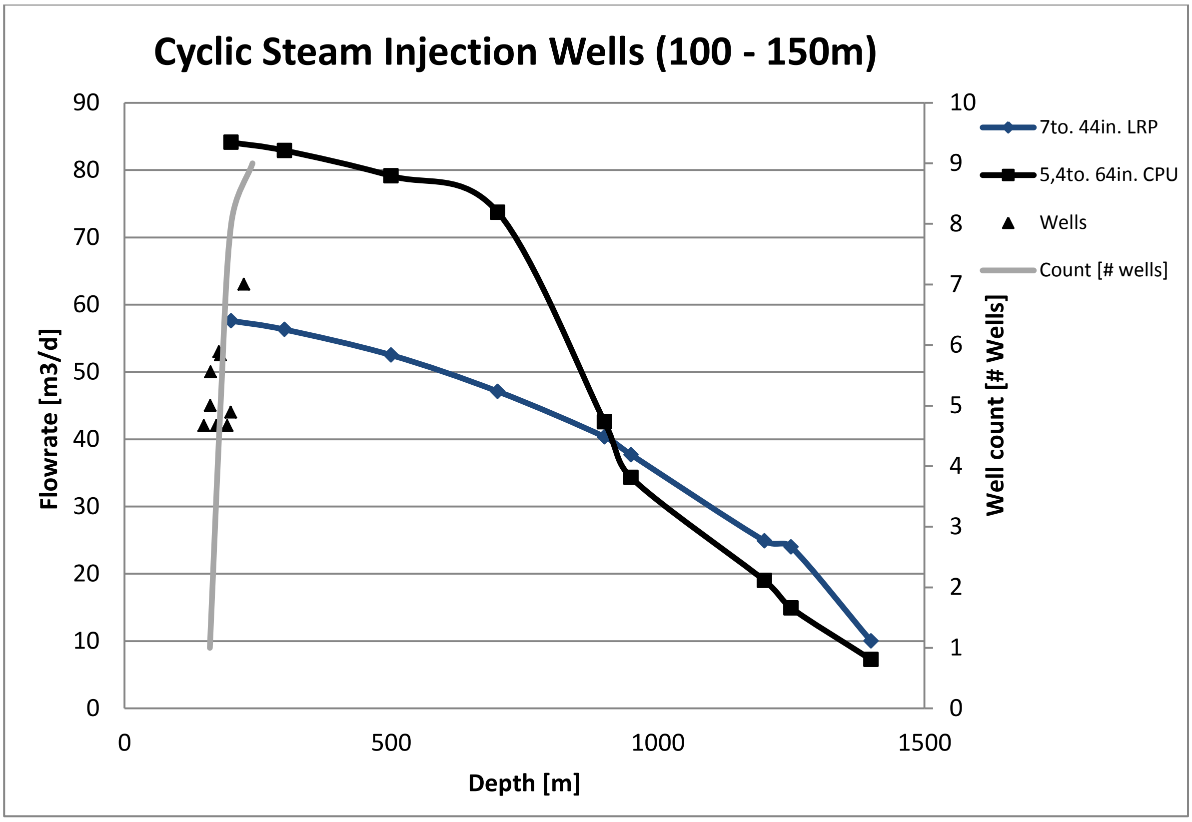


Figure 60: Cyclic Steam Injection Wells (100 till 150m)

5.3 Remaining Wells with Pump Off Conditions (Excluding Heavy Oil Wells with Pump Off Conditions and Cyclic Steam Injection)

In this next screening case the entire pump off condition wells (2201 wells) are taken into account, excluding possible heavy oil and cyclic steam injection wells which have been already examined earlier. Almost all the remaining 2201 pump off wells are producing less than 50 m^3/d. and are found in a depth range of 200 till 2750 m, which makes the pumping unit selection dependent on the individual pumping unit range areas and costs.

Table 33 outlines an approximate pumping unit cost comparison with automation already installed. Highlighted in green are the LRP models that are more economic than conventional pumping unit models in terms of unit price for a similar flowrate and depth coverage. In case of the remaining pump off condition wells the LRPs are the preferable choice till a depth of 1250m. Beyond that depth other pumping unit systems become more attractive in terms of unit cost and flowrate/depth ranges for this scenario. These pumping unit systems are clearly subdivided with a thick line in *Table 33* and are marked in grey.

Table 33: Pumping unit system comparison due to unit costs for pump off conditions

Pumping unit model	Approximate cost w/ automation [€]
L137-g-mmmm-032 / 3to.32 in.	***22,000***
L137-g-mmmm-044 / 3to. 44 in.	24,000
L239-g-mmmm-032 / 5to. 32 in.	***27,000***
C 57D-76-42 / 3,5to. 42 in.	29,000
L239-g-mmmm-044 / 5to. 44 in.	29,000
L381-g-mmmm044 / 7to. 44 in.	***35,000***
L381-g-mmmm-056 / 7to.56 in.	38,000
C 80D-119-64 / 5,4to. 64 in.	35,000
L472-g-mmmm-086/ 10to. 86 in.	70,000
C 160D-143-74 / 7,9to. 74 in.	***48,000***
L472-g-mmmm-100 / 10to. 100 in.	77,000
L767-g-mmmm-100 / 13,6to. 100 in.	81,000
C 456D-256-144 / 11,6to. 144 in.	***85,000***
Powerlift PL 300 / 11to. 256 in.	***100,000***
Rotaflex 1151 / 22,6to. 366 in.	***Beyond 100,000 (estimated price)***

The screening of the remaining wells with pump off conditions till a depth of 1250 m shall be executed in the same manner as already prosecuted for heavy oil wells and high viscous oil wells with cyclic steam injection. Additionally all the screened wells for this scenario have an API range of over 22.5 till 49 °API, which means that they are lighter than the heavy oil and cyclic steam injection wells.

As pictured in *Figure 61* a total of 615 wells (see well count) till a depth of 700m are eligible to be covered by the 3 to. 32 in. LRP marked again in orange.

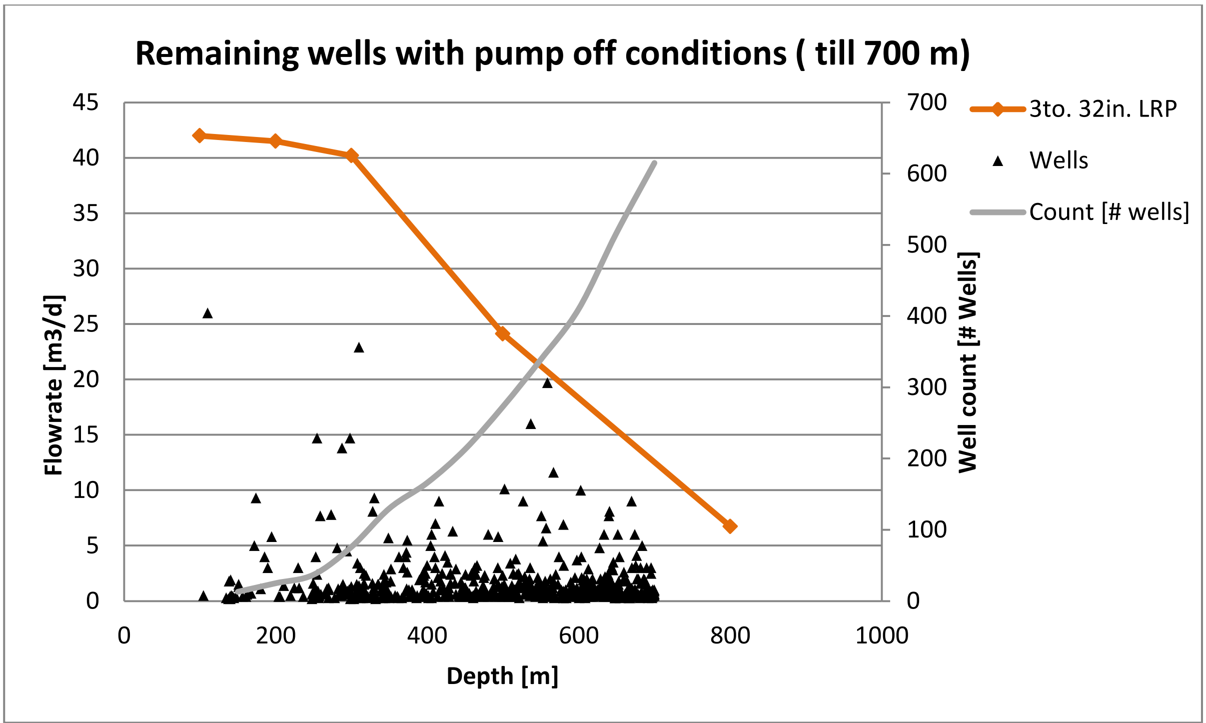


Figure 61: Remaining wells with pump off conditions till 700 m

The next depth interval which goes from 700 till 900 m is capable of being covered by the 5to. 32 in. LRP marked in green as seen in *Figure 62.* This interval obtains a well count of 413 wells with pump off conditions. Wells, which suit in this interval but cannot be covered by the 5to. 32 in. LRP due to higher production rates may be covered by the 7to. 44 in. LRP pictured in *Figure 63.*

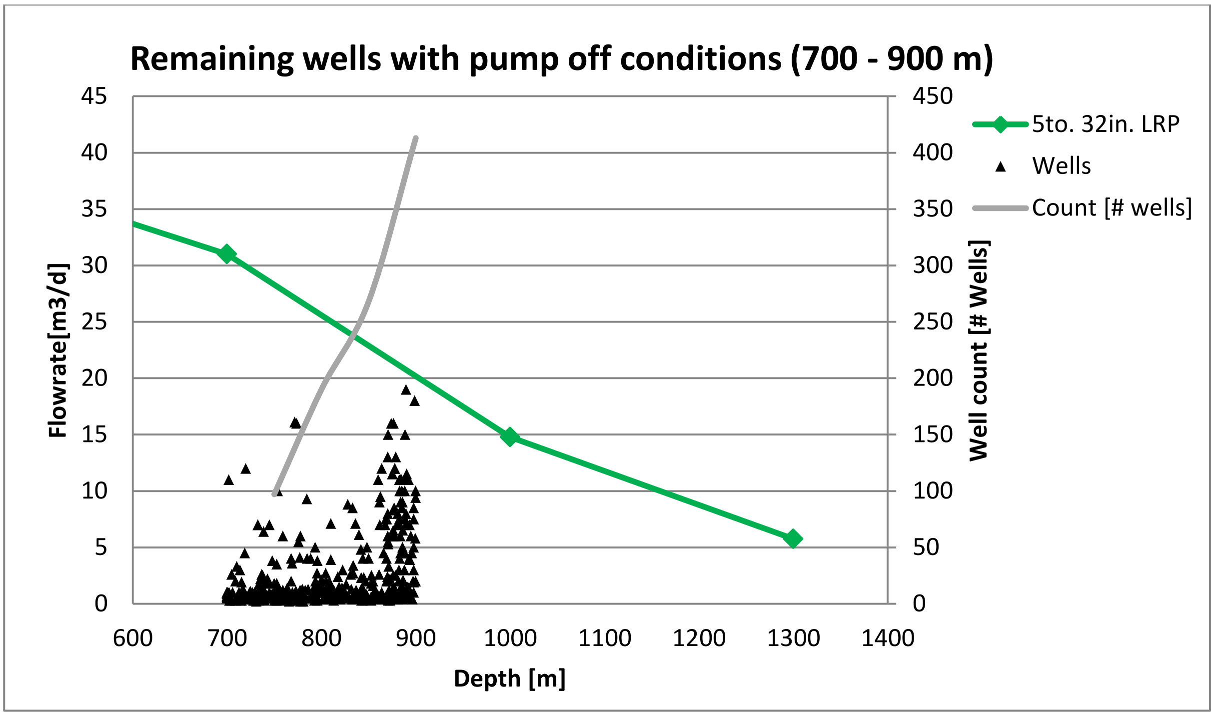


Figure 62: Remaining wells with pump off conditions from 700 till 900m

Illustrated in *Figure 63* are the remaining potential LRP candidate wells which are able to be covered by the 7 to. 44in. highlighted in blue. In this flowrate depth area 562 wells are present.

When a sum up of the remaining wells with pump of conditions is performed 1590 wells are able to be produced with the LRP being the potential candidate.

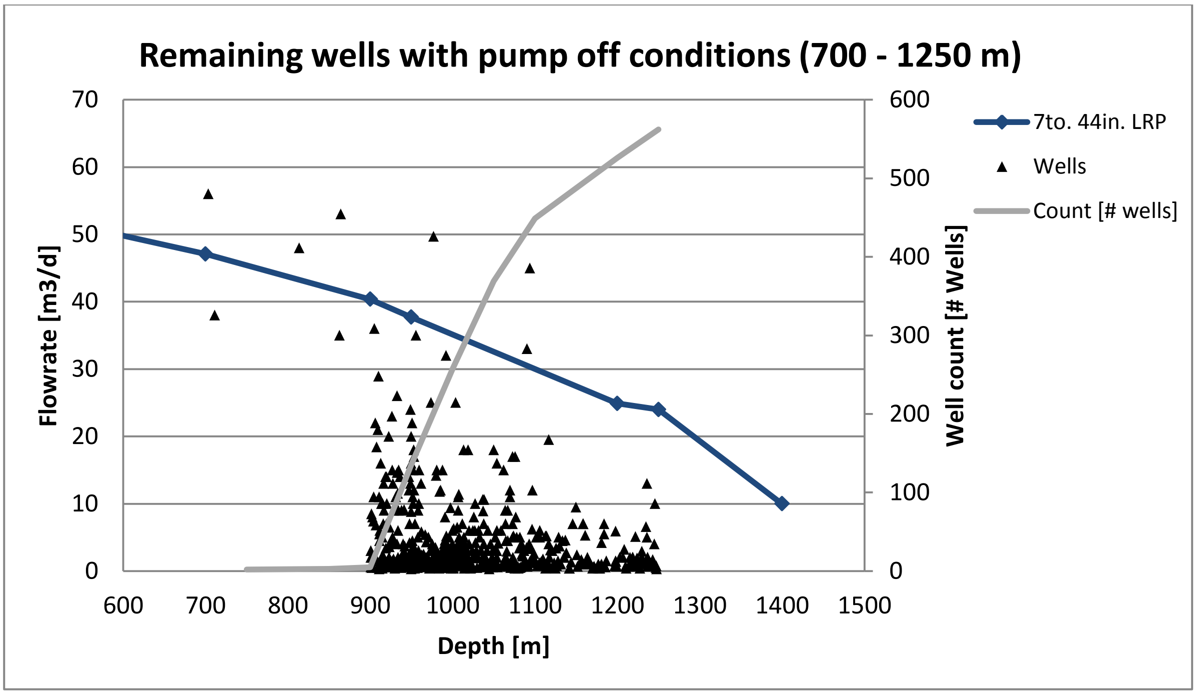


Figure 63: Remaining wells with pump off conditions from 700 till 1250m

5.4 Wells without Pump Off Conditions

As discussed in subchapter 3.2.1.2 “Usage of Automation”, when no pump off condition is present and no data transmission is required, there is no reason to install well automation on the pumping unit. This scenario depicts wells with these characteristics and after a screening of all the wells has been done, it will become evident, whether LRPs are the more economic choice or not.

- *Note:* Limiting conditions: Wells which contained no data (blank) in terms of depth or flowrate have been neglected, a minimum production of 1.1 m^3/d and an overall pump efficiency of >50% had to be present.

There are a total of 1819 wells at PETROM in Romania that shows no pump off condition characteristics. As the wells differ from each other in terms of depth and pump displacement significantly from each other, a wide variety of the described pumping units can be chosen to cover screened well areas and to become potential candidates for this condition in due consideration of pumping unit price and MPUL / surface stroke length characteristics.

Seen in

Table 34 is a list of pumping units that cover the screened wells depending on their pump displacement and depth rates. As wells without pump off conditions have been screened and no automation is installed on the units, consequently the conventional pumping unit’s price is more economic.

For deeper wells, starting at approx. 2000 m, a hydraulic pumping unit may be utilized to cover the wells with that depth range, because of the longer stroke length and reservoir fluid lifting capacity.

Due to the fact that the LRP is not the preferable choice for wells without pump off conditions, no further flowrate vs. depth charts will be described for this scenario.

Table 34: Pumping unit system comparison due to unit price for no pump off conditions

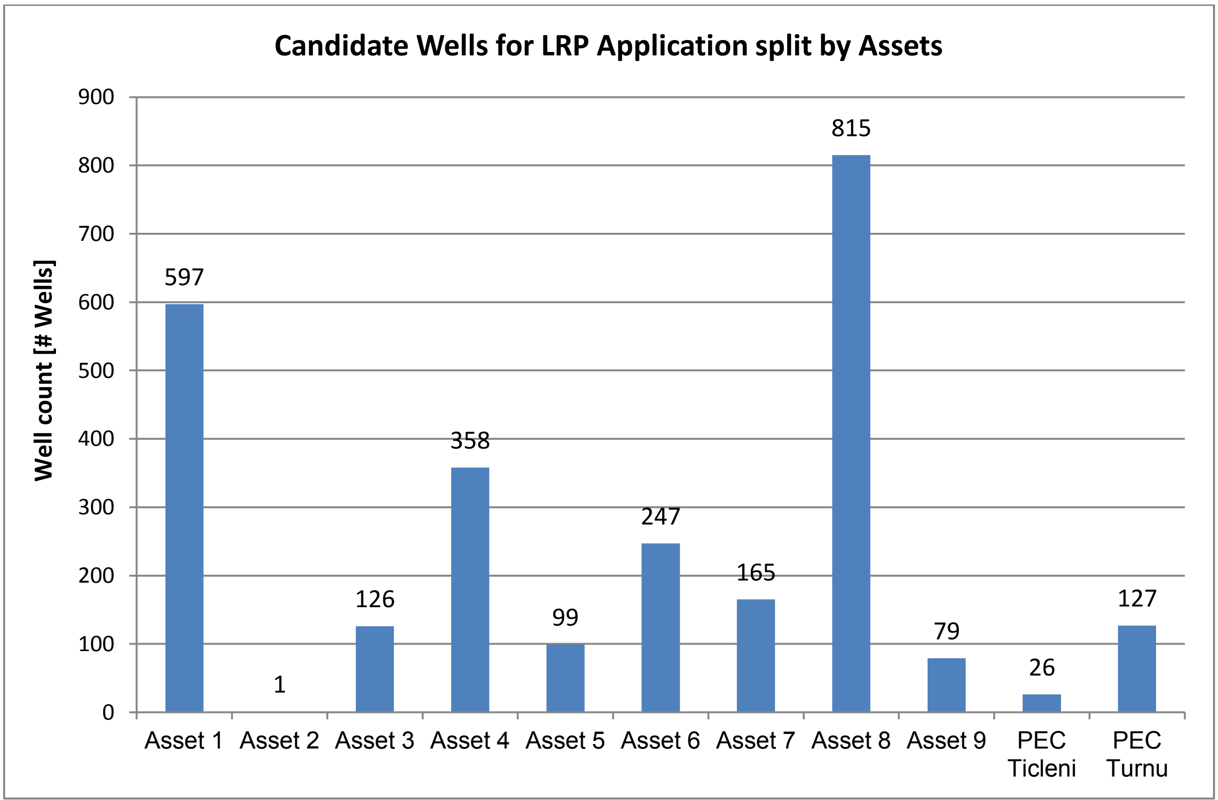
Pumping unit model	Approximate cost w/o automation [€]
L137-g-mmmm-044 / 3to. 44 in.	24,000
L239-g-mmmm-032 / 5to. 32 in.	27,000
C 57D-76-42 / 3,5to. 42 in.	***14,000***
L239-g-mmmm-044 / 5to. 44 in.	29,000
L381-g-mmmm044 / 7to. 44 in.	35,000
L381-g-mmmm-056 / 7to.56 in.	38,000
C 80D-119-64 / 5,4to. 64 in.	***20,000***
L381-g-mmmm-086 / 7to. 86 in.	42,000
L472-g-mmmm-086 / 10to. 86 in.	70,000
C 160D-143-74 / 7,9to. 74 in.	***33,000***
L472-g-mmmm-100 / 10to. 100 in.	77,000
L767-g-mmmm-100 / 13,6to. 100 in.	81,000
C 456D-256-144 / 11,6to. 144 in.	***70,000***
Powerlift PL 300 / 11to. 256 in.	***100,000***

5.5 Candidate Wells for LRP Application

LRP Application split by Assets

Subsequent to the scanned cases that have been examined earlier, a total of 2640 wells[ee] remain available as potential candidates for LRP application and the best three LRP model types that can cover these wells, have been picked and are seen in the figures to come. *Table 35* points out the number of wells that are covered by their belonging asset.

Table 35: 2640 wells for LRP application split by Assets



- *Note:* Disclosed in Appendix J a selected assortment of the screened 2640 wells is listed comprehensively with their individual corresponding asset, field cluster, sector, automation, status of the well, LRP installation depth, flowrate, pumping unit model and UWI number.

[ee] *456 Heavy oil wells with pump off condition + 594 high viscous oil wells with pump off conditions + 1590 remaining wells with pump off conditions*

Potential LRP types for Candidate Wells

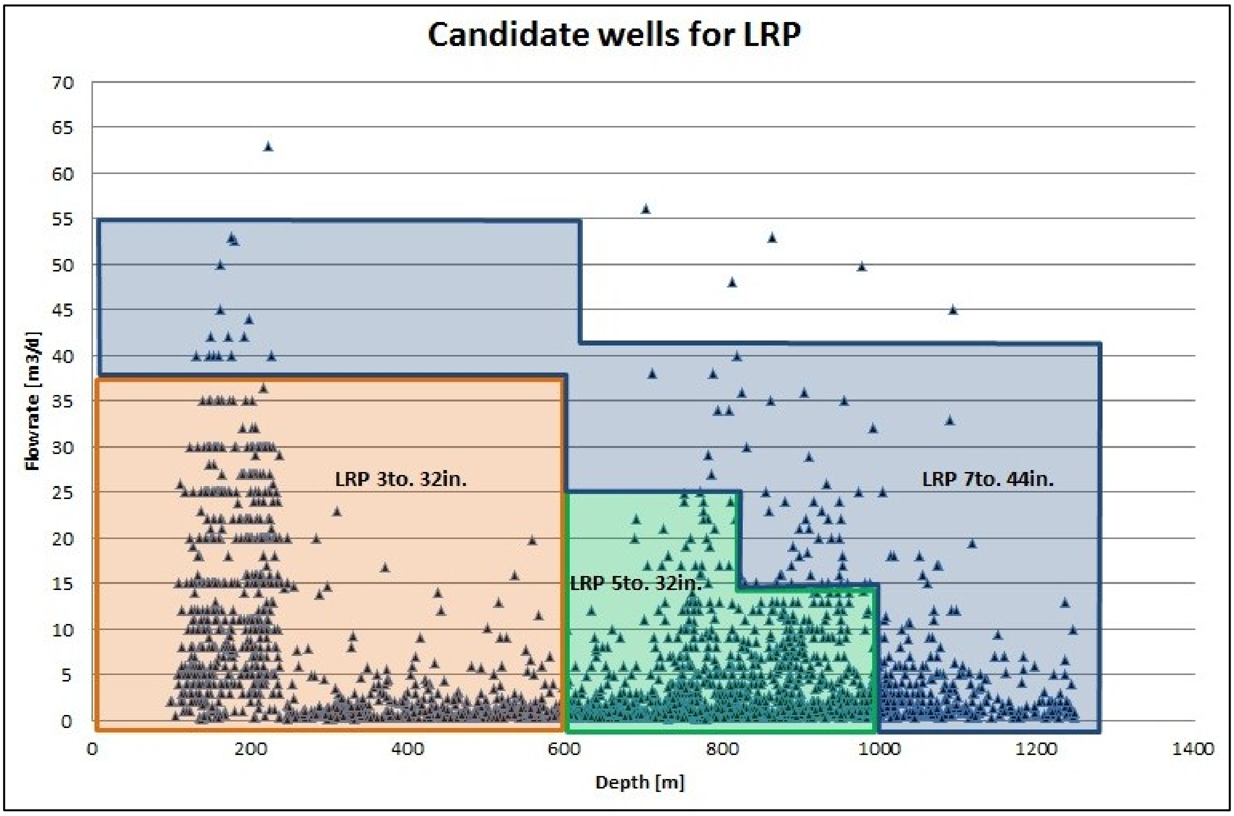


Figure 64: Candidate wells for potential LRP application

Figure 64 points out all the 2640 wells in a depth vs. flowrate chart and the three colored remaining LRP units with their MPUL and surface stroke length each marked in a different color. Every LRP can cover a certain well range to be analyzed in the figures to come.

Explaining the above mentioned pump off condition wells as deep as 600 m or shallower which produce 35 m^3/d or less are best covered by the LRP type which has a MPUL of 3 to. and a surface stroke length of 32 in. pictured in orange in *Figure 65*. The wells that can be covered by the 3to. 32 in. LRP are approximatelly 40% off all the candidate wells for LRP application.

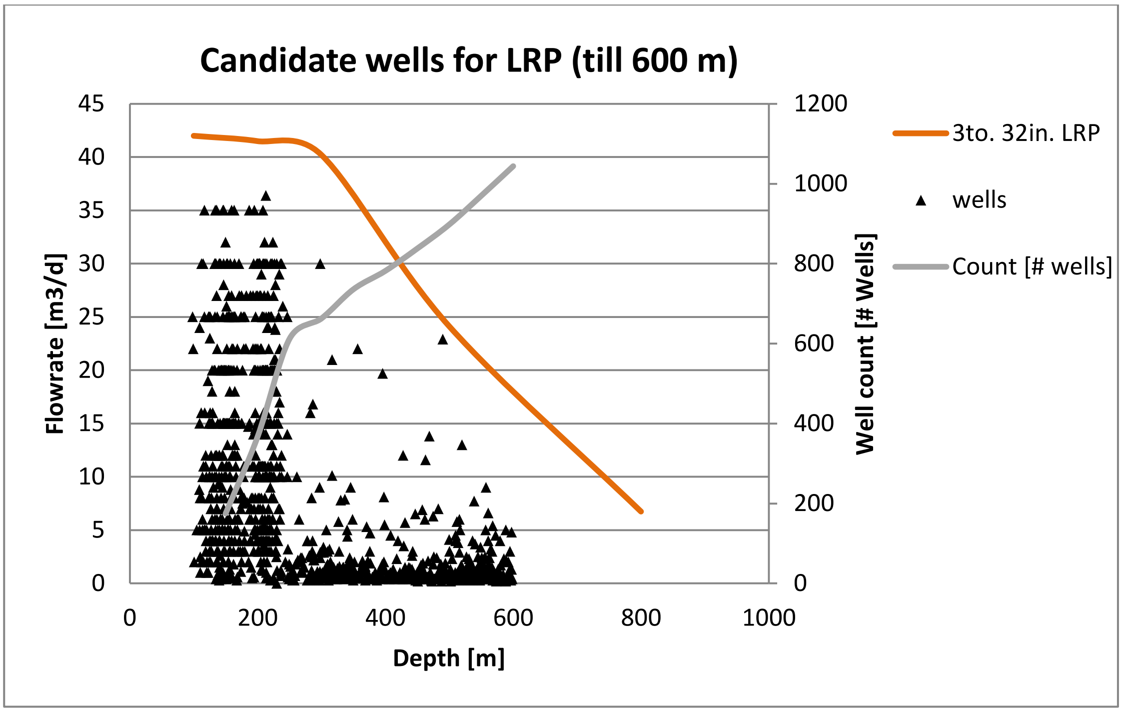


Figure 65: Candidate wells for LRP (till 600 m)

The next depth interval goes from 600 till 1000 m and has a flowrate range of up to 25 m^3/d depending on the depth. As depicted in detail in *Figure 66*, the 5 to. 32 in. LRP unit covers these wells satisfyingly. Here, the wells that can be covered by the 5to. 32 in. LRP are approximatelly 45% off all the candidate wells for LRP application.

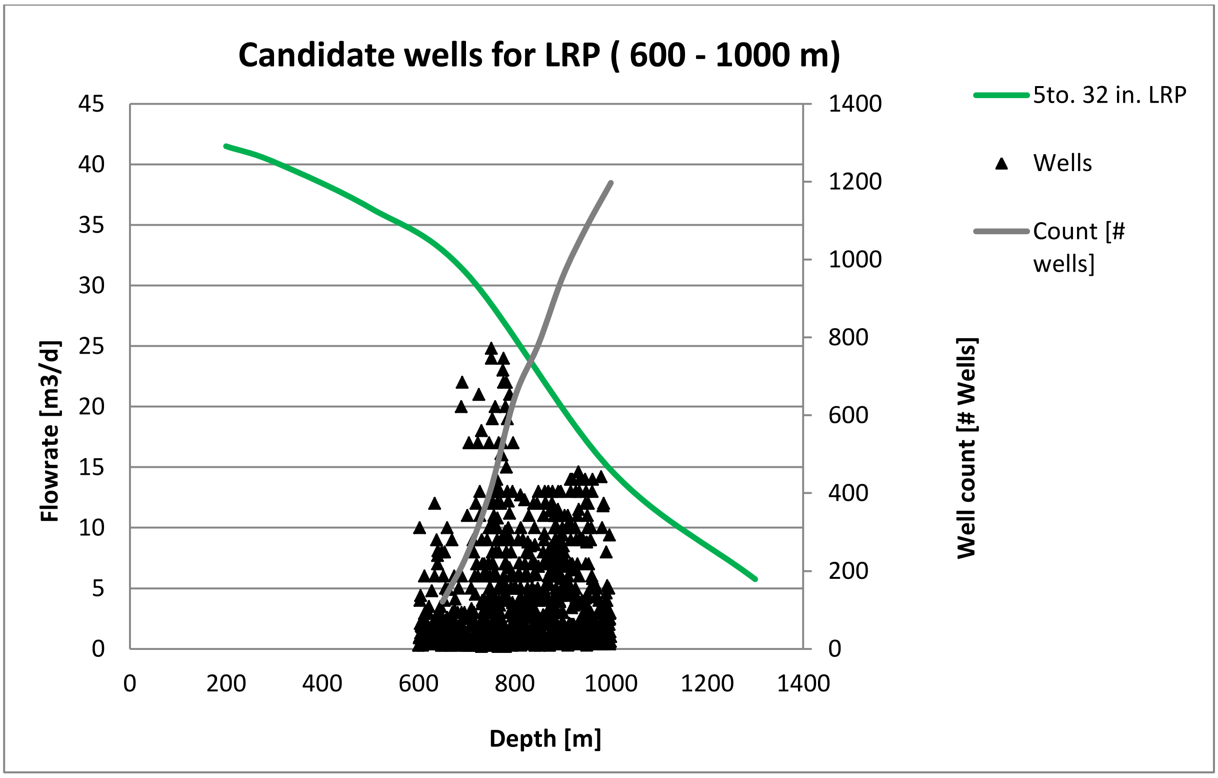


Figure 66: Candidate wells for LRP (600 - 1000m)

The last depth interval which basically covers the higher producing wells in the shallower depth section and the remaining wells that are not covered by the 5to. 32 in. LRP may be covered by the 7 to. 44 in. LRP and is pictured in *Figure 67*. It can be stated that approximatelly 15% of all the candidate wells for LRP application can be covered by this particular LRP.

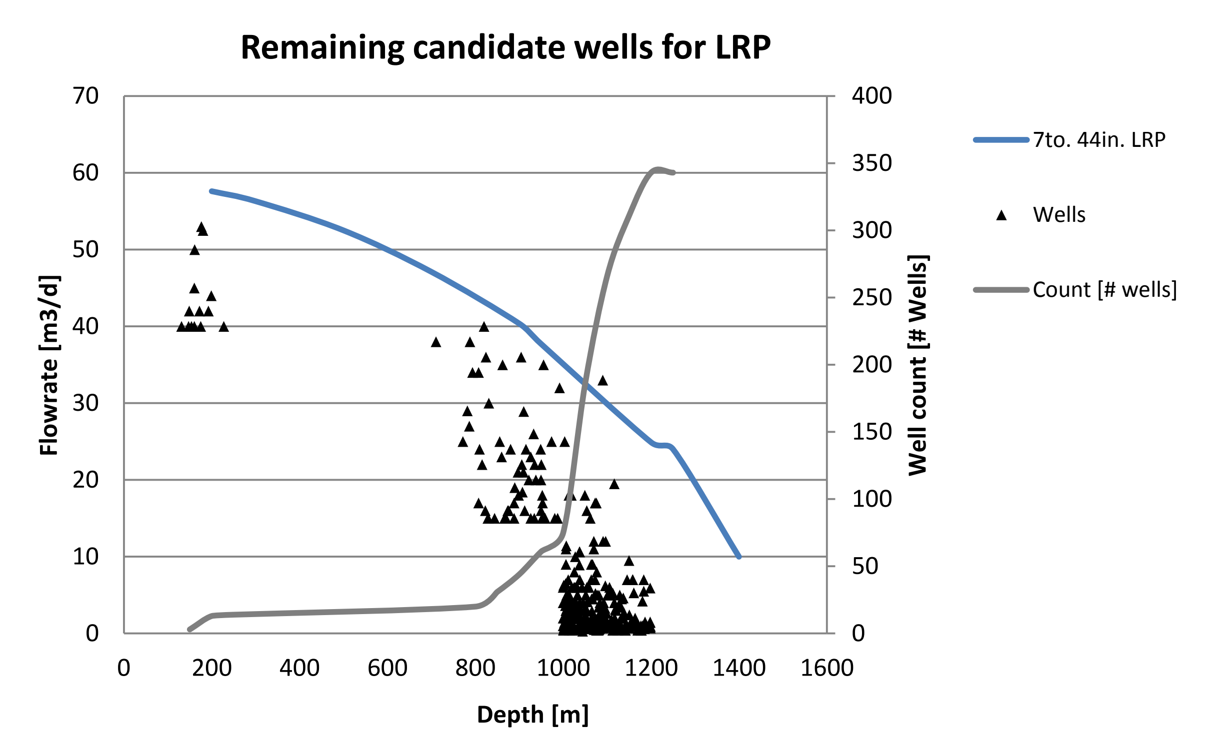


Figure 67: Remaining candidate wells for LRP

Operating ranges

Pictured in *Figure 68* is a graphical illustration of the operating range of the elected candidate wells for LRP application. The y-axis represents the occurrence of wells for a certain depth (Frequency). The depth itself is shown on the x-axis. After analyzing the well frequency vs. depth plot, two peaks marked with a red dot can be spotted. They present the two most frequent operating depths for the candidate wells. The first operating range has a total of 217 wells at a depth of 178 m, whereas the second operating range is at 773 m and a total of 234 wells are operating at this depth.

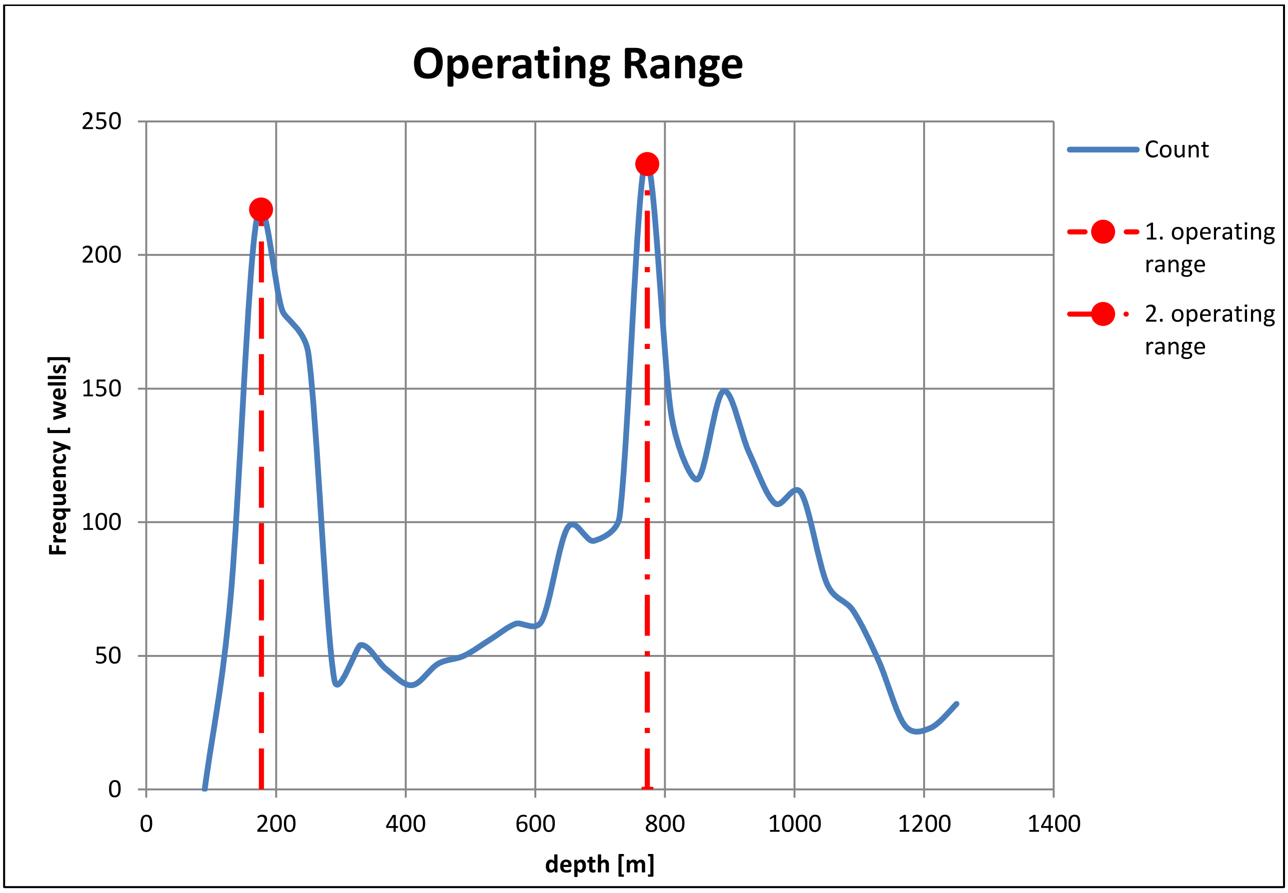


Figure 68: Operating range of candidate wells

Summarizing, three LRP types are eligible to cover the screened candidate wells. *Figure 69* describes the percentage of candidate well to be covered by their chosen LRPs.

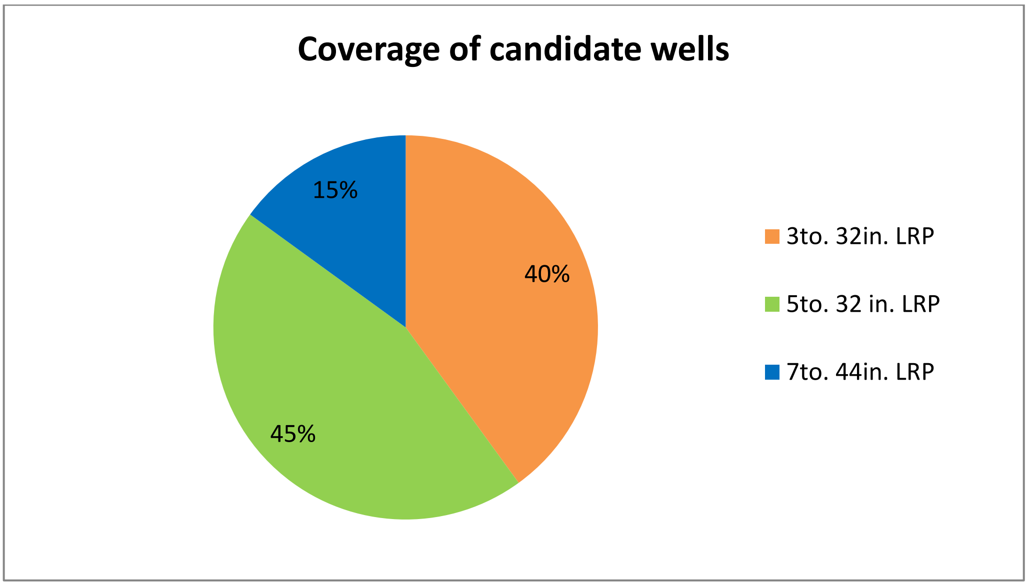


Figure 69: Coverage of candidate wells by LRP

6 Standardization

There is room for standardization recommendations as the essential LRP installation areas are applicable preferably at moderate depths and low flowrates (50 m^3/d or less). The candidate LRP types discussed in chapter 5.5 “Candidate Wells for LRP Application” are covering debated flowrate and depth areas and therefore utilized for similar wells and well conditions. As a logical step for a standardization proposal, individual motors for the chosen candidate LRPs have to be picked in respect to the selected wells for a specific area.

6.1 LRP Standardization Recommendation

As the individual motor frames for any given LRP are known due to UNICO motor design recommendations, a standardization proposal can be performed and the considered wells for LRP application are also being taken into account. At this point it has to be mentioned, that special emphasis has been given to the motor power. The motor design in detail with gearbox size, gearbox ratio and consequently the ultimate LRP model number would go beyond this thesis’ scope and are not discussed in detail.

Figure 70 shows three motor frame/kW charts for the 3to. 32 in. LRP. Also depicted in this chart are the wells and the initially initiated LRP which are suitable for this pump displacement and depth area. Considering a safety margin, due to the possibility of the motor being under designed and due to the fact that the smaller motor illustrates the maximum coverage area possibility, the 7.5 kW performance curve with the 160S4 motor frame should be considered as the preferred choice for the shallow wells till 600 m seen in *Figure 70.*

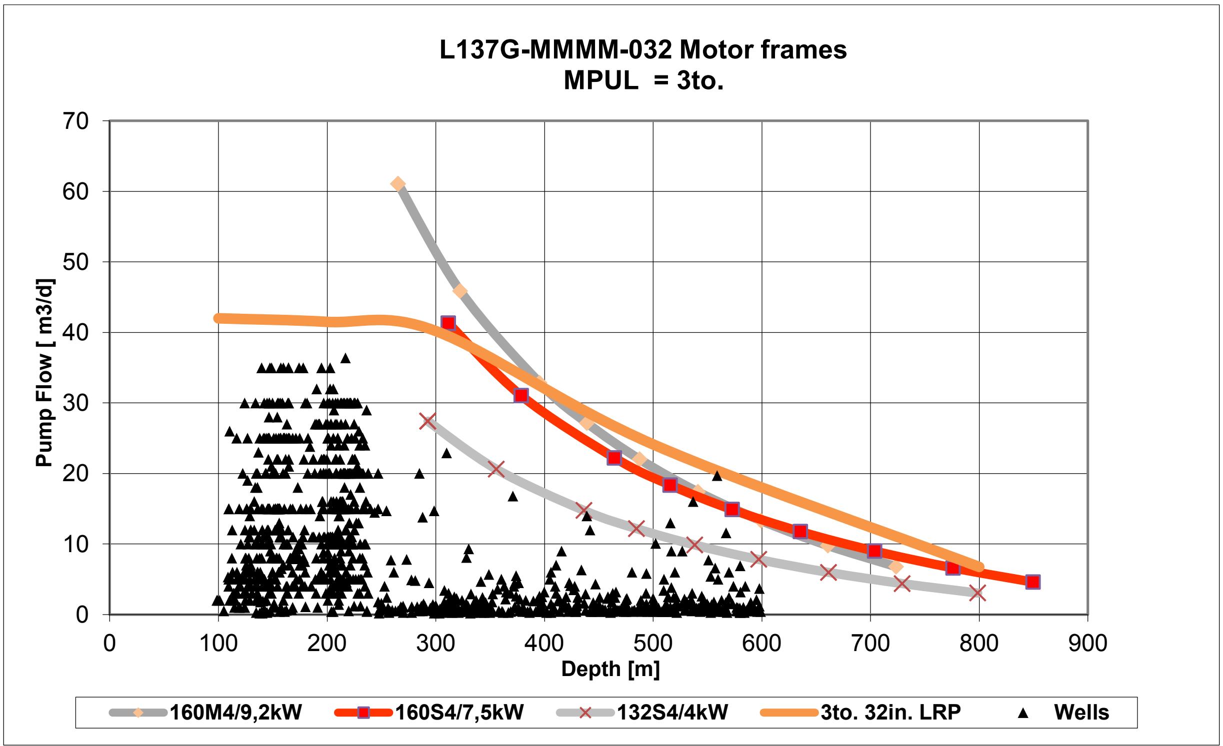


Figure 70: Motor frame/kW performance charts for 3to. 32 in. LRP

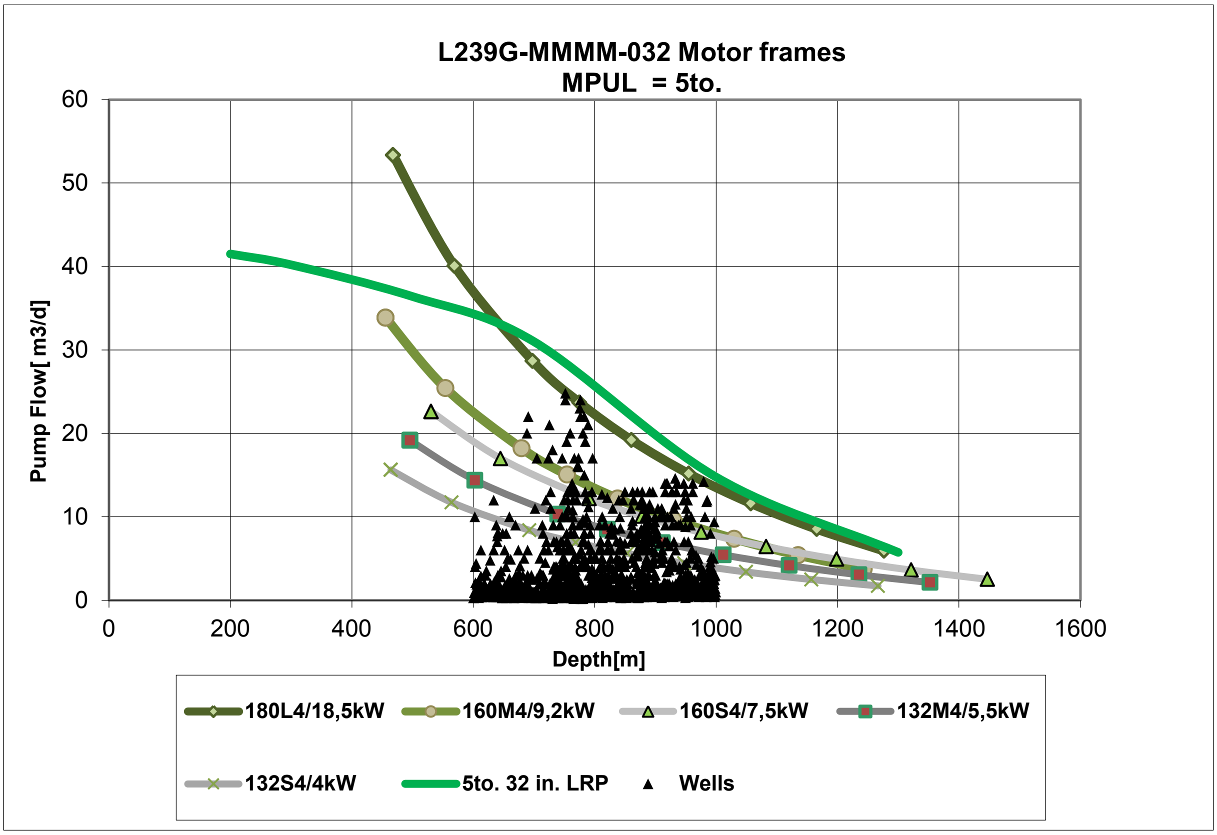


Figure 71: Motor frame/kW performance charts for 5to. 32 in. LRP

Figure 71 presents different kinds of motor frames/motor power curve suggestions for the 5to. 32 in. LRP with their corresponding wells for the depth area 600 -1000 m and maximum flowrate of 25 m^3/d. In case of *Figure 71,* two different kinds of motor frame/motor power curves may be introduced as potential motors for this scenario. The 160M4/9.2kW curve is the preferable choice for wells with a depth of 600 - 1000 m and applicable for a minimum flowrate range of 10-12 m^3/d. For the wells which produce more, the 180L4/18.5kW is the desirable selection.

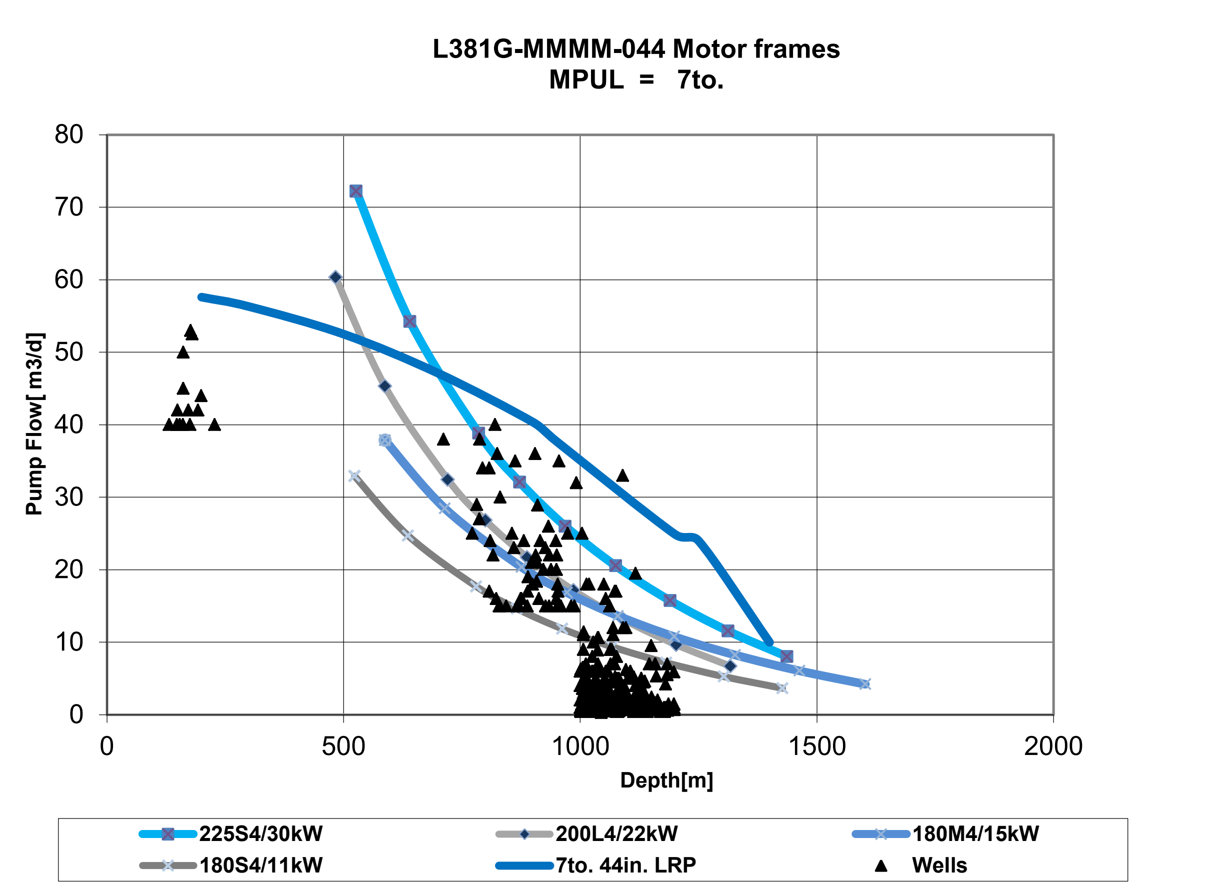


Figure 72: Motor frame/kW performance charts for 7to. 44 in. LRP

In the case of the last standardization recommendation for the 7to. 44 in. LRP, the same procedure as the last two standardization suggestions has been implemented. For the depth/flowrate interval depicted in *Figure 72* the 180M4/15kW curve is able to manage the shallower wells till 500 m. This motor type can also handle depth till 1000 m till an approx. flowrate of 15 m^3/d. For higher production rates the 225S4/30kW may be the preferable alternative. Detailed motor design and motor recommendation is finally left to the LRP supplier where other factors also might be of importance.

7 Observation and Conclusion

During the course of this thesis the LRP and mentioned pumping unit systems have been examined and their characteristics have been compared. In order to find potential well candidates for LRP application, specific selection criteria was made and during the simulation and screening, well recommendations were developed.

Summarizing, shallow pump off condition wells with low flowrates and in particular heavy oil wells with pump off conditions and cyclic steam injection are preferable candidates for LRP application due to operational flexibility and adjustable pumping speed, which can be changed individually for the up and down stroke for each well.

Furthermore, due to the fact that the LRP system contains well automation (VSD) as part of the standard delivery package, it is an economic alternative to other pumping systems which need additional investment for automation.

The elaborated LRP selection criteria and recommendations will help PETROM to choose new LRP candidates in the future. In addition a standardization recommendation of LRP types and motor sizes has been developed which will help reducing maintenance and purchasing requirements.

After the LRP candidate screening and standardization was completed it has been decided to exclude the already installed LRP units (89 of 163 installed in total) from the 2640 selected LRP well candidates. Furthermore, wells which are already equipped with a conventional pumping unit including well automation (1086 wells) have been excluded from the priority list as well, because the replacement of these pumping units with a new LRP would be hard to justify, because they require additional investment. The remaining 1465 wells suitable for LRP installation reflect a similar distribution comparable to the distribution of all candidate wells for LRP application and are depicted in *Figure 73* overleaf.

All in all, the results of the thesis show that the LRP application has a wide application potential for PETROM and is an economic alternative to other pumping systems considering the criteria mentioned above. Consequently it is recommended to consider the utilization of an LRP system for every new well drilled or when conventional pumping systems have to be replaced because of age wear.

In addition the Linear Rod Pump is a good candidate for wells with limited life expectancy which are in many cases pump off condition wells. Accompanying that, when it comes to well to well move for temporary installations and installation in remote locations LRP application is the possible preferable choice. Moreover, the LRP installation is beneficial for fast production restart, since the full installation of the unit can be executed within a couple of hours and the unit is mounted directly on the wellhead and therefore concrete pads are unnecessary and other site preparations are not needed.

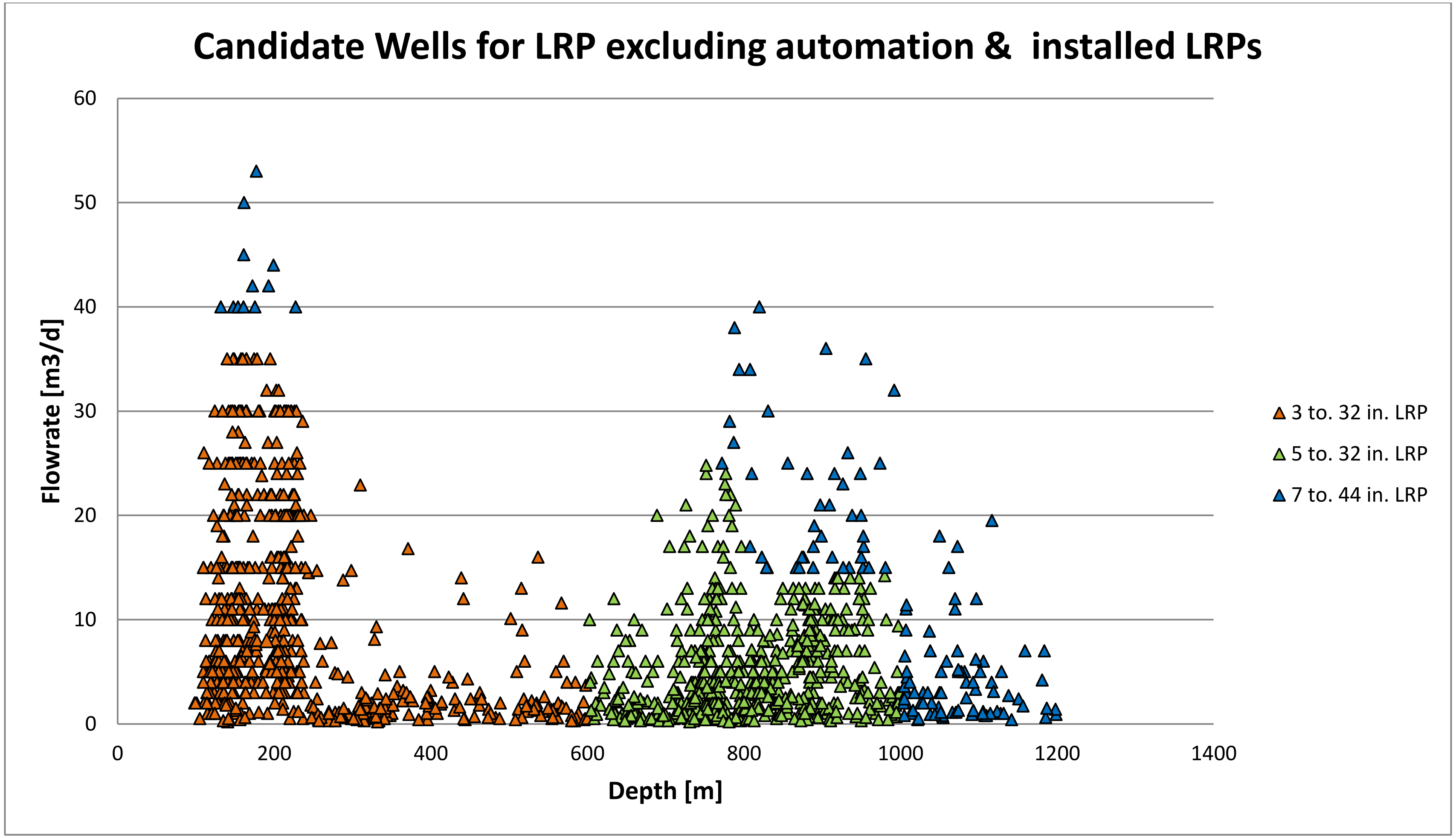


Figure 73: Candidate wells for LRP after excluding automation and installed LRP

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9 Appendices

Appendix A Miscellaneous

Table 36: Unit conversions

bar	x100,000	=Pa
bbl (Imp.)	x 159.1132	=liter
bbl.	x 0.159	=m^3
bbl/d (BPD)	x 0.158987	= m^3/d
BPD	x 1/543,396	=m^3/s
cP	x 0.001	=N-s/m^2
F	(F-32)/1.8	=°C
ft	x 0.3048	=m
Ft^3,cuf	x 0.0283169	=m^3
in	x 0.0254	= m
lb.	x 0.0004535	=tons
lb.	x 0.453593	=kg
lbf in	x 0.11298483	=Nm
m^3/d	x 6.2898	=bbl/d
N	x 0.1019716	=kg
N	x 0.224808943	=lb.
Nm	x 0.101972	=Kgf m
psi,psia,psig	x 6894.757	=Pa

Appendix B

Table 37: API standardisation of old beam pump types to new type [35]

#	API-Standardized Type	Old Type	
		Type	**Qty**
1	**C 57D-76-42** (3.4T-1067-657)	3T-1200-500B	3
		3T-1200-1000B	978
		3T-1500-500-Wulfer	8
		3T-1500-1000-Wulfer	4
		4T-1230-790-,,1MAI"Ploiesti-Concordia	1
2	**C 80D-119-64** (5.4T-1626-922)	5T-1200-1000C	1
		5T-1500-1000C	31
		5T-1200-1000MTD-Resita	67
		5T-1500-1130-Wulfer	1
		6T-1626-1380,,1MAI"Ploiesti-Concordia	4
3	**C 160D-143-74** (6.5T-1880-1880)	3T-1500-2000	2
		5T-1500-2000	1066
		7T-2000-2000	29
		7T-2000-2000MTD-Resita	78
		5T-1500-2000C,,1MAI"Ploiesti-Concordia	21
		5T-1500-2000-Teleajen	4
4	**C 228D-173-74** (7.8T-1880-1880)	7T-2000-3500	1655
		9T-2000-3000MTD-Resita	36
		7T-2000-3500-Teleajen	1
		7T-2000-3500-Vilmar Rm.Valcea	14
5	**C 228D-173-100** (7.8T-2540-2627)	5.2T-2700-3500	6
		7T-2500-3500	1
		7T-2500-3500 ,,1MAI"Ploiesti-Concordia	2
6	**C 320D-213-120** (9.7T-3050-3687)	6.4T-3500-5500	151
		6.4T-3500-3500	7
		7T-3500-3500	2
		9T-2500-3500	135
		9T-3000-3500	52
		9T-3500-3500	10
		9T-3000-3500 ,,1MAI"Ploiesti-Concordia	2
7	**C 456D-256-144** (11.6T-3658-5254)	6.4T-4200-5500	3
		7T-3500-5500	39
		9T-2500-5500	194
		9.7T-3500-5500	1
		12T-3000-5500	90
		9T-3600-5500 ,,1MAI"Ploiesti-Concordia	4
		9T-2500-5500-Vilmar Rm.Valcea	34

#	API-Standardized Type	Old Type	
		Type	**Qty**
8	**C 640D-256-144** (11.6T-3658-7374)	9T-4000-7500	409
		12T-3000-7500	229
		12T-4000-7500	3
		9T-4000-7500 ,,1MAI"Ploiesti-Concordia	1
		12T-3000-7500 ,,1MAI"Ploiesti-Concordia	12
		9T-4000-7500 Vilmar Rm.Valcea	6
		12T-4000-7500 Vilmar Rm.Valcea	18
9	**C 640D-305-168** (13.8T-4270-7374)	12T-5000-7500	14
		15T-3000-5500	1
		15T-3000-7500	3
		15T-4000-7500	16
		15T-4000-7500MTD-Resita	1
10	**C 912D-305-168** (13.8T-4270-10508)	9T-4000-10000	44
		12T-4000-9000	3
		12T-5000-10000	73
		15T-4000-9000	9
		15T-3000-10000	1
		15T-4000-10000	163
		12T-4000-10000,,1MAI"Ploiesti-Concordia	6
		15T-4000-10000,,1MAI"Ploiesti-Concordia	4
		15T-4000-10000 Vilmar Rm.Valcea	7
11	**C 912D-365-192** (16.6T-4877-10508)	15T-5000-10000	96
		19.3T-3650-7500	1

Appendix C

Table 38: CPU vs. LRP Design Comparison

Well: 2811 Babeni
Date: 23.08.2013

RODSTAR-V
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INPUT DATA

Target prod. (bfpd):	79	Fluid level	
Run time (hrs/day):	24,0	(ft from surface):	2776
Tubing pres. (psi):	63,1	(ft over pump):	98
Casing pres. (psi):	0	Stuf.box fr. (lbs):	100
		Pol. Rod Diam: 1.5"	

Fluid properties

Water cut:	75%
Water sp. gravity:	1,05
Oil API gravity:	23,0
Fluid sp. gravity:	1,0165

Motor & power meter

Power Meter	Detent
Electr. cost:	$,1/KWH
Type:	NEMA D

Pumping Unit: Lufkin Conventional - New (C-80D-119*)

API size: C-80-119-64 (unit ID: CL99)

Crank hole number	#3 (out of 3)
Calculated stroke length (in):	42,5
Crank Rotation with well to right:	CCW
Max. CB moment (M in-lbs):	Unknown
Structural unbalance (lbs):	0
Crank offset angle (deg):	0,0

Tubing and pump information

Tubing O.D. (ins)	2,875	Upstr. rod-tbg fr. coeff:	0,300
Tubing I.D. (ins):	2,441	Dnstr. rod-tbg fr. coeff:	0,300
Pump depth (ft):	2874	Tubing is not anchored	
Pump condition:	Full	Pump load adj. (lbs):	0.0
Pump type:	Insert	Pump vol. efficiency :	85%
Plunger size (ins)	1,75	Pump friction (lbs):	200,0

Rod string design

Diameter (inches)	Rod Grade	Length (ft)	Min. Tensile Strength (psi)
0.875	D (API)	1437	115000
0.875	D (API)	1437	115000

NOTE Stress calculations do not include buoyancy effects.

CALCULATED RESULTS (TOTAL SCORE: 80% Grade: B)

Production rate (bfpd):	80	Peak pol. rod load (lbs):	9552
Oil production (BOPD):	20	Min. pol. rod load (lbs):	4329
Strokes per minute:	7,38	MPRL/PPRL	0,453
System eff. (Motor->Pump):	47%	Unit struct. loading:	80%
Permissible load HP:	7,2	PRHP / PLHP	0,34
Fluid load on pump (lbs):	3100	Buoyant rod weight (lbs):	5571
Polished rod HP:	2,4	N/No: ,087 , Fo/SKr:	,137

Required prime mover size (speed var. not included) — BALANCED (Min Torq)

NEMA D motor:	5 HP
Single/double cyl. engine:	5 HP
Multicylinder engine:	5 HP

Torque analysis and electricity consumption — BALANCED (Min Torq)

Peak g'box torq.(M in-lbs):	61
Gearbox loading:	76,2%
Cyclic load factor:	1,4
Max. CB moment (M in-lbs):	149,0
Counterbalance effect (lbs):	7145
Daily electr.use (KWH/day):	63
Monthly electric bill:	$193
Electr.cost per bbl. fluid:	$0,080
Electr.cost per bbl. oil:	$0,318

Tubing, pump and plunger calculations

Tubing stretch (ins):	1,9
Prod. loss due to tubing stretch (bfpd):	4,3
Gross pump stroke (ins):	37,5
Pump spacing (in. from bottom):	8,6
Minimum pump length (ft):	7,0
Recommended plunger length (ft):	2,0

Rod string stress analysis (service factor: 0,9)

Stress Load %	Top Maximum Stress (psi)	Top Minimum Stress (psi)	Bot. Minimum Stress (psi)	Stress Calc. Method
38%	15967	7614	3571	API MG
30%	10752	3571	-333	API MG

Input Parameters	Value	Units	Value	Units
Rod String Length	2,875	Feet	876	Meters
Sinker Bar Length		Feet	0	Meters
Tubing Anchor Point	0	Feet	0	Meters
Fluid Over Pump	100	Feet	30	Meters
Deviation Radius	0	Feet	0	Meters
Upper Deviation Kickoff	0	Feet	0	Meters
Lower Deviation Kickoff	0	Feet	0	Meters
Upper Deviation Angle	0.0	Degrees	0.0	Degrees
Lower Deviation Angle	0.0	Degrees	0.0	Degrees
Upper Rod Diameter	0.875	Inches	22.23	MM
Lower Rod Diameter	0.875	Inches	22.23	MM
Sinker Bar Diameter	1.000	Inches	25.40	MM
Upper Rod Fraction	50.0%		50.0%	
Lower Rod Fraction	50.0%		50.0%	
Rod String Grade	D		D	
Plunger Diameter	1.750	Inches	44.45	MM
Tubing Diameter	2.875	Inches	73.03	MM
Rod Friction	2,000	Pounds	907	Kg
Pump Friction	200	Pounds	91	Kg
Friction Coefficient	20%		20%	
Pump Efficiency	85%		85%	
Water Cut	75%		75%	
Water Specific Gravity	1.050		1.050	
API Oil Grade	23.0		23.0	
Flowline Pressure	100.0	Psi	690	Kp
Tubing Pressure	50.0	Psi	345	Kp
Casing Pressure	0.0	Psi	0	Kp
Electrical Power Cost	$0.100	$/Kwh	$0.100	$/Kwh
Unit Type Selection	LRP		LRP	
Unit Stroke Length	44.0	Inches	1,118	MM
Unit Gearbox Size	381		381	
Unit Gearbox Ratio	C		C	
Unit Input Voltage	575	Vrms	575	Vrms
Unit Motor Frame	286E		286E	

Calculated Parameters	Value	Units	Value	Units
Actuator Model	L381C-286E-044			
Maximum Plunger Diameter	2.750	Inches	69.85	MM
Pump Depth	2,875	Feet	876	Meters
Fluid Level	2,775	Feet	846	Meters
Maximum Pump Speed	6.92	Spm	6.92	Spm
Total Power Cost	$492	$/Mon	$492	$/Mon
System Efficiency	18.6%		18.6%	
Pump Fluid Flow	79.1	Bbl/Day	12.58	M^3/Day
Pump Oil Flow	19.8	Bbl/Day	3.15	M^3/Day

Appendix D

Table 39: Full list of "Rotaflex" Long-Stroke Pumping Unit specifications [40]

Model	900	1100	1150	1151
Reducer torque (*in.-lbf*, kN.m)	*320,000*, 36.16	*320,000*, 36.16	*320,000*, 36.16	*420,000*, 47.45
Stroke length (*in.*, m)	*288*, 7.3	*306*, 7.8	*366*, 9.3	*366*, 9.3
Maximum polished rod weight (*lb.*, kg)	*36,000*, 16,329	*50,000*, 22,680	*50,000*, 22,680	*50,000*, 22,680
Maximum speed without variable frequency drive (SPM)	4.50	4.30	3.64	3.75
Minimum speed (SPM)	No absolute minimum	No absolute minimum	No absolute minimum	No absolute minimum
Weight of counterweight assembly (*lb.*, kg)	*9,400*, 4,264	*9,800*, 4,445	*9,800*, 4,445	*9,800*, 4,445
Auxiliary counterweight (*lb.*, kg)	*21,980*, 9,969	*30,200*, 13,698	*30,200*, 13,698	*30,200*, 13,698
Total weight (*lb.*, kg)	*31,380*, 14,234	*40,000*, 18,144	*40,000*, 18,144	*40,000*, 18,144
Unit dimensions, L x W x H, (*ft*, m)	*21.8 x 7.8 x 40.5* 6.64 x 2.38 x 12.34	*23.8 x 8.5 x 44.5* 7.25 x 2.59 x 13.56	*23.8 x 8.5 x 49.5* 7.25 x 2.59 x 15.09	*23.8 x 8.5 x 49.5* 7.25 x 2.59 x 15.09
Working temperature (*°F*, °C)	*-40° - +140°* -40° - +60°	*-40° - +140°* -40° - +60°	*-40° -+140°* -40°- +60°	*-40° - +140°* -40°- +60°
Load belt tensile strength (*lb.*, kg)	*10,000*, 4,536	*10,000*, 4,536	*10,000*, 4,536	*10,000*, 4,536

Appendix E

Table 40: Power Unit technical data [59]

Hydraulics	Electrical	Automation
100 bar continuous pump pressure rating	Electric motor: max 22kW,1500 rpm	PLC(Programmable Logic Controller)
250 bar valve component ratings	380 VAC three phase electrical power	Continuous oil pressure monitoring for alarms and shut down
Variable pump displacement	Thermal magnetic motor overload protection	Continuous oil level and temperature monitoring
Continuous automatic cooling system control	Circuit breakers and thermal fuse protection on all control devices and loads	Control software
Continuous pump strainer filtration		Data based collection and analysis
Manually adjustable pressure relieve valve		
Continuous return filtration		

Appendix F

Table 41: Motor Frame Descriptions for LRP [XXXII]

Motor Frame Descriptions			
184S	5 Hp	TEFC	Class 1 Division 2
184E	5 Hp	TEFC	Explosion Proof
215S	10 Hp	TEFC	Class 1 Division 2
215E	10 Hp	TEFC	Explosion Proof
254S	15 Hp	TEFC	Class 1 Division 2
254E	15 Hp	TEFC	Explosion Proof
256S	20 Hp	TEFC	Class 1 Division 2
256E	20 Hp	TEFC	Explosion Proof
284S	25 Hp	TEFC	Class 1 Division 2
284E	25 Hp	TEFC	Explosion Proof
286S	30 Hp	TEFC	Class 1 Division 2
286E	30 Hp	TEFC	Explosion Proof
324S	40 Hp	TEFC	Class 1 Division 2
324E	40 Hp	TEFC	Explosion Proof
326S	50 Hp	TEFC	Class 1 Division 2
326E	50 Hp	TEFC	Explosion Proof
1852	15 Hp	TEFC	Class 1 Division 2
1853	20 Hp	TEBC	Class 1 Division 2
2162	20 Hp	TEFC	Class 1 Division 2
2163	25 Hp	TEBC	Class 1 Division 2
2168	25 Hp	TEFC	Class 1 Division 2
2169	30 Hp	TEBC	Class 1 Division 2
2173	30 Hp	TEFC	Class 1 Division 2
2174	40 Hp	TEBC	Class 1 Division 2
2570	40 Hp	TEFC	Class 1 Division 2
2571	50 Hp	TEBC	Class 1 Division 2
2578	50 Hp	TEFC	Class 1 Division 2
2579	60 Hp	TEBC	Class 1 Division 2
2586	60 Hp	TEFC	Class 1 Division 2
2587	75 Hp	TEBC	Class 1 Division 2

Table 42: Gearbox ratios[XXXIII]

RATING	RATIOS								
Nm	A	B	C	D	E	F	G	H	J
820	12,48	15,19	24,00	35,62	48,77	60,66	76,37	102,62	123,54
1550	12,36	17,87	25,62	40,04	51,18	64,75	78,07	97,05	128,52
2700	12,56	17,42	24,92	36,52	44,02	63,00	79,34	102,71	126,91
4300	11,99	18,96	24,75	38,30	47,93	62,55	77,89	96,80	123,93

XXXII *Accommodated by PETROM(Production System Optimization department) from LRP report on 15.11.2012*

XXXIII *Provided by Alfera, UNICO representative in Romania (LRP performance summary) on 16.09.2012*

Appendix G

RODSTAR-V 3.3.1

Company: PETROM
Well: 18 Beciu
Disk file: 18 BECIU.rsvx
Comment: Beam Pumping Unit

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Page 1 of 1
User: Hannes Abdalla
Date: 09.11.2012

INPUT DATA

Strokes per minute:	5	Fluid level	
Run time (hrs/day):	24.0	(m from surface):	596
Tubing pres. (kPa):	203	(m over pump):	0
Casing pres. (kPa):	101	Stuf.box fr. (N):	445
		Pol. Rod Diam:	1.25" (31.8 mm)

Fluid properties		Motor & power meter	
Water cut:	58%	Power Meter	Detent
Water sp. gravity:	1.05	Electr. cost:	$.12/KWH
Oil density (g/cm³):	0.83	Type:	NEMA D
Fluid sp. gravity:	0.9576	Size:	10 hp

Pumping Unit: Vulcan Conventional (UP5T-1500-2000C*)

API size: C-173-110-59 (unit ID: VC27)	
Crank hole number	#1 (out of 5)
Calculated stroke length (cm):	149.7
Crank Rotation with well to right:	CCW
Max. CB moment (N-m):	Unknown
Structural unbalance (N):	0
Crank offset angle (deg):	0.0

Tubing and pump information

Tubing O.D. (mm	73.025	Upstr. rod-tbg fr. coeff:	1.660
Tubing I.D. (mm):	62.001	Dnstr. rod-tbg fr. coeff:	1.660
Pump depth (m):	596	Tubing is not anchored	
Pump condition:	Full	Pump load adj. (N):	0
Pump type:	Insert	Pump vol. efficiency :	85%
Plunger size (mm	31.8	Pump friction (N):	890

CALCULATED RESULTS

Production rate (m³/D):	7	Peak pol. rod load (N):	20686
Oil production (m³/D):	2.9	Min. pol. rod load (N):	11081
Strokes per minute:	5	MPRL/PPRL	0.536
System eff. (Motor->Pump):	22%	Unit struct. loading:	42%
Permissible load power (k	5.6	PRHP / PLHP	0.17
Fluid load on pump (N):	4506	Buoyant rod weight (N):	13893
Pol. rod power (kW):	1	N/No: .037 ,	Fo/SKr: .027

Prime mover speed variation
Speed variation not considered

Torque analysis and electricity consumption	BALANCED (Min Ener)	BALANCED (Min Torq)
Peak g'box torq.(N-m):	5101	4807
Gearbox loading:	26%	25%
Cyclic load factor:	1.5	1.5
Max. CB moment (N-m):	11166.75	11664.99
Counterbalance effect (N):	3608	3769
Daily electr.use (KWH/day):	47	48
Monthly electric bill:	$168	$172
Electr.cost per m³ fluid:	$0.787	$0.809
Electr.cost per m³ oil:	$1.875	$1.925

Tubing, pump and plunger calculations

Tubing stretch (cm):	1.1
Prod. loss due to tubing stretch (m³/D):	.1
Gross pump stroke (cm):	145.0
Pump spacing (cm from bottom):	14.9
Minimum pump length (m):	2.4
Recommended plunger length (m):	.6

Rod string design

Diameter (mm)	Rod Grade	Length (m)	Min. Tensile Strength kPa
22.2	D (API)	185	792897
19.1	D (API)	411	792897

Rod string stress analysis (service factor: 0.76)

Stress Load %	Top Maximum Stress (kPa)	Top Minimum Stress (kPa)	Bot. Minimum Stress (kPa)	Stress Calc. Method
17%	52793	30327	18070	API MG
19%	49648	23896	-3121	API MG

NOTE Stress calculations do not include buoyancy effects.

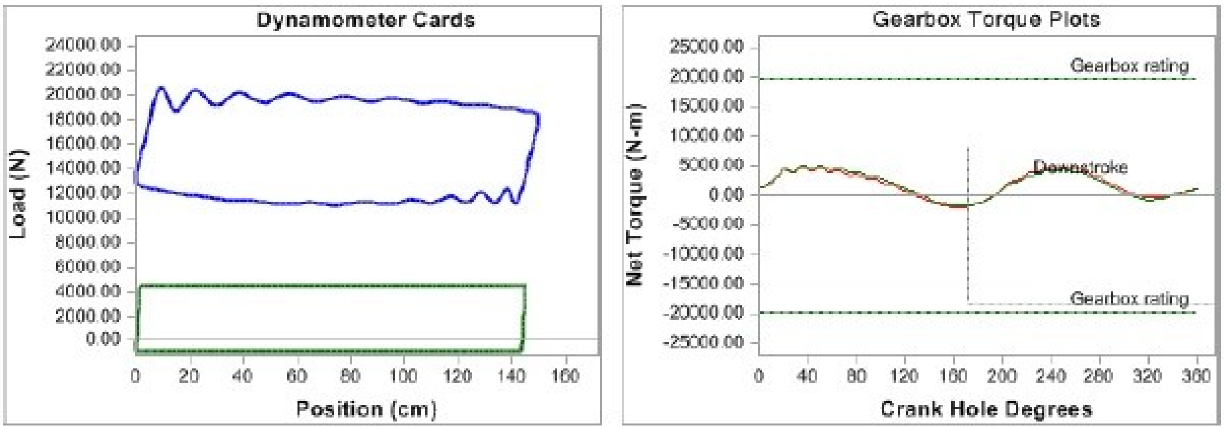

Figure 74: RODSTAR design for Beam Pumping Unit

Appendix H

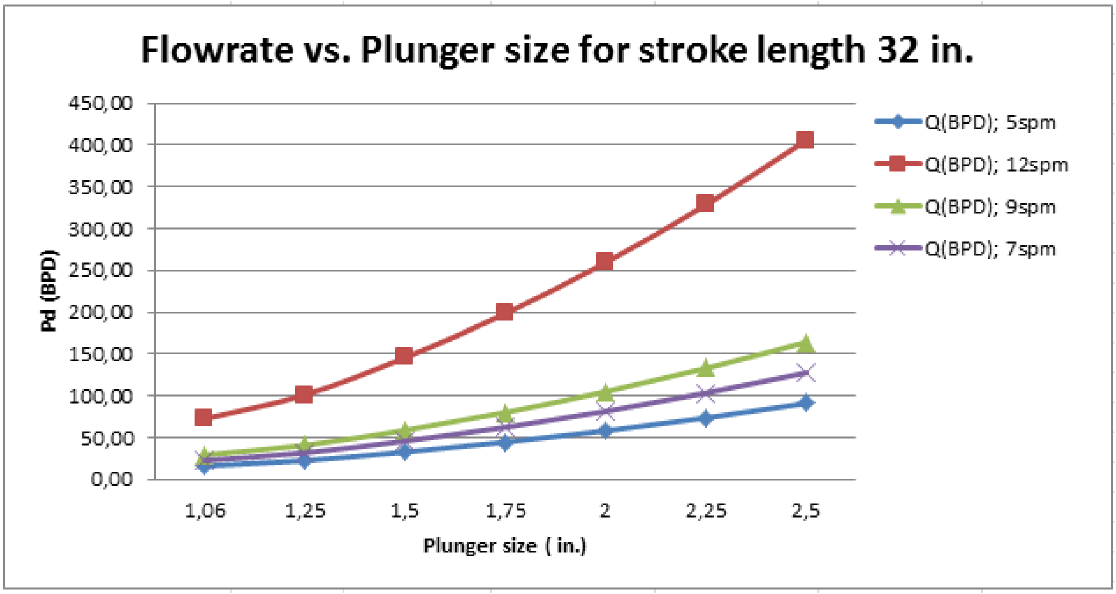

Figure 75: Pump displacement vs. Plunger size for stroke length 32 inch

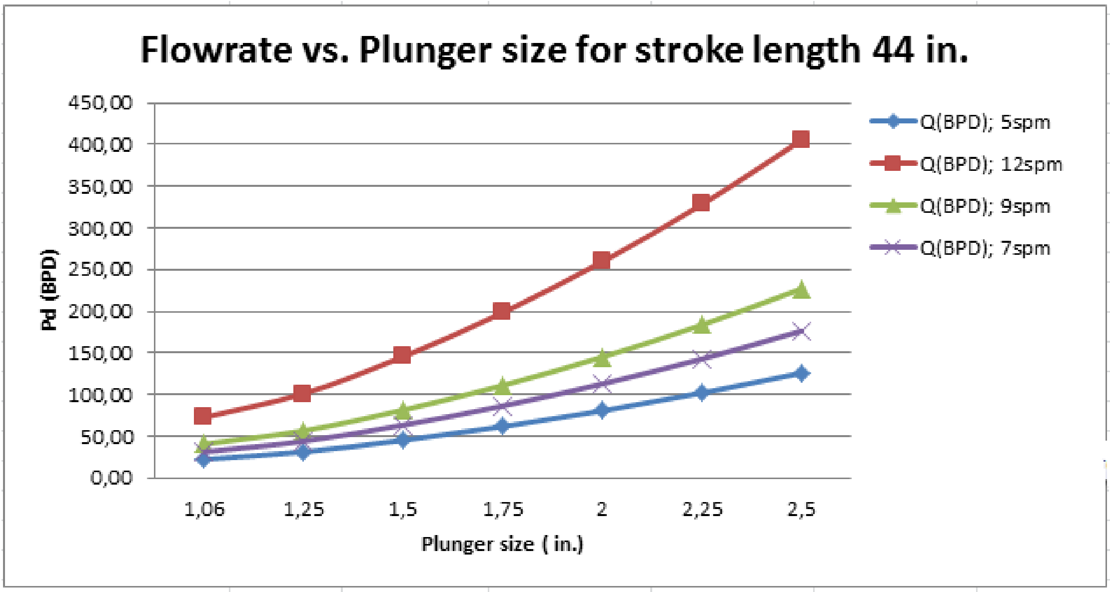

Figure 76: Pump displacement vs. Plunger size for stroke length 44 inch

Appendix I

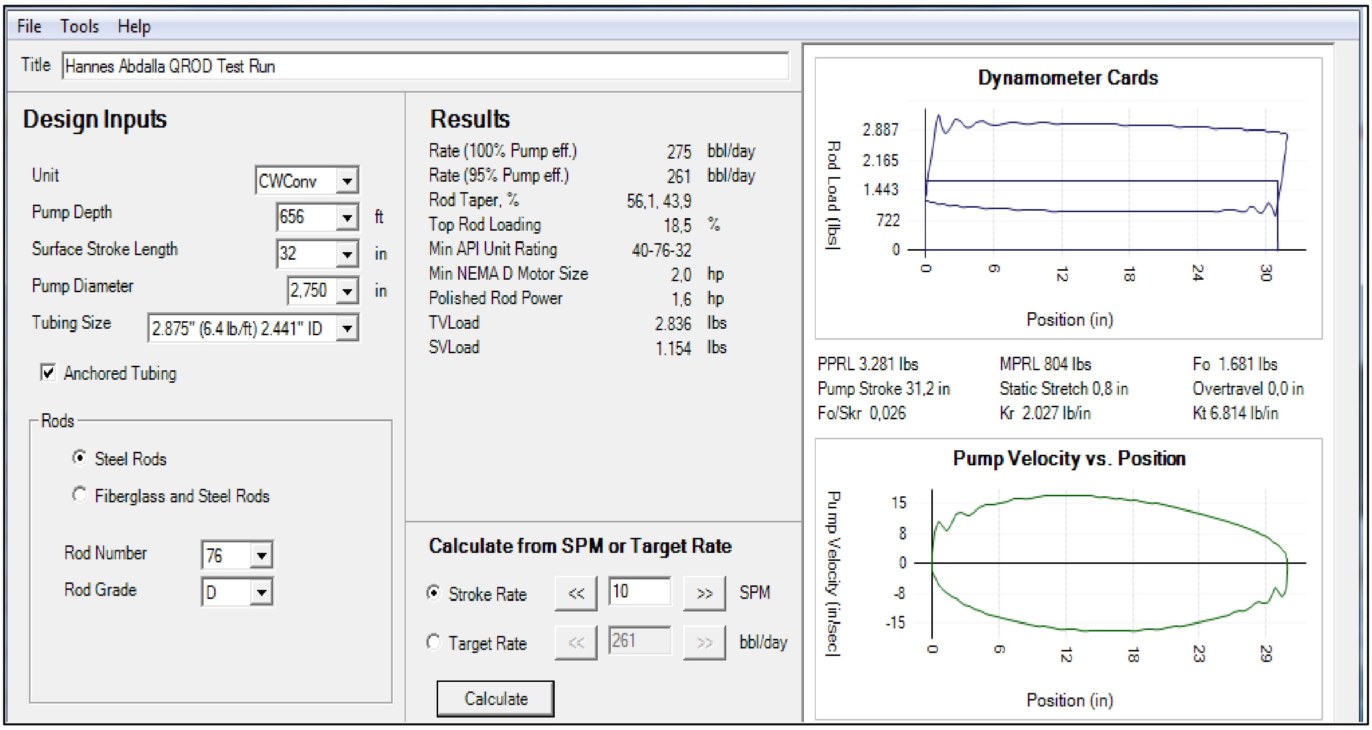

Figure 77: Screen shot of first QROD test run

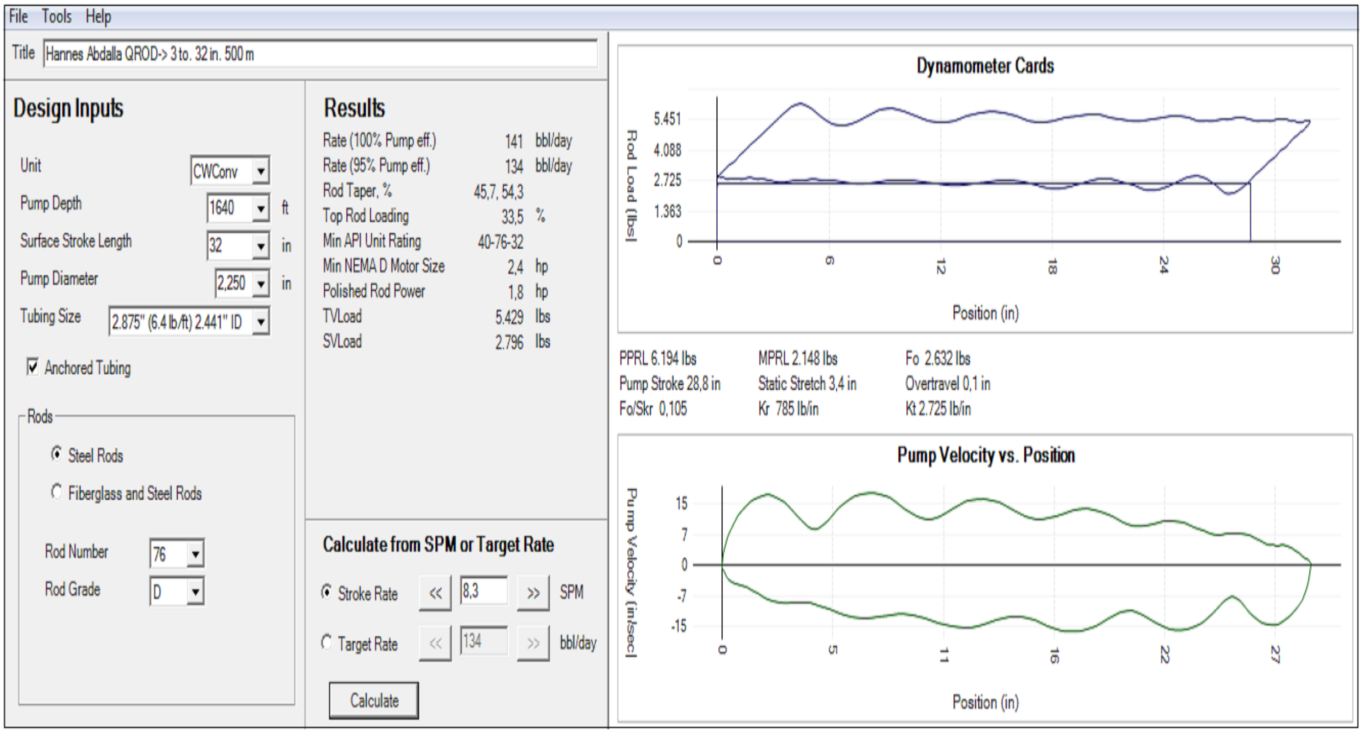

Figure 78: Screen shot of the 3 to. 32 in. LRP @ 500 m

Appendix J

Table 43: Selection of the 2640 candidate wells for LRP application

UWI	ASSET	FC NAME	SECTOR	PARC	SONDA	SIST EXPLOATARE	AD FIXARE POMPA	CONTROLLER	BRUT Rate [m3/d]	Pumping Unit	Pumping Unit Model
RO58158393	Asset VI - Muntenia Central	20 Moreni	PS 20 Moreni	SSTG 2 EPS	350 L Moreni Sud	PU	337,1	Timer	2	VULCAN ROMANIA	7-2000-3500
RO49607303	Asset I - Crisana-Banat	2 Suplac	PS 2 Suplac	SSTG Mini Parc	1803 Suplacu	PU	194,6	LRP UNICO Controller	5	UNICO	L137B-254E-044
RO84927812	Asset I - Crisana-Banat	2 Suplac	PS 2 Suplac	SSTG Mini Parc 48 Suplac	1238 Suplacu	PU	195,9	LRP UNICO Controller	15	UNICO	L239C-254E-044
RO01004104	Asset I - Crisana-Banat	2 Suplac	PS 2 Suplac	SSTG 7 Suplac	4219 Suplacu De Barcau	PU	187,5	LRP UNICO Controller	22	UNICO	L137B-245E-044
RO59829698	Asset I - Crisana-Banat	2 Suplac	PS 2 Suplac	SSTG 8 Suplac	140 Suplacu	PU	137		11	VULCAN ROMANIA	3-1200-1000
RO01014393	Asset I - Crisana-Banat	2 Suplac	PS 2 Suplac	SSTG 41 Suplac	4082 Suplacu de Barcau	PU	180,9	LRP UNICO Controller	15	UNICO	L381A-256E-056
RO33826740	Asset VI - Muntenia Central	20 Moreni	PS 20 Moreni	SSTG 305 Tuicani	93 MP Moreni Sud	PU	206		7	VULCAN ROMANIA	6,4-3500-5500
RO42990959	Asset VI - Muntenia Central	20 Moreni	PS 20 Moreni	SSTG 2 AR	242 MP Moreni Sud	PU	180,5	WTF Controller	52,5	VULCAN ROMANIA	6,4-3500-5500
RO39230106	Asset III - Muntenia Vest	10 Poiana Lacului	PS 10 Poiana Lacului	SSTG 4 Sapata	2460 Vata	PU	962	SAM Controller with Trans	14	VULCAN ROMANIA	9-2500-5500
RO84637038	Asset VIII - Moldova Nord	31 Dofteana	PS 31 Dofteana	SSTG 2 Dofteana Modernizat	104 Dofteana	PU	776	LRP UNICO Controller	0,8	UNICO	L381F-215E-032
RO64436805	Asset IV - Moesia Sud	13 Videle Vest	PS 13 Videle Vest	SSTG Parc 13 Videle	2031 Videle Vest	PU	743	SAM Controller with Trans	2	VULCAN ROMANIA	9-2500-5500
RO14861765	Asset III - Muntenia Vest	9 Otesti	PS 9 Otesti	SSTG 10 Otesti	1618 Otesti	PU	878	SAM Controller with Trans	3,4	VULCAN ROMANIA	5-1500-2000
RO01004723	Asset IX - Moldova Sud	37 Oprisenesti	PS 37 Oprisenesti	SSTG 5 Stancuta	531 Stancuta	PU	383		2	UNICO	L239C-254E-044
RO79146527	Asset VI - Muntenia Central	19 Targoviste Est	PS 19 Targoviste Est	SSTG 295 Dealul Batran	433 MP Viforata	PU	376,5	WTF Controller with Trans	4,5	VULCAN ROMANIA	5-1500-2000
RO96272778	Asset VI - Muntenia Central	20 Moreni	PS 20 Moreni	SSTG 70 AR Moreni	1479 MP Moreni Nord	PU	335,1	Timer	0,6	VULCAN ROMANIA	5-1500-2000
RO91322150	Asset VII - Muntenia Est	25 Ploiesti Est	PS 25 Ploiesti Est	SSTG 12 Urlati	336 MMPG Urlati	PU	721		0,6	VULCAN ROMANIA	5-1500-2000
RO12265279	Asset PEC Turnu	Zona 1 PEC Turnu	87 Turnu Nord	SSTG 3 Turnu Nord	1177 Turnu	PU	934,6		15	VULCAN ROMANIA	7-2000-3500
RO32564348	Asset VIII - Moldova Nord	29 Tazlau	PS 29 Tazlau	SSTG 9 Pietrosu	942 MMPG Tazlau	PU	900	SAM Controller	9,4	VULCAN ROMANIA	7-2000-3500
RO29188321	Asset IX - Moldova Sud	33 Berca	PS 33 Berca	SSTG 35 Plopeasa	110 MPC Plopeasa	PU	822,8		3	VULCAN ROMANIA	5-1500-2000
RO96238889	Asset V - Moesia Nord	17 Preajba Sud	PS 17 Preajba Sud	SSTG 41 Baciu	2178 Bis Baciu	PU	898	SAM Controller with Trans	3	VULCAN ROMANIA	7-2000-3500
RO38470508	Asset I - Crisana-Banat	2 Suplac	PS 2 Suplac	SSTG Mini Parc 48 Suplac	2355 Suplacu	PU	218	LRP UNICO Controller	12	UNICO	L137B-245E-044
RO01004101	Asset I - Crisana-Banat	2 Suplac	PS 2 Suplac	SSTG 50 Suplac	4194 Suplacu De Barcau	PU	226,6	LRP UNICO Controller with Trans	5	UNICO	L137B-245E-044
RO01006654	Asset I - Crisana-Banat	2 Suplac	PS 2 Suplac	SSTG 49 Suplac	4169 Suplacu De Barcau	PU	225	LRP UNICO Controller	16	UNICO	L381A-256E-056