DEVELOPMENT OF EXPERT SYSTEM FOR ARTIFICIAL LIFT SELECTION

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ABSTRACT

DEVELOPMENT OF EXPERT SYSTEM FOR ARTIFICIAL LIFT SELECTION

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During the reservoir production life reservoir pressure will decline. Also after water breakthrough the fluid column weight will increase as hydrostatic pressure will increase because of increased water and oil mixture density. In this case, reservoir pressure may not be enough to lift up the fluid from bottom to the surface. These reasons decrease or even may cause to stop flowing of fluids from the well. Some techniques must be applied to prevent the production decline. Artificial lift techniques are applied to add energy to the produced fluids. It increases production rate by reducing down-hole pressure and so that by increasing the drawdown. Artificial lift techniques increase production either by pumping the produced fluid from the bottom to the surface or reduce bottom-hole pressure by reducing the fluid column weight as a result of decreased fluid mixture density. Artificial lift is used worldwide in approximately 85% of the wells, thus its impact in overall efficiency and profitability of production operations cannot be overemphasized.

The most important problem is how to select optimum artificial lift techniques by taking into consideration the reservoir, well, environmental conditions. Selection of poor technique could cause decrease in efficiency and low profitability. As a result, it will lead to high operating expenses. Several techniques have been developed for selection of optimum artificial lift techniques. Expert Systems (ES) is the most suitable technique used in these selection techniques. Because the use and availability of required parameters is easy. Also in this selection method most of the artificial lift techniques are analyzed rather than other selection techniques. Expert Systems program mainly consist of three modules: (1) Expert Module, (2) Design Module, and (3) Economic Module. By entering required data to the system, program automatically suggests the feasible artificial lift techniques those might be used referring to given data. In this thesis work the artificial lift selection criteria and Expert Systems available in the literature have been studied. A Microsoft Windows based program has been developed to predict suitability of artificial lift methods for a given set of wells and produced fluid parameters. For the selected artificial lift method (i.e. sucker rod pump, ESP, gas lift, hydraulic pump, PCP) the program is able to perform basic calculations for the given data. Different case studies have been performed by running the program with actual data from fields. Well data of Venezuela, Azerbaijan and Iranian oil fields has been used in case studies. The results have been compared with previous studies those have been done on these fields with other selection techniques and current artificial lift techniques are being applied in selected wells. The obtained program results have been overlap with current real field application and previous studies.

ÖZ

YAPAY ÜRETİM SİSTEMLERİNİN SEÇİMİ İÇİN PROGRAM GELİŞTİRİLMESİ

Aliyev, Elshan
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Şubat 2013, 127 sayfa

Rezervuarın üretim hayatı süresinde rezervuar basıncı zamanla azalmaya başlayacaktır. Su üretiminin başlamasını takiben su ve petrol karışının youğunluğunun artması nedeniyle sıvı kolonunun kütlesi ve dolayısıyla hidrostatik basınç artar. Bu nedenle rezervuar basıncı sıvıyı kuyu dibinden yüzeye çıkartmak için yeterli olmaz. Bu da üretimin düşmesine hatta durmasına neden olur. Üretim düşümüne engel olmak için bazı teknikler uygulanmalıdır. Yapay üretim teknikleri üretilen sıvıya enerji kazandırmak için uygulanır. Bu teknikler, kuyu dibi basıncını düşürerek basınç farkını artırır ve dolayısıyla üretim debisi artar. Yapay üretim teknikleri ile ya üretilen sıvı yüzeye pompalanır ya da sıvı kolonunun ağırlığı azaltılarak kuyu dibi basıncı düşürülür. Yapay üretim dünya çapındaki kuyuların yaklaşık %85'inde uygulanmaktadır ve bu yüzden üretim operasyonlarına olan etkisi ve karlılığı küçümsenemeyecek kadar çoktur.

Rezervuar, kuyu ve çevre şartlarının hepsini birden hesaba katarak en uygun yapay üretim tekniğini belirlemek büyük bir sorundur. Uygun olmayan bir tekniğin seçilmesi etkinliğin düşmesine ve düşük karlılığa neden olabilir. Çünkü yüksek işletim maliyetine neden olacaktır. En uygun yapay üretim tekniğinin belirlenmesi için çeşitli yöntemler geliştirilmiştir. Uzman Sistemler (ES) bu teknikler arasında en uygun olanıdır. Çünkü bu yöntemin kullanımı kolay ve gereken parametreler kolay bulunabilmektedir. Aynı zamanda bu seçim yönteminde diğer seçim yöntemlerinden farklı olarak yapay üretim tekniklerinin çoğu analiz edilmektedir. Uzman sistemler programı temelde üç modülden oluşmaktadır: (1) Uzman Modülü, (2) Tasarım Modülü ve (3) Ekonomi Modülü. Gerekli veri sisteme girildiğinde program otomatik olarak girilen veriye uygun yapay üretim tekniğini önerir. Bu tez çalışmasında yapay üretim tekniği seçme kriterleri ve Uzman Sistem hakkındaki literatür araştırılarak bir Microsoft Windows tabanlı program yazılmıştır. Bu program verilen kuyular ve üretilen sıvı özelliklerine bağlı olarak yapay üretim tekniklerinin uygunluğu değerlendirmektedir. Ayrıca, çeşitli yapay üretim teknikleri (örneğin at başı pompa, ESP, gazla çıkartım, hidrolik pompa, PCP) için verilen bilgileri kullanarak temel hesaplamaları yapabilmektedir. Geliştirilen program gerçek veriler kullanılarak değişik koşullar için denenmiştir. Venezuella, İran ve Azerbaycanda bulunan bazı petrol sahalarının kuyu verileri bu çalışmada kullanılmıştır. Bu sahalarda diğer seçim teknikleri kullanılarak belirlenen yapay üretim teknikleri ile geliştirilen program ile önerilen teknikler karşılaştırılmış ve aynı sonuçların elde edildiği görülmüştür.

To my family

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SYMBOLS	
BHP	Bottom-hole pressure
BHT	Bottom-hole temperature
GOR	Gas-oil ratio
SRP	Sucker Rod Pump
ESP	Electric Submersible Pump
PCP	Progressing Cavity Pump
HPP	Hydraulic Piston Pump
PL	Plunger Lift
GL	Gas Lift

CHAPTER 1

INTRODUCTION

Fluids will flow from reservoir to the surface when the well is completed and reservoir pressure is sufficient to receive fluid from matrix, transport it to the wellbore and lift to the surface. During the reservoir production life reservoir pressure will decline and this could cause increase in water cut and decrease in gas fraction. These reasons decrease or even may cause to stop flowing of fluids from the well. Some techniques must be applied to prevent the production decline. Before artificial lift application the wells were being produced only naturally. Therefore, most of the brown fields were abandoned as reservoir pressure depleted. Because wells were produced under the natural flow regime and there wasn't any additional energy to the well as bottom-hole pressure decreased. Additional energy source must be added to the well in order to lift up the fluid to the surface. In these cases, artificial lift techniques are applied to add energy to the produced fluids. It increases production rate by reduction down-hole pressure referring to increase in drawdown. Major artificial lift techniques are: gas lift (GL), electrical submersible pump (ESP), sucker rod pump (SRP), hydraulic pump (HP) and progressive cavity pump (PCP). Artificial lift techniques are different from pressure maintenance techniques. Because they add energy to the produced fluid in the well rather transfer it to the reservoir. Some types of artificial lift techniques increase the production rate by pumping the fluid from bottom to the surface. It causes the reduction in bottom-hole pressure and increase in drawdown as results with increased production rate. Other types of artificial lift techniques decrease the BHP by lightening the fluid column. Decrease in fluid column causes the reduction in bottom hole pressure (BHP). Therefore, artificial lift techniques are classified into two groups: (1) energy supply with down-hole pumps: sucker rod pumping, electrical submersible pumping, progressive cavity pumps, hydraulic (piston and jet) pumping, (2) decreasing the weight of fluid column in the wellbore: gas lift and plunger lift. Artificial lift techniques are usually applied at later life of fields.

It has been estimated that in 1985, 80% of the wells in the world were stringer wells and production rate was less than 10 bopd. 80% of the applied artificial lift technique was sucker rod pumping (SRP), other 20% included: 54% SRP, 27% gas lift (GL) and other techniques. But in 1994, there were nearly more than 900000 wells in the world. Only 7% of them were naturally flowing wells, but remaining 93% were produced by artificial lift techniques.

The most important problem is how to select optimum artificial lift techniques by taking into consideration reservoir, well, environmental conditions. Also economic implications are important (such as investment and work over costs). Selection of poor technique could result in a decrease in the efficiency and low profitability. As a result, it will lead to high operating expenses.

Several techniques have been developed for selection of optimum artificial lift techniques such as OPUS [1], Expert Systems (ES) [5], Multi-Criteria Decision Making Methods (MCDM) [14]. Expert Systems includes: SEDLA, PROSPER, Expert Systems Environment (ESE). Depending on the problem MCDM is divided into two parts: (1) Multi Attribute Decision Making Method and (2) Multi Objective Decision Making Method. MCDM includes: TOPSIS Model [9], ELECTRE Model [9], SAW (simple additive weighting) model, WPM (weighting product model). The advantages and disadvantages of each selection technique have been discussed in Chapter 3.

ES is one of the best ways for the application of the selection of optimum artificial lift techniques. There are several advantages of ES from other selection techniques. ES contains all three models in itself. But OPUS model doesn't reflect design model. In this thesis, ES has been developed and different case studies have been run in the program. There are several reasons for making a thesis research on ES selection method:

(1) Lately developed ES software commercially is more beneficial. Because several ES programs have been developed and they are more expensive than that one.
(2) As technology and modification on artificial lift techniques is making progress very fast, operating limits of each technique changes time by time. This program has been developed taking into consideration recent operating limits. Therefore, this technique is more feasible than other techniques in field applications
(3) Other selection techniques show only best appropriate technique for the well regarding input data. One of the main advantage of developed ES is that program lists all techniques from the best to the worst one for each well. Also, user could easily get information about the reasons that makes each technique not recommended or recommended with warnings.
(4) In this program all 6 main artificial lift techniques have been considered. But in other methods less number of techniques has been considered. The availability of all major artificial lift techniques make this program more feasible in field applications.

Expert Systems program mainly consist of three modules: (1) Expert Module, (2) Design Module, and (3) Economic Module. Module 1 is an expert module that ranges artificial lift methods from the best to the worst that could be applied in the well for the given data. Selected methods could be ranked with coefficients range between 1, 5, which 1 indicates the least suitable method and 5 is the best suitable method for the well based on given data. In this module, also some warnings and concerns could be listed. Module 2 is a design module that advices of design for the methods listed in Module 1. Module 3 is an economic module that evaluates expenses and profitability of listed methods.
Expert Systems are based on if then conditions, in the form,

If (condition) Then (suitable artificial lift method)
If (Production rate is 30000 barrels per day) Then (Gas Lift), 5

ES is an expert system that developed for the selection of the best artificial lift techniques [5]. ES includes following artificial lift techniques:

(1) Sucker Rod (walking beam/hydraulic)
(2) Electrical Submersible Pump
(3) Gas Lift (continuous and intermittent)
(4) Intermittent gas lift with plunger
(5) Gas lift with continuous slug injection
(6) Hydraulic Pump (jet/piston)
(7) Progressive Cavity Pump
(8) Plunger Lift

In this expert system, all the artificial lift methods are ranked from the best one to the worst one. Therefore, the advantage of this program is that warnings are shown for non-suitable methods.

In the current work, Visual Basic based Expert System program has been developed and applied for the selection of optimum artificial lift techniques. Different field data has been used for the selection. The objective of this study is:

(1) Learn basic information about artificial lift types used in industry.
(2) Development of the Expert System artificial lift selectıon technique based on recent operating limits of each artificial lift technique.
(3) Determine suitable artificial lift type regarding application conditions for particular well or group of well with given data.
(4) Compare the obtained results with actual field applications and previous studies on other selection methods.

Chapter 3 presents a short review of the developed artificial lift selection techniques. Chapter 2 gives common information of available artificial lift types. Chapter 4 presents of development of Expert Systems and Chapter 5 present application of different case studies.

CHAPTER 2

ARTIFICIAL LIFT LITERATURE SURVEY

2.1 The Need for Artificial Lift

Fluids will flow from reservoir to the surface when the well is completed and reservoir pressure is sufficient to receive fluid from matrix, transport it to the wellbore and lift to the surface. Figure 2.1 presents the schematic pressure profile for production system.

During the reservoir production life reservoir pressure will decline and this could cause increase in water cut and decrease in gas fraction. These reasons decrease or even may cause to stop flowing of fluids from the well. Figure 2.2 presents the IPR curve that decreases with time.

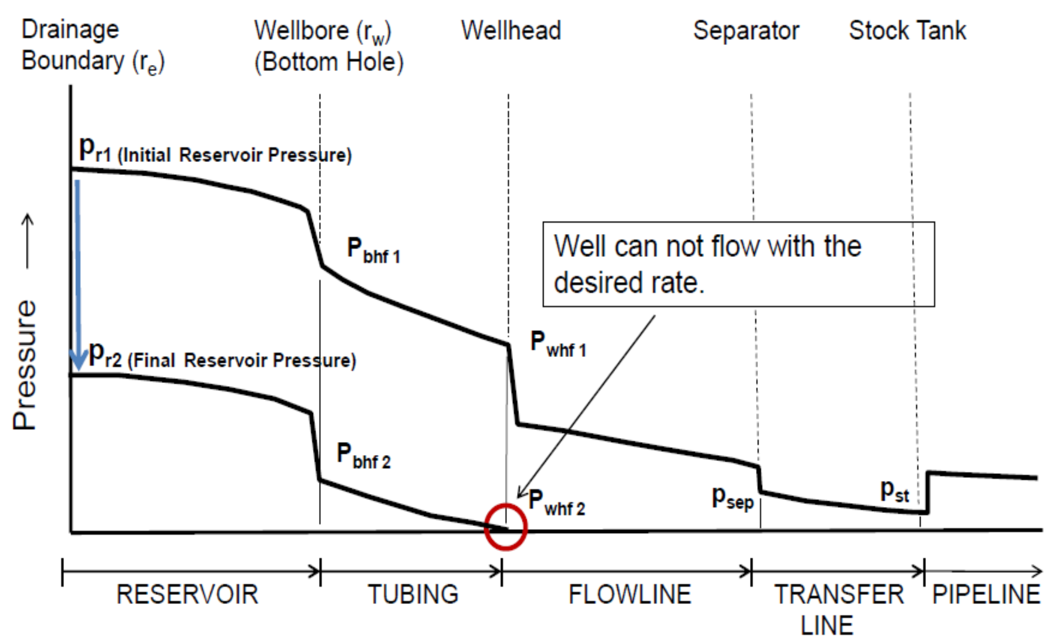


Figure 2.1 Schematic Pressure Profile for Production System [12]

Some techniques must be applied to prevent the production decline. In these cases, artificial lift techniques are applied to add energy to the produced fluids. Figure 2.3 presents the systematic pressure profile for production system after installation of artificial lift system. It increases production rate by reducing down-hole pressure referring to increase in drawdown.

Artificial lift is applied in wells which:

(1) Do not have enough reservoir pressure for flowing fluid from the well
(2) To supply natural reservoir drive to produce fluids out of the wellbore

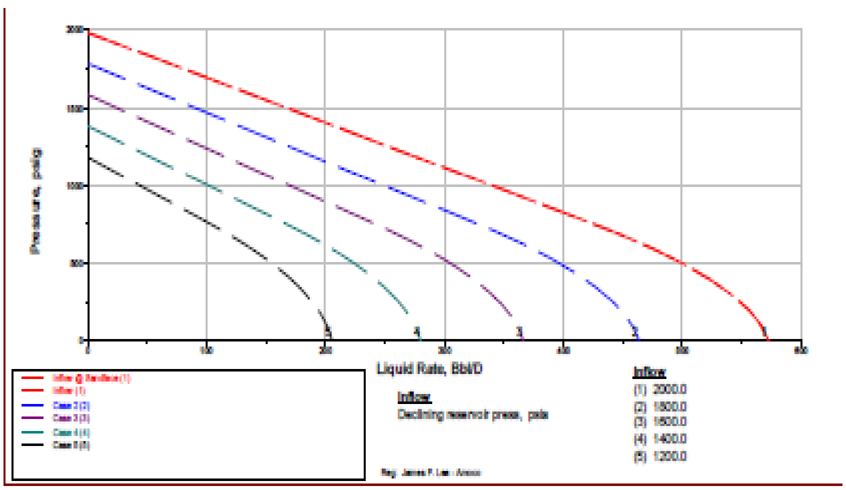


Figure 2.2 IPR curve decreases with time [12]

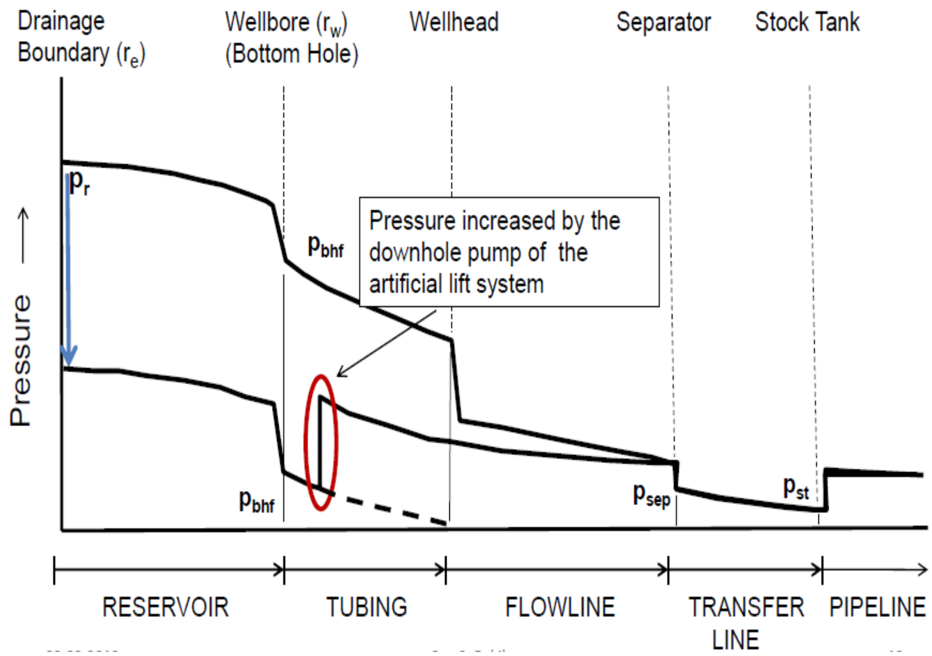


Figure 2.3 Schematic Pressure Profile for Production System [12]

Figure 2.4 presents the case that reservoir pressure so low that static liquid level in annulus is below the wellhead. In this case the well could flow only if Productivity Index (PI) is high and gas-liquid ratio (GLR) is enough to lift up the liquid.

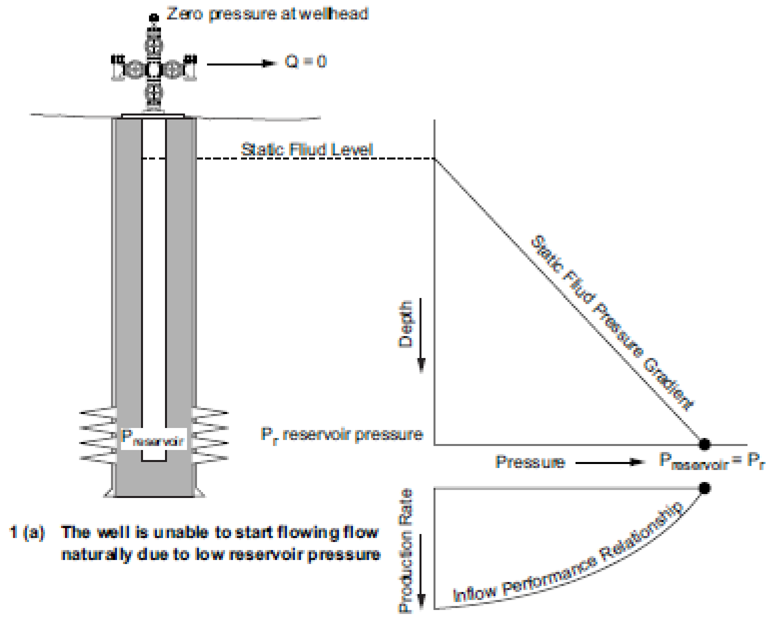


Figure 2.4 The well is unable to natural flow [15]

The main purpose of artificial lifts is to pump the well to low bottom-hole pressure (BHP) to increase the drawdown and to allow flowing of fluid. Figure 2.5 shows how the installation of pump below the static liquid level creates a small drawdown and flow rate. Pressure drop regarding to the frictional losses are small at this flow rate.

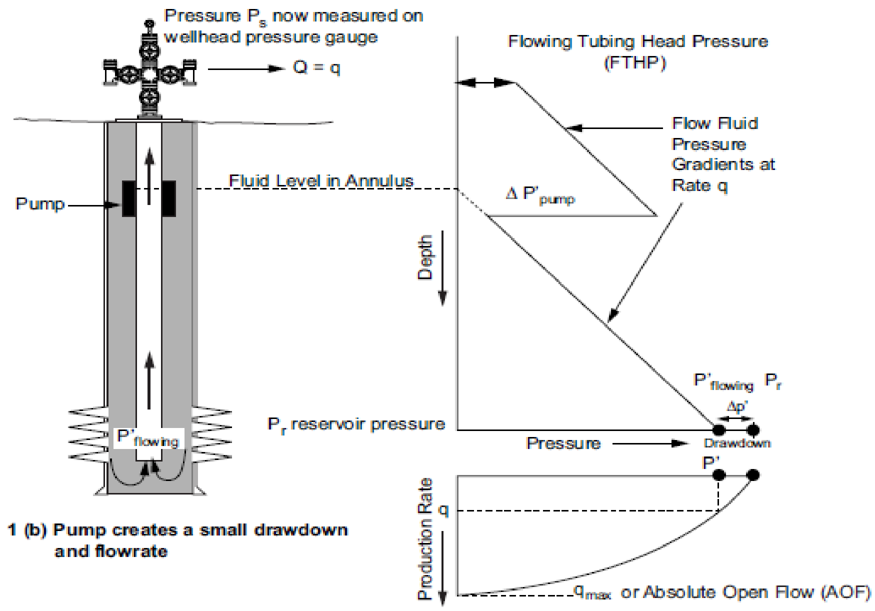


Figure 2.5 Pump creates a small drawdown and flow rate [15]

It can be seen that by placing the pump near the perforations could cause maximum flow rate by achieving large drawdown. In this case, production rate will be a little bit lower than Absolute Open Flow (AOF). Figure 2.6 presents the case that installation of pump near perforations increases potential drawdown and maximizes flow rate.

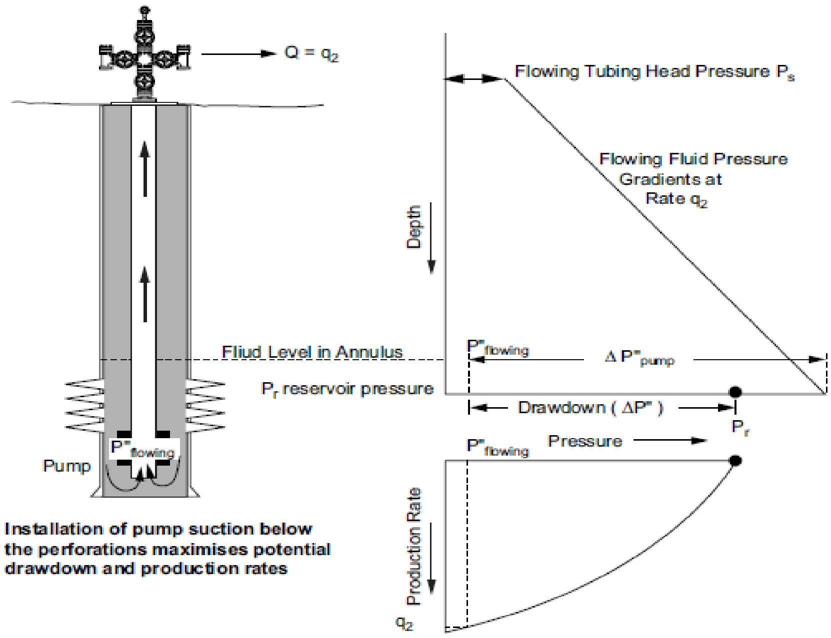


Figure 2.6 Installation of pump suction below perforations increases drawdown and flow rate [15]

2.1.1 When Artificial Lift Should Be Considered

Artificial lift should be considered by taking into account the whole life of the well. Figure 2.7 presents consideration of artificial lift. It is seen on the figure that AL applications must be considered pre-development of the field. So, in the future AL techniques could be applied easily when they are required. But in most of the brown fields in the world, AL installations were not considered before field development. Therefore, today it is very difficult to install AL techniques in such fields and it causes low production rate in the wells. After installation of AL, they must work at the maximum efficiency and periodically data must be revised for continuous surveillance and well testing.

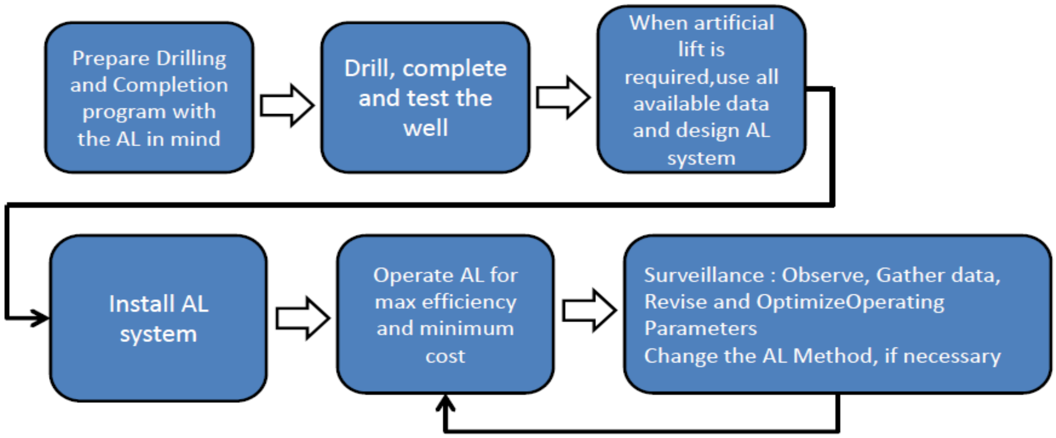


Figure 2.7 Consideration of artificial lift throughout of the well life [12]

2.2. Review of Artificial Lift Techniques

The major types of artificial lift techniques are presented in Figure 2.8 and 2.9. As it is seen in given figures major artificial Lift techniques are: Gas Lift (GL), electrical submersible pump (ESP), sucker rod pump (SRP), hydraulic pump (HP), progressive cavity pump (PCP).

In turn, artificial lift techniques are classified into two groups: (1) Energy supply with down-hole pumps: sucker rod pumping, electrical submersible pumping, progressive cavity pumps, hydraulic (piston and jet) pumping, (2) decreasing the weight of fluid column in the wellbore: gas lift and plunger lift. Classifications of pumps are presented in Figure 2.10.

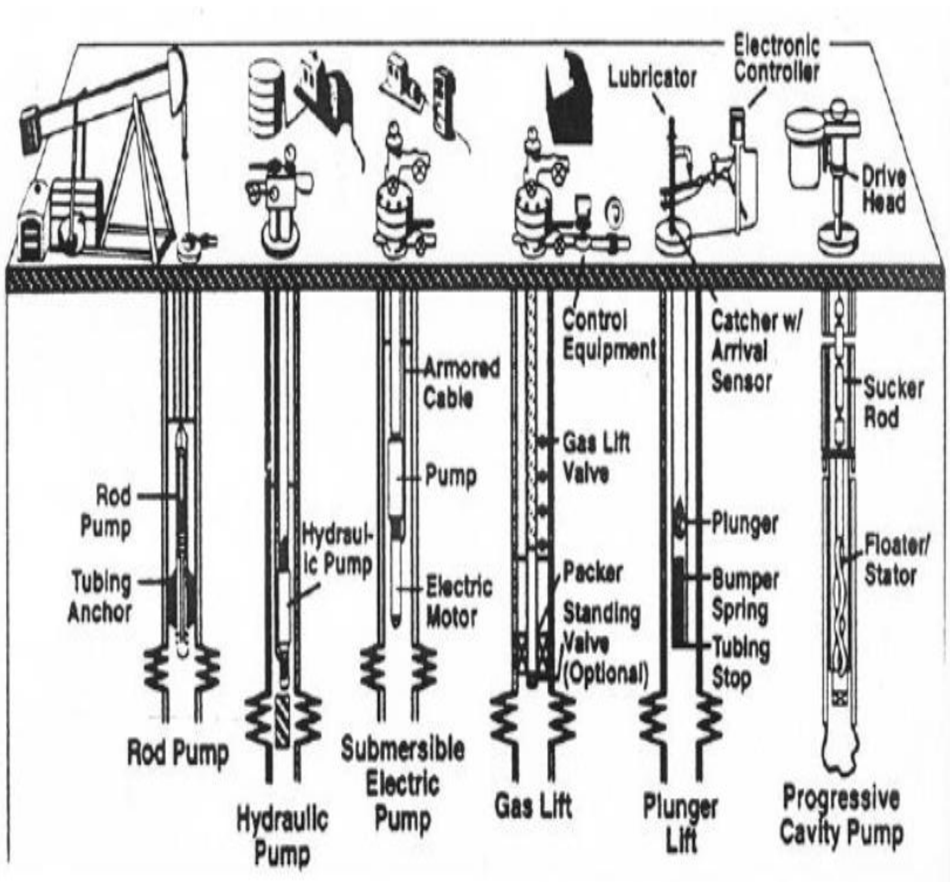


Figure 2.8 Major types of artificial lift techniques

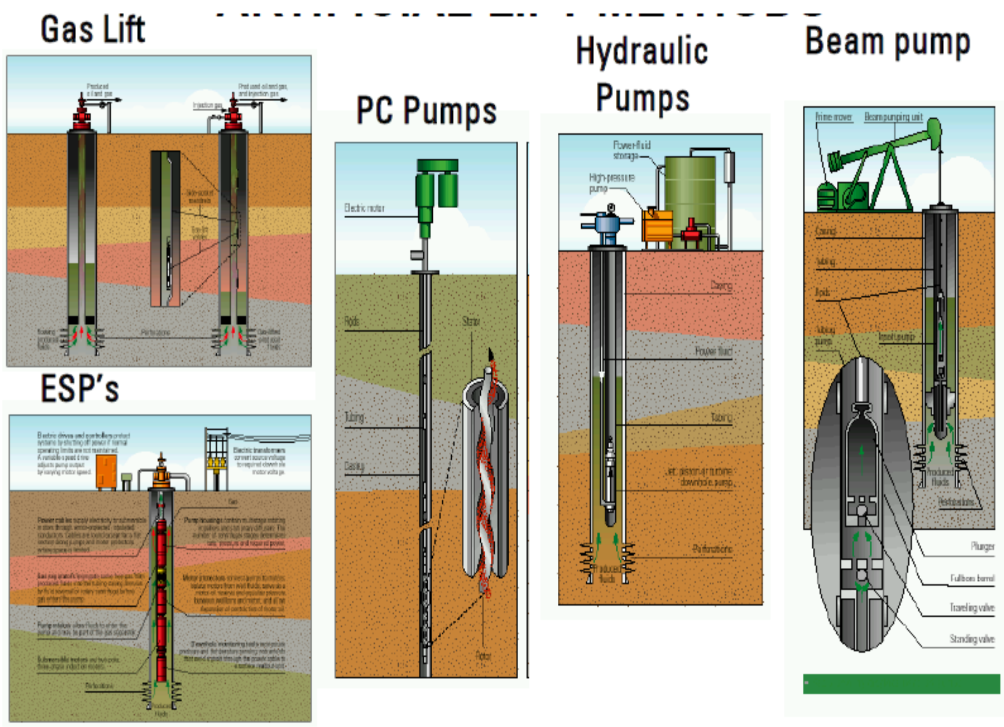


Figure 2.9 Major types of artificial lift techniques [15]

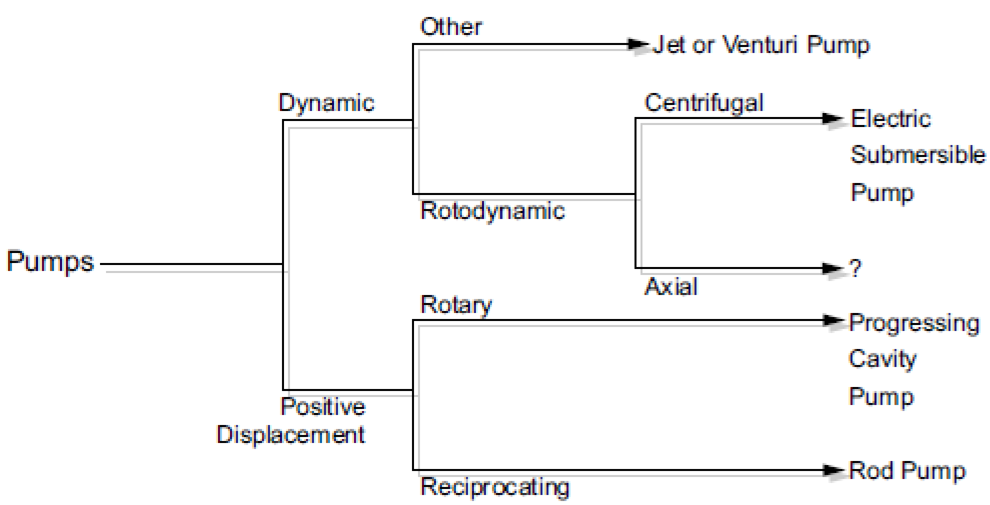
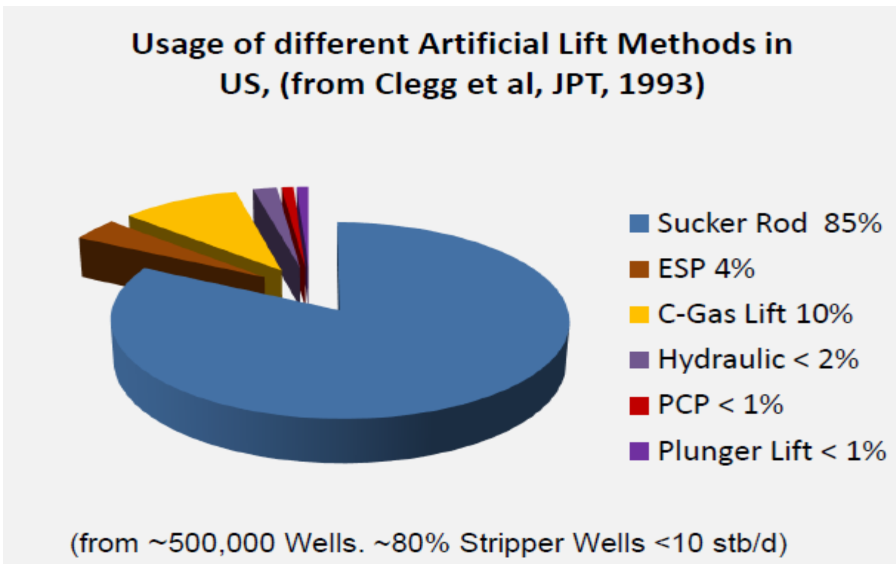


Figure 2.10 Pump classification

It has been estimated that in 1985, 80% of the wells in the world were stringer wells and production rate was less than 10 bopd. In this case, SRP was the most suitable technique and this technique was applied in 80% of the existing wells, other 20% was included: 27% SRP, 54% gas lift (GL) and other techniques. But through the life of field the rate declined in most of the wells and this raises a need of application of artificial lift techniques. For example, in 1994 there were nearly more than 900000 wells in the world. Only 7% of them were naturally flowing wells, but remaining 93% were produced by artificial lift techniques. And the average production rate is nearly 70 bopd. Figure 2.11 presents distribution of production from artificial lift wells. Figure 2.12 presents estimated worldwide usage of different artificial lift methods.



(from Clegg et al, JPT, December 1993)

Figure 2.11 Production from artificial lift wells

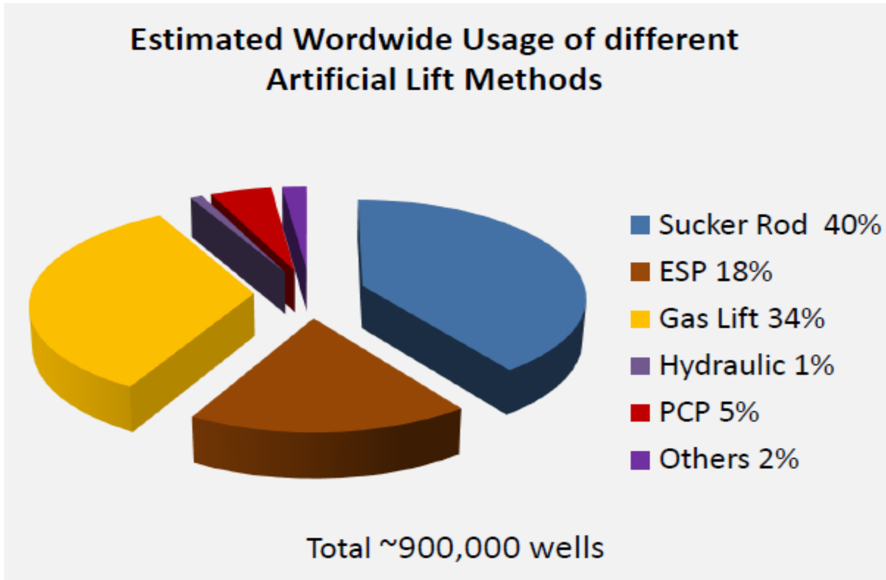


Figure 2.12 Estimated usage of different artificial lift types

2.3 Artificial Lift Selection Criteria

Several factors influence on selection of suitable artificial lift type for particular well or group of wells. Table 2.1 and 2.2 present a total view of surface and field operating considerations. These factors could be classified as below:

Table 2.1 Surface considerations

Flow rates	Flow rates are governed by wellhead pressures and backpressures in surface production equipment (i.e., separators, chokes and flowlines).
Flowline size and length	Flowline length and diameter determines wellehad pressure requirements and affects the overall performance of the production system.
Fluid contaminants	Scale, paraffin or slat can increase the backpressure on a well.
Power sources	The availability of electricity or natural gas governs the type of Artificial lift selected. Diesel, propane or other sources may also be considered.
Field location	İn offshore fields, the availability of space and placement of directional wells are primary considerations. İn onshore fields, such factors as noise limits, safety, environmental, pollution concerns, surface access and well spacing must be considered.
Climate environment	Affect the performance of surface equipment.

Table 2.2 Field operating considerations

Long-range recovery plans	Field conditions may change over time.
Pressure maintenance Operations	Water and gas injection may change the artificial lift requirements for a field.
Enhanced oil recovery Projects	EOR processes may change fluid properties and require changes in the artificial lift system.
Field automation	İf the surface control equipment will be electrically powered, an electrically powered artificial system should be considered.
Availability of operating and service personnel and support services	Some artificial lift systems are relatively low-maintenance: others require regular monitoring and adjustment. Servicing requirements should be considered . Familiarity of field personnel with equipment should also be taken into account.

2.3.1 Well and Reservoir Characteristics

Table 2.3 presents reservoir considerations for selection of artificial lift types.

Table 2.3 Reservoir considerations in selection an artificial lift methods

IPR	A well inflow performance relationship defines its production potential
Liquid production rate	The anticipated production rate is a controlling factor in selecting a lift method: positive displacement pumps are generally limited to rates of 4000-6000 B/D
Water cut	High water cuts require a lift method that can move large volumes of fluid
Gas- liquid ratio	A high GLR generally lowers the efficiency of pump-assisted lift
Viscosity	Viscosities less than 10 cp are generally not a factor in selecting a lift method: high-viscosity fluids can cause difficulty, particularly in sucker rod pumping
Formation volume factor	Ratio of reservoir volume to surface volume determines how much total fluid must be lifted to achieve desired surface production rate
Reservoir drive mechanism **Reservoir drive mechanism**	*Depletion drive reservoirs*: late-stage production may require pumping to produce low fluid volumes or injected water *Water drive reservoirs*: high water cuts may cause problems for lifting Systems *Gas cap drive reservoirs*: increasing gas-liquid ratios may affect lift Efficiency
Other reservoir problems	Sand, paraffin or scale can cause plugging and/or abrasion. Presence of H2O, CO2 or salt water can cause corrosion. Down hole emulsions can increase backpressure and reduce lifting efficiency. High bottom hole temperatures can affect down hole equipment.

Table 2.4 and Table 2.5 present well considerations in selection an artificial lift methods and operating limits for each artificial lift type.

Table 2.4 Well considerations in selection an artificial lift methods

Well depth	The well depth dictates how much surface energy is needed to move fluids to the surface and may place limits on sucker rods and other equipment.
Completion type	Completion and perforation skin factors affect inflow performance.
Casing and tubing sizes	Small-diameter casing limits the production tubing size and constrains multiple options. Small-diameter tubing will limit production rates, but larger tubing may allow excessive fluid fallback.
Wellbore deviation	Highly deviated wells may limit applications of beam pumping.

Table 2.5 Operating characteristics of artificial lift types

Operating Parameters	***Rod Pump***	***PCP***	***Hydraulic Piston***	***ESP***	***Hydraulic Jet***	***Gas lift***	***Plunger lift***
Typical Operating Depth (TVD)	100 to 11000 ft	2000 to 4500 ft	7500 to 10000 ft	1000 to 1000 ft	5000 to 10000 ft	5000 to 10000 ft	To 8000 ft
Maximum Operating Depth (TVD)	16000 ft	6000 ft	17000 ft	15000 ft	15000 ft	15000 ft	20000 ft
Typical Operating	5 to 1500	5 to 2200	5 to 500	100 to 30000	300 to 4000	100 to 10000	1-5 BFPD

As it is seen in the table main reservoir and well characteristics in selection an artificial lift types are:

(1) Casing and tubing size
(2) Depth and deviation of the well
(3) Fluid characteristics
(4) Reservoir Drive Mechanism
(5) Problems regarding to reservoir and well
(6) Required production rate

2.3.2 Field Location

Several factors influence on artificial lift selection types that depend on field location:

(1) Construction of offshore platform with maximum size and weight for installation artificial lift facilities
(2) Problem regarding to onshore field is remote location of the field that causes insufficient supply of infrastructure
(3) Climatic conditions also influence on selection of artificial lift types (e.g. arctic, desert conditions). Figure 2.13 present different locations for oil and gas fields.
(4) The source of power for prime mover that is very important in equipment design. Table 2.6 presents list of source powers for different artificial lift types.

Figure 2.13 Different locations for oil and gas fields [12]

Table 2.6 Power sources of different artificial lift types

Operating Parameters	*Rod pump*	*PCP*	*Hydraulic Piston*	*ESP*	*Hydraulic Jet*	*Gas lift*	*Plunger lift*
Prime Mover	Gas or electric	Gas or Electric	Multi-cylinder or electric	Electric motor	Multi-cylinder or electric	Compres sor	Well Natural energy
Offshore Applications	limited	Good	Good	Excellent	Excellent	Excellent	Good
System Efficiency	45%-60%	40%-70%	45%-55%	35%-60%	10%-30%	10%-30%	10%-30%

2.3.3 Operational Problems

(1) Some artificial lift types are more suitable to solids (sand, formation fines) than others
(2) Potential well problems such paraffin collapse, asphaltenes, hydrates are treatable by inhibitors. In this case, additional facilities should be installed and inhibitor cannot be carried in all artificial lift types.
(3) Selection of materials for equipment manufacturing is dependent on:
   (a) Temperature
   (b) Presence of H_2S or CO_2 that causes corrosion of well facilities
   (c) Extent of sand (erosion)

Artificial Lift considerations are:

(1) Commingled completions
(2) Gas influx ability
(3) Application on offshore
(4) Handling capability of heavy components
(5) Handling capability of solids
(6) Handling capability of high viscous liquids
(7) Applicable in high bottom hole temperatures
(8) Applicable in high deviated wells
(9) Applicable in slim holes
(10) Handling capability of erosive and corrosive particles

Table 2.7 presents operational characteristics for each artificial lift types.

Table 2.7 Operational characteristics of artificial lift types

Operating Parameters	*Rod Pump*	*PCP*	*Hydraulic Piston*	*ESP*	*Hydraulic Jet*	*Gas lift*	*Plunger lift*
Volume	BFPD	BFPD	BFPD	BFPD	BFPD	BFPD	
Maximum Operating Volume	6000 BFPD	4500 BFPD	4000 BFPD	60000 BFPD	$\geq$ 15000 BFPD	30000 BFPD	200 BFPD
Typical Operating temperature	100 – 350 °F	75 – 150 °F	100 – 250 °F		100 – 250 °F	100 – 250 °F	120 °F
Maximum Operating Temperature	550 °F	250 °F	500 °F	400 °F	500 °F	400 °F	500 °F
Typical Wellbore Deviation	0 – 20 deg landed pump	N/A	0 – 20 deg landed pump		0 – 20 deg hole angle	0 – 50 deg	N/A
Maximum Wellbore Deviation	0 – 90 Deg	0 – 90 Deg	0 – 90 deg	0 – 90 deg	0 – 90 deg	70 deg. short to medium radius	80 deg.
Corrosion handling	Good to excellent	Fair	Good	Good	Excellent	Good to excellent	Excellent
Gas handling	Fair to Good	Good	Fair	Fair	Good	Excellent	Excellent
Solids handling	Fair to Good	Excellent	Poor	Fair	Good	Good	Poor to fair
Fluid gravity	$\geq 8^\circ$ API	$\leq 35^\circ$ API	$\geq 8^\circ$ API	$\geq 10^\circ$ API	$\geq 8^\circ$ API	$\geq 15^\circ$ API	$\geq 10^\circ$ API

2.3.4 Economics

Figure 2.14 presents economic unit changing through production life. Economic factors that influence on selection an artificial lift type are:

(1) Capital Expenses (CAPEX)
(2) Operating Expenses (OPEX) per month
(3) Life of installed equipment
(4) Supplement of equipment
(5) Well production life
(6) Work over costs
(7) Number of wells that require artificial lift installation
(8) Number of employers needed for equipment control

Initial capital expenses play important role in installation of required artificial lift types. But operating expenses are more important than initial capital expenses through life cycle of the well (see Figure 2.15). From the figure it could be seen that initial capital investment contains only 1% of the total project value. But operating costs contain 6% of total project costs. Therefore, it is valuable to make sure to the installation of reliable equipment that causes reduce in operating costs and increase in production costs. One key issue that influences on operating costs is energy efficiency (additional gas purchase) and reliability. Figure 2.16 presents energy efficiency for different artificial lift types.

Work over costs are dependent on location of operating field (it requires high costs for remote fields), also service company contract terms.

Another key factor that will influence on operating cost is the number of wells that require installation of artificial lift types. Number of employers that needed for installation and equipment control will influence on operating costs.

Table 2.8 and 2.9 presents operational costs for low rate and high rate cases for different artificial lift types.

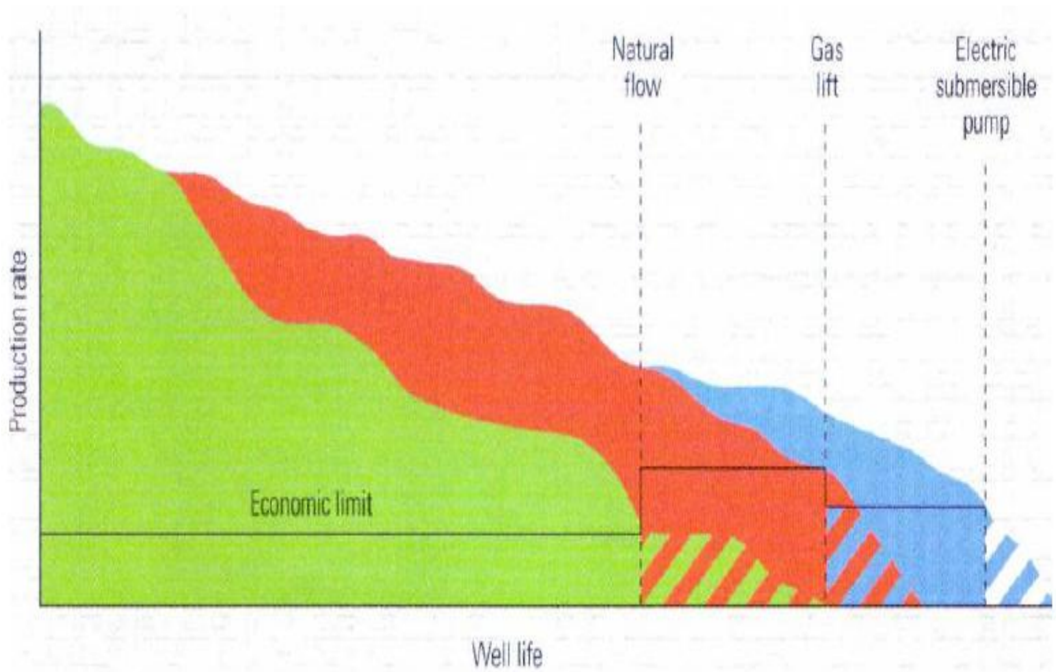


Figure 2.14 Economic limits changing through production life [12]

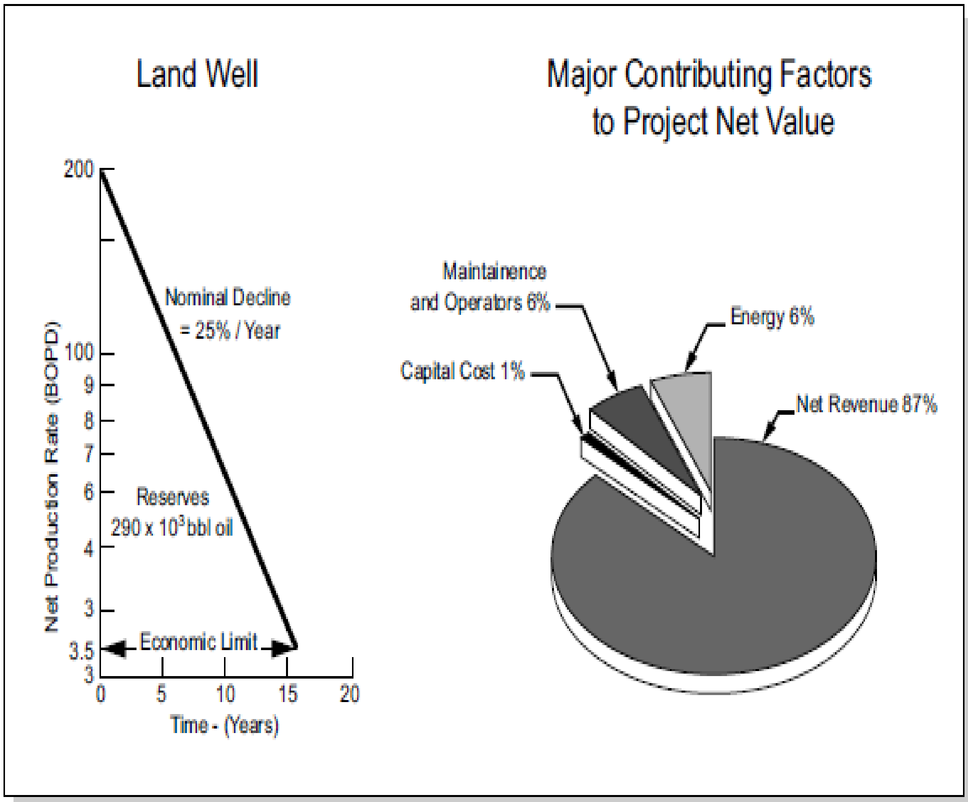


Figure 2.15 Full life cycle economics [15]

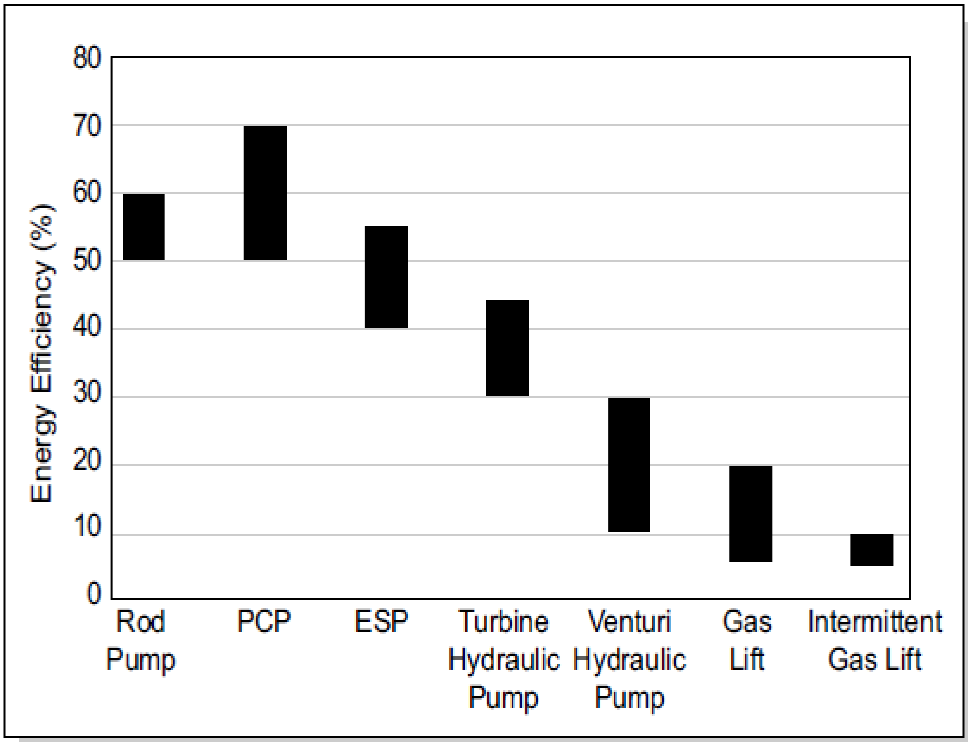


Figure 2.16 Comparison of energy efficiency of different artificial lift types [15]

Table 2.8 Lift Methods Costs: Low Rate Case [8]

Parameters	*Beam*	*Hydraulic*	*Gas Lift*	*ESP*
Target Rate (bbl/day)	1000	1000	1000	1000
Initial Installation ($)	141000	173000	239000	105000
Energy Efficiency (%)	58	16	15	48
Intake Pressure (psi)	900	900	900	900
Lift Energy (kw/bbl/day)	0.025	0.096	0.1	0.031
Work over Cost ($/day)	1000	1000	1000	1000
Wire line Cost ($/day)	-	-	1000	-
Injection Gas ($/Mscf)	-	-	0.24	-
Maintenance Costs ($/month)	200	2900	600	225

Table 2.9 Lift Methods Costs: High Rate case [8]

Parameters	*Jet*	*Gas Lift*	*ESP*
Target Rate (bbl/day)	17000	17460	17020
Initial Installation ($)	200000	265000	150000
Energy Efficiency (%)	21	16	41
Lift Energy (kw/bbl/day)	0.042	0.056	0.022
Work over Cost ($/day)	2000	2000	2000
Wire line Cost ($/day)	-	2000	-
Injection Gas ($/Mscf)	-	0.24	-
Maintenance Costs ($/month)	2900	3000	225

2.3.5 Implementation of Artificial Lift Selection Techniques

Most of the time engineers face with the problem applying of determined artificial lift type in a particular well. There are certain conditions that raise challenges in application of selected artificial lift method. For example, as it is seen in Figure 2.4 sucker Rod Pumping is the most applicable method in the world. Because most of the wells in the wells are stringer wells and the average production is 10 bopd. But densely human populated cities, offshore fields eliminate the application of sucker rod pumping. Also sucker rod pumping must be eliminated in deep and high productive wells. Such environmental and geographic conditions must be considered to make sure when such conditions work.

The main purpose of artificial lift types is to reduce bottom hole flowing pressure to the lower value. But in some artificial lift types are unable to reduce bottom hole flowing pressure to lower value.

The properties of formation fluids also must be considered. Compositional analyses must be carried out, because high paraffin content in the fluid could cause paraffin/wax collapse in the well. This could cause problems for some types of artificial lift such as ESP, SRP and etc.

Gas phase fraction in the fluid is also one key parameter that must be taken into consideration. Presence of free gas makes challenges for all pumping types, while it is additional source of energy for gas lift. The efficiency of gas lift increases as gas liquid ratio is high. Also, it is beneficial economically. In high GLR wells small volume of gas are required to be injected. Table 2.10 and 2.11 present the major advantages and disadvantages of each artificial lift type.

All these considerations are taken into account for long term reservoir performance. Because production rate changes over life of the reservoir, also increase in water cut could cause low efficiency of installed artificial lift method. And therefore, design of tubing size regarding to desired production rate must be considered. Otherwise, changing tubing size at different rates will increase long term operational expenses. Tubing size is designed dependent on production rate and most suitable artificial lift method is selected mainly dependent on required production rate and depth. Figure 2.17 presents application areas of different types of artificial lift.

Table 2.10 Advantages of major artificial lift methods [15]

Rod Pumps	Electric Submersible Pump	Venturi Hydraulic Pump	Gas Lift	Progressing Cavity Pump
Simple, basic design Unit easily changed Simple to operate Can achieve low BHFP Can lift high temperature, viscous oils Pump off control	Extermely high volume lift using up to1,000 kw motors Unobtrusive surface location Downhole telemetry available Tolerant high well elevation / doglegs Corrosion / scale treatments possible	High volumes Can use water as power fluid Remote power source Tolerant high well deviation / doglegs	Solids tolerant Large volumes in high PI wells Simple maintenance Unobtrusive surface location / remote power source Tolerant high well deviation / doglegs Tolerant high GOR reservoir fluids Wirleine maintenance	Solids and viscous crude tolerant Energy efficient Unobtrusive surface location with downhole motor

Table 2.11 Disadvantages of major artificial lift methods [15]

Rod Pumps	Electric Submersible Pump	Venturi Hydraulic Pump	Gas Lift	Progressing Cavity Pump
Friction in crooked / holes Pump wear with solids production (sand, wax etc.) Free gas reduces pump efficiency Obtrusive in urban areas Downhole corrosion inhibition difficult Heavy equipment for offshore use	Not suitable for shallow, low volume wells Full workover required to change pump Cable susceptible to damage during installation with tubing Cable deteriorates at high temperatures Gas and solids intolerant Increased production casing size often required	High surface pressures Sensitive to change in surface flowline pressure Free gas reduces pump efficency Power oil systems hazardous High minimum FBHP. Abandonment pressure may not be reached	Lift gas may not be available Not suitable for viscous crude oil or emulsions Susceptible to gas freezing / hydrates at low temperatures High minimum FBHP. Abandonment pressure may not be reached Casing must withstand lift gas pressure	Elastanes swell in some crude oils Pump off control difficult Problems with rotating rods (windup and after spin) increase with depth

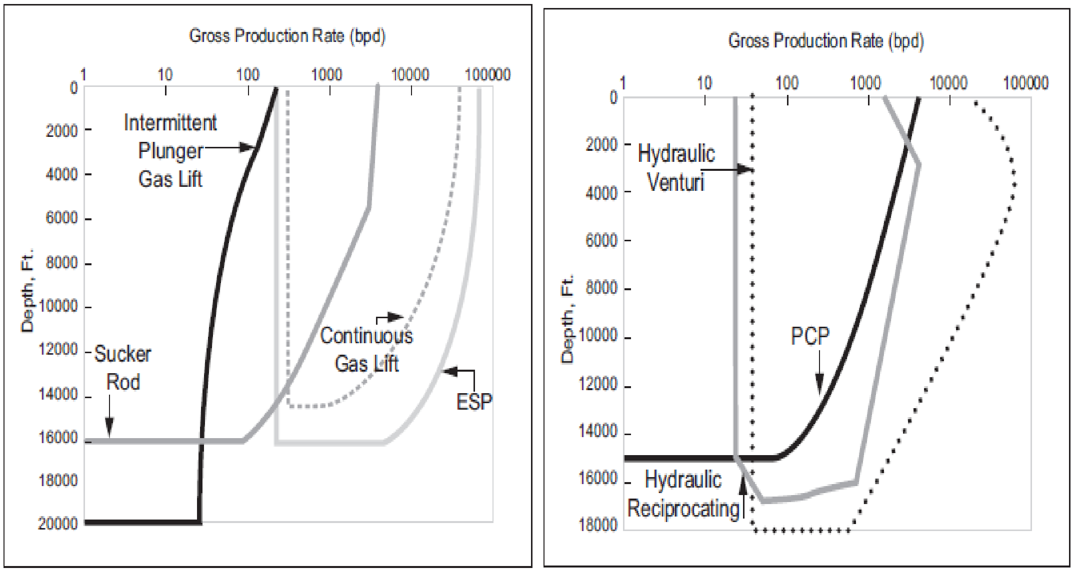


Figure 2.17 Application areas of main artificial lift methods [15]

2.4 Sucker Rod Pumps

2.4.1 Introduction

Sucker rod pump is the oldest and most widely used artificial lift method in the world. Figure 2.18 shows schematic pumping system. It has been estimated that in 1980, 80% of the wells were low productive wells and sucker rod pump was used in more than 80% of artificial lifted wells. (see Fig 2.4). In 1993, 85% of the wells in USA were pumped by sucker rod pumping system. Today SRP is used more than 40% in artificial lifted wells. (see Fig 2.5).

Sucker rod pumps mainly used for low productive wells and production ranges between 10-1000 bopd. In some cases, production rate could be as high as 3000 bopd. Well depth ranges between 7000-14000 feet. If sulphur content is high in produced fluid then production depths decrease down to 4000-10000 feet.

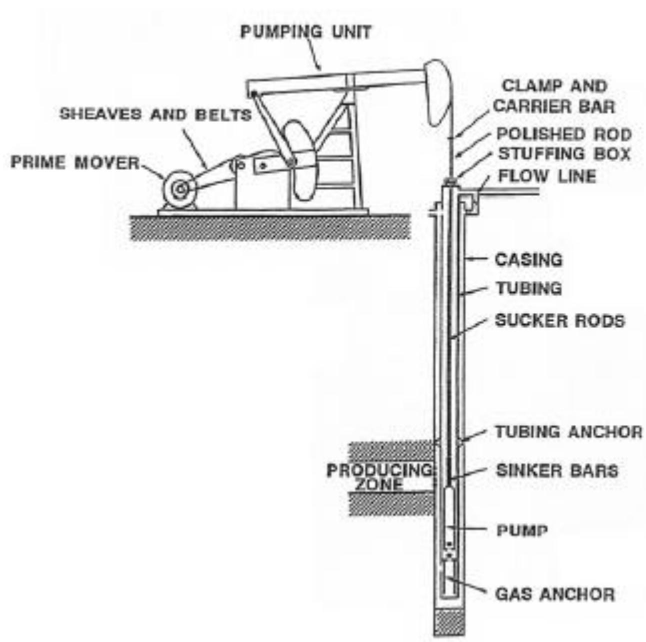


Figure 2.18 Sucker Rod Pump systems

Sucker rod pumping system is divided into two parts: (1) surface equipment and (2) subsurface equipment.

Surface equipment:

The schematic view of surface equipment is presented in Figure 2.19.

(1) **Prime mover**- it could be an electric motor, natural gas or internal combustion steam engines. Prime mover mainly supplies mechanical energy for surface equipments.
(2) **Surface Pumping Unit**- its function is to convert action from prime mover to rod lift action
(3) **Sucker Rods**- the function of sucker rods is to be a link between surface and downhole pump. (see Figure 2.20)

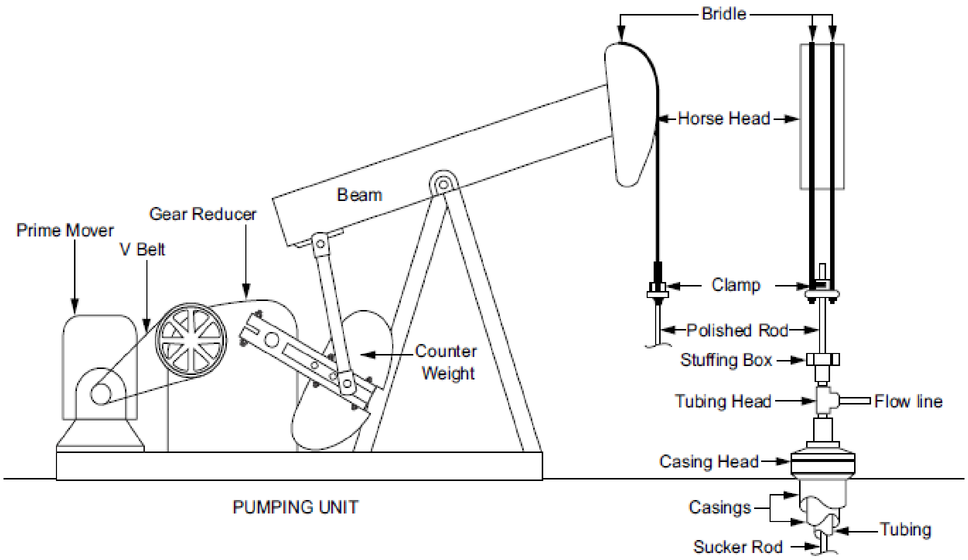


Figure 2.19 Schematic view of Surface equipment [15]

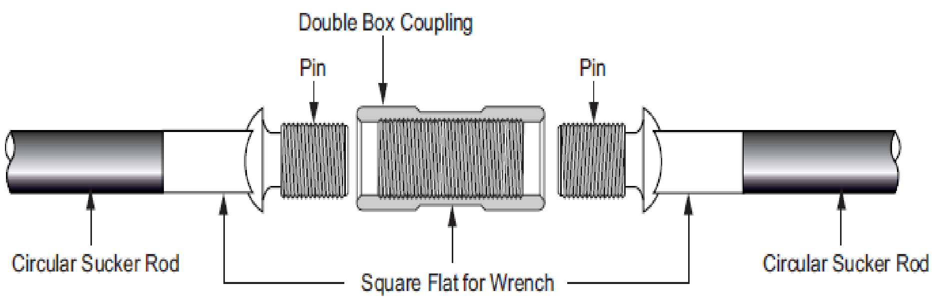


Figure 2.20 Schematic view of Sucker Rod [15]

The revolution of prime mover is 600 rpm. But it is reduced down to 4-40 rpm by gear reducer and motion is given to crank arm. In turn, transfers the motion to walking beam by pitman arm. The task of horse head and bridle is to keep stuffing box and polished rod vertical, so that no bending moment to stuffing box. Polished rod moves inside the stuffing box. Main task of polished rod and stuffing box is to prevent liquid leakage and transfer produced liquid to the T-connection.

Subsurface equipment:

(a) **Downhole Pump-** it is a positive displacement pump and main task is to move up the produced fluid. As it is seen in Figure 2.5 and 2.6 pump mainly placed below static liquid level and it works more efficiently when it is seated near the perforations. Schematic view of pump and pumping operation is given in Figure 2.21.

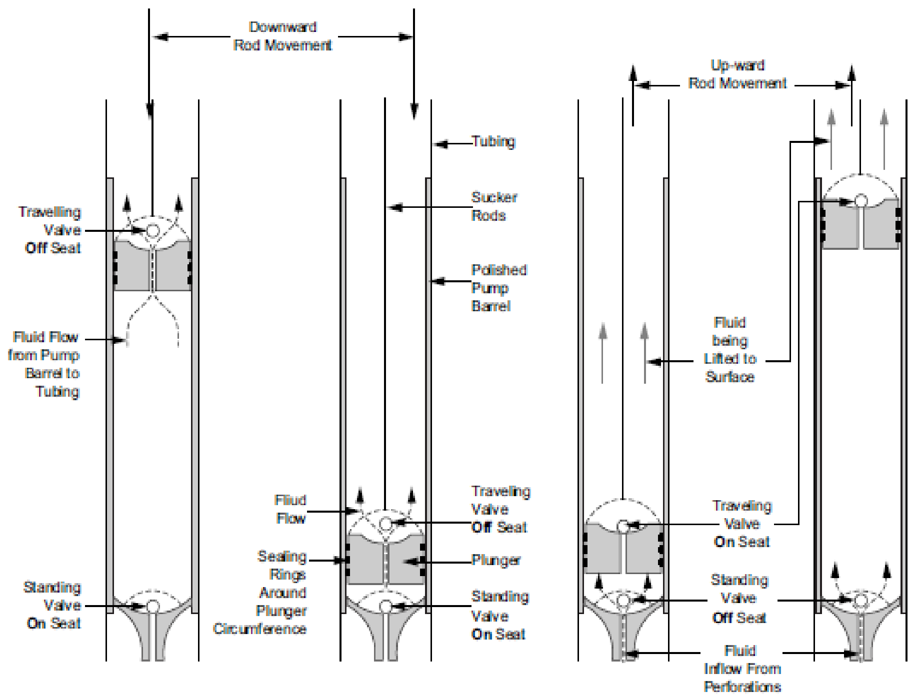


Figure 2.21 Rod Pump operations [15]

As it is seen in the figure, downhole pump consist of: plunger moving inside the pump, pump barrel, travelling valve and standing valve. In the UPWARD movement of plunger, pressure reduces in the pump and it allows fluid movement into the pump and keeps standing valve in opened situation. At this moment, travelling valve is closed. But in the DOWN movement of plunger, standing valve closes, travelling valve opens and liquid moves up through travelling valve.

The rate of pump could be found from Eq. 2.1:

$$Q = K \cdot V \cdot N \cdot \emptyset = K \cdot A \cdot S \cdot N \cdot \emptyset \quad (2.1)$$

A- Pump are

S- Pump stroke length

ϕ - Efficiency factor

K- Unit conversion factor

N- Pump speed

Table 2.12 gives value of pump speed regarding to stroke length.

Table 2.12 Pump speed regarding to stroke length

Stroke Length (in.)	30	60	90	120	180	240	300
Maximum Pump Speed (SPM)	34	24	19	17	14,5	11.5	10.5

2.4.2. Problems Associated with Sucker Rod Pumps

In spite of that sucker rod pumps are widely used artificial lift technique in the wells, there are certain problems associated with them. They are listed below:

(1) Sucker Rod Pumps are not suitable for high productive wells. Maximum capacity could be 3000 bopd in certain conditions, but usually it ranges between 10-1000 bopd.
(2) Sucker Rod Pumps are usually installed in shallow wells. Because rod load increases as depth increases. But well depth mainly dependent on production rate. For example, 200 barrels oil could be lifted from 14000 feet, in turn 1000 barrels oil could be lifted from 7000 feet. But H2S content in produced fluid limits the depth. In this condition, 200 barrels of oil is lifted from 10000 feet, while 1000 barrels of oil is lifted from 4000 feet.
(3) Unlike other artificial lift techniques, sucker rod pump works under high depression. Therefore, the potential of corrosion is high in this method. System must be strongly protected against corrosion to be sure for a long time reservoir performance.
(4) Sucker rod pumps ability is limited to lift the fluids with high sand content. But this limitation could be overcome by suitable construction stuff and pump design.
(5) The efficiency of pump can be limited with the existence of wax and paraffin. Paraffin can be removed by circulation of hot water\oil or solvents. Scaling could be treated by injection of inhibitors.
(6) The existence of free gas is another key factor that reduces pumping efficiency. The separation of free gas mainly occurs when annulus is small or if there is not an efficient use of annulus. Also, if the pump design and selection is not suitable. All these reasons could lead to gas lock. In this case, pump is placed below perforations. By doing like that, using of annulus capacity could be maximized and drawdown increased. But in practical there are certain difficulties to place the pump below perforations. In this case, gas anchors are used. The main purpose in using gas anchors is to make sure that gas is separated from liquid and only liquid enters pump and gas in accumulated at low pressures. In multiphase flow, packer and crossover is used to make sure the separation of gas from liquid and only liquid enters pump. Figure 2.22 presents the set of gas anchor in production well.
(7) Another problem associated with sucker rod pump is the leakage of liquid in stuffing box. But this disadvantage could be minimized by proper pump design and operating limits of pump.

(8) Sucker rod pumps are applicable in deviated wells, but in such wells wearing potential is high. It could reduce the life of rods and tubing. In this case, centralizer is used to reduce the wearing potential of rods and tubing. Fıgure 2.23 presents the schematıc centralizer in the well.

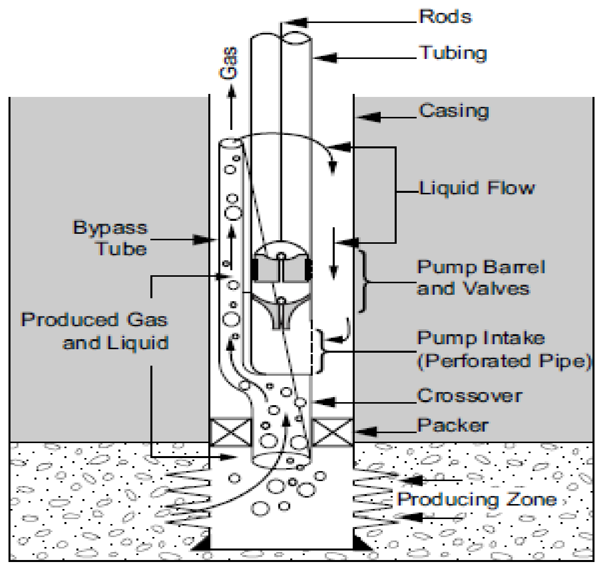


Figure 2.22 Gas anchor set in the well [15]

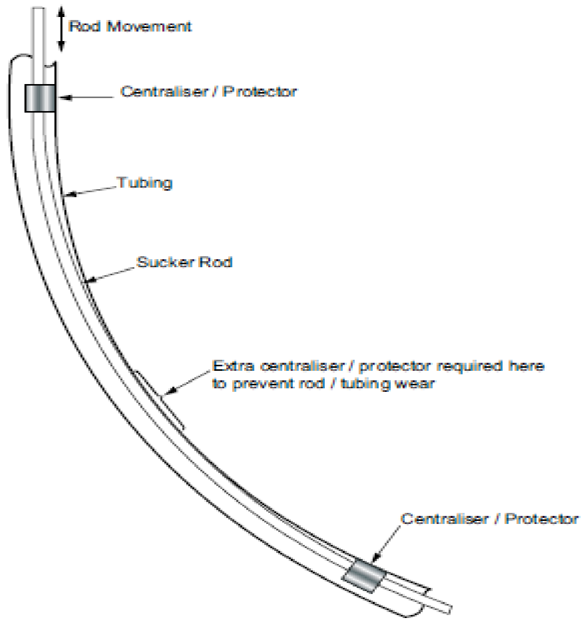


Figure 2.23 Centralizer set in the well [15]

2.4.3 Advantages of Sucker Rod Pumps

The advantages of sucker rod pumps could be listed as below:

(1) The installation and operation of sucker rod pumps is very simple and easy. It could be easily changed to other wells. Therefore, from economic aspects the initial capital expenses is low for sucker rod pumping system. Table 2.13 presents expenses of low and high production cases for sucker rod pumping system.
(2) Sucker rod pumps are applicable in deviated wells, also in slim holes and commingled wells.
(3) Sucker rod pumps can be installed in high bottom hole temperature wells.
(4) Electricity, natural gas and steam can be used as power source.
(5) As it was discussed in Section 2.4.2 scaling and paraffin limits the operating condition of pump. But these problems could be easily treated by hot water or solvents.
(6) In gas lock, cavitation, mechanical damage of pump cases pump-off condition could occur. It reduces the efficiency of pumping system. Sucker rod pumps suitable for pump off control.
(7) Sucker rod pumping system is analyzable. Dynamometer is applied to analyze pump performance and determine problems. Figure 2.24 presents ideal form of dynamometer if there is not any problem that listed above.

The operating values of sucker rod pumps are listed in Table 2.14 and 2.15.

Table 2.13 Equipment costs for Low rate case

Item	Cost ($)	Life (yrs)
Tubing	80000	15
Rods	20000	4
Pump	6000	-

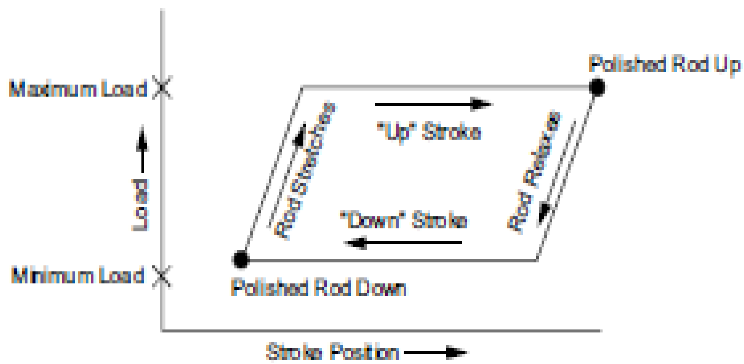


Figure 2.24 Dynamometer in ideal condition

Table 2.14 Operating limits of sucker rod pumps

Parameters	Typical Range	Maximum
Operating Depth	100 – 11000 TVD	16000 TVD
Operating Volume	5 – 1500 BPD	5000 BPD
Operating Temperature	100 – 350 °F	550 °F
Wellbore Deviation	0 - ° 20	0 - ° 90

Table 2.15 Production Considerations of SRP

Corrosion Handling	Good to Excellent
Gas Handling	Fair to Good
Solids Handling	Fair to Good
Fluid Gravity	$\geq 8^{\circ}$ API
Servicing	Workover or Pulling Rig
Prime Mover Type	Gas or Electric
Offshore Application	Limited
System Efficiency	45 – 60 %

2.5 Electric Submersible Pumps

2.5.1 Introduction

Electrical Submersible Pumps are one of the widely used artificial lift methods in the world. These pumps are mainly used in operations ranging between 150 and 20000 bopd moderate volumes. Schematic view of ESP is presented in Figure 2.25.

Production rate could be maximized up to 60000 bopd. But in modern ESPs even 120000 bopd fluids could be produced. First ESP was introduced in Russia. But in the USA the use of ESP started in 1926.

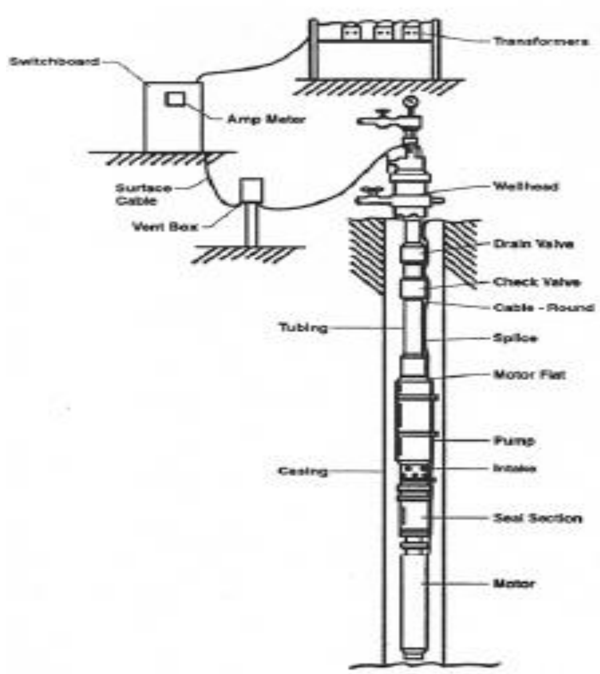


Figure 2.25 Schematic view of ESP

Electrical Submersible Pumps are divided into two parts: (1) surface components and (2) subsurface components.

Surface components:

(a) Motor controller
(b) Transformer
(c) Surface electric cable

Subsurface components:

(a) Pump
(b) Motor
(c) Seal section
(d) Gas separator

The operation of ESP is similar to other industrial electric pump. Electric cables provide electric energy to the down-hole motor. These cables are attached on the tubing. Electric motor and pump directly connected each other by shaft. In ESP classifications, the key parameter is the outside diameter of the down-hole components. Outer diameter mainly ranges between 3.5- 10 in. Pump length ranges between 40- 344 in.

(a) *Vent box*- the main function of vent box is to separate surface cables from subsurface cables. This separation is carried out to make sure that separated gas from liquid does not enter switchboard in the surface.
(b) *Subsurface electric cables*- the main function of subsurface electric cables is to transport energy to the electric motor.
(c) *Pump unit*- the main parts of pump unit are diffusers and impellers that running inside diffusers. Schematic view of pump is given in Figure 2.26. Fluid is lifted up by rotation of impellers that increases the lifting velocity of produced fluid. In diffuser this kinetic energy is converted to the potential energy and thus pressure increases. The increase of pressure causes increase in number of stages. Based on the pressure. Number of stages could be from 10 up to 100.

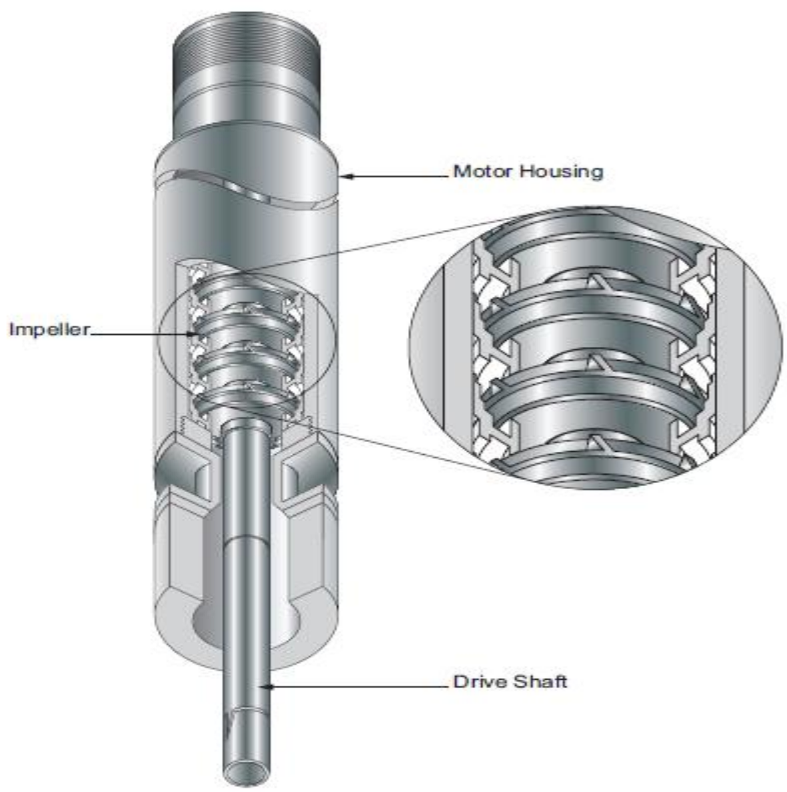


Figure 2.26 Schematic view of ESP pump [15]

(d) *Pump intake*- the efficiency of impellers in pump unit decreases if the fraction of gas in the produced fluid is higher than 20%. In this case, pump intake is used. The main part of pump intake is a gas separator that separates gas phase from liquid phase based on density difference. Like in sucker rod pumps, the presence of free gas reduces pump efficiency in electric submersible pump. But installation of gas separation system increases ESP gas handling efficiency up to 80%. Even installations of two separators are more efficient that increases gas handling capacity up to 90%. But it is not always applicable in practice. Because, solids could damage separators. Therefore, in this case, gas anchor could be used to prevent gas influx in pump like in sucker rod pump.

(e) *Seal System or The Protector*- electric motor and pump is connected to each other by seal section. Seal section also carries out below tasks:
   (1) Isolation produced fluids from motor fluids
   (2) Separation produced fluids from electrical wiring

(f) *Surface controller*- the main function of surface controller is to drive the ESP, shut-down depending on pressure switches.

(g) *Motor*- The main function of motor is to drive the pump to lift the fluid to the surface. Electric motors are drived by electric energy that supplied via electric cable from the surface. The size of motor can range from 15 up to 900 HP at 50 Hz or 60 Hz. Power requirement for electric motor is 420-4200 V.

2.5.2 ESP Applications

Key parameters in ESP application are listed below:

(1) Well Productivity Index (PI)
(2) Well size (including casing and tubing sizes)
(3) Static liquid level

ESPs are mainly applied in the wells with high Productivity Index. Casing and tubing sizes are also very important in designing of subsurface components. All these factors influence on fluid flow rate. Tubing size and flow rate is used to calculate and determine the total dynamic head (TDH). TDH usually is given with feet or meters of head. In US units it is converted as,

$$h = \frac{\Delta p}{0.433} \qquad (2.2)$$

h- Pump head, ft

Δp - pump pressure differential, psi

Figure 2.27 presents the schematic view of parameters that must be considered in determination of TDH. As it seen in the figure, hydrostatic pressure, friction and surface pressure must be considered in calculation of TDH.

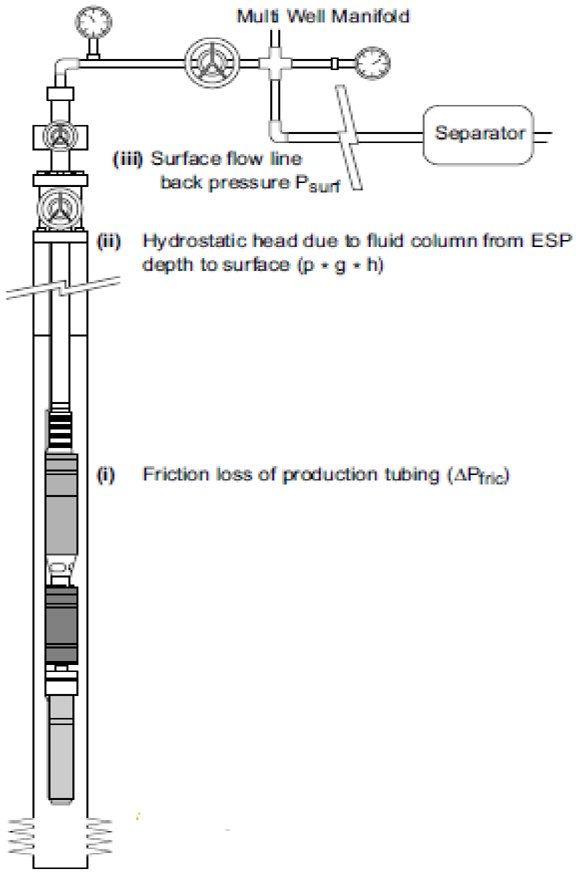


Figure 2.27 Pump TDH requirements [15]

(I) Pressure loss because of friction ($\Delta P_{friction}$)

(II) Hydrostatic pressure from pump to the surface. It is equal to multiplication of fluid density (ρ) with the vertical depth of pump (H) and gravity (g).

(III) Surface pressure ($\Delta P_{surface}$) that requires transporting of produced fluid from well-head to the separator.

In sum, TDH could be calculated as,

$$\text{TDH}= \rho * g * h + \Delta P_{fri} + \Delta P_{sur} \qquad (2.3)$$

2.5.3. Advantages of ESPs

Advantages of ESPs are listed below:

(1) Installation and operation of ESPs are easy. Table 2.16 and 2.17 gives expenses of ESP operations for low rate and high rate cases.
(2) Unlike sucker rod pumps, ESPs can lift high volume of oil. The average lifting volume is 20000 bopd. But modern ESPs can lift 120000 bpd from water wells.
(3) ESPs are applicable in offshore fields.
(4) They could be easily applied in deviated wells or crooked holes.
(5) Lifting costs decrease as produced fluid volume increases. Even efficient energy usage is possible $\rangle$ 50%
(6) ESPs also could be applied in high water cut wells.
(7) In spite of that gas influx decreases pump efficiency, gas influx could be reduced by installation of gas separator system or gas anchors.
(8) Unlike sucker rod pumps ESPs are unobtrusive in urban location. Because, they need small area for installation and they are not noisy.

Operating conditions of ESPs are given in Table 2.18 and 2.19.

Table 2.16 ESP equipment costs: Low rate case

Item	Cost ($)	Life (yrs)
Tubing	80000	15
Pump	25000	-
Protector	4000	-
Separator	5000	-
Motor	15000	-
Cable	50000	6
Cable Protector	20000	15
Transformer	12000	15
VSD	35000	15

Table 2.17 ESP equipment costs: High rate case

Item	Cost ($)	Life (yrs)
Tubing	80000	15
Pump	25000	-
Protector	4000	-
Separator	5000	-
Motor	15000	-
Cable	50000	6
Cable Protector	20000	15
Transformer	12000	15
VSD	35000	15

Table 2.18 ESP operating considerations

Parameters	Typical Range	Maximum
Operating Depth	1000 – 10000 TVD	15000 TVD
Operating Volume	200 – 20000 BPD	30000 BPD
Operating Temperature	100 – 275 °F	400 °F
Wellbore Deviation	$^{\circ}10$	$0 - {}^{\circ}90$

Table 2.19 ESP production considerations

Corrosion Handling	Good
Gas Handling	Poor to Fair
Solids Handling	Poor to Fair
Fluid Gravity	$\geq 10^{\circ}$
Servicing	Workover or Pulling Rig
Prime Mover Type	Electric Motor
Offshore Application	Excellent
System Efficiency	35 – 60 %

2.5.4 Disadvantages of ESPs

As it was discussed above the application area of ESPs are very wide. ESPs could be applied in wells with 12000 ft depths and 45000 bbl/day flow rates. But there are certain factors that reduce efficiency of ESPs. These factors are listed as below:

(1) High gas content in produced oil
(2) High bottom-hole temperature
(3) High viscous oil
(4) High sand content in produced fluid
(5) Heavy components in produced fluid

High free gas content in oil causes cavitation in pump and it conducts to the fluctuations in the motor. As a result, profitability and operating life of motor reduces.

High viscous oil reduces the TDH that was discussed in Section 2.5.2. In this case, number of pump stages and horsepower must be increased.

High solid content in produced fluid leads to wearing and choking in the pump.

In summary, disadvantages of ESPs are given below:

(1) Power source of ESPs is only electric motor. Internal combustion team or natural gas can not be used as a source power.
(2) ESPs require high electricity. The average electricity requirement is 1000 V.
(3) ESPs are not applicable in deep wells. Because transferring of electricity to the down-hole creates challenges in deep wells. The average limit for the depth is 10000 ft (3048 m).
(4) ESPs are not suitable in low- volume wells. As it was discussed above, this method is applicable in high volume wells. This method is not applicable in flow rates below 150 bpd.
(5) High temperature damages electric cables and motor
(6) Unlike sucker rod pumps, ESPs are not applicable in commingled wells.
(7) Maintenance and workover costs of ESPs are costly. It requires higher pulling costs while changing equipments. Also, tubing must be pulled in replacing pump.
(8) Solids and gas content in produced oil reduces pumping efficiency. But as it was discussed in Section 2.5.1, some techniques could be used to overcome gas problem.

2.6. Hydraulic Pumps

2.6.1 Introduction

As it was discussed above, hydraulic pumps are applied in nearly 1% of wells in the world. Hydraulic pumping systems are the only pumping method that could pump large volume oil fluid from the greatest depths because of the „U-balance' system between produced and injected fluids. First hydraulic pumps were introduced in 1930. The major element of hydraulic pumps is power fluid that energy is transmitted to the down-hole by it. Hydraulic pumps are applicable in offshore, remote areas and urban fields. There is no need to rig in this method. Figure 2.28 presents a schematic view of hydraulic pump. As it is seen, pumping system mainly consists of surface and subsurface parts.

Surface elements

The main elements of surface facilities are power fluid storage tank, fluid cleaning and pump to inject fluid to the down-hole.Storage tanks are used to store the power fluids that are injected into the well.

Settling tanks are commonly used cleanings systems. Recently, desanding hydrocyclone is used in settling tanks to remove solids from power fluid.

Surface pumps are used to inject power fluid to subsurface pump in order to drive it. Different types of pumps are used: triplex plunger pumps, multistage centrifugal pumps, quintiplex plunger pumps, electric submersible pumps. Triplex plunger pumps are commonly used types. Required surface pressure for injection ranges between 1500-4000 psi. Plunger pumps are effective in low rates (≤ 10000 bpd) and high pressure installations (≥ 2500 psi). The average production depth ranges from 5000 to 6000 ft. But lifting depth could be increased up to 8000-9000 ft if approxımate pump injection pressure is 3500 psi.

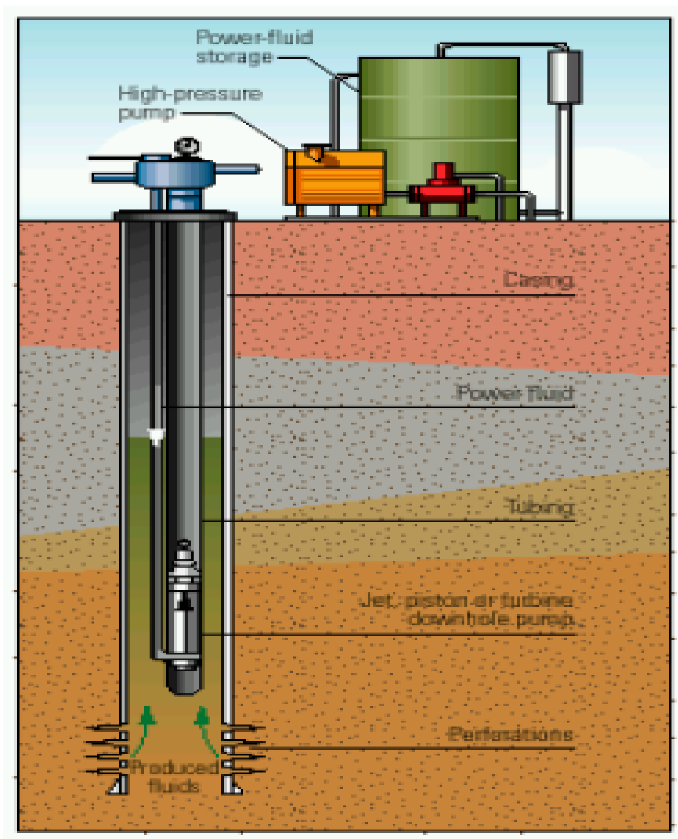


Figure 2.28 Schematic view of Hydraulic Pump [12]

Subsurface part

Hydraulic pumps are classified by subsurface pumps. There are two basic types of hydraulic pumps:

- **Piston Pump**- these pumps are derived by injected power fluids and fluid is lifted up to the surface by pump piston
- **Jet Pump**- produced fluid is lifted by venture effect that is created by injection of power fluid into nozzle

Hydraulic Piston Pumping (HPP)

HPP is applied in the high productive and great depth wells. The main source of HPP is power fluid. But natural gas and electricity also could be used as source power. HPP could be applied in commingled wells and offshore fields. High solid content in produced fluid reduces the efficiency of HPP.

The major part of HPP is an engine that consists of reciprocating piston. Piston is driven by injected power fluid. Piston is connected with another piston in the end of pump. Injected power fluid drives piston that create pressure to lift the produced fluid. HPP could be double acting, which fluid is moving downstroke and upstroke in the pump. Figure 2.29 presents schematic view of HPP for both downstroke and upstroke displacement.

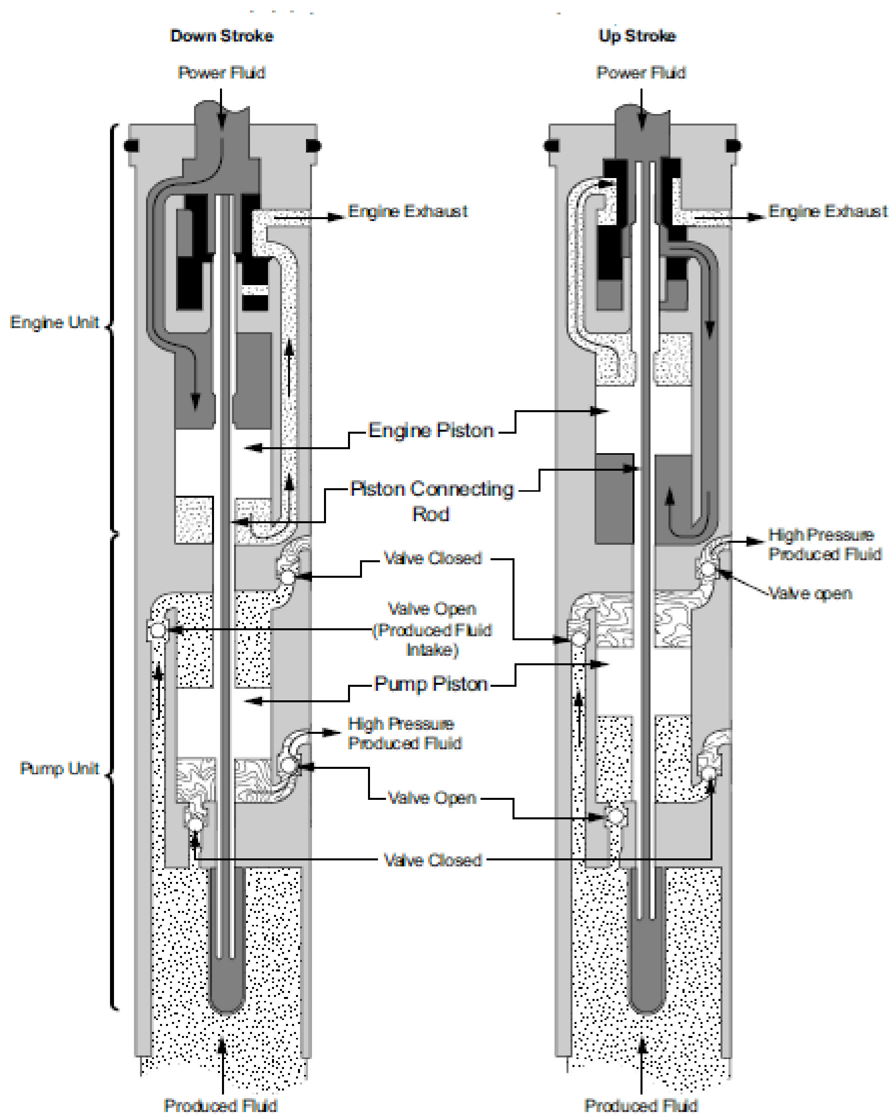


Figure 2.29 Operation of Hydraulic Piston Pump [15]

Hydraulic Jet Pump

The major part of Hydraulic Jet Pump is subsurface pump. Injected power fluid in converted to the energy by pump that moves up produced liquid. Unlike HPP, hydraulic jet pump does not have any moving pump. Therefore, free gas and sand does not create problem for the subsurface pump. But the efficiency of these pumps is low (20-30%).

Figure 2.30 presents schematic view of hydraulic jet pump. Unlike hydraulic piston pump, the pressure of produced fluid is increased by jet nozzle. Hydraulic jet pump is a dynamic-displacement pump. In this method, power fluid is injected through the tubing to the pump. The velocity of power fluid is increased in the nozzle and it mixes with the produced fluid in the pump throat. In this way, the pressure of the power fluid is transferred to the produced fluid and increases its kinetic energy.

Power Fluid

Oil or water could be used as a power fluid. Power fluid in transferred to the subsurface pump through injection tubing.

There are two kinds of installations: (a) open power fluid system and (b) closed power fluid system. If the injected power fluid is returned to the surface in separate tubing commingled with produced fluid then it is called open power fluid system. The installation of this system is difficult and very costly. Therefore, closed system is installed, which injected power fluid is returned to the surface through other tubing. Figure 2.31 presents installations of pump systems.

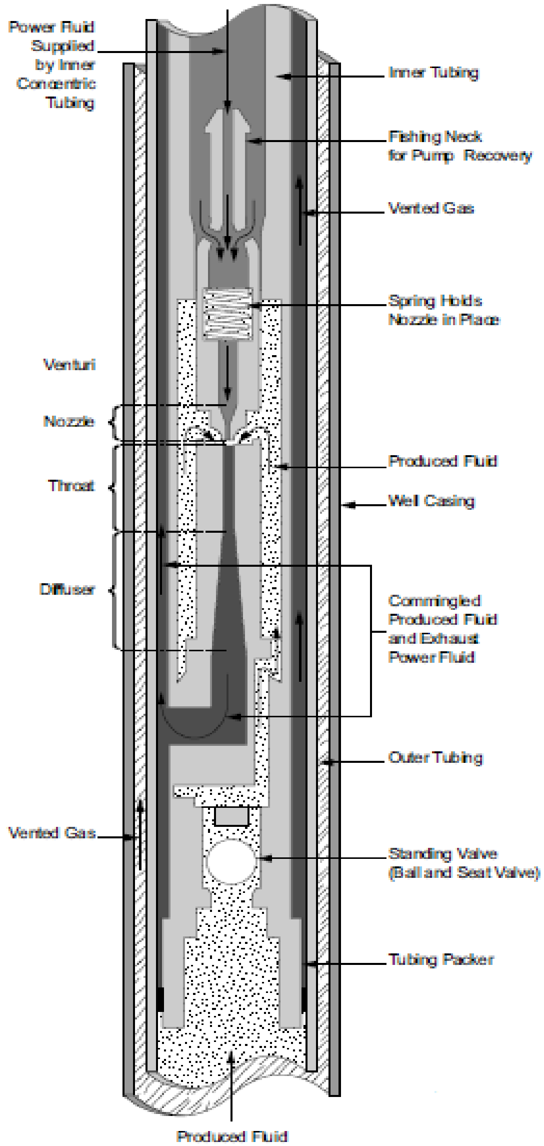


Figure 2.30 Schematic view of Jet pump operation [15]

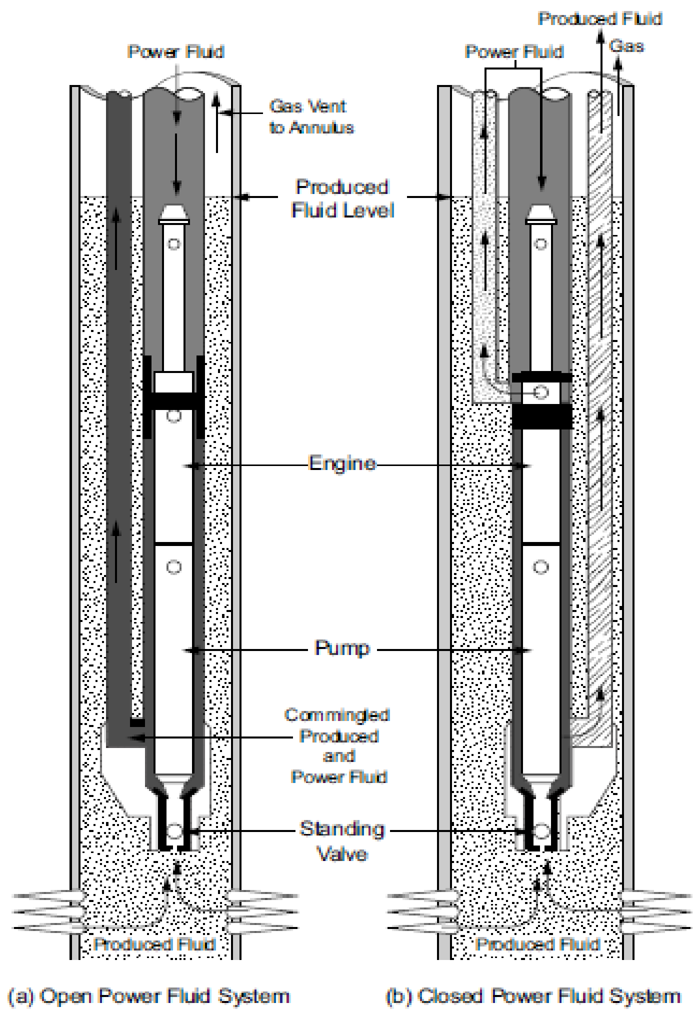


Figure 2.31 Hydraulic pump installation types [15]

2.6.2 Advantages of Hydraulic Pumps

The major advantages of Hydraulic pumps are listed below:

(1) Hydraulic pumps are applicable in crooked and highly deviated wells
(2) Hydraulic pumps could be produced fluid from the greatest depths, because of the balance between injected fluid and produced fluid. The average production depth is 17000 ft. Jet pumps could produce fluid from as deep as 20000 ft.
(3) As it was discussed above, jet pump has no moving pumps. Therefore, it could easily handle solids and free gas.
(4) Power source could be remotely controlled. It makes hydraulic pumps attractive in offshore and urban fields.
(5) Production problems such as scaling, corrosion, emulsion can be treated. Because, power fluid has the capability to carry inhibitors to the down-hole.
(6) Except power fluid, natural gas and electricity also could be used as a power.
(7) Hydraulic pumps also could be applied in commingled wells.

Table 2.20 and 2.21 gives economic evaluation of hydraulic pumps. Table 2.22 and 2.23 presents the major operating limits of hydraulic pumps.

Table 2.20 Hydraulic Pump equipment cost: Low rate case

Item	Cost	Life (yrs)
Tubing	80000	15
Pump	20000	-

Table 2.21 Hydraulic Pump equipment cost: High rate case

Item	Cost	Life (yrs)
Tubing	80000	15
Pump	20000	-

Table 2.22 Operating Limits of Hydraulic Pumping System

Parameters	Typical Range	Maximum
Operating Depth	5000 – 10000 TVD	15000 TVD
Operating Volume	300 – 1000 BPD	≥ 15000 BPD
Operating Temperature	100 – 250 °F	500 °F
Wellbore Deviation	0 - $^\circ$20	0 - $^\circ$90

Table 2.23 Production considerations of Hydraulic Pumping System

Corrosion Handling	Excellent
Gas Handling	Good
Solids Handling	Good
Fluid Gravity	$\geq 8^{\circ}$ API
Servicing	Hydraulic or Wire line
Prime Mover Type	Multi-Cylinder or Electric
Offshore Application	Excellent
System Efficiency	10 – 30 %

2.6.3 Disadvantages of Hydraulic Pumps

In spite of that hydraulic pumps are applicable in wide range of well, there are several factors that limit operation of hydraulic pumps. The main disadvantages of hydraulic pumps are below:

(1) As it was discussed above, hydraulic jet pump has no moving parts. Therefore, solid containing power fluids do not decrease the profitability of jet pumps. But efficiency decreases in pumps with moving parts.
(2) The efficiency of jet pumps is low (20-30%).
(3) Oil power fluids are dangerous for fire hazard.
(4) Hydraulic pumping system requires high surface injection pressure to inject power fluid through injection tubing.
(5) As it was seen on Table 2.20 and 2.21, design and installation expenses are high in this method.
(6) It is difficult to carry out well test analyzes in low productive wells.
(7) Power oil system requires high safety actions during injection.

2.7 Progressing Cavity Pumps

2.7.1 Introduction

The development of Progressing Cavity Pump (PCP) was done by Moineau in 1920s. But the use of PCP in oil industry began in 1970s. As it was developed by Moineau, PCP also called Moineau pump. The design of PCP is very simple and recently the requirement for PCP has been widely increased in production of high viscous fluids. PCPs are applicable in horizontal and deviated wells.

PCPs can handle large amount of water. Therefore, PCPs are also applicable in water wells, coal bed methane fields. Installation of PCPs is very expensive, but they decrease energy requirement as production increases. PCP could be installed at 4000 ft depth. Down-hole pump has a moving part with no reciprocating part. Therefore, there is no gas lock, paraffin plugging, scaling in PCPs and they could easily handle fluids with high sand content.

Figure 2.32 presents schematic view of PCP system. As it is seen in the figure PCPs have three major components:

(a) Surface components- this part drives rods to activate pump. Mainly electric or hydraulic motors are used to drive rods.
(b) Rods- this part is used to connect surface components with subsurface components.
(c) Subsurface unit- down-hole pump is the main component of this unit, which consists of rotor and stator.

The main part of subsurface unit is down-hole pump. This pump is a positive-displacement pump and consists of rotor and stator. Rotor is located inside a stator and made of steel rod. The stator is inside a casing and molded in the shape of helix. Rotor and stator acts as a pump. The rotation of stator creates a cavity and it goes up as rotor rotates inside a stator. Increase in the pressure could be gained by number of stages. Estimation of pressure increase per stage is 200-300 kPa. But pressure could decrease if there is a friction between rotor and stator. Therefore, lubrications are used to avoid these problems. Figure 2.33 presents a schematic view of PCP, rotor stator.

Like in other artificial lift methods, presence of free gas in produced fluid decreases the efficiency of pump. Therefore, gas anchor also is installed in completions.

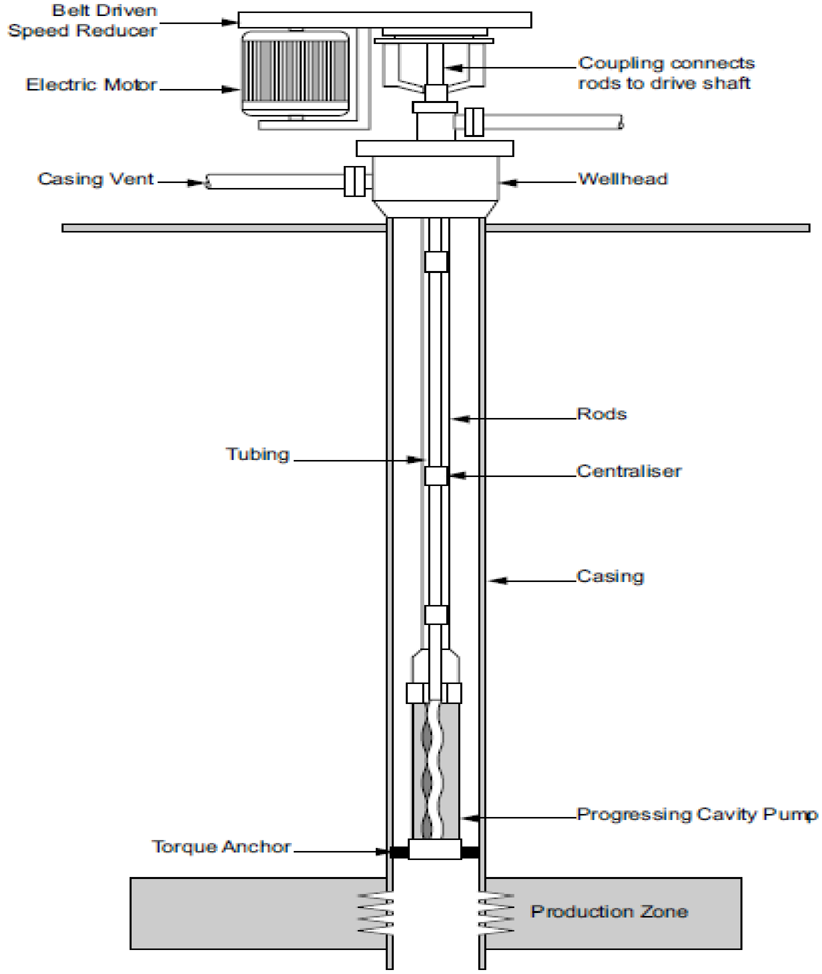


Figure 2.32 Schematic view of PCP system [15]

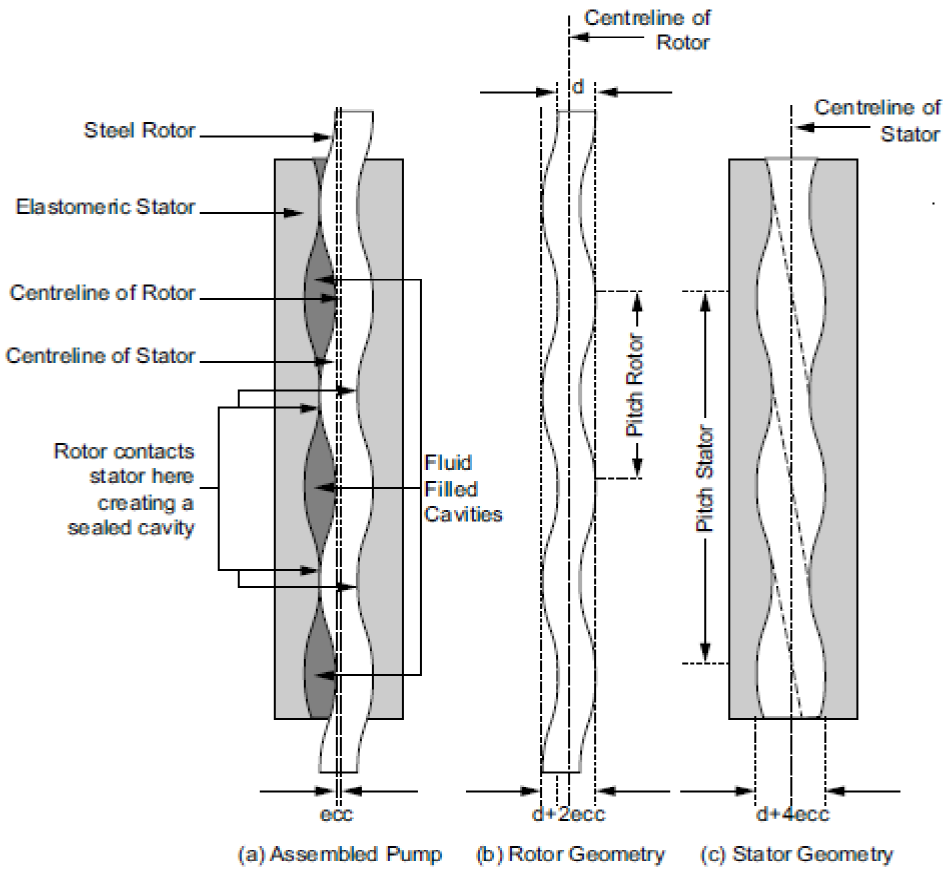


Figure 2.33 Schematic view of PCP and its components [15]

2.7.2 The Electric Submersible Progressing Cavity Pump (ESPCP)

As it was stated above PCP is driven by electric or hydraulic motor that mounted on the surface. Electric motor turns rods that directly connected to down-hole pump. In this case, there is a possibility of rod and casing wearing. To avoid this problem new technology ESPCP developed in Russia. The main parts of this system are: (1) PCP, (2) electric motor, (3) seal section, (4) electric cable. Figure 2.34 presents a schematic view of ESPCP system. As it is seen in the figure, PCP is located on top of the assembly.

Seal section is used to protect down-hole motor from the fluids. The main problem in this system is that PCP revolution is 3-600 rpm, but ESP motor revolution is 3500 rpm. To avoid this problem, gear reducer is used to connect PCP to ESP motor to balance the turns.

Another advantage of ESPCP is that it could be applied in deviated or horizontal wells.

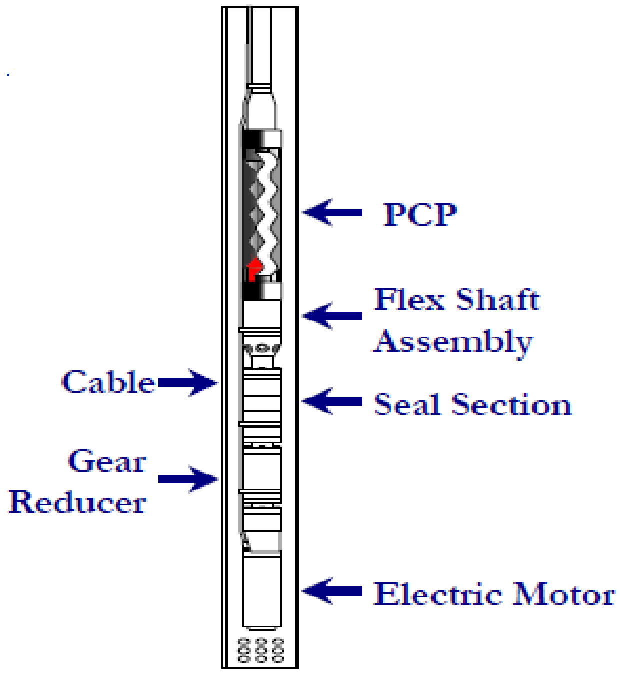


Figure 2.34 Schematic view of ESPCP [8]

2.7.3 Advantages of PCPs

The main advantages of PCPs are listed below:

(1) PCPs are able to produce high viscous fluids.
(2) As there is only one moving part in PCPs, there is no sand problem in this system.
(3) Existence of free gas does not reduce the efficiency of PCP. Also gas anchor is installed in well completions.
(4) Capital and operating expenses are low of this system.
(5) PCPs handles very well in abrasive fluids, paraffin plugging and scaling.
(6) Volumetric efficiency of PCPs is high.

Table 2.24 and 2.25 gives operating limits and production considerations of PCPs.

2.7.4 Disadvantages of PCPs

(1) PCPs are limited in producing high volume of liquid. The available maximum production limit is nearly 5000 bpd.
(2) PCPs are also limited in depth. The depth limit is 4000 ft of PCPs.
(3) Volumetric efficiency decreases if there is high content of gas in produced liquid.
(4) Elastomers in the stator can be solved in the aromatic oil types.
(5) Before development of ESPCP, rod and casing wear was problem in deviated and horizontal wells.

Table 2.24 Operating limits of PCPs

Parameters	Typical Range	Maximum
Operating Depth	2000 – 4500 TVD	6000 TVD
Operating Volume	5 –2200 BPD	4500 BPD
Operating Temperature	75 – 150 °F	250 °F
Wellbore Deviation	N/A	$0 - {}^{\circ}90$

Table 2.25 Production considerations of PCPs

Corrosion Handling	Fair
Gas Handling	Good
Solids Handling	Excellent
Fluid Gravity	$\leq 35^{\circ}$ API
Servicing	Workover or Pulling Rig
Prime Mover Type	Gas or Electric
Offshore Application	Good (ESPCP)
System Efficiency	40 – 70 %

2.8 Plunger Lift

2.8.1 Introduction

Plunger lift could be applied in both oil wells with high gas-liquid ratio and gas wells. But it is mostly applied in gas wells to remove liquid that loading in the tubing. Plunger lift method is applicable in wells with scaling, paraffin, hydrate and sand production problems. The well depth limitation mainly ranges between 300-5000 m in 50 to 1500 psi bottom-hole flowing pressures.

The installation of plunger lift systems is very inexpensive and they are good in production rates less than 200 bopd.

As it was stated, recently plunger lift systems have been used gas wells to remove liquid (water and condensate). As it is known in PVT properties of fluids, in pressure values above dew point pressure in gas wells, liquid phase is in mist form in gas phase. As pressure decreases below critical level, liquid phase begins to separate and accumulate in the tubing (liquid loading). In this case, BHP increases and creates high back pressure. As a result, gas production rate begins to decline. Low gas production rate will result with bubble flow and cease production. In such cases, removal of loaded liquid is very important.

The main parts of plunger lift systems are:

(1) Lubricator
(2) Plunger
(3) Bumper spring
(4) Controller

2.8.2 Working Principle

The main part of plunger lift system is free piston that travels through tubing and moves up liquid above the piston. The schematic view of plunger lift system is presented in Figure 2.35. The main task of plunger lift system is to allow the well to produce the gas at low bottom-hole pressure by removing liquid loaded in the tubing or wellbore. In the cases without plunger system, gas velocity must be very high to carry up liquid. But in plunger lift applications, gas velocity could be low. Plunger plays interface role between gas and liquid phases and uses wells own energy.

There are two periods in plunger lift operations: (1) shut-in period and (2) flow period. In turn, flow period has two periods: (a) unloading period and (b) flow after plunger arrival.

In the first period, plunger moves down to the bottom of the well. Simultaneously, gas pressure builds up because of shut-in of the well. This pressure will lift up plunger and liquid above the plunger to the surface. The duration of well shut-in must be enough to build energy to the sufficient level. In order to overcome friction and line pressures. Second period begins when pressure reached to a sufficient level. In the beginning of this period, the plunger and liquid above the plunger moves up. The low density of gas allows the quick flow of gas above the plunger into flowline. At the end of this stage, liquid is unloaded as plunger arrives to the surface.

The production of liquid continues as pressure again drops and liquid begins to load in the tubing. In this case, cycle again repeats by shut-in the well and moving down the plunger to the bottom of the well. Plunger is moved up and down by lubricator.

The number of cycle and efficiency of the system is dependent on GLR and shut-in time. Because, it has been estimated that high gas production rate could be achieved if system works against low bottom-hole pressure. Also, system efficiency will decrease if GLR is low. Therefore, optimum value for shut-in time should be selected.

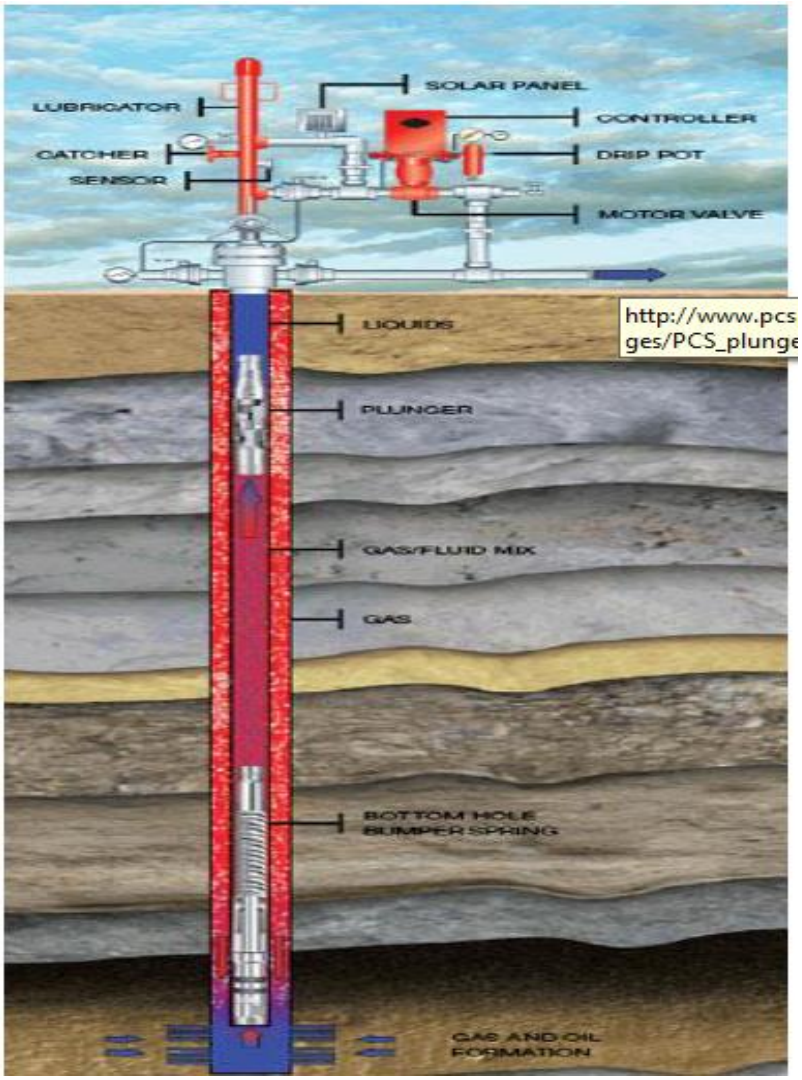


Figure 2.35 Schematic view of Plunger Lift system

2.8.3 Advantages of Plunger Lift Systems

Advantages of plunger lift systems are listed below:

(1) As it was discussed above, the installation of plunger lift systems are very inexpensive.
(2) These systems are applicable in the wells with scale, paraffin, sand production problems.
(3) Like in gas lift method, plunger lift is also applicable in high gas-liquid ratio wells.
(4) Plunger lift systems could be applied in both oil and gas wells. In gas wells they are mainly used to remove the liquid.

Table 2.26 and 2.27 gives the operating and production considerations of plunger lift systems.

Table 2.26 Operating considerations of Plunger Lift

Parameters	Typical Range	Maximum
Operating Depth	8000 TVD	19000 TVD
Operating Volume	1 –5 BPD	200 BPD
Operating Temperature	120 °F	500 °F
Wellbore Deviation	N/A	$^{\circ}80$

Table 2.27 Production considerations of Plunger Lift

Corrosion Handling	Excellent
Gas Handling	Excellent
Solids Handling	Poor to Fair
GLR required	300 scf/bbl/1000 depth
Servicing	Wellhead Catcher or Wire line
Prime Mover Type	Reservoir energy
Offshore Application	N/A at this time
System Efficiency	N/A

2.8.4 Disadvantages of Plunger Lift Systems

There are several factors that limit application of plunger lift systems:

(1) They may not be used in the wells which are depleted. In this case, another lifting method could be applied.
(2) They are very good in low rate wells less than 200 bopd.
(3) It could create a danger if plunger reaches to a high velocity and causes surface damage.
(4) There is a requirement of good operation for tubing and casing communication.

2.9 Gas Lift

2.9.1 Introduction

The introduction of gas lift was in 1910 and the wide use of gas lift began in 1920. Unlike other AL methods, gas lift is widely used method in offshore fields. The design of gas lift is very simple and it has very few moving parts. Gas lift method is applicable in highly deviated, high GOR wells and fluids with high sand content. Compressed high pressure gas is used as a main source in gas lift method. Therefore, availability of gas source is very important.

As it was discussed above, gas lift and plunger lift methods are based on theory to reduce back pressure by lightening fluid column in the well. In gas lift method, production is increased with reduction of bottom-hole pressure by injection of compressed gas through the annulus or orifice that installed in the tubing. In this case, gas has two impacts on liquid: (a) as it is known from PVT properties of fluids, gas causes expansion in liquid phase and moves oil to the surface, (b) gas decreases the density of oil which causes decrease in hydrostatic pressure and helps to lift to the surface. Gas lift method could be applied in four types of wells:

(1) High BHP and high productivity index (PI) wells
(2) Low BHP and high PI wells
(3) High BHP and low PI wells
(4) Low BHP and low PI wells

In summary, gas lift could be summarized in four steps:

(1) Compression of gas at the surface and transportation to the appointed wells
(2) The compressed gas is injected to the annulus or orifice through gas lift valves
(3) Injected gas lifts reservoir fluids to the surface
(4) Gas and liquid is separated in the separator and after separation gas could be again compressed or transported to the sales manilfolds.

Schematic view of gas lift system is presented in Figure 2.36.

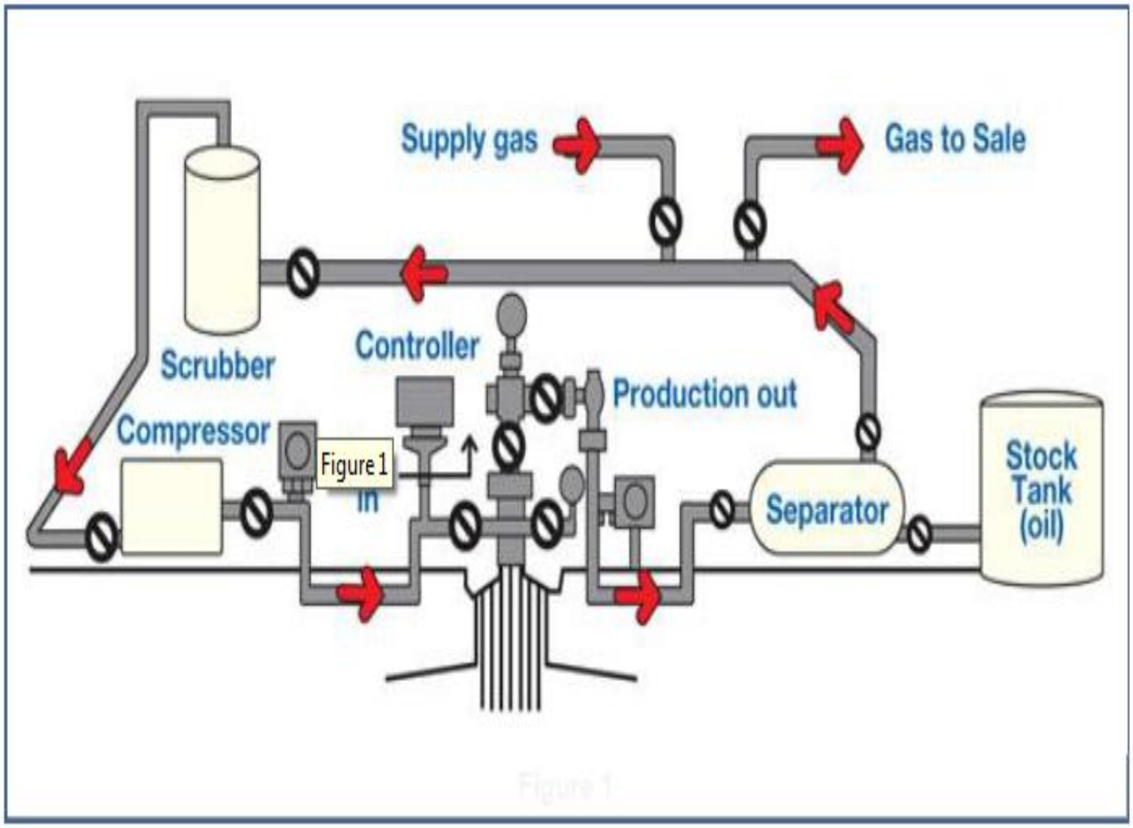


Figure 2.36 Schematic view of Gas Lift system [13]

2.9.2 Gas Lift System

The main parts of gas lift system are: station for gas compression, injection manifold, injection chokes, surface controllers, injection valves and chamber that installed in down-hole. Figure 2.37 presents view of these parts.

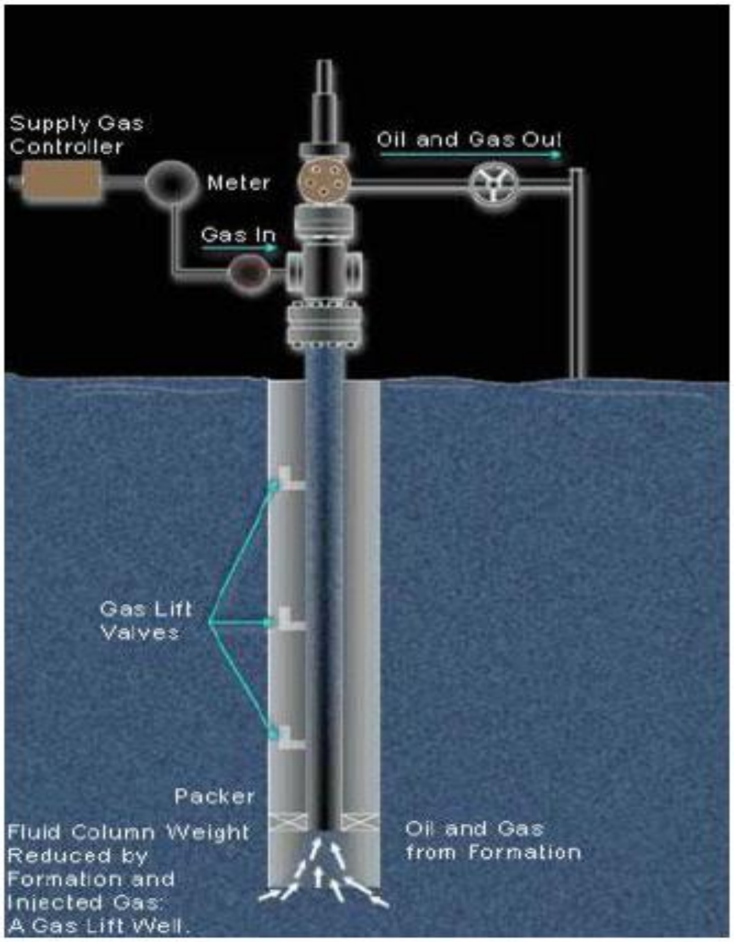


Figure 2.37 Main parts of Gas Lift system [12]

Gas lift valves are usually open at the first stage. Injected gas enters from the first valve, it mixes with the liquid and creates low density mixture. Low density mixture begins to expand and moves up to the surface. After this process first valve begins to close and allow gas to go through other valves and aerate much liquid. Only operating valve is always open to allow gas to enter and lighten fluid column.

There are two main types of gas lift system: (1) continuous gas lift and (2) intermittent gas lift.

Continuous gas lift

Continuous gas lift is also called constant flow gas lift and it is a steady-state flow. Continuous gas lift is mainly applied in the high PI and high bottom-hole wells. In this type, production rate varies between 100 to 30000 bopd. In continuous gas lift flow a small volume of gas is required to be injected. Therefore, it would be better to install valves as deep as possible to lighten much liquid.

Continuous gas lift is the best application for the reservoirs with water drive or waterflooding. This type is better for high GOR wells. As was stated above, in high GOR wells only a small volume gas will be required to contribute to the formation gas to lighten the fluid column and increase production rate. But in this type of gas lift, gas supply must be maintained throughout the life of the well. As water cut increases in the well gas production will decline. In this case, much gas will be required to be injected in order to achieve the desired depth. Because, poor gas supply even could stop the production. The schematic view of continuous gas list is presented in Figure 2.38.

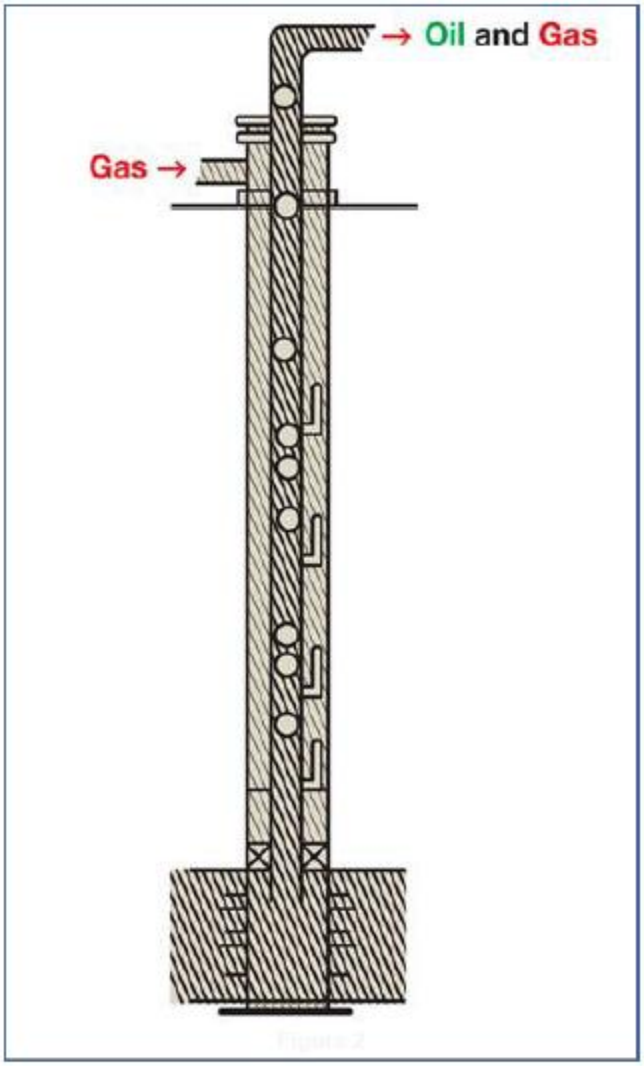


Figure 2.38 Continuous Gas Lift [15]

Intermittent gas lift

As reservoir pressure reduces down to a certain level, continuous gas lift changes to intermittent gas lift. Therefore, production rate in intermittent gas lift is lower. The approximate production rate is lower than 200 bopd in this type. Intermittent gas lift could be considered in two kinds of wells: (1) wells with low BHP and high PI or (2) wells with high BHP and low PI.

The equipment used in continuous gas lift flow is the same with intermittent gas lift flow. But working principle is different from each other. Intermittent gas lift is a unsteady-state flow and it is based on start-stop flow regime.

As it was discussed, continuous gas lift flow produces liquid to the surface by reducing the density of the column. But intermittent gas lift produces liquid slug to the surface. Therefore, gas injection is stopped to allow accumulation of liquid into the wellbore. As certain volume of liquid is accumulated in the wellbore, compressed gas is injected to lift u this liquid slug. Figure 2.39 presents schematic view of intermittent gas lift.

It is very important to know gas lift equipment and operation principles of each gas lift type and gas lift technology for proper selection. The basic equipment of GL system is:

(1) Operating and unloading valves
(2) Mandrels
(3) Check valves
(4) Surface controllers
(5) Gas compression stations
(6) Wire-line systems to control gas lift operations

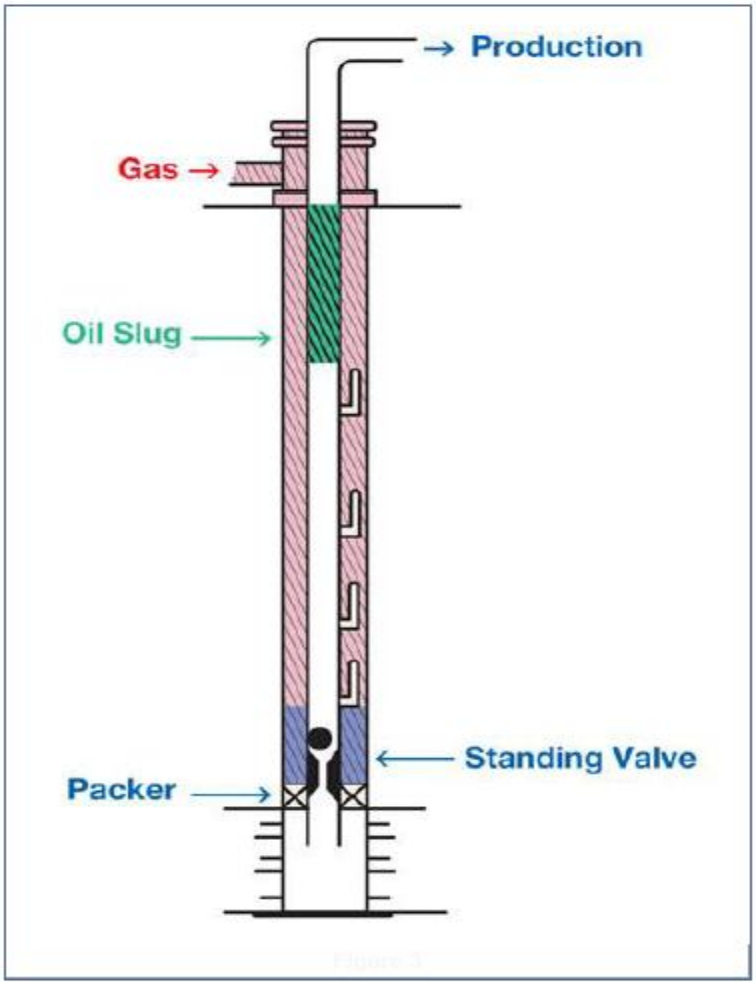


Figure 2.39 Intermittent Gas Lift [15]

2.9.3 Advantages of Gas Lift Systems

The main advantages of gas lift method are listed below:

(1) This method is capable of handling high volume of solids easily.
(2) Production rate is very high in this method. The maximum production rate could be 50000 bopd.
(3) As it was discussed above, it could be changes from continuous gas lift to intermittent gas lift flow as reservoir pressure declines to a certain level.
(4) Gas lift method could be installed in urban locations.
(5) Remote control is possible in this method by wire-line adaptations.
(6) High gas content in produced liquid makes beneficial this method.
(7) GL is applicable in high deviated and offshore wells.

Economic evaluations for low rate and high rate cases are presented in Table 2.28 and 2.29. Table 2.30 and 2.31 presents operation consideration of gas lift.

Table 2.28 Gas Lift equipment cost: low rate case

Item	Cost	Life
Tubing	80000	15
Valve	2000	3
Mandrel	5000	10

Table 2.29 Gas Lift equipment cost: high rate case

Item	Cost	Life
Tubing	80000	15
Valve	2000	3
Mandrel	5000	10

Table 2.30 Operation considerations of Gas Lift

Parameters	Typical Range	Maximum
Operating Depth	5000 – 10000 TVD	15000 TVD
Operating Volume	100 –10000 BPD	30000 BPD
Operating Temperature	100 – 250 °F	400 °F
Wellbore Deviation	$0 - {}^{\circ}50$	${}^{\circ}70$

Table 2.31 Production considerations of Gas Lift

Corrosion Handling	Good to Excellent
Gas Handling	Excellent
Solids Handling	Good
Fluid gravity	300 scf/bbl/1000 depth
Servicing	Wire line or Work over Rig
Prime Mover Type	Compressor
Offshore Application	Excellent
System Efficiency	10 – 30 %

2.9.4 Disadvantages of Gas Lift Systems

(1) High volume of gas is required to lighten the fluid column. But this amount of gas may not be always available.
(2) Emulsions and high viscous liquid creates problems in gas lift operations.
(3) Unlike other lift methods, energy efficiency is lower in GL.
(4) They are incapable of reducing BHP as well as pump applications.
(5) Freezing and hydrate problems could be occurred in manifold systems.
(6) Corrosive gas could make problems in production such as damaging tubing/casing system.
(7) Wire line problems could occur in remote controlling.
(8) High paraffin content in the produced liquid also could make severe problems in production.

CHAPTER 3

ARTIFICIAL LIFT SELECTION TECHNIQUES

3.1 Introduction

Fluids will flow from reservoir to the surface when the well is completed and reservoir pressure is sufficient to receive fluid from matrix, transport it to the wellbore and lift to the surface. During the reservoir production life reservoir pressure will decline and this could cause increase in water cut and decrease in gas fraction. These reasons decrease or even may cause to stop flowing of fluids from the well. Some techniques must be applied to prevent the production decline. In these cases, artificial lift techniques are applied to add energy to the produced fluids.

Major artificial lift techniques are:

(1) Sucker Rod Pump
(2) Hydraulic Pump
(3) Electrical Submersible Pump
(4) Progressive Cavity Pump
(5) Continuous gas lift
(6) Intermittent gas lift
(7) Intermittent gas lift with plunger
(8) Constant slug injection gas lift
(9) Chamber gas lift
(10) Conventional plunger lift

The most important problem is how to select optimum artificial lift techniques taking into consideration reservoir, well, environmental conditions. Also economic implications are important (such as investment, work over costs).

Selection of poor technique could result with decrease in efficiency and low profitability. As a result, it will lead to high operating expenses. Several techniques have been developed for selection of optimum artificial lift techniques. For example, OPUS (optimal pumping unit search) firstly was introduced by Valentine et al. (1988) for selection of optimum artificial lift techniques. The advantage of OPUS is that this program takes into consideration technical and financial issues of each artificial lift techniques.

Therefore, economic parameters such as initial capital expenses, monthly operating expenses, workover costs and operating criteria of each artificial lift techniques are very important. Cleg (1988) developed further studies on artificial lift methods technical abilities and economical aspects for development of selection techniques.

Furthermore, SEDLA artificial lift selection technique was developed by Espin et al. (1994). This computer program mainly consists of three modules: (1) Expert Module, (2) Design Module, and (3) Economic Module. Also, „'the decision tree'' was used by Heinze et al. (1995) for selection of artificial lift techniques. Finally, Alemi et al (2010) used TOPSIS model (technique for order preference by similarity to ideal solution) of artificial lift selection for Iranian fields [9].

3.2 Multi Criteria Decision Making Methods (MCDM)

Depending on the problem MCDM is divided into two parts: (1) Multi Attribute Decision Making Method and (2) Multi Objective Decision Making Method. These two methods are applied depending on problem whether it is related to selection or design.

MODM method is usually used when there are large numbers of choices and based on the constraints and preferences the best method is selected. Criteria are included: (1) reservoir, well and production constraints, (2) produced fluid properties and (3) surface infrastructure. Table 3.1 presents conditions for one of the Iranian oil field. This table is presented as a input data for TOPSIS model. MADM method is used when there is no need to mathematical assessments and limited number of alternatives (Kusumadewi et al. 2006) [14]. SRP, PCP, HP, GL and ESP are considered as alternatives.

There are certain models that based on MCDM model:

(1) TOPSIS (technique for order preference by similarity to ideal solution)
(2) SAW (simple additive weighting) model
(3) ELECTRE (elimination et choice in translating to reality) model
(4) WPM (weighting product model)

Table 3.1 Conditions of one of the Iranian field

1	Number of wells	3
2	Production rate (bbl/d)	1340
3	Well depth (ft)	4513
4	Casing size (inch)	7
5	Well inclination	vertical
6	Dog leg severity	2
7	Temperature (F)	144
8	Safety barriers	1
9	Flowing pressure (psi)	425
10	Reservoir access	required
11	Completion	dual
12	Stability	stable
13	Recovery	primary
14	Water cut (%)	33.5
15	Fluid viscosity (cp)	0.1206
16	Corrosive fluid	YES
17	Sand content (ppm)	9
18	GOR (scf/stb)	576
19	VLR	0.01
20	Contaminants	asphaltene
21	Treatment	acid
22	Location	onshore
23	Electric power	utility
24	Space restrictions	No
25	Well service	Pulling unit

3.3 TOPSIS Model

As it has been discussed in previous section, TOPSIS model is based on MCDM model. TOPSIS model has been applied in different oil fields and therefore, it is validated model than other model that based on MCDM model. TOPSIS model is software based on Visual Basic.net code. The main difference of TOPSIS model from other models is that it does not give only best appropriate method for the given data, at the same time it gives the worst method that could be applied. Hwang and Yoon (1981) developed this software.

The basic concept of this program is that the best suitable method should be in the shortest distance from the ideal solution and the worst suitable method should in the farthest distance from the ideal solution. For that, scores must be given to the artificial lift methods in scale ranging from 0 to 10. These scores are dependent on certain parameters as it is given on Table 3.1: (1) Reservoir, Wells and Production parameters, (2) Produced Fluid Properties and (3) Surface parameters. There are three level of assessment. Based on the Schlumberger reports value 1 is considered as good to excellent and conversion in 10 point scaling range its value is 7, value 2 is considered as fair to good and in 10 point scale its value is 7 and value 3 is considered as poor (which is not suggested) and its value is 3 in 10 point scale. As it is discussed in Chapter 2 each artificial lift method has its operating limits. After setting the well data the separation of artificial lift techniques from the ideal solution is obtained.

Figure 3.1 presents the final result of the selection technique. This is the result of the Iranian oil field that was studied using data in Table 3.1. It is seen that regarding to input data ESP is the best suitable artificial lift technique for the well. The same data has been used in developed Expert System case studies.

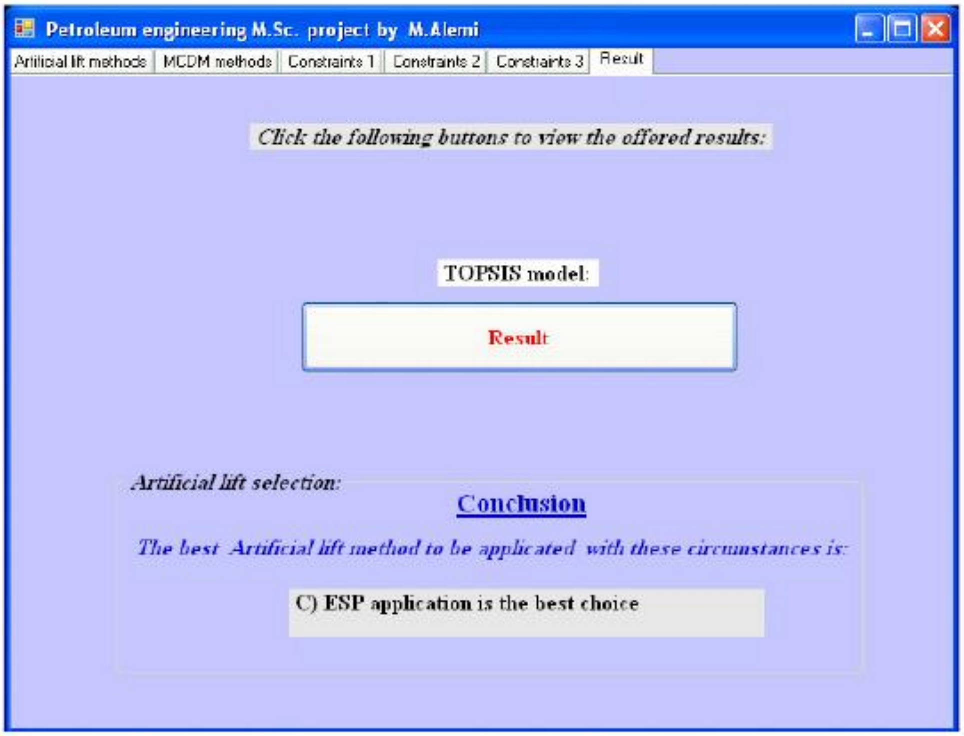


Figure 3.1 Artificial Lift Selection result by the TOPSIS software

3.4 Optimal Pumping Unit Search (OPUS) Method

3.4.1 Program Development

OPUS has been used as an operational product since 1987. In first stage OPUS program was developed by team of IFP using DIEZOL inference engine. But in later stages further development of program was done in S1 engine offered by Framentec. Installation of first version of S1 engine was on Xerox 1108 to be benefited from all advantages of this program. But in the first version of this program some defects appeared. Because, it was not possible to interface with other programs and program was very slow.

As a result, next installation of S1 engine was on Vax. This program was written in C language. Existing problems in previous version such as being impossible to interface with other programs, slowness of the program were solved. But the disadvantage of this version was that it was impossible to use menu, graphs. In this program mainly basic engineering calculations, technical knowledge and economic evaluations have been considered. Absence of design module is the main difference from SEDLA program. Therefore, OPUS could be divided into two parts: (1) representation of knowledge and (2) technical and economic considerations.

Representation of Knowledge

The representation of knowledge is done by some rules. Facts are represented by: (1) attribute, (2) object and (3) value triplets. The task of „'control block „' is to define rules and facts. As in other artificial lift selection techniques, in OPUS production considerations are valued with coefficients which is called suitability coefficients (SC). OPUS method is based on ''If Then'' condition, in the form,

If (condition) then (process type regarding to consideration value)

Values of production consideration coefficients range between -1 and +1. -1 indicates that the process is not suitable for the well. +1 indicates that system is the best suitable for the well. Program analyzes all the coefficients for specific processes and as a result, program presents the overall suitability of each artificial lift type.

Several rules must be followed in coefficient scaling:

(a) If system eliminates any artificial lift method at any evaluation stage, then, it must be remained as eliminated method in all stages, in spite of that there is a positive judgement in other stages about eliminated method. For example, high flow rate is characteristic for centrifugal pumps. Then, in this case, any process with high bottom-hole temperature must be eliminated.
(b) Suitability coefficients individually analyzed in each stage. The value of coefficient could be different in various stages, dependent on the impact of process that coefficient represents on that stage.

Economic and Technical Assessment

Algorithmic programs are used for economic and technical assessment. Technical assessment is mainly related to pumping system. It determines the diameters of pumping units, liquid flow in the well and flow from wellhead to stock tank. Having all this information helps engineers to have a view about production system. In economic assessment, each process is evaluated. In this evaluation, initial capital expenses, monthly operating expenses and maintenance expenses are considered.

3.4.2 Operational Product

OPUS program achieve to the final result in three phases:

(1) Entering well data to the program
(2) Analyzing data
(3) Expert recommendations with technical and economic considerations

In first phase, engineer must include main well data to the program such as reservoir charatceristics, production and operation considerations, fluid properties, etc. By using these parameters system begins to eliminate some processes. For example, if the viscosity of produced fluid is high, then gas lift and centrifugal pump systems will be eliminated. After that, system continues to analyze the suitability of other parameters such as temperature, the depth of the well, well deviation, flow rate. As a result, system shows the suitability of artificial lift methods in three categories:

(a) Not recommended system
(b) Systems recommended with restrictions. For example, sucker rod pump could be suitable for the given well data. But, high free gas content in the produced fluid could decrease the pumping efficiency. In this case, installation of gas separators in the down-hole could remve the problem.
(c) Recommended systems

Figure 3.2 presents schematic view of program diagnosis.

```
NOT RECOMMENDED SYSTEMS :

     Centrifugal.pump
     Gas.lift

RECOMMENDED SYSTEMS with restrictions :

  +  Progressive.cavity.pump
     Rod.pump
  -  Piston.pump

RECOMMENDED SYSTEMS :

  +  Jet.pump
```

Figure 3.2 Schematic view of program diagnosis

As it was discussed above in early stages of program development it was impossible to use menu, dynamic graphs in the program. New version of OPUS is developed in FRANLAB by IFP. In this version, different type of menus, dynamic graphs will be used. Figure 3.3 presents the view of last version of OPUS.

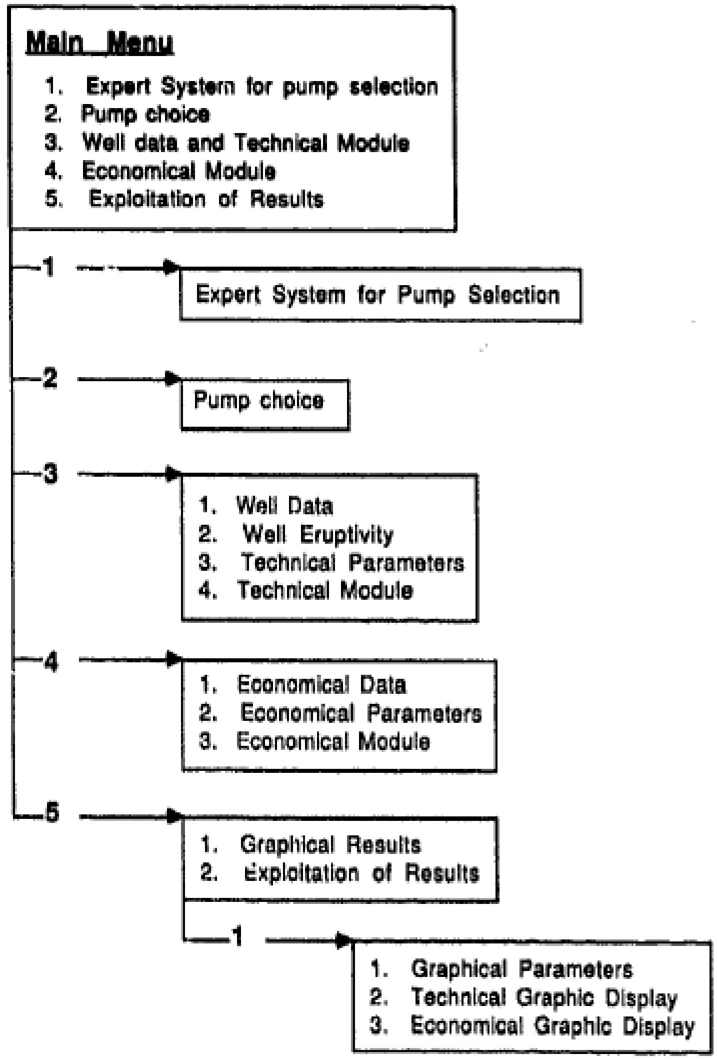


Figure 3.3 Final structure of OPUS system [1]

3.5 Expert System

3.5.1 Introduction

Expert System (E.S.) is computer software that provides expert advice to petroleum engineers in solution the selection of best or optimum artificial lift techniques. This software developed nearly in 1980's and have been applied in many engineering disciplines. After 1980, different expert systems have been developed for gas lift and sucker rod pumping systems. In the early times of development of expert systems only a few artificial lift techniques were known to engineers. Also, in some selection techniques economic implications such as capital investment expenses, operating expenses were not taken into consideration. Production environment considerations including exsistence of H2S, CO2, sand content in produced fluid and other solid contents (asphaltene, paraffin) decreased the efficiency of suitable artificial lift technique. In this case, the need for the application of Expert Systems was very high.

As it was discussed above, different models and methods have been developed for selection of suitable artificial lift techniques. For example, A.L. is applied to select suitable technique among four techniques using basic engineering calculations. But in this method design and economical evaluations have not been considered. In OPUS method, basic engineering calculations and economic analysis have been considered.

Expert System differs from these methods with including basic engineering calculations and base of knowledge driven from nine well-known experts in the world. Also, design of selected lift technique and economic analysis has been considered in this software. Therefore, selected method by Expert System could be considered best for both technical and economical sides.

Expert System includes below artificial lift techniques:

(1) Sucker Rod (walking beam/hydraulic)
(2) Electrical Submersible Pump
(3) Gas Lift (continuous and intermittent)
(4) Intermittent gas lift with plunger
(5) Gas lift with continuous slug injection
(6) Hydraulic Pump (jet/piston)
(7) Progressive Cavity Pump
(8) Plunger Lift
(9) Chamber Lift

3.5.2 Program Structure

Expert System was developed for using expert system called ESE (Expert System Environment). Expert System Environment is a trademark of IBM (International Business Machine). This program consists of three modules: (1) Expert module, (2) Design module, (3) Economic module. Figure 3.4 presents the schematic view of Expert System. Module 1 is an expert module that includes basic engineering calculations and written theoretical knowledge about each artificial lift types. This module is build up by human expertise. Module 2 is a design module. In this module, the design of components of selected artificial lift type is considered. For example, casing and tubing size in given production rate. Module 3 is an economic module that includes economic evaluation of lift profitability.

Figure 3.5 presents the chart of program flow. In program interface well data and production environment is included as a list. Taking into consideration all these production conditions and given well data expert module 1 analyzes all the artificial lift techniques regarding to their operating limits. After analyzing all artificial lift techniques according to given data, module 1 ranks all the available lift methods from the best to the worst with stating warnings and suggestions. Warnings and suggestions are very important at this point. Because some artificial lift techniques could be suitable according to the included well data, but production conditions limits its application. For example, sucker rod pumps are applicable in shallow and low productive wells, but they are not applicable in offshore wells, also in urban areas because of the space limitation and noise. This will help engineers to select the most suitable method.

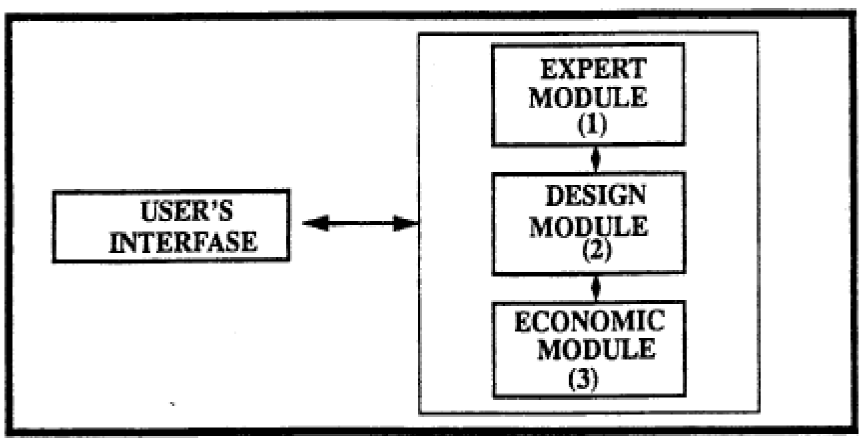


Figure 3.4 ES structure [5]

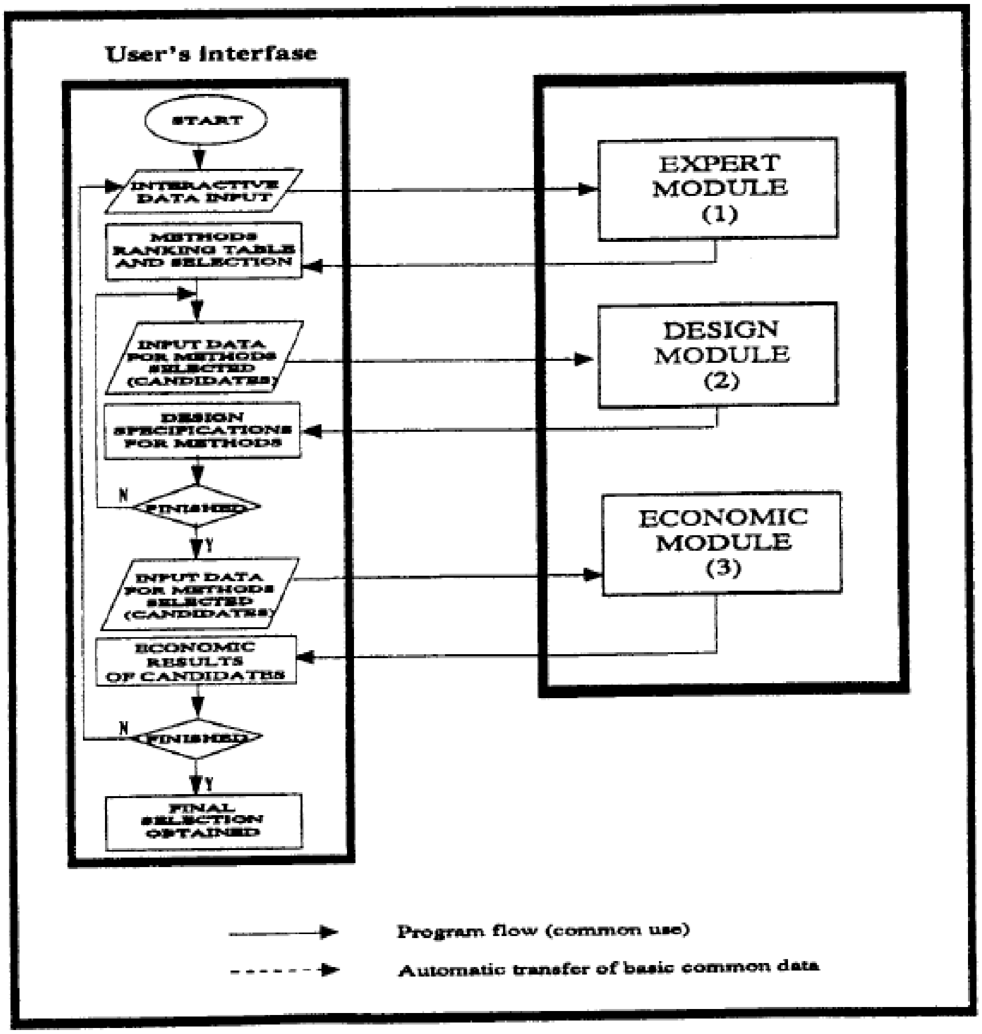


Figure 3.5 ES program flow

Design module is used for the designing of selected artificial lift technique. In this stage, engineers also take into consideration warnings and suggestions that has been stated in expert module. This module shows required equipment that is needed for the application of best design of selected technique. Estimated production rate plays important role in this stage. For example, by using basic engineering calculations tubing size could be determined for the required production rate.

Module 3 evaluates the expenses of surface and subsurface equipment. Also initial capital expenses, operation expense and work over costs are considered in evaluation. Using basic calculations, profitability of each method could be determined based on production rate that estimated in module 2.

3.5.3. Expert System Development

Three groups of parameters are required for the development of expert systems. They are listed as below:

(1) Quantity parameters
(2) Quality parameters
(3) Parameters regarding to production problems

Above parameters help to specify the best appropriate lift method for particular well or group of wells.

Quantity parameters are:

(1) Well depth
(2) Estimated production rate
(3) Reservoir deliverability (PI)
(4) Gas-oil ratio (GOR)
(5) Water cut
(6) API gravity
(7) Reservoir and bottom-hole flowing pressure
(8) Bottom-hole temperature
(9) Well size (casing and tubing size)

Quality parameters are:

(1) Field location (onshore, offshore, urban)
(2) Type of completion (single, dual)
(3) Availability of gas (for gas lift method)

Production problems are:

(1) Corrosion (high sulphur content in produced fluid)
(2) Erosion (obtrusive sand content in produced fluid)
(3) Paraffin collapse)
(4) Scaling
(5) Hydrate formation
(6) Emulsion and foams
(7) Excessive water production
(8) Excessive gas production
(9) Heavy compounds in produced fluid (asphaltene)

Then, the best artificial lift technique will be selected according to above parameters. For each of these parameters will be pointed coefficients as in TOPSIS model.

In ES program coefficient values vary from „’1’’ to „’5’’. These values reflect the impact of each parameter on artificial lift technique suitability. The magnitude of coefficient value indicates the suitability of method. Coefficient „’1’’ indicates that method is not suitable, but coefficient „’5’’ indicates the suitability of method. In this expert system, all the artificial lift methods are ranked from the best one to the worst one. Therefore, the advantage of this program is that warnings are shown for non-suitable methods. As it was discussed above factors influencing on artificial lift selection techniques could be grouped as quantity, quality parameters and production problems. Each of these parameters has an impact weight on particular artificial lift methods. As a result, taking into consideration the specific coefficients all these parameters total coefficient is obtained for each artificial lift types and ranged with suitability percentage. Expert Systems are based on if then conditions, in the form,

If (condition)   Then (suitable artificial lift method)

If (Production rate is 30000 barrels per day)   Then (Gas Lift), 5

Table 3.2 and 3.3 show schematic view of program, includes interface and result of expert module.

Table 3.2 Schematic view of program interface

DATA SUPPLIED

Cuantitative data (1-5):

Well depth (ft)	:	8950
Expected fluids rate (bpd)	:	800
Productivity Index P.I. (bpd/psi)	:	0.70
Gas Liquid Ratio G.L.R.(scfd/bpd)	:	128
Water cut (%)	:	3
API	:	10.6
Reservoir pressure (psi)	:	2770
Reservoir temperature (t)	:	180
Casing diameter (in)	:	9.62
Tubing diameter (in)	:	4
Tubing head pressure (psi)	:	0
Gas injection pressure available (psi)	:	230
Maximum electrical power fluctuation (%)	:	6

Production Problems (1-5)

Corrosion	:	0
Paraffins	:	0
Sand	:	3
Well Deviation	:	0
Emulsions	:	0
Foam	:	0
Asphaltenes	:	0
Scale	:	0
Aromatics	:	0

Cualitative data (1-5):

Field expertise available:

Continuous gas lift (T/A)	:	3/5
Intermittent lift	:	2
Intermittent lift with plunger	:	0
Chamber lift	:	1
Constant slug injection gas lift	:	0
Conventional plunger lift	:	0
Sucker rod pumping	:	5
Progressive cavity pump	:	5
Electrosumersible pump	:	1
Hydraulic jet pump	:	1
Hydraulic piston pump	:	1

Adaptability to reservoir depletion	:	0
Gas availability (Limited / Unlimited / None)	:	N
Well location (Urban / Offshore / Field)	:	O
Completion Type (Single / Double / Triple)	:	S

Table 3.3 Schematic view of Expert Module

RESULTS OF EXPERT MODULE (1) CONSULTATION

LIFT METHOD	SCORE	WARNING
Electrosumersible pump	45	0
Hydraulic jet pump	31	1
Sucker rod pumping	25	0
Hydraulic piston pump	21	1
Progressive cavity pump	16	2
Continuos gas lift tubing	3	3
Constant slug injection gas lift	3	3
Continuous gas lift anular	2	3
Chamber lift	1	4
Intermittent lift with plunger	0	4
Intermittent lift	0	4
Conventional plunger lift	0	3

Profitability Analysis Results

NPV (@10%) ESP :	1420 MUS$
NPV (@10%) ROD PUMPING:	1461 MUS$

In summary, the advantages of application of ES could be listed as below:

(1) Artificial lift selection techniques for particular well or group of wells.
(2) Widely used expert program for engineers
(3) Program was acquired from the integration of experts and field experiences.
(4) Selection and design module for each type of artificial lift.

CHAPTER 4

STATEMENT OF THE PROBLEM

During the reservoir production life reservoir pressure will decline. Also after water breakthrough the fluid column weight will increase as hydrostatic pressure will increase because of increased water and oil mixture density. In this case, reservoir pressure may not be enough to lift up the fluid from bottom to the surface. These reasons decrease or even may cause to stop flowing of fluids from the well. Some techniques must be applied to prevent the production decline. Artificial lift techniques are applied to add energy to the produced fluids. The most important problem is how to select optimum artificial lift techniques taking into consideration reservoir, well, environmental conditions. Selection of poor technique could result with decrease in efficiency and low profitability. As a result, it will lead to high operating expenses. Several techniques have been developed for selection of optimum artificial lift techniques. But the developed programs are more expensive and commercially it may not be beneficial for users. Also, most of the developed programs are based on old ranges of parameters and those programs could miss other artificial lift techniques in suggestions. Furthermore, previous studies and developed programs shows only suitable artificial lift technique referring to input data and user are not able to get information about other techniques. Moreover, previous developed programs contain limited number of techniques and therefore, sometimes system may not give exact selection technique for the set of wells.

In this thesis work a windows based program has been developed to predict suitability of artificial lift methods for a given set of wells and produced fluid parameters. For the selected artificial lift method (i.e. sucker rod pump, ESP, gas lift, hydraulic pump, PCP) the program is able to perform basic calculations for the given data. Last updated ranges of parameters have been used for each artificial lift technique. Also, all six major artificial techniques have been considered in developed program. Developed ES is commercially cheaper than other developed systems. Different case studies have been performed by running the program with actual data from fields. Well data of Venezuela, Azerbaijan and Iranian oil fields has been used in case studies. The results have been compared with previous studies those have been done on these fields with other selection techniques and current artificial lift techniques are being applied in selected wells. The obtained program results have been overlap with current real field application and previous studies.

CHAPTER 5

DEVELOPMENT OF EXPERT SYSTEM

5.1 Program Structure

This program has been developed for selection of suitable artificial lift method for a given well data among six artificial lift types. Program includes below artificial lift types:

(1) Sucker Rod Pumps
(2) Electrical Submersible Pumps
(3) Gas Lift
(4) Hydraulic Pump (piston/jet types)
(5) Progressing Cavity Pumps
(6) Plunger Lift

Expert System has been developed by using Visual Basic software. This program consists of Expert module. Expert module contains basic engineering calculations and theoretical knowledge of each artificial lift type. In order to do all these calculations, well data and production environment is included as list. Figure 5.1 presents the schematic view of program work flow.

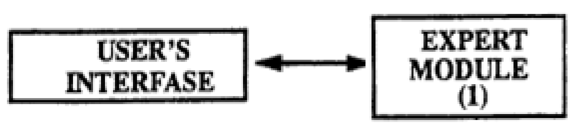


Figure 5.1 Expert System structure

Production conditions and well data are compared with the operating limits of each artificial lift type. After analyzing given well data, program ranks suitable types from the best to the worst with stating suitability percentage. In these calculations some warnings must be considered. Some artificial lift types could be suitable for given ell data, but production environment may limit its application. For example, sucker rod pumps are applicable in low rate and shallow depth wells. But they are not applicable in offshore fields because of space restriction. Also, sucker rod pumps are not recommended for urban applications because of noise. Also other parameters such as saturation pressure, problem handling capability, dog leg severity, wellbore deviation versus depth of each type must be taken into consideration. Because if pump intake pressure is lower than saturation pressure then gas will separate from oil and it will cause cavitation that could reduce pump efficiency. Also problem handling capability of each type differs from each other. For example, high sand content is limited in sucker rod pumps while it is not problem in gas lift type.

Program is based on ''If Then'' condition,

If (condition) then (process type regarding to consideration value)

In the development of this program some parameters are considered with the coefficients in range from 0 to 5. Program analyzes all the coefficients for specific processes and as a result, program presents the overall suitability of each artificial lift type with percentage.

In this case, several rules must be followed:

- If system eliminates any artificial lift method at any evaluation stage, then, it must be remained as eliminated method in all stages. For example, gas lift is available in high productive wells, but it must be eliminated if there is not an available gas source.
- Suitability coefficients individually analyzed for each artificial lift type. The value of coefficient could be different in various stages, dependent on the impact of process that coefficient represents on that stage.

In summary, Expert System reaches to the result in three stages:

(1) Entering well data to the program.
(2) Analyzing data with the set of tables and theoretical knowledge of each artificial lift type.
(3) Expert suggestions with technical and theoretical considerations.

As a result, system ranks suitable artificial lift types with three categories:

(a) Recommended systems
(b) Not recommended systems
(c) Recommended systems with warnings and restrictions

At the final step, user will be able to get information about warnings and restrictions or the reasons that make systems not recommended by clicking "Why" bottom in fornt of the each system. Figure 5.2 presents the program view of result section of the program.

Figure 5.2 Program view of result section

System could ask additional information if entered data in limited to begin the analysis. For example, PI, reservoir pressure, water cut, pump submergence will be asked to calculate pump operating depth.

5.2 Program Development

Three groups of parameters have been used in development of Expert System:

(1) Quantitative parameters
(2) Qualitative parameters
(3) Production problems

These parameters help in determination of best suitable artificial lift type for a well or group of wells. In quantitative parameters user will enter exact number for required field. In qualitative parameters section user will select one option among given options. But in production problems section user will have to specify the existence of specified well problems by selecting „Yes' or „No' bottom. Figure 5.3 shows the program view of these parameters.

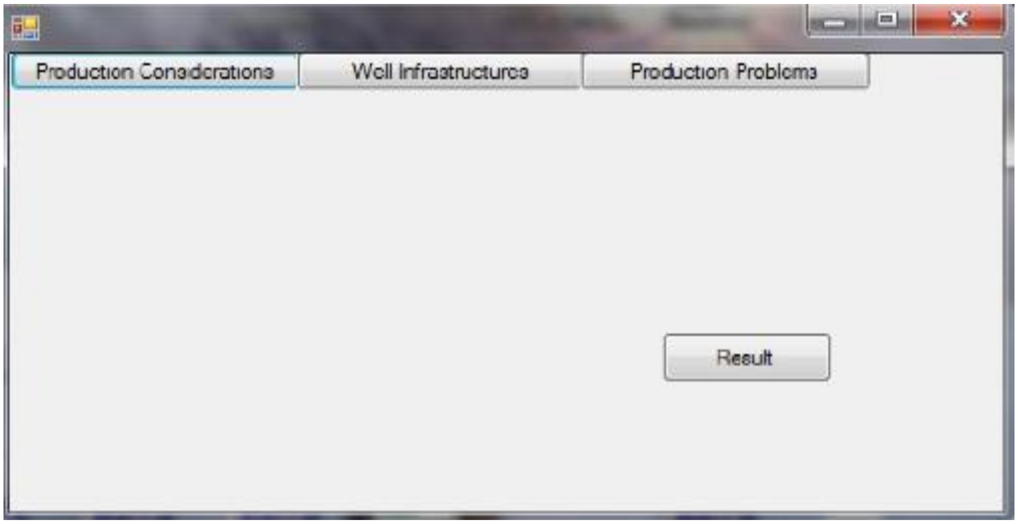


Figure 5.3 Program view of parameters

Quantitative parameters

In this program quantitative parameters considered as production considerations. The main parameters of production considerations that have been used in this program are given in Table 5.1.

Table 5.1 Production considerations

1	**Production rate (bpd)**
2	**Operating depth (ft)**
3	**Casing ID (in)**
4	**Wellbore angle versus depth**
5	**Maximum dog leg severity (deg/100 ft)**
6	**Bottom Hole Temperature (deg F)**
7	**Tubing Head Pressure (psi)**
8	**Fluid viscosity (cp)**
9	**API gravity**
10	**Saturation pressure (psi)**
11	**GOR (scf/bpd)**
12	**Sand content (%)**

As it was discussed above, for calculation of pump operating depth some parameters will be required. Table 5.2 presents parameters for pump depth calculation.

Table 5.2 Parameters for Pump depth calculation

1	**Productivity Index (bbl/psi/day)**
2	**Reservoir pressure (psi at _ ft.)**
3	**Water cut (%)**
4	**Pump Submergence (ft)**
5	**Well depth (ft)**
6	**Perforation depth (ft)**

The calculation of pump depth is very important in this stage. As it was discussed above, artificial lift selection is based on rate and depth suitability. Figure 5.4 shows the program view of production considerations.

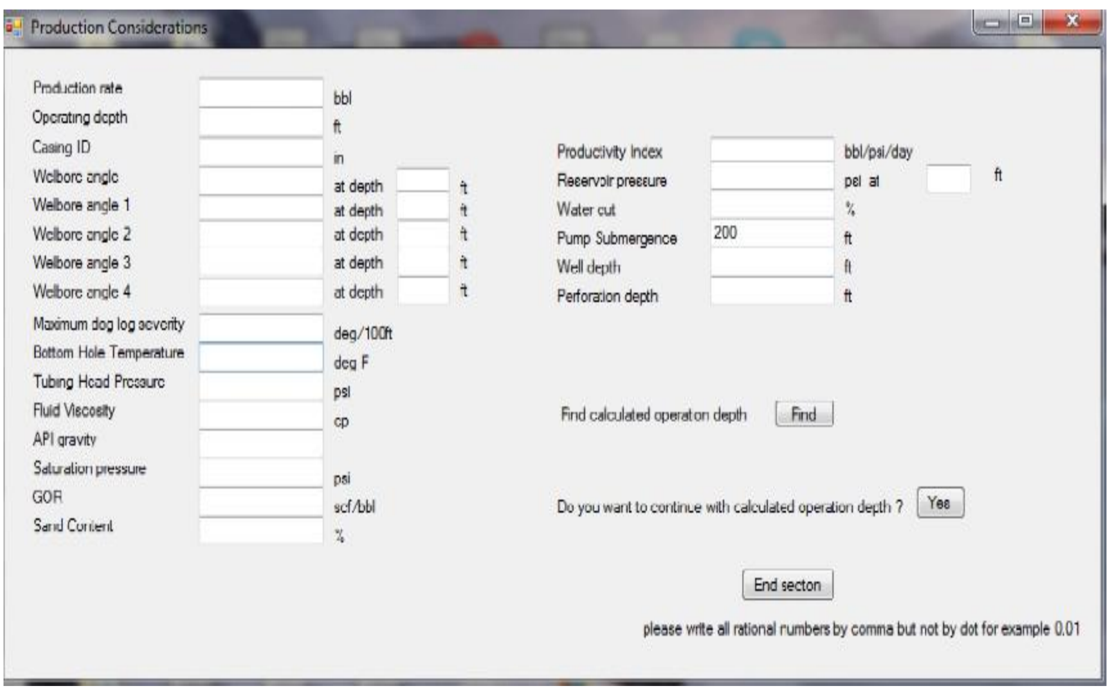


Figure 5.4 Production considerations

It could be seen for the program, user will be given two options regarding two options: either continue with given pump depth by user or calculated pump depth that will be calculated by program automatically if user want to find and continue with this depth. I this case user will click on the bottom “Find” in order to calculate the operating depth üith given data and “Yes” bottom in order to continue evlauation with calculated operating depth.

Pump depth will be calculated using Eq. 5.1:

$$q = J \cdot (P_{res} - P_{bhf}) \qquad (5.1)$$

J - Productivity Index, bbl/psi/day

P_{res} - Reservoir pressure at given depth, psi

P_{bhf} - Bottom hole flowing pressure at given depth, psi

P_{bhf} will be calculated from Eq. 5.1 and will be used in calculation of H liquid column height with Equation 5.2:

$$. P_{bhf} = \mathrm{H} \cdot \left(0.433\,\frac{\mathrm{psi}}{\mathrm{ft}}\right) \cdot (\mathrm{sp.gr}) \qquad (5.2)$$

H- liquid column height, ft
0.433 psi/ft- pressure gradient of water
Sp.gr.- specific gravity of liquid.

If liquid is a mixture of oil and water then specific gravity will be calculated with below equation:

$$\gamma = (1.0)(watercut) + (0.85)(1 - watercut) \qquad (5.3)$$

Oil specific gravity is 0.85 and water specific gravity is 1.0.

Dynamic liquid level will be calculated with below equation:

$$D = D_{datum} - H \qquad (5.4)$$

D_{datum} - Datum depth, ft

Finally, pump depth will be equal to the sum dynamic liquid level and pump submergence. The average value of pump submergence is 200 ft. Calculated pump depth will be compared with operating depth of each artificial lift types that have been given as a table to the program. Appropriate types will pass to the next evaluations meanwhile, inappropriate types will be eliminated.

Also, calculated pump depth will be compared with well depth and perforation depth. If pump depth is bigger than perforation depth then it will be informed to the user. But pump are eligible to work in this case. If pump depth is bigger than well depth then selected pump type will be unable to work in this condition.

As it was stated above, another important factor is a production rate. Desired production rate will be entered by user. Entered rate number will be compared with the range of each artificial lift types that has been given to the program. Also in this stage, appropriate types will forward to next evaluations, but inappropriate types will be eliminated.

As it is known, there is a relationship between casing size and production rate. Different sizes of casing could allow of production of certain range of fluid. Entered production rate by user, will be compared with table of rate versus casing size that given to the program. Then, appropriate casing size for desired rate will found from table and compared with the user entered casing size. If entered casing size is appropriate with desired production rate then program will run to next evaluations, otherwise this case will be warned to the user. Table 5.3 gives casing sizes for different production rates of ESP applications.

Table 5.3 Capacity ranges of different casing size of ESP applications

Min. Casing size (in.)	***Min. Flow rate (bbl/day)***	***Max. Flow rate (bbl/day)***
4.500	82	1700
5.500	82	4400
6.625	667	10000
7.000	1320	8806
7.000	7668	21700
8.625	5000	21000
10.750	10000	27000
11.750	20000	49200
13.625	44700	80000
8.625	9120	45000

Except rate and operating depth, other parameters also will be entered to the program as a table. Table 5.4 gives the ranges of different parameters that will be compared and influence on selection of best artificial lift types.

Table 5.4 Operation range of production considerations

Operating parameters	***Rod Pump***	***PCP***	***Hydraulic Piston***	***ESP***	***Jet***	***Gas lift***	***Plunger***
Max. Production rate (bpd)	5-5000	5-4500	50-4000	200-40000	300-30000	100-50000	1-200
Normal Production rate (bpd)	5-1500	5-2200	50-1500	200-20000	300-1000	100-10000	1-200
Max. Operation depth (ft.)	100-16000	2000-6000	7500-20000	1000-15000	5000-15000	5000-15000	100-20000
Normal Operating Depth (ft)	100-11000	2000-4500	7500-15000	1000-10000	5000-10000	5000-10000	100-8000
Bottom-hole temperature (°F)	100-550	75-250	100-500	100-400	100-500	100-400	120- 500
Wellbore deviation (deg.)	$0-{}^{\circ}20$	$0-{}^{0}20$	$0-{}^{\circ}20$	$0-{}^{\circ}10$	$0-{}^{\circ}20$	$0-{}^{\circ}50$	$0-{}^{\circ}80$
Max. wellbore deviation (deg.)	$0-{}^{\circ}90$	$0-{}^{\circ}90$	$0-{}^{\circ}90$	$0-{}^{\circ}90$	$0-{}^{\circ}90$	$0-{}^{\circ}70$	$0-{}^{\circ}80$
Maximum dog leg severity (deg/100 ft)	$\leq^{\circ}15$	$\leq^{\circ}15$	$\leq^{\circ}15$	$\leq^{\circ}10$	$\leq^{\circ}24$	Full Range	Full Range
Fluid viscosity (cp)	0 - 500	Full Range	0 – 800	0 - 200	50 - 800	0 - 1000	0 - 1000
API	$\geq 8^{\circ}$	$\leq 35^{\circ}$	$\geq 8^{\circ}$	$\geq 10^{\circ}$	$\geq 8^{\circ}$	$\geq 15^{\circ}$	$\geq 10^{\circ}$
GOR (scf/stb)	≤ 500	<2000	≤ 500	≤ 500	≤ 1000	Full range	Full range
Max. GOR (scf/stb)	500-2000	Full range	500-2000	500-2000	1000-2000	Full range	Full range
Sand content (%)	0 – 0.1	Full Range	0 – 0.01	0 – 0.01	0 - 3	Full range	Full range

It is seen on the table that some parameters are characterized with maximum and normal operating ranges. In this case, if entered data is between normal operating ranges then technique evaluation will continue as recommended system. But if data is between maximum operation ranges then systems evaluation will continue as recommended system with warnings that parameter is not within normal operating range. Otherwise, system will be evaluated as not recommended system.

Qualitative parameters

In this program qualitative parameters considered as well infrastructure. User will have to select one option among several options for certain parameters. Table 5.5 presents the parameters and selective options that used in this section. Figure 5.5 presents the program view of well infrastructure parameters.

Table 5.5 Well infrastructure parameters

1	**Location (Urban / offshore/ onshore)**
2	**Space restriction (Yes/No)**
3	**Gas availability (Limited/ unlimited/ none)**
4	**Completion type (single/ double)**
5	**Power source (electric/ natural gas/ oil)**
6	**Casing Integrity (Yes/No/Not available)**

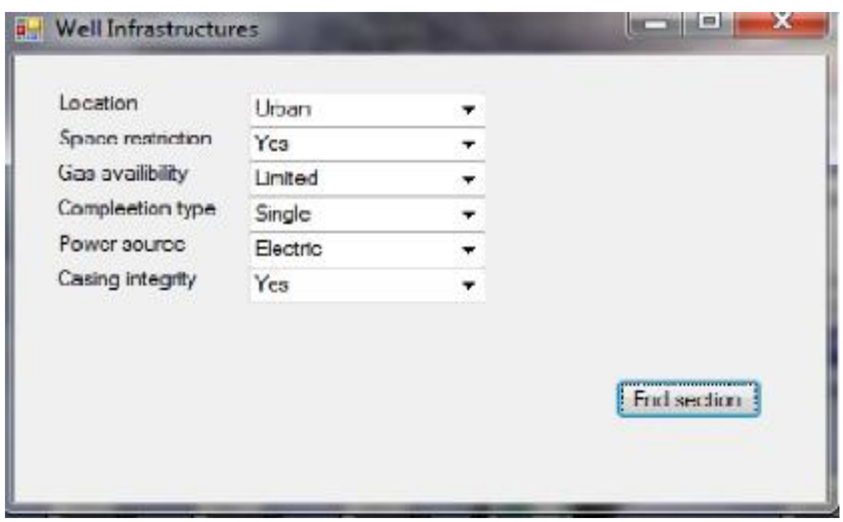


Figure 5.5 Program view of Well Infrastructure parameters

In Chapter 2, operation environment, power source, working principles was discussed. It is known that depending on these factors the feasibility of different artificial lift techniques changes. For example, sucker rod pumps are easily applicable in onshore fields, in spite of that they are not applicable on onshore fields and could be applied on urban fields with considerations.

Table 5.6 presents the feasibility of different artificial lift techniques dependent on various offered options.

Table 5.6 Feasibility of artificial lift types in various options

Parameters	Options	*Sucker Rod*	*ESP*	*Gas Lift*	*PCP*	*Jet Pump*	*Hydraulic Pump*	*Plunger*
Location	Onshore	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Offshore	No	Yes	Yes	Yes	Yes	Yes	Offshore
	Urban	Conditional(1)	Yes	Conditional(2)	Yes	Conditional(3)	Conditional(3)	Yes
Space Restriction	Yes	No	Yes	Conditional(4)	Yes	Yes	Yes	Yes
	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Gas Availability	Limited	NA	NA	Conditional	NA	NA	NA	Conditional(5)
	Unlimited	NA	NA	Yes	NA	NA	NA	Yes
	None	NA	NA	No	NA	NA	NA	Conditional(5)
Completion Type	Single	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Double	No	No	Conditional(6)	Yes	No	No	No
Power Source	Electrical	Yes	Conditional(7)	Yes	Yes	Yes	Yes	NA
	Gas	Yes	No	Yes	Yes	Yes	Yes	NA
	Oil	Yes	No	Yes	Yes	Yes	Yes	NA
Casing Integrity	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	No	Yes	Yes	Conditional(8)	Yes	Conditional(8)	Conditional(8)	Conditional(8)
	Not Available	Yes	Yes	Conditional(9)	Yes	Conditional(9)	Conditional(9)	Conditional(9)

As it is seen on the table, in some boxes the feasibility of technique is marked with NA. For programming "NA" is equal to "YES".

In this section, if selected option of different parameters is "YES" for evaluated artificial lift techniques then evaluation for those techniques will continue to the next step as recommended systems. If selected option of different parameters is "NO" for evaluated techniques then it means that technique can not be applied in this case and system evaluation will continue as a not recommended system.

In some boxes the feasibility of system is marked with "Conditional" sign. In this case, system will continue as a recommended system with warnings. The list of warnings for this case is given on Table 5.7 for different artificial lift techniques.

Table 5.7 Conditions for different artificial lift techniques

Conditional1	Noise, obtrusive
Conditional2	Compressor requirement, noise, high pressure gas lines
Conditional3	high pressure power fluid lines, pump noise
Conditional4	Space needed for compressor
Conditional5	Check if gas injection will be used
Conditional6	Check casing ID to allow for two production strings
Conditional7	Check if electrical power source is available for ESP operations
Conditional8	Casing integrity must be checked before the application
Conditional9	Check casing ID to allow for parallel installation

Production Problems

In this section two options will be offered to the user for each production problems: “Yes” or “No”. Table 5.8 presents the list of production problem parameters. Figure 5.6 shows the program view of production problems.

Table 5.8 Production problem parameters

1	**Corrosion (Yes/No)**
2	**Paraffin (Yes/No)**
3	**Emulsion Forming (Yes/No)**
4	**Foam Forming (Yes/No)**
5	**Asphaltenes (Yes/No)**
6	**Scale (Yes/No)**
7	**Gas handling (Yes/No)**

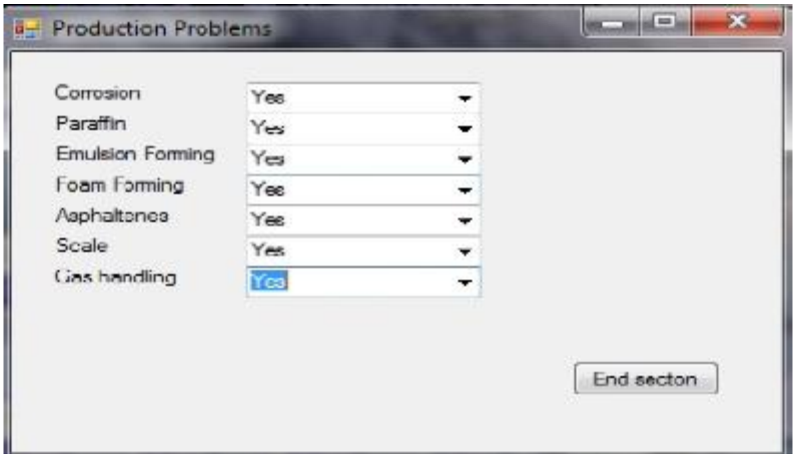


Figure 5.6 Program view of Production problems

Each production problem is characterized with coefficients ranging from 0 to 5. If user selects option "NO" for any artificial lift type then program will continue the evaluation as a recommended system. If user selects option "Yes" then systems will be evaluated with the appropriate coefficients of each production problem parameter for different artificial lift type. Table 5.9 presents the appropriate coefficient of each production problem for different artificial lift types.

If production problem is marked with coefficient "0" then it means production problem does not affect. It is possible if user chooses only NO option. The effects of production problems on application of artificial lift techniques regarding to coefficients are listed as below:

(1) If "1" then very minor effect
(2) If "2" then minor effect
(3) If "3" then effected
(4) If "4" then highly effected
(5) If "5" then this artificial lift type cannot be used without any treatment

If selected artificial lift technique coefficient for certain production problem is "0" or "1" then system will be evaluated as recommended system. If coefficient is "2", "3" and "4" then system will be evaluated as recommended system with warnings. If coefficient is "5" then system is not recommended system.

Table 5.9 Production problem coefficients for different systems

Parameters	Coefficient range	Sucker Rod	ESP	Gas Lift	PCP	Jet Pump	Hydraulic Pump	Plunger
Corrosion	0 to 5	3	2	2	3	1	1	1
Paraffin	0 to 5	3	2	2	3	2	2	1
Emulsion Forming	0 to 5	3	4	1	1	3	3	1
Foam Forming	0 to 5	2	2	1	1	2	2	1
Asphaltenes	0 to 5	3	4	3	1	2	3	1
Scale	0 to 5	2	4	2	2	3	3	2
Gas Handling	0 to 5	3	4	0	2	2	3	0

CHAPTER 6

CASE STUDIES

Real field data have been applied in case studies. Mainly, data of Iran, Canada and Azerbaijan well have been used as an inout data. These wells are real oil wells which are still on production and different artificial lift techniques have been applied through the field. Also, several studies have been done on these wells with other artificial lift selection techniques. Obtained result have been compared with real field applications and previous study results.

Case 1.

In first case, well data of one Iranian field have been applied. This well is an onshore well and the production rate is moderate. The fluid characteristics is very good as API gravity is high and viscosity is low. Table 6.1 shows the well data used as an input in program.

Table 6.1 Well data of Iranian oil field

1	Production Rate	1340 (bbl/day)
2	Operating Depth	4000 (ft.)
3	Casing ID	8 (in.)
4	Well bore angle	7 deg. at 1500 ft.
5	Wellbore angle1	35 deg. at 2200 ft.
6	Wellbore angle 2	14 deg.at 3000 ft.
7	Wellbore angle 3	12 deg. at 3800 ft.
8	Wellbore angle 4	5 deg. at 4400 ft.
9	Maximum dog leg severity	2 deg/100 ft.
10	Bottom Hole temperature	144 degF
11	Tubing Head Pressure	150psi
12	Fluid viscosity	120 cp
13	API gravity	28
14	Saturation pressure	200 psi
15	GOR	576 scf/bbl
16	Sand content	0,009 %
17	Productivity Index	0.45 bbl/psi/day
18	Reservoir Pressure	2500psi at 4700 ft.
19	Water Cut	33,5 %
20	Pump Submergence	200 ft.
21	Well depth	4700 ft.
22	Perforation depth	4600 ft.
23	Location	Onshore
24	Space restriction	No
25	Gas availability	Unlimited
26	Completion type	Dual
27	Power source	Electric
28	Casing Integrity	Yes
29	Corrosion	Yes
30	Paraffin	No
31	Emulsion Forming	No
32	Foam Forming	No
33	Asphaltenes	Yes
34	Scale	No
35	Gas handling	No

As it is seen on the table, it is an onshore well producing light oil with low productivity. The problems related to the well is corrosion and high asphaltene content in the produced oil. Input data run in the program and Figure 6.1 presents the final result of program running.

Figure 6.1 Final result of case study 1

As it seen on the figure, ESP, PCP, GL and Jet pumping are the best suitable techniques for this well. But there are some points that user must take into consideration. As it is seen on the warning section, user should take care of casing size for dual completions. Casing size must be appropriate for ESP applications (Figure 6.1). As it has been discussed in Chapter 3, Iranian oil well data also has been used in TOPSIS model selection method and as a result ESP has been recommended as the best artificial lift technique for this well. Currently ESP technique is applied in this well. Because, commercially ESP is more appropriate in this well. New developed ES informs to the user the points that must be taken into consideration, also program suggests that PCP, GL and Jet pumping also could be used in this well with warnings. Warning is that corrosivity must be taken into consideration in PCP applications. Because, PCP is mainly applied in high viscous oil fields. But the viscosity is very low in this well, therefore from commercial side it is more suitable to apply ESP technique.

As it was discussed above, in order to get information about the reasons that make other methods not recommended user must click on button “Why” before each type. Figure 6.2-6.5 presents the reasons that make gas lift, jet pumping recommended systems with warnings and plunger lit not recommended.

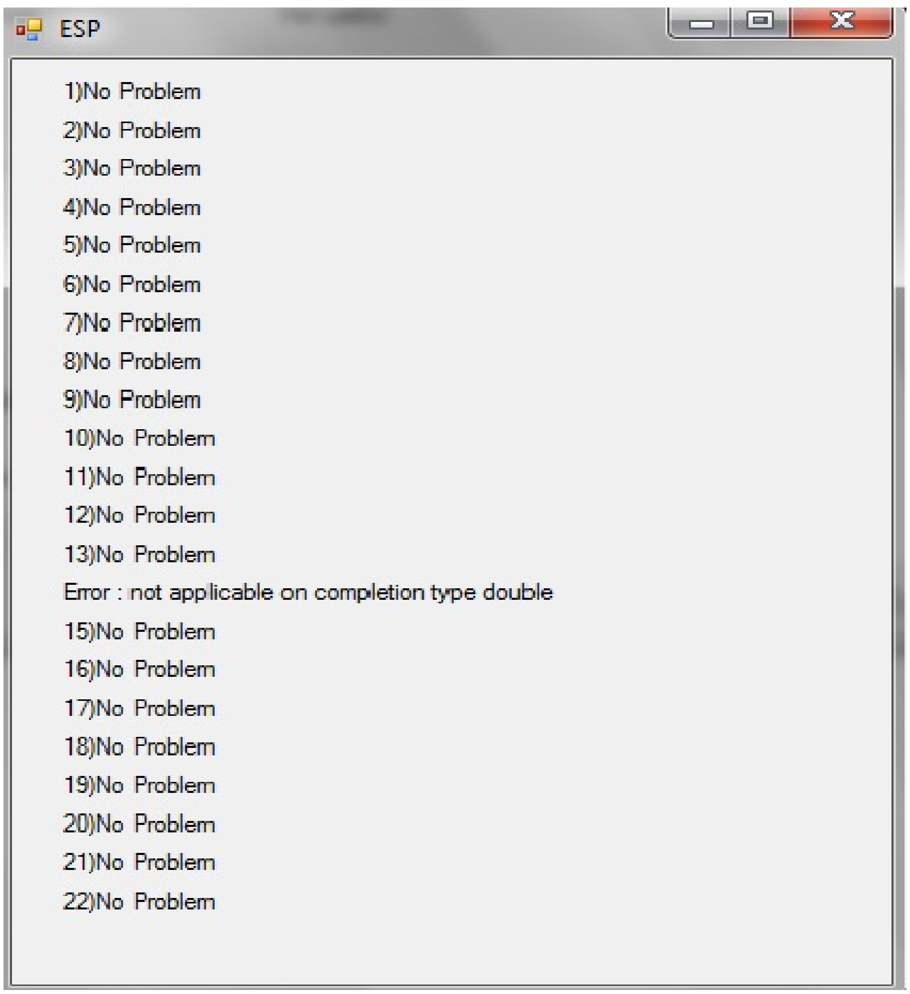


Figure 6.2 ESP result for case study 1

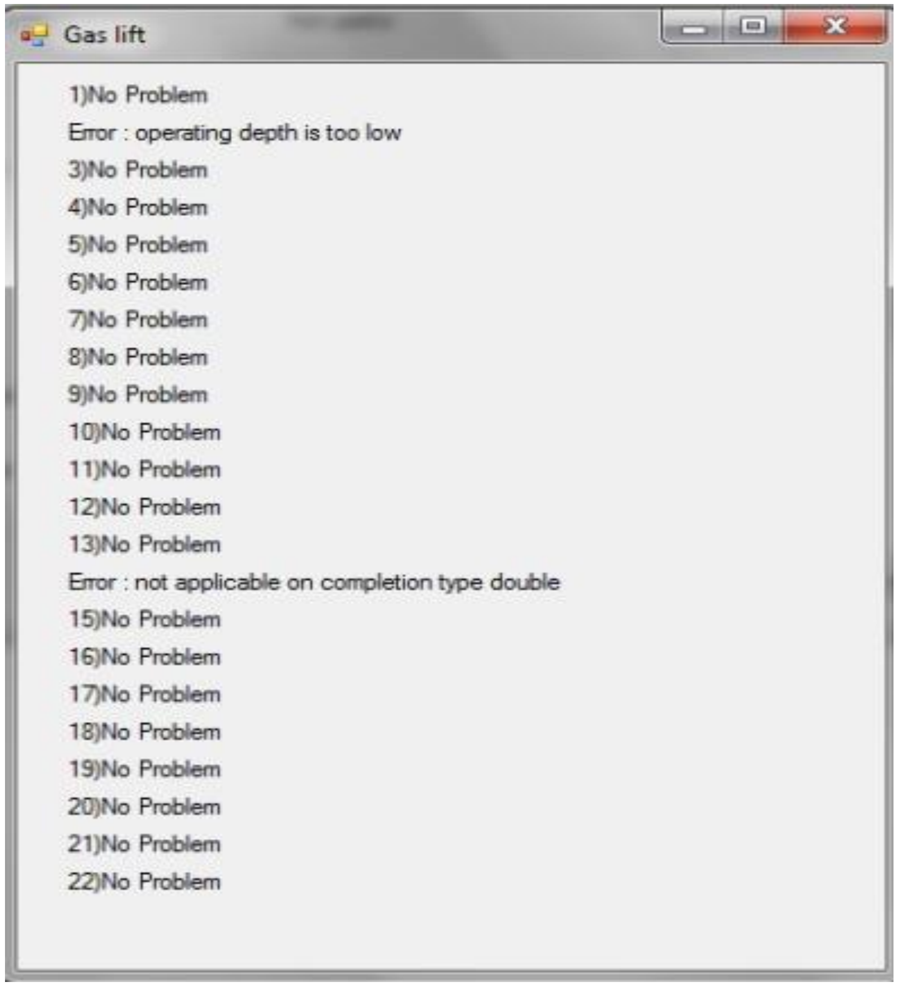


Figure 6.3 Gas Lift result for case study 1

Program suggests that GL also might be used with some warnings. Like in ESP application casing size also should be taken into consideration GL application for dual completions. But another important warning is that GL usually applied in high productive wells up to 50 mbpd. But in applied well the prodctuin rate is about 1000 bbl/d therefore, the application of GL is not feasible from economic side. Also, as it is the light well, BHP is enough to lift up the fluid column to the surface, but GL is applied when BHP is not sufficient to lift up the whole fluid column. As a result, GL is not suggested in well with low production rate.

Also in jet pumping some warnings should be followed. The consideration of casing size is important in jet pumping applications. The application of jet pumping is very expensive and it usually applies in well with high depth. As it has been discussed in Chapter 2, jet pumping is the only artificial lift techniques that could applied in the wells with highest depths. But the depth of well that has been run in developed program is low for jet pumping applications. Therefore, commercially it is also not feaible to apply jet pumping technqiue.

Plunger lift technique is usually beneficial in wells with production rate lower than 200 bpd. In this well, the production rate is higher than 1000 bpd. Therefore, this method is not suggested by the program.

In summary, the obtained results from developed Expert System program overlap with current field application and previous study on the same well, also this program suggests several appropriate artificial lift techniques rather than other developed technqiues. This allow user to be able to apply different techniques dependent on availability of each technique.

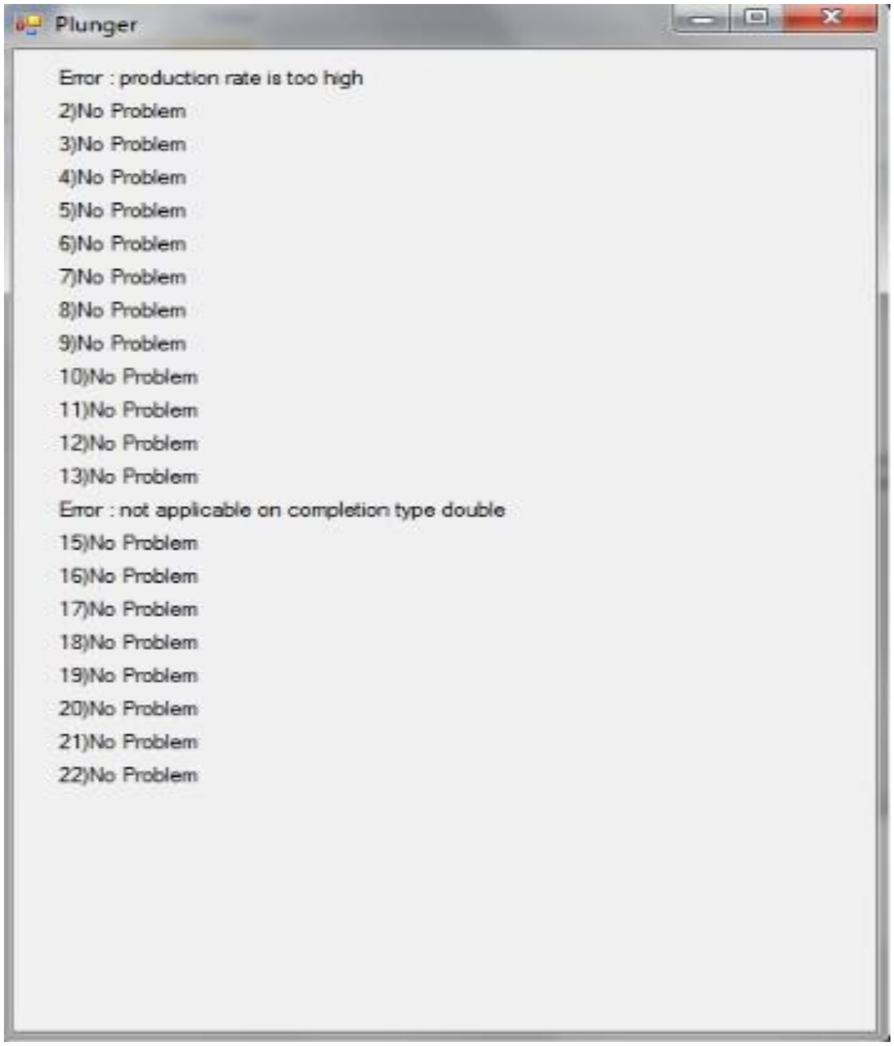


Figure 6.4 Plunger lift result for case study 1

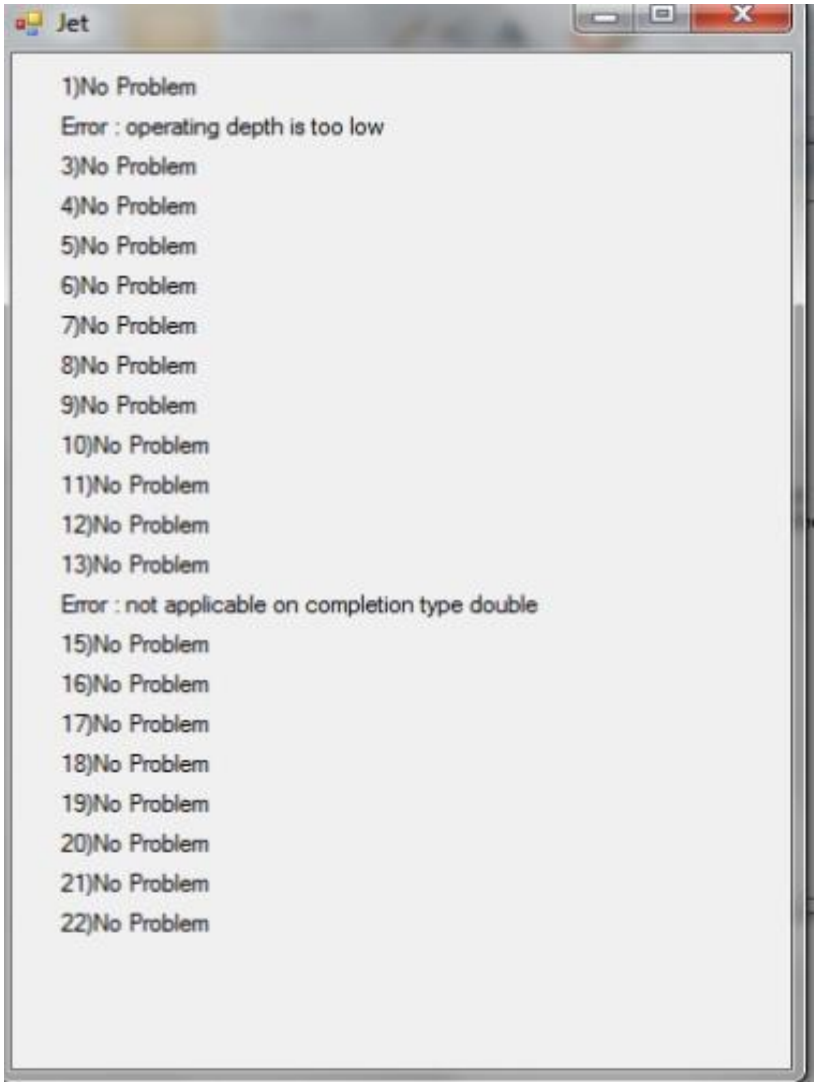


Figure 6.5 Jet pump result for case study 1

Case study 2.

In this case study heavy oil Venezulean field data has been used as an input data. This well is an offshore well and fluid characteristics of produced fluid is not very good as the API gravity is low and fluid viscosity is very high in this well. Also, fluid is produced from high depth with low production rate that creates another challenge in production.

Saturation pressure is about 200 psi that causes low GOR value in this well. Therefore, absence of free gas increase the weight of fluid column in the tubing and as a result BHP might be not sufficient to lift up fluid to the surface. Also, another important value is water cut value which is low in this well.

The main production problems are scaling and asphaltene existence in the wellbore. Such problems may restrict the application of different artificial lift technqiues.

Table 6.2 shows the input data of this well.

Table 6.2 Well data of Venezuela oil field

1	Production Rate	800 (bbl/day))
2	Operating Depth	8700 (ft.)
3	Casing ID	9.62 (in.)
4	Well bore angle	15 deg. at 2500 ft.
5	Wellbore angle1	12 deg. at 2800 ft.
6	Wellbore angle 2	17 deg. at 3500 ft.
7	Wellbore angle 3	10 deg. at 4000 ft.
8	Wellbore angle 4	8 deg. at 5000 ft.
9	Maximum dog leg severity	2 deg./100 ft.
10	Bottom Hole temperature	180 deg. F
11	Tubing Head Pressure	500 psi
12	Fluid viscosity	1000 cp.
13	API gravity	15
14	Saturation pressure	200 psi
15	GOR	128 scf/bbl
16	Sand content	0.01 %
17	Productivity Index	0.70 bbl/psi/day
18	Reservoir Pressure	2770 psi at 9300 ft.
19	Water Cut	3 %
20	Pump Submergence	200 ft.
21	Well depth	9300 ft.
22	Perforation depth	9000 ft.
23	Location	Offshore
24	Space restriction	Yes
25	Gas availability	Unlimited
26	Completion type	Single
27	Power source	Electric
28	Casing Integrity	Yes
29	Corrosion	No
30	Paraffin	No
31	Emulsion Forming	No
32	Foam Forming	No
33	Asphaltenes	Yes
34	Scale	Yes
35	Gas handling	No

Data has been run in the program and final result is illustrated in Figure 6.6.

Figure 6.6 Final result of case study 2

Program suggests that Gas Lift is the only technique that could be used in this well. As it has been discussed in Chapter 2, Gas Lift might show low performance in the existence of asphaltene in produced fluid. Another point that must be taken into consideration is the low flow rate. As it has been discussed above, GL usually applied in high productive wells. But API gravity is very low in this well, therefore it will increase the fluid hydrostatic pressure as a result BHP will be sufficient to lift up the fluid. Therefore, GL must be applied in order to lighten the fluid column.

ESP is not applicable in this well. Because as it has been discussed in Chapter 2, ESP is not feasible in viscous fluids. Therefore, program suggests ESP as not reecommended system. SRP technique is also not applicable because of several reasons: (1) as this well is an offshore well, SRP is not applicable in offshore operations, (2) moreover, sufficient area is required in SRP applications, but in this case there is a space restriction, (3) SRP is not recommended system in high viscosity wells. PCP would be the best technique for high viscous and low API gravity wells. But in this case, the operating depth is too high for PCP applications. Therefore, it is not recommended to use PCP in this well. Jet pump also is not recommended because of high viscosity value. As it has been discussed above sections, Plunger lift is beneficial only the wells with low production rate. The production rate in this well is 800 bpd that makes Plunger lift not useful.

Currently, Gas Lift is applied in this well. The best suitable method for high viscous and low API gravity wells is PCP technique, but because high operating depth the last decision has been made to apply Gas Lift in this well. Also, the availability of gas is unlimited for this well that eases the application of GL.

Figure 6.7-6.11 presents the reasons of other systems that make them not useful.

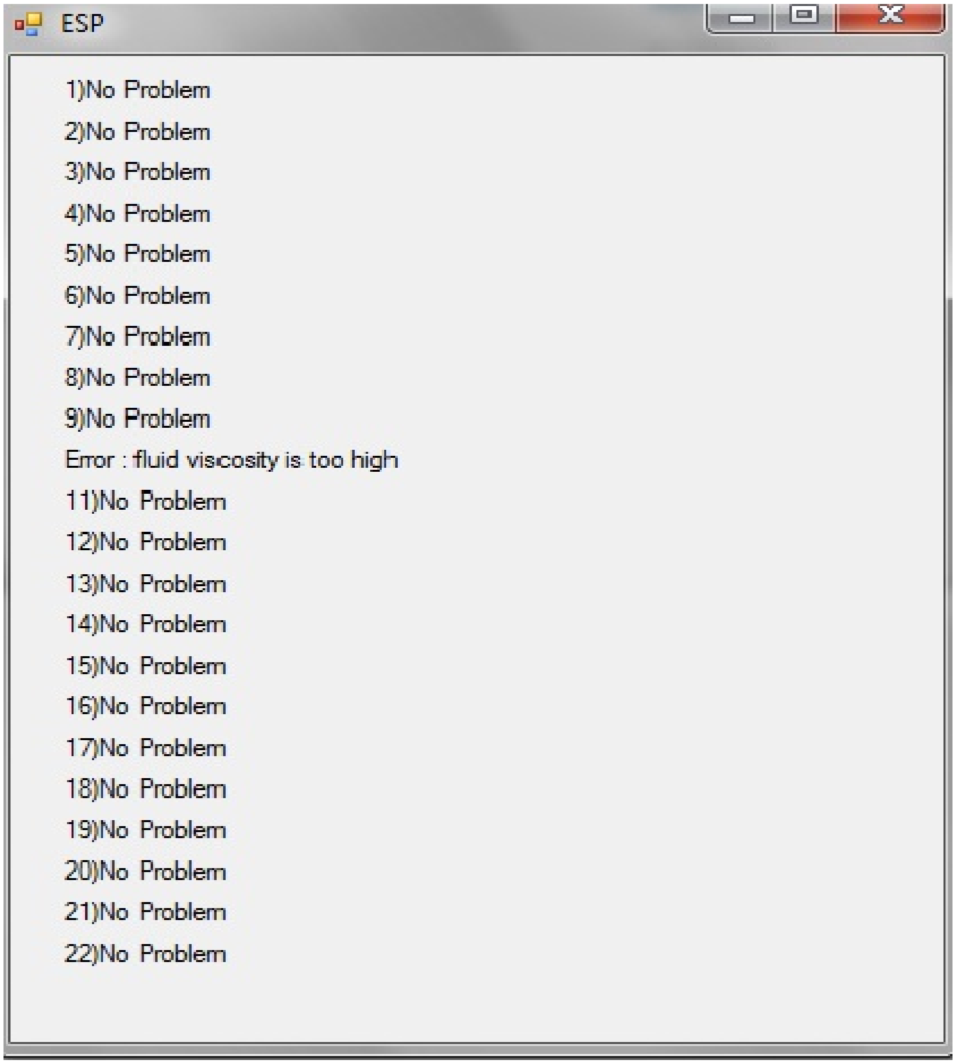


Figure 6.7 ESP result for case study 2

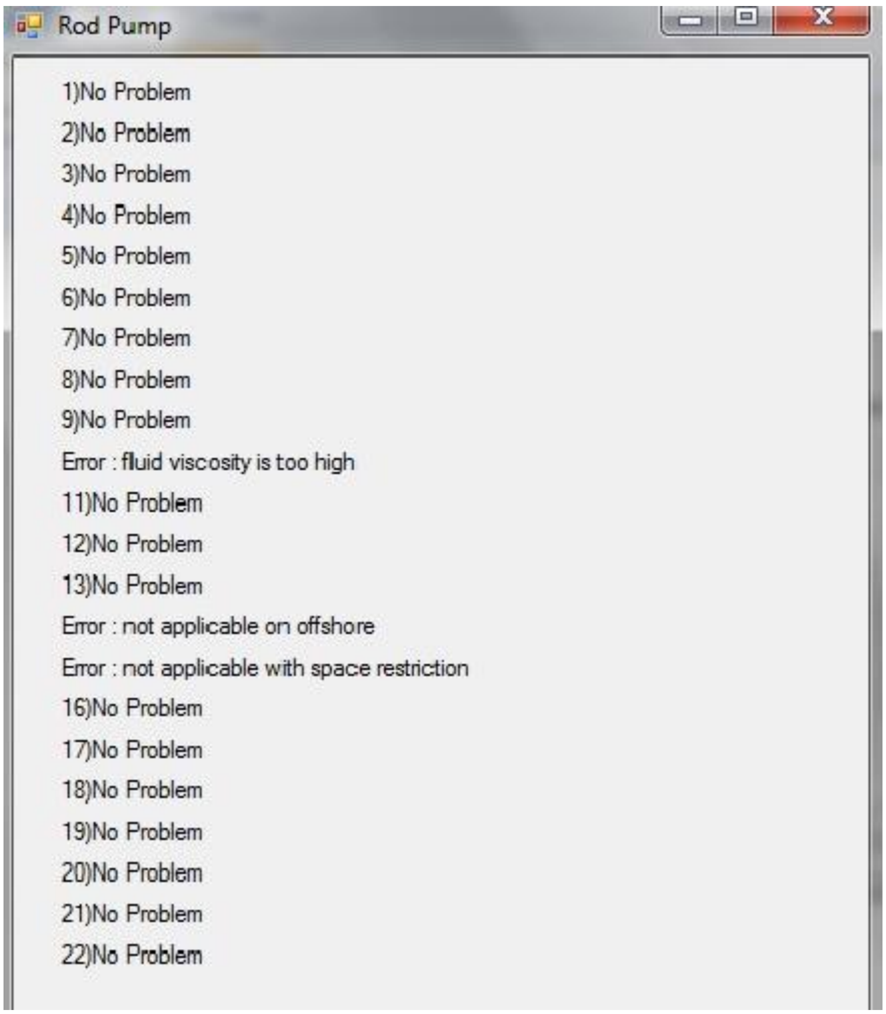


Figure 6.8 Rod Pump result for case study 2

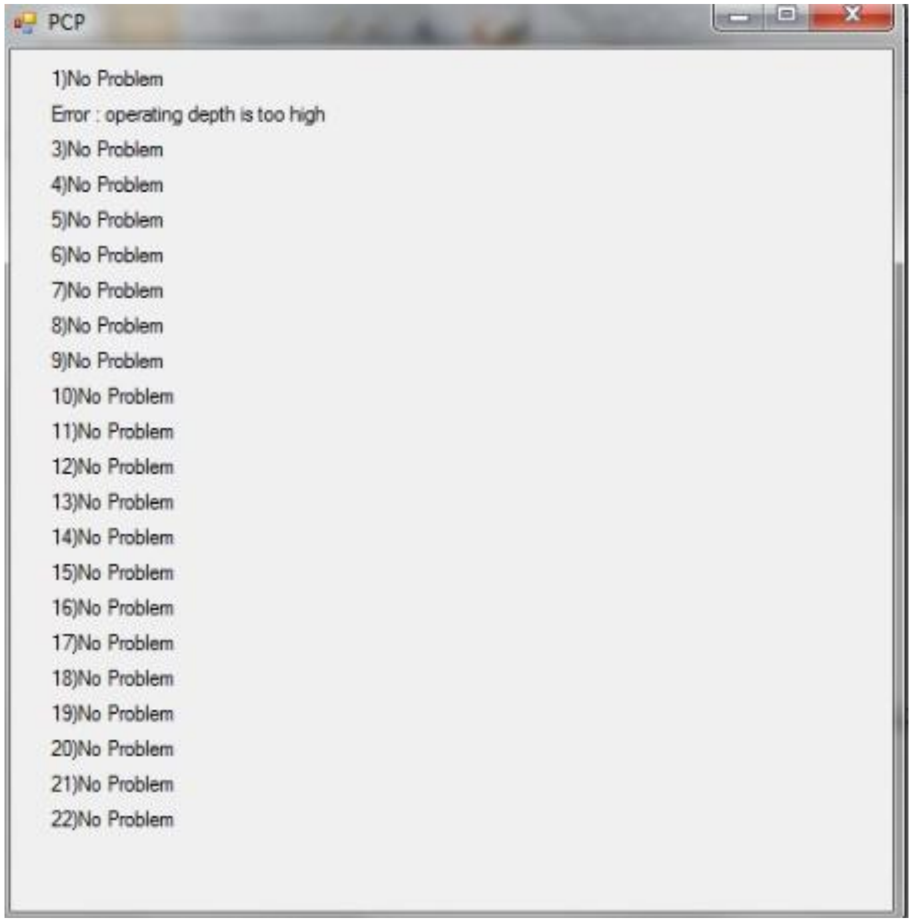


Figure 6.9 PCP result for case study 2

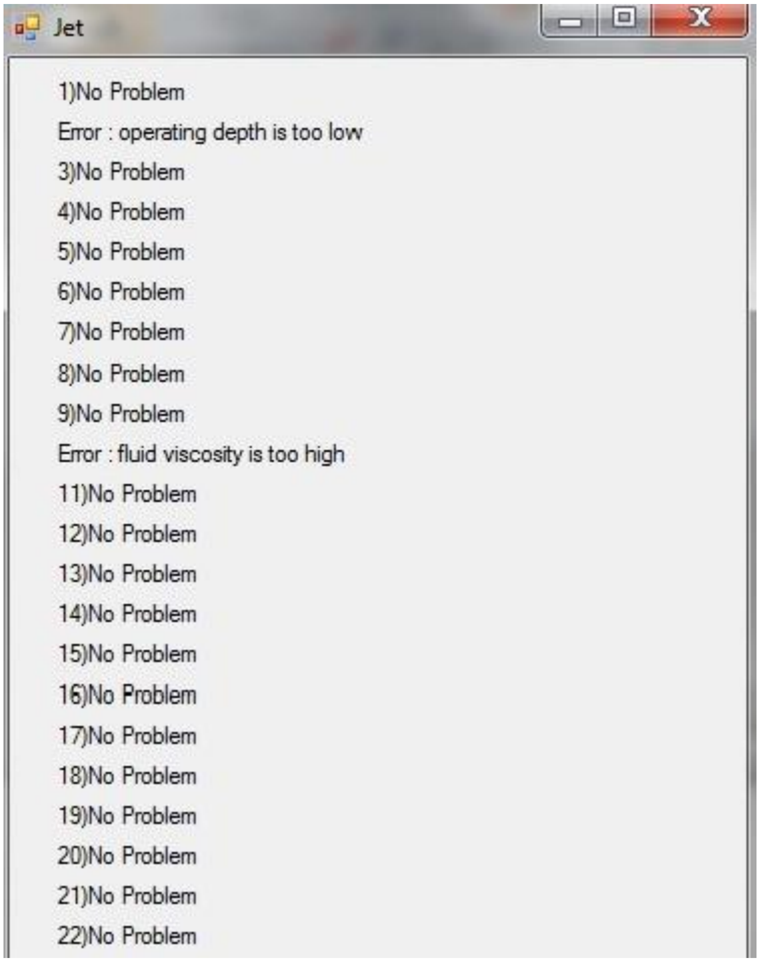


Figure 6.10 Jet pump result for case study 2

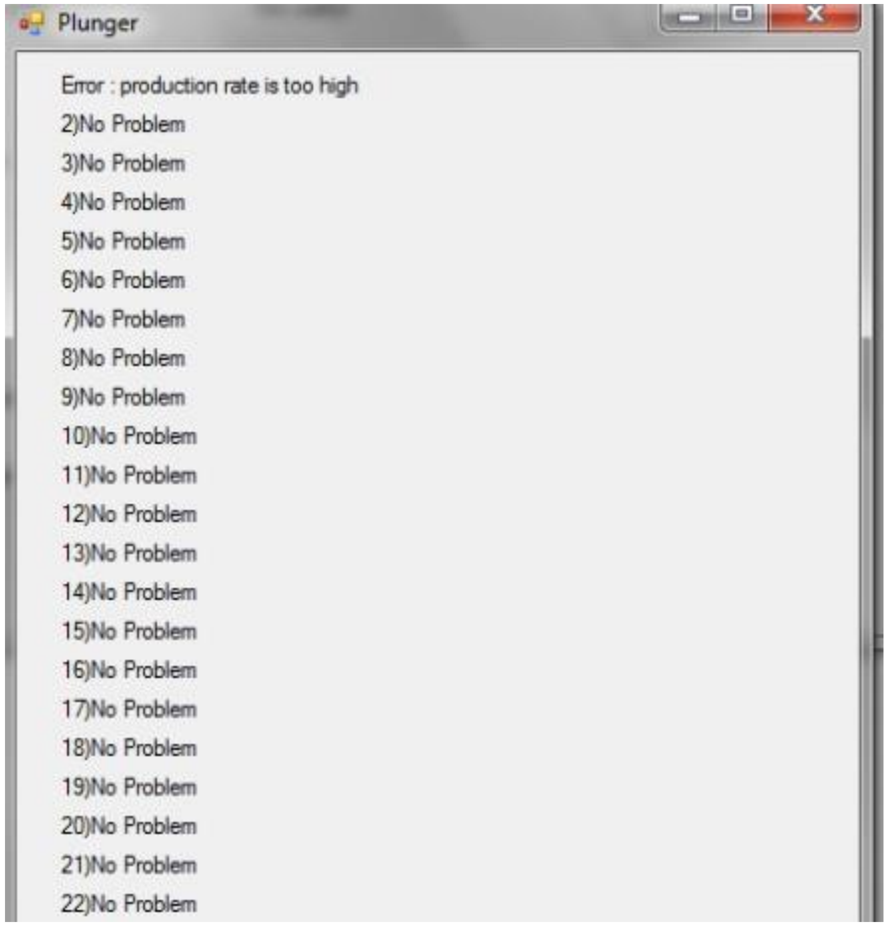


Figure 6.11 Plunger lift result for case study 2

Case study 3

In this case study the well data of Azerbaijan oil field have been considered. The data has been taken from brown oil field that has been produced more than 100 years. It is an onshore field with light oil. There are 12 horizonts in the reservoir, but fluid mainly produced from 2 horizonts. Waterflooding is applied as a secondary production phase in this field.

In spite of that it is a brown field but the production rate is high for the well. It is nearly deep well and fluid characteristics is very good: (1) high API gravity and (2) low viscosity. Saturation pressure is low and GOR is moderate for this well. The well shows slight high water cut content. As it is an onshore field, there is not a space restriction for application of any artificial lift technique. The main problem related to this well is that bottom hole temperature is high and paraffin collapse existence in the well.

Currently Electrical Subemrsible Pump and Sucker Rod Pump techniques are applied in the field. Table 6.3 shows well data that has been used as an inout data in this case.

Table 6.3 Well data of Azerbaijan oil field

1	Production Rate	1000 (bbl/day))
2	Operating Depth	6000 (ft.)
3	Casing ID	9 (in.)
4	Well bore angle	20 deg. at 1000 ft.
5	Wellbore angle1	25 deg. at 1500 ft.
6	Wellbore angle 2	15 deg. at 2500 ft.
7	Wellbore angle 3	13 deg. at 3000 ft.
8	Wellbore angle 4	10 deg. at 3900 ft.
9	Maximum dog leg severity	1 deg./100 ft.
10	Bottom Hole temperature	350 deg. F
11	Tubing Head Pressure	1500 psi
12	Fluid viscosity	100 cp.
13	API gravity	28
14	Saturation pressure	400 psi
15	GOR	500 scf/bbl
16	Sand content	0.001 %
17	Productivity Index	0,8 bbl/psi/day
18	Reservoir Pressure	4000 psi at 6600 ft.
19	Water Cut	10 %
20	Pump Submergence	200 ft.
21	Well depth	6600 ft.
22	Perforation depth	6300 ft.
23	Location	Onshore
24	Space restriction	No
25	Gas availability	Unlimited
26	Completion type	Single
27	Power source	Electric
28	Casing Integrity	Yes
29	Corrosion	No
30	Paraffin	Yes
31	Emulsion Forming	No
32	Foam Forming	No
33	Asphaltenes	No
34	Scale	No
35	Gas handling	No

Data has been run in the program and Figure 6.12 shows the obtained results.

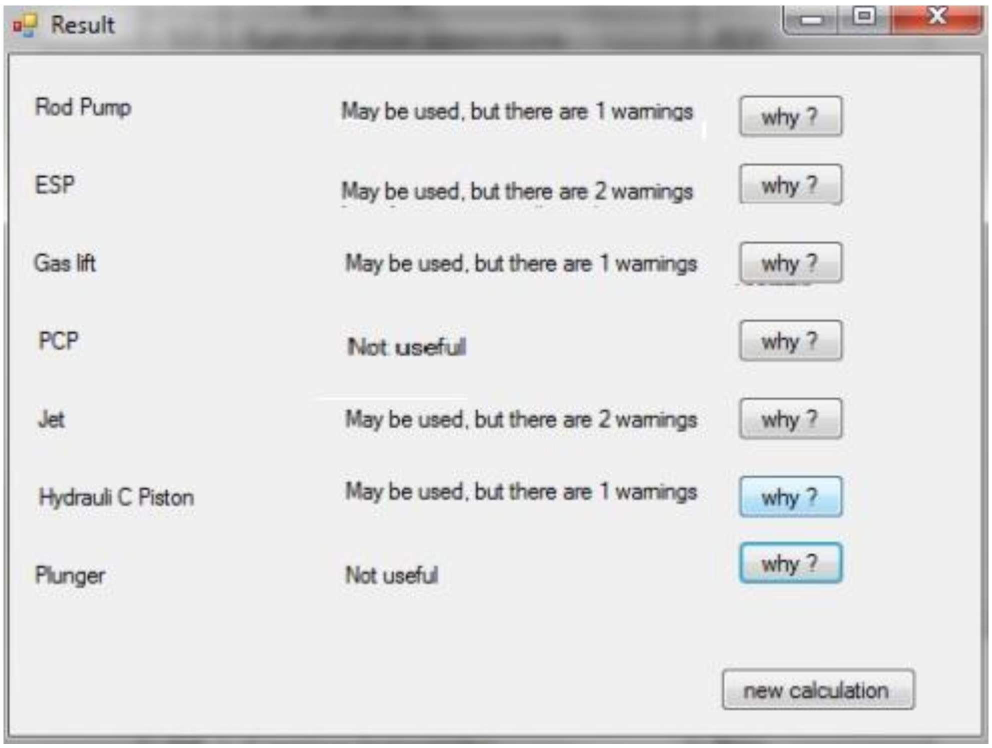


Figure 6.12 Final result of case study 3

As it is seen, in this case SRP, ESP, GL, Jet pump and HPP are applicable techniques for this well. But there are several warnings that user must take them into consideration. As it is seen in well data at different depths the wellbore deviation value is higher than normal operating range. Therefore, in SRP applications it shoud be noticed. But this value does not restrict the application of SRP in this well.

ESP is also another technique that recommended by program. But the main warnings for ESP are: (1) as in SRP the wellbore deviation angle is above normal operating range in certain depths, (2) high paraffin content could reduce the efficiency of ESP.

The main warning for GL is high paraffin content in produced fluid. As it was discussed in Chapter 2, high paraffin content could reduce the efficiency of ESP and GL.

The main warning for HPP is operating depth. As it has been discussed above, HPP is mainly applied in wells with high operating depth. Also the installation cost of HPP is highly expensive. Therefore, it is not recommended to be applied from economic side if another available technique exists.

Plunger lift and PCP are not recommended techniques for this well. In all case studies it has been suggested that Plunger lift is beneficial in lower production rates than 200 bpd. But in all cases the production rates are higher than this value. Also in this case study the saturation value is low and GOR value is low that required for Plunger Lift applications. Because in Plunger Lift the main energy source is gas. These resons make Plunger Lift not useful for this well. The only reason that makes PCP not useful is high bottom hole temperature.

In summary, program suggested five possible artificial lift technqiues that are recommended to this well. Currently, SRP and ESP are applied throught the field. Only one well data has been used but other wells also show the similiar performance. As other techniques are not feasible commercially only two techniques are applied. Developed program results overlap with real field applications in all cases.

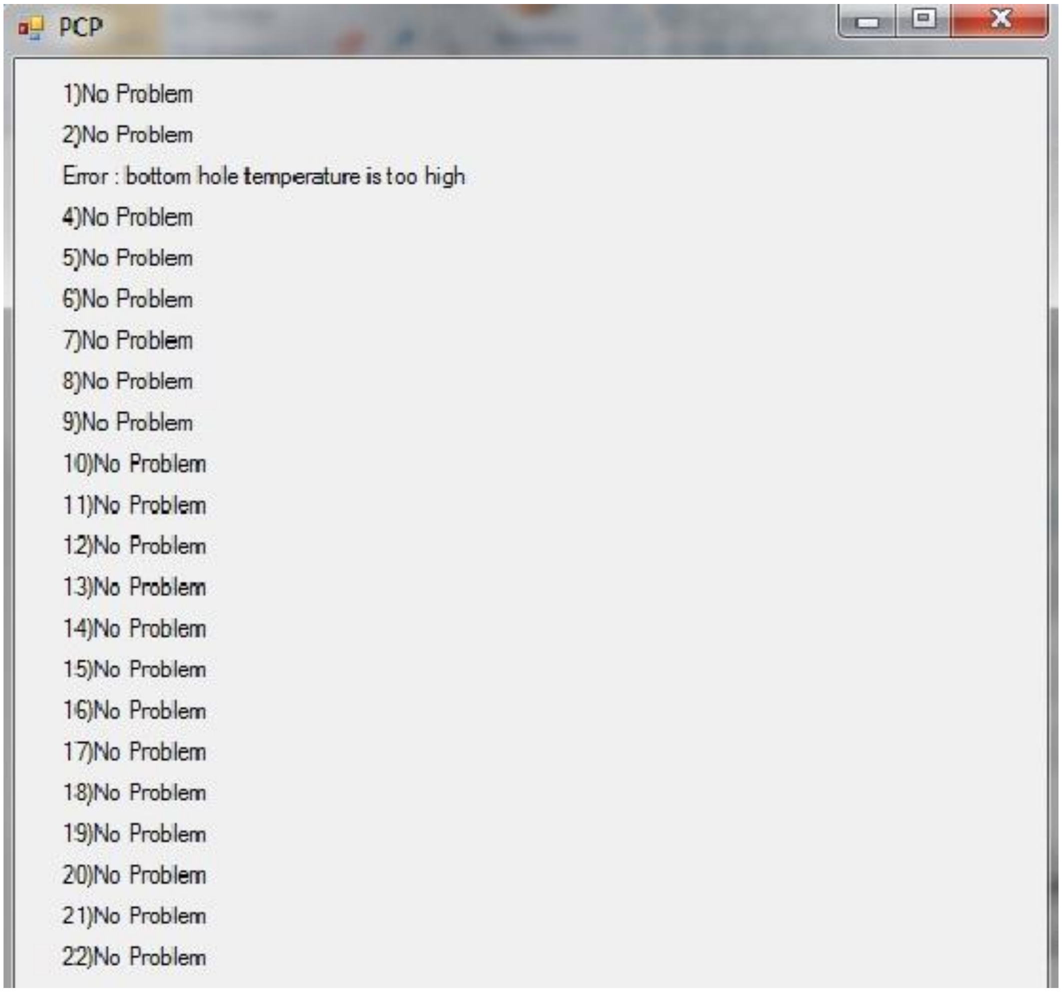


Figure 6.13 PCP result for case study 3

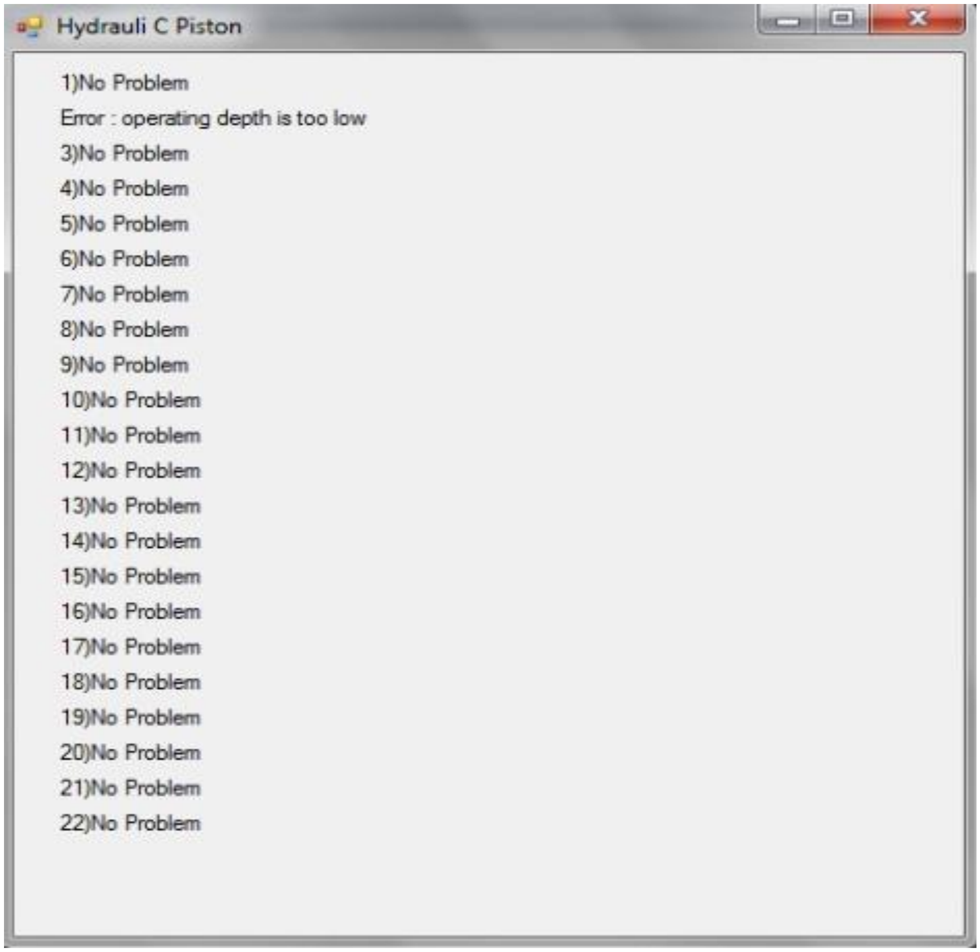


Figure 6.14 HPP result for case study 3

CHAPTER 7

CONCLUSION

Three cases has been run in developed Expert System program and results have been obtained by using well data of different oil fields. The obtained results have been compared with real field applications and previous studies those have been carried out on these fields. In all cases obtained program results overlap with real field applications and prevoius studies. This shows the well development of program and it is feasibility in real field applications. The conclusions that have been drawn during study are:

(1) GL and HPP techniques are the most appropriate technqiues in offshore applications. Other techniques, such as ESP, PCP are also applicable in offshore fields but certain considerations must be taken into account. SRP not suitable for offshore applications, but it is the best technique for onshore applications as they are easily controlled and is applied in the wells with low production rate.

(2) As it was seen in dual completion well types, casing size must be taken into consideration. In first case study the is dual completed and in the results system warnes some techniques for appropriate casing size. Therefore, specially in pump installations casing size must be considered.

(3) Also, during the study it has been observed that production rate and operating depth are the main parameters for artificial lift selection procedure. In case studies it has been observed that most artificial lift types have been suggested as not recommended system because of operating depth and rate. In all three cases these results could be seen.

(4) Also, in spite of that some techniques are recommended in high productiv and deep wells, they could be restricted with certain production considerations. Specially, it was observed that ESP is the worst technqiue if the well has severe sand production issues. Furthermore, high deviation angle and severity is the main concern for pump applications. In above case studies the suggested pump installation depths have been suggested above the high deviated intervals.

(5) During the study it has been observed that the application of some techniques depends on water cut value. Specially, in high oil rate wells GL is the best technique to be applied. Because the operating rate of GL as high as 50000 bopd. But in low productivity wells SRP is suggested as an appropriate technique.

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