# Selection Criteria for Artificial Lift System Based on the Mechanical Limits: Case Study of Golfo San Jorge Basin

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## Abstract

The Golfo San Jorge basin is the oldest productive basin of Argentina, and is located in south Patagonia. With 12,630 active oil wells, the basin produces 269,937 bpd of oil, and 2.9 MM bdp of water.

The artificial lift systems are distributed as follows: 9,648 Sucker Rod Pumps (SRP), 1,615 Progressing Cavity Pumps (PCP) and 1,336 Electric Submersible Pumps (ESP). There are some important experiences with gas lift, plunger lift and hydraulic jet pump, but are not considered in this study. Close than 90% of the pumps are installed between 3,000 ft to 8,000 ft depth, producing flow rates over 1,500 bpd of fluid

More than 3.1 MMbpd of water are injected in 2,400 wells in water flooding projects, therefore 41% of the oil is produced from this method. Due to the mature state of the basin, every year, new waterflooding projects are implemented for increasing and to hold the oil production of the basin. With every new project, not only increases the gross production per well, but also increases the depth of the new reservoirs.

The combination of these factors resulted in a higher power to be transmitted from the prime mover to the pump, coupled with the increasing down hole temperature.

Another factor, is the restriction provided by the most common casing diameter (5 ½ "), limiting the outside diameter of the pumps, the tubings and sucker rod sizes, and the shaft diameter too in some systems.
In order to overcome these conditions, not only requires new technology in materials and design, but criteria for operation on the surface to achieve it.

This paper presents a theoretical and practical analysis of the mechanical and operational limit of the most used artificial lift systems in Golfo San Jorge Basin such as the PCP, ESP and SRP.

The analysis not only considers the technical aspects of each critical component and new technologies, but also is supported by reservoir information, operational conditions from 11,000 wells and software simulations for each system.

One of the main objectives of this paper is to provide a guide for selecting and designing artificial lift Systems as SRP, PCP and ESP in similar oilfields and conditions.

**The Golfo San Jorge Basin**

The East-West trending Golfo San Jorge basin is the oldest and most prolific oil basin of Argentina It covers 28,000 M Acre, with 1,127 MMbo (Dec-05) of OOIP and is located in the central Patagonia. **(Figure 1 -Appendix )**

The first commercial oil discovery took place in 1907 and since then close to 2,900 MMBOE were extracted. Located in the central part of Patagonia Terrain, it is an intracratonic extensional basin. During late Jurassic-early Cretaceous times, the extension related to the Gondwana break-up generated many isolated small half-graben basins, with a NW-SE structural trend. Later, a new extensional-transtensional stress field originated a WNW-ESE trending, and reduced extensional deformation continued until the Oligocene.

The basin is essentially asymmetric; in the eastern section the dominant extensional faults are on the northern flank with the southern flanks being a less faulted, flexural type margin. In contrast, the western section is asymmetric but its major faults are on the southern flank, being the northern flank a flexural margin. The central section of the San Jorge basin is dominated by NW and NNW trending extensional faults that were reactivated by compression in Tertiary times.

**Artificial Lift Systems (ALS) in GSJB**

From the beginning of the activity in Golfo San Jorge Basin, 100 years ago, several ALS have been used in order to produce the oil from each well.

The basin offers different conditions depending of the mature state of the oilfields: high water percentage, high and low flow rate, free gas and in solution, heavy and light oil, flowing wells and high GOR reservoirs.

At the present time, ALS as SRP, PCP and ESP are the most popular systems used for producing 98 % of the total fluid of the basin. And in smaller quantity, wells produced by hydraulic jet pump, plunger and gas lift.

The growing reservoir depth and flow rate of fluid per well, present a permanent challenger for the different ALS and specialist.

In this context, the selection, operation and optimization of the different systems plays one of the most important roles for following the basin development.

The follow cross plot represent information from 9,000 wells running in GSJB.
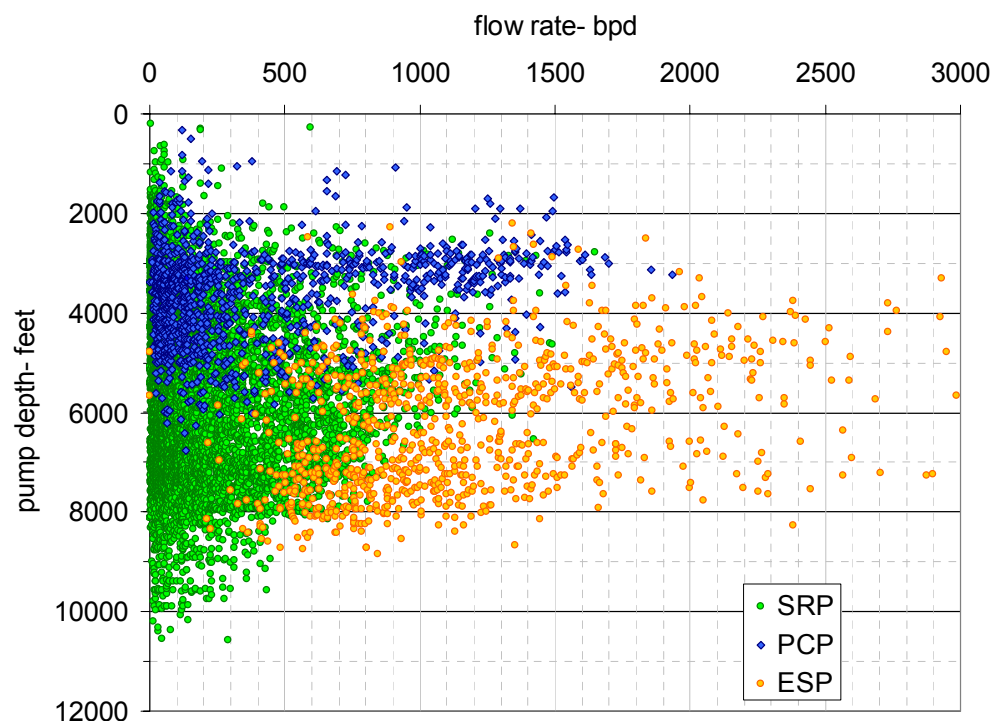
## Power transmission and mechanical limits

The analysis of a production system from the concept of nodal analysis, localizing the node at the Pwf position **(Figure 1),** separates the systems in two:

1.  Inflow: Flow of the fluid trough the reservoir to the well

$$P_{wf} = P_r - \Delta P_{reservoir}$$ ....................................................................................................................................... (1)

2.  Outflow: Flow of the fluid from the down hole to the surface, trough the tubing and line pipe

$$P_{wf} = P_{sep} - \Delta P_{linepipe} - \Delta P_{tubings}$$ ........................................................................................................................... (2)

Depending on the dynamic pressure (pfw), flow rate target and analyzing the pressure required to overcome the pressure drop in the tubings and surface installations, we can analyze if we will need an external system (artificial lift system ) to provide sufficient energy to the fluid to overcome these restrictions, and how provide the energy to these systems. **(Figure 2),**
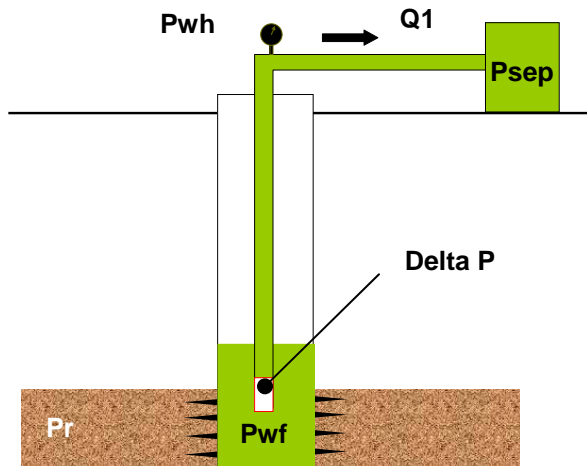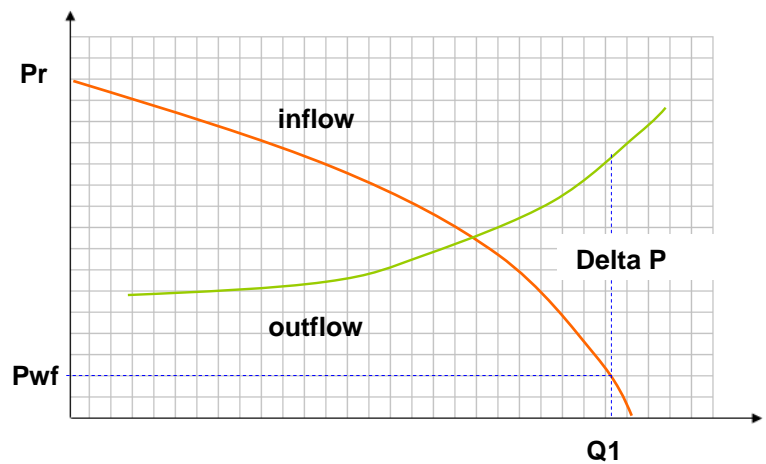


**Figure 1**

**Figure 2**

## Hydraulic Horse Power

To establish a definition of the mechanical limits of the artificial lift, we must establish a definition of the useful work that an artificial lift system performs. If it is agreed that the down hole pump does work equal to the volumetric flow rate times the pressure increase delivered by the pump, then the following two equations can be used for a definition of the horse power of an artificial lift system.

1.  Input horse power to the system (HP$_{in}$)

$$HP_{in} = \frac{Kw}{0.746}$$ ……………………………………………………………………………………………….. (3)

2.  Output horse power to the produced fluid (HP$_{out}$)

$$HP_{out} = 0.000017 \, Q \, D_p$$ …………………………………………………………………………………….... (4)

In other words, a more power is necessary to transmit from the prime mover to the pump when the flow rate or/and pressure is increasing

**Power transmission**

Every ALS presents different elements as power transmitter between the prime mover and the downhole pump, where the mechanical limits of each element is essential for increasing the run life of the systems producing the maximum fluid from the reservoir.

| Prime Mover | Conversor | Power transmission to the pump | Down hole pump |
|---|---|---|---|
| Energy | Pumping units | Sucker Rod | Flowrate vs Pressure |
| | PCP drive head | | |
| | ESP Protector | ESP Motor and protector Shafts | |
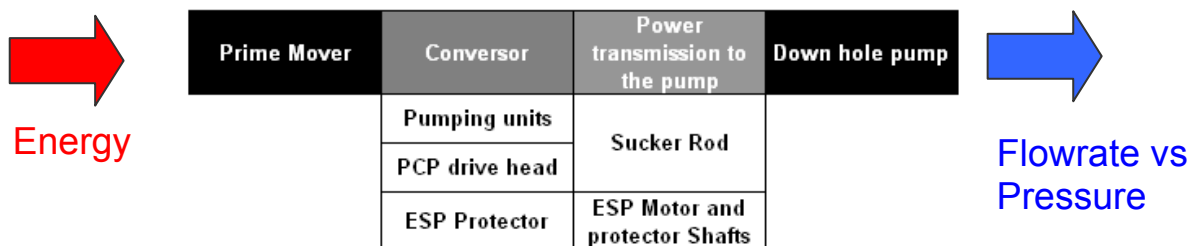
(*) Support torsional, structural and axial load during the pumping.

During the pumping action, each components of the ALS is subject to various efforts and environmental conditions affecting the performance of each, which there are listed below:
- Cyclic loads
- Tensional and torsional loads in sucker rods and shafts
- Surface structural and torsional loads
- Pressure capability  of the pumps
- Downhole temperature
- Frictional effort

These efforts may be related to
- How the power is transformed from electricity or gas combustion to an alternative or rotational movement.
- How this movement is transferred to the pump.
- The operational conditions: pumping speed, Stroke length, RPM, pumping pressure
- Well geometry and design
- And in turn affected by the temperature of bottom

In Golfo San Jorge Basin, the main challenge has been how to transfer the horsepower to the pump in 51/2 " casing, restricting the maximum tubing, sucker rod, and pump diameter. The **Table 1** shows the maximum diameter of each down hole component for 51/2 " casing 15.5#

| Casing 5 1/2 in 15.5# - ID | | |
|---|---|---|
| SRP | PCP | ESP |
| Tubing 2 7/8 in 6.4 # | | |
| 1 inch API Sucker rod - Slim hole cupling | | 456 Series Motor 400 Series Pumps |
| | 48 mm hollow rod | |
| 1 1/8 in Continuos Sucker rod | | |
| Tubing Pump 3 1/2 in | Housing pump  OD 4 1/2 in | |

## Sucker Rod Pumping

The pumping action consists in producing an up and down movement at the surface by a pumping unit, and this movement is transferred by a sucker rod string to the down hole mechanic pump. During this process, the down hole and surface installations are subjected to different loads that limit the lift capacity of the system.

The maximum rate of the SRP system is based upon the mechanical limit of three components: sucker rod string, the structure and the reduction gears. But the sucker rod string is normally considered the weak link in a pumping system because of the following limitations:

- Size restraints (the tubing ID restricts the maximum coupling and sucker rod diameter)
- Adverse environment
- Strength limitations

During the design process and operation, different combinations of structural and torque ratings, sucker rod design, pump diameter are matched to fit the design in a safety zone for increasing the system run life.

### Sucker Rod String loads

The possible rod loads during a complete pumping cycle at any depth in the string can be classified into the following groups:

1. Weight of rods. This force is distributed along the string. At any section, it is equal to the weight of the rods below the given section. It is positive for both the upstroke and the down stroke.

2. Buoyant force. This force always opposes the rod weight and is equal to the hydraulic lift caused by immersing the rods into the produced liquid. It is customary to handle the sum of the rod weight and buoyant force by using specified rod weights in fluid.

3. Fluid Load. This is concentrated force acting at the bottom of the string only during upstroke, and it equals to the force resulting by the net hydrostatic pressure of the fluid lifted, acting on the area of the pump plunger. It is always positive.

4. Dynamic Loads. They are the results of changes in acceleration, during the pumping cycle, of the moving masses (rods and fluid column). The magnitude and direction of these forces is constantly changing during the pump stroke, but generally dynamic loads result in a positive net load for the upstroke and a negative load for the down stroke.

5. Friction Forces. These forces are of two kinds: fluid friction and mechanical friction. Fluid is moving with the rods during upstroke and against the rods on the down stroke. Mechanical friction forces oppose the movement of rods; they are positive during upstroke and negative during down stroke.

One of the behaviors that present the basic dynagraph card, is the relationship between loads and pumping speed. Today, long stroke pumping units allows increasing the Pumping Stroke (S) and reducing the Pumping Speed (N), reducing the dynamic loads, and increasing the loads ranges of the total system.
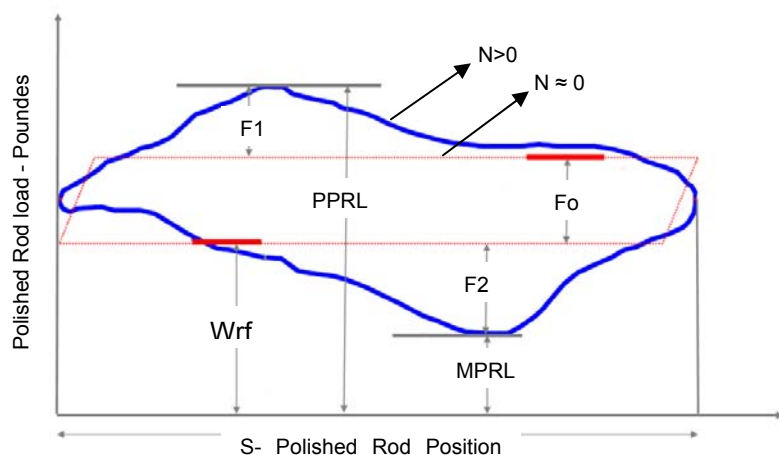


**Basic Dynagraph Card - API 11L**

Wrf  - Total weight of rods in fluid, pounds
PPRL – Peak polished Rod, pounds
MPRL – Minimum polished Rod, pounds
Fo – Differential Fluid Load on full plunger area, pounds
F1 – PPRL factor
F2 – MPRL factor
N – Pumping Speed, Strokes Per Minute
S – Polished Rod Stroke, inches
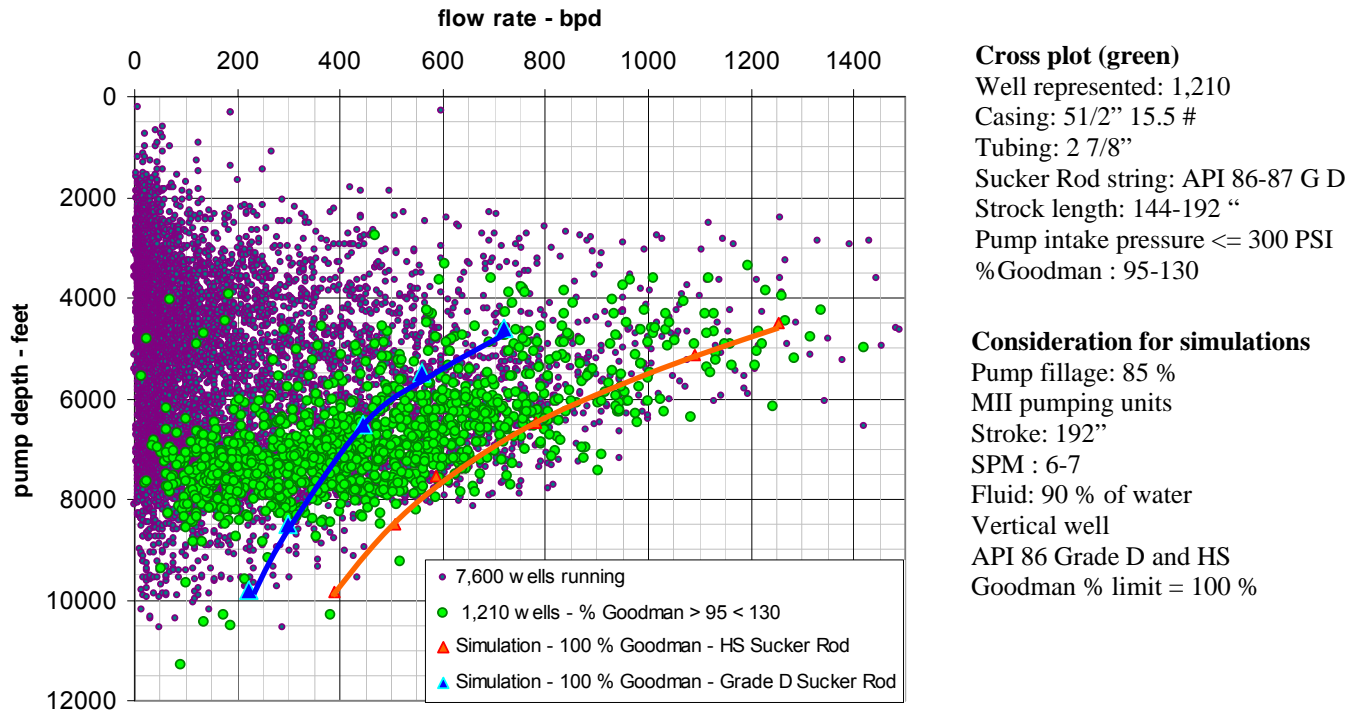
**Goodman Diagram**

The behavior of the sucker rods in the transfer of forces and loads determines the action of the pump. Their inherent characteristics affect the loads imposed on the surface equipment. For years, the Goodman diagram is the basis of analyzing the endurance (fatigue) life of ferrous material. Goodman published the diagram during the year 1908. An American Petroleum Institute (API) Committee suggested several design factors for Goodman Diagram in order to adapt it specifically to specifically sucker-rod pumping installations.

The diagram is known as the API Modified Goodman diagram and this allows consideration of both maximum stress and stress range. The modified Goodman Diagram is discussed on page 9 of the API RR 11 BR bulletin.

**Sucker rod limit in GSJB**

Considering the most common casing and tubing used are 5 ½ " and 2 7/8 ", the bottleneck of the system is the sucker rod string, where a combination between design, new materials and technologies, and operation condition, are the right way for increasing the rating of the system.

Analyzing dynamometric information and information from 4,000 wells operated by SRP, different areas where delimited considering a safety zone for producing wells, below the maximum strength of the sucker rod string. This real information is complemented by software simulation for different sucker rods and pumping conditions **(Graph 1)**



**Cross plot (green)**
Well represented: 1,210
Casing: 51/2" 15.5 #
Tubing: 2 7/8"
Sucker Rod string: API 86-87 G D
Strock length: 144-192 "
Pump intake pressure <= 300 PSI
%Goodman : 95-130

**Consideration for simulations**
Pump fillage: 85 %
MII pumping units
Stroke: 192"
SPM : 6-7
Fluid: 90 % of water
Vertical well
API 86 Grade D and HS
Goodman % limit = 100 %

**Graph 1** – Cros plot with real information vs simulations

A summary of the simulations is presented in the following table

| Pump depth | Stroke | Speed | Pump | Grade D SR | | Grade HS SR | |
| --- | --- | --- | --- | --- | --- | --- | --- |
| | | | | Flowrate | Tensile | Flowrate | Tensile |
| Feet | Inches | SPM | Inches | bpd | KSI | bpd | KSI |
| 9800 | 168 | 6 | 1.50 | 221 | | 388 | |
| 8500 | 192 | 7 | 1.50 | 298 | | 508 | |
| 6500 | 192 | 7 | 1.75 | 444 | 115-140 | 780 | 140-160 |
| 5500 | 192 | 7 | 2.00 | 559 | | 1089 | |
| 4600 | 192 | 7 | 2.25 | 720 | | 1252 | |

## Progressive Cavity Pumping

The progressing cavity pump consists of a single helical rotor which rotates inside a double helical elastomeric gear (stator) of the same minor diameter and twice the pitch length. The pump stator is attached to the rod string that connects at surface in to the wellhead drive unit. Surface equipment transmits power from a prime mover to the wellhead drive in order to rotate the rod string.

The operational conditions of theGolfo San Jorge Basin and requirements for the PCP are: larger volumes of displacement and produce deeper wells. Because of that, the manufacturers are made modifications in some of the components, but the main analysis in this paper is about the limits of the common components used at the GSJB.

By the pumping action and the downhole conditions, the system can presents two mechanical limits:
- Load in the Rod String
- Downhole Temperature

### Rod String Loading
The power transmitted from the wellhead drive in the surface, reach the pump by the rod string. This power produces a series of efforts in the rod string. The rod string must be capable of carrying an axial load and transmitting torque to the downhole pump. If the axial load and torque produce a combined stress that exceeds the yield capacity for the size and grade of the rod material, failure will occur. To determinate the minimum size and material of the rod, we must find the combined stress for the operational conditions required in the well.

### Axial Load and Torque
The axial load and the torque at any location along a rod string are made up of several components. These components are applied in two sections: at the downhole pump and distributed along the length of the rod string. In almost all cases, the rod string axial load and torque are highest at the polished rod connection at surface.

In the axial load are involved several efforts at the same time:
1. Pump pressure Load ($L_{pump}$)
2. Sum of rod string weight ($L_{weight}$)
3. Sum of uplift forces ($F_{uplift}$)

$$L_{rodstring} = L_{pump} + \sum L_{weight} - \sum F_{uplift} \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \text{(5)}$$

The pump pressure load is the result of a different pressure across the pump acting on the pump rotor and is analogous to the plunger load in beam pumping, its pumping action could compared to that of a piston moving through a cylinder of infinite length. There is some controversy as to how this load develops on the rotor and as a result several different formulations have been published. This one was presented by Alhanati and Skoczylas (2004):

$$L_{pump} = 0.2248 \left[ \left( P_{\text{discharge}} - P_{\text{intake}} \right) \left( 8eD + \frac{\pi}{4} D^2 \right) - P_{\text{discharge}} \left( \frac{\pi}{4} D_{rod}{}^2 \right) \right] \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \text{(6)}$$

The rod string weight is a function of the unit weight and vertical length of the rod string. The total rod weight can be calculated as follows:

$$L_{weight} = W_r \, L_v \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \text{(7)}$$

The only positive consequence of flow losses is that they produce forces that act on the rod string in the direction of flow causing a reduction in rod tension. These forces are applied to the couplings and rod body in the form of uplift and surface uplift forces, respectively. The calculus of these forces is beyond the study of this paper.

The torque is the principal effort acting in the PCP. We can define it, how the required energy to rotate the rotor inside the stator and produce the well fluid, to overcome the static head and head loss thru the tubing. This effort consists of three main components:
1. Pump hydraulic torque ($T_{hydraulic}$)
2. Pump friction torque ($T_{friction}$)
3. Resistive torque ($T_{resistive}$)

The torque in the rod string is equal to:

$$T_{rodstring} = T_{hydraulic} + T_{friction} + \sum T_{resistive} \ \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots.. \ (8)$$

The pump hydraulic torque provides the energy to displace the produced fluid across the differential pump pressure (equation 9) and can be calculated using equation 10.

$$P_{lift} = P_{discharge} - P_{intake} \ \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots.\dots\dots\dots\dots\dots\dots\dots\dots\dots \ (9)$$

$$T_{hydraulic} = 0.0897 \ V \ P_{lift} \ \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots..\dots.. \ (10)$$

The pump friction torque is the required energy to overcome: the pump interference between rotor and stator, the lubricant properties of well fluid and, long and type of pumps. This can be estimated by subtracting the hydraulic torque, calculated by the measured pump torque in a test bench.

As the rod string spins within the tubing, surface shear forces develop between the fluid and rod string. These forces are reacted by the rod string producing a resistive torque. The calculus of this torque involves the properties of well fluid and installation parameters, and this is beyond the scope of this paper.

**Combined Stress**
The combined loading of the rod string due to axial load and torque can be represented by the effective (Von Mises) stress:

$$\sigma_e = \sqrt{0.000016 \frac{L_{rodstring}^2}{\pi^2 \ D_{rod}^4} + 0.1106 \frac{T_{rodstring}^2}{\pi^2 \ D_{rod}^6}} \ \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \ (11)$$

This equation show that effective stress is primary a function of torque, although tension does impact the magnitude at lower torque values. For the operational conditions of the GSJ Basin the torque is the main effort applied to the rod string. It is advisable to use at least a 20% safety factor in rod sizing. This will allow for unanticipated torque increases that might be brought about by factors such as sand slugs, stator swelling or start-up friction.

**Downhole Temperature**
The second mechanical limitation, is the temperature at which will be operate the downhole pump, at bottomhole conditions. In the beginner of the operational life of the PCP, the elastomer was considered as the weak point of the system. The continuous efforts made to improve its run life. The temperature of the elastomer in its first applications could not exceed 60ºC (150ºF), this change in the latest times to an operative range of  195-215 °F for NBR elástomers and 215-260 °F for HNBR elástomers.

The exposure of the elastomer to heat causes an overall expansion of the material and it may also cause a reaction that alters the chemical structure. This reaction, which involves intermolecular crosslinking, usually results in an overall irreversible deterioration of material properties. The temperature resistance of an elastomer is depend on its chemical structure include the base polymer, fillers and crosslinking structure.

The temperature at bottomhole conditions is a function of three variables:
1.  Installation depth. Due to the geothermic gradient.  For GSJ Basin  **(See Figure 2 - Appendix)**
2.  Rate of displacement. The cyclic deformation of the elastomeric material can produce the Hysteresis phenomena. A portion of the flexing energy is converted into thermal energy. The elastomer temperature is approximately 20 % more than the downhole temperature.
3.  Composition of the well fluid. This variable depends on the thermal conductivity of the produced fluid, to refrigerate the pump, while it is passing.

**Combined stress or Torque Effort analysis to the Operational Parameters in the GSJB**
Displacement and pressure threshold at which the magnitude of the hydraulic torque loading of a pump would alone be sufficient to begin to cause yielding of the rod. Note that it does not take into consideration other torsional loads inherent in PCP applications (e.g. friction torque in the pump, resistive torque along the rod), or the reduced torque loading capability caused by the presence of axial load in the rod string. When the friction torque and axial load are considerate in the stress equation, it is clear that many of the pumps presently on the market will substantially overload a 1 in, grade D rod string when operate near their rated pressure.

The follows graph, present information (flow rate vs. pump depth) from 1,175 PCP running, and simulations for different sucker rod used in GSJB. The criteria for the simulation were to operate the pump at 300 RPM, at 90 % of the maximum admissible sucker rod torque **(Graph 2)**
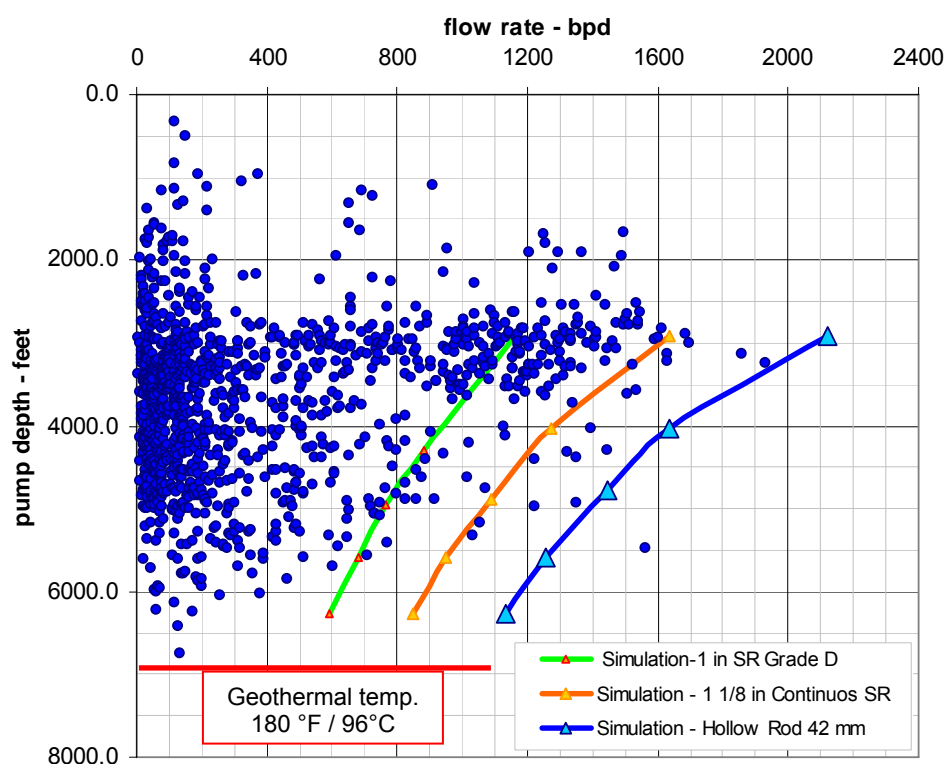


**Consideration for simulations**
Vertical well
Fluid: 90 % of water (low frictional effect and pressure losses)
Pressure intake = 300 PSI
No Gas
Volumetric Efficiency = 90%
Well head pressure = 100 PSI

**Graph 2** – Cros plot with real information vs simulations

Depending on the water %, flow rate, and RPM, the elastomer temperature could increase 60 °F over the down hole temperature. The **Grah 2**, shows not only the limit of the sucker rod, but also the current temperature limit of the elastomer, considering the effect explained before

A summary of the simulations is presented in the following table

| Pump depth | Speed | 1" GD - 800 lbxft | | 1 1/8" GD - 1140 lbxft | | Hollow Rod 42 mm - 1500 lb xft | |
| | | Flowrate | pump desplacement | Flowrate | pump desplacement | Flowrate | pump desplacement |
| Feet | RPM | bpd | bpd@RPM | bpd | bpd@RPM | bpd | bpd@RPM |
| 2920 | 300 | 1182 | 4.44 | 1635 | 5.70 | 2119 | 7.86 |
| 4040 | 300 | 883 | 3.12 | 1270 | 4.50 | 1635 | 6.04 |
| 4770 | 300 | 764 | 2.70 | 1088 | 3.84 | 1447 | 5.35 |
| 5580 | 300 | 679 | 2.40 | 950 | 3.36 | 1258 | 4.65 |
| 6271 | 300 | 594 | 2.10 | 849 | 3.00 | 1132 | 4.21 |

The **Graph 3**, represent the pump displacement in bpd/RPM, recommended for operating the pumps with different sucker rod, at 300 RPM and 90 % of maximum admissible sucker rod torque.

**bpd/RPM**
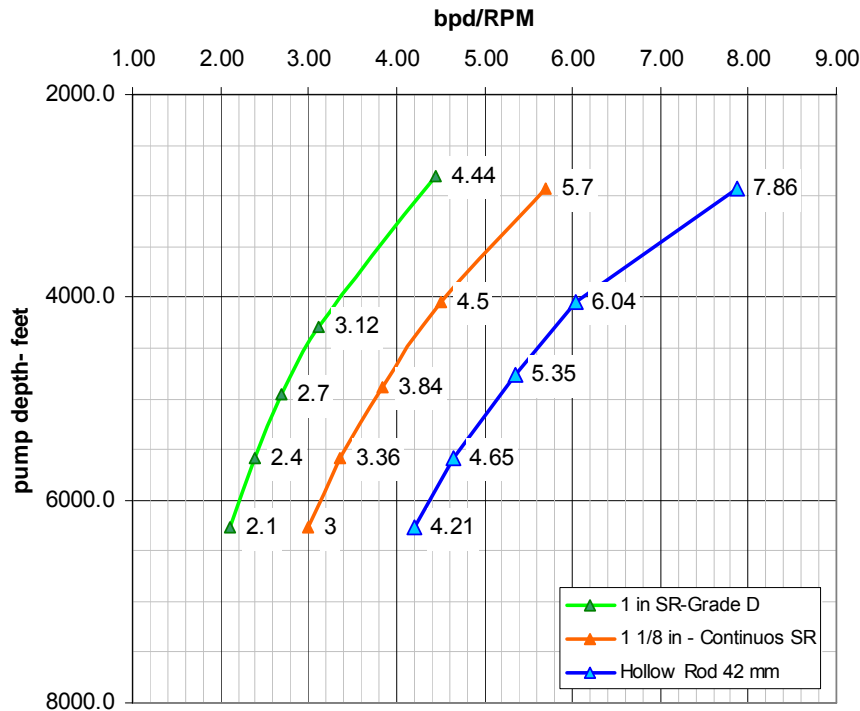


**Graph 3** – Recommended pump displacement

## Electric Submersible Pump System (ESP)

The conventional installation of ESP units run on the tubing string and is submerged in well fluids. The electric submersible motor is at the bottom of the unit and is cooled by the wellstream passing by its perimeter. It is connected to the protector section that provides many crucial functions for the safe operation of the unit. On top of the protector a pump intake or gas separator is situated which allows well fluids to enter the centrifugal pump and, at the same time, can remove low quantities of free gas from the wellstream. Liquid is lifted to the surface by the multistage centrifugal pump, the heart of the ESP system.

The mechanical limit of the ESP systems is based upon the maximum temperature limit of the electric components and the mechanical limit of shaft, coupling, and bearings

**Power transmission and loads**

During the pumping, the motor transmit the power to the pump through the shafts and coupling (union between shaft), and the pressure over the pump generates an axial load observed by the thrust washers of the stage (floating impeller) and the pump shaft/protector thrust bearing.

In fixed impeller pumps, in contrast to those with floating impellers, high axial loads develop in the pump stages and these are directly transferred to the protector's thrust bearing. The calculation of these forces, however, requires that measured thrust values for the given stage be available.

$$ F_{TB} = 0.785\, P_{max}\, d^2 \ \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \ (12) $$

Where:   Pmax: maximum internal pressure in the pump (psi)
            d: the shaft diameter (in)

The main thrust bearing of the ESP unit, contained in the protector, must be capable to withstand the maximum anticipated axial force coming from the pump. Since the viscosity of motor oil is lower at elevated temperatures, the oil film between the thrust runner and the thrust shoes becomes thinner at higher operating temperatures. This is the reason why, the load rating of protectors must be decreased at higher temperatures. **(See Figure 3 -Appendix)**

In Golfo San Jorge Basin, due to the multilayer reservoir and in order to obtain an optimal reservoir draw down, most of the pumps are installed below the perforations, where the use of a shroud to route fluid by the motor is necessary. The diameter

of this shroud for 51/2 inches casing is 4 inches, for this reason 375 series motor and 300 series seal section are necessary. The follow table shows the maximum power transmission for two sizes of protectors:

|  |  |  |  | Shaft limit | |
| --- | --- | --- | --- | --- | --- |
| Housing | Hz | Shaft Diameter | Cupling Diameter | Estándar | High Strenghth |
| 4.00 inch | 50 | 0.875 inch | 0.875 inch | 213 HP | 342 HP |
| 3.38 inch | 50 | 0.750 inch | 0.750 inch | 133 HP | 213 HP |

**Downhole temperature**
ESP motors, like any electric motor, are very sensitive to operating temperature and their run lives are severely shortened at temperatures above their design specifications. Therefore, a proper installation design must ensure that no overheating occurs during operation. Other critical component affected by the temperature is the pothead insolate.
Motor temperature is a function of the following effects:

- Ambient (geothermal) temperature**, (See Figure 2 – Appendix)**
- The heat generated in the motor during operation, and
- The cooling effect of the wellstream flowing past the motor.

The main effects of high temperatures on the performance of submersible equipment are diverse and can be classified as:
- Elastomers used in ESP equipment for sealing, etc. are weakened and their service life is shortened accordingly,
- The dielectric properties of insulation materials deteriorate and motor or cable insulations may loose their dielectric strength causing burnouts,
- The electrical resistance of the conductor in the submersible cable increases causing an increased power loss in the cable,
- The viscosity of motor oil decreases and the load carrying capacity of the main thrust bearing, usually situated in the protector section, decreases, **(See Figure 3 -Appendix)**
- Due to the different thermal expansion of dissimilar metals mechanical failures in rotating machinery can occur, and
- Scale formation on the inside and outside surfaces of ESP equipment becomes more pronounced.

The flow of well fluids past the motor is crucial for maintaining proper cooling of the unit. This is why in most installations the motor is set above the perforations to ensure fluid flow past the motor. The cooler effect of the fluid will depend on the velocity and the % of water of the fluid, and is represented by the **Figure 4- Appendix**

**The ESP system in GSJB**
The **Graph 3** represents information from 1,100 ESP running for TR3 (500 wells) and TR4 series Motor (900 wells).
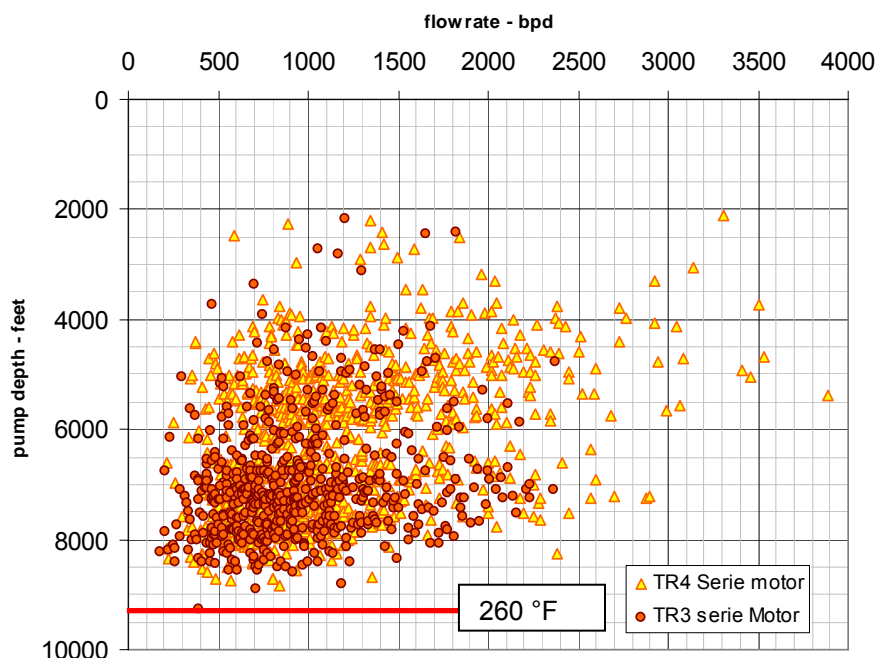
In this graph you can highlight the following aspects:

- The equipments with TR3 series Motor (with shroud and below the perforations) have reached the capacity of the TR4 series Motor, despite its reduction in shaft and coupling diameter. The main reason of this has been the continuous modifications, new designs and new technologies applied by the main ESP service company in GSJB.
- The maximum depth is associated to the temperature limit of the dielectric components. This limit is increasing every day with new technology and materials, but it also depends on the cooler effects of the fluid (**Figure 4-Appendix)**

## Conclusions

If we consider the restriction of the casing diameter, and the increasing flowrate and pump depth per well, the maximum power transmission from the prime mover to the pump is a common factor on the three systems. To enhance this capability has been requested a combination between new materials, design and operational condition.

Sucker Rod Pumping: The use of high-strength sucker rod and premium connections, have been a common practice during the last years. The use of the long stroke pumping units is other new practice that will allows reaching more flow rate and depth, to reduce the dynamic loads (this practice was not discussed in this paper)

Progressing Cavity Pumping: As the SRP system, the use special sucker rods have been one of the most important practices. The hollow rod, continues rods, high-strength and premium connections, have allowed to increase close to 100 % of the torque transmission in 27/8" tubing if we compare with the most common sucker rod, 1" API Grade D.
For increasing the flowrate capacity of the pump, the last trends have been to increase the volumetric displacement in pumps, increasing the stage length and reducing the eccentricity of the rotor. In addition, RPM over 500 RPM is a common practice in shallows wells (3,000 feet depth).
Respect to elastomers, the new developments have been associated to increase the millon of cicles of deformation, beforefatigue (hysteresis)

Electric Submersible Pumping:The equipments with TR3 series Motor (with shroud and below the perforations) have reached the capacity of the TR4 series Motor, despite its reduction in shaft and coupling diameter. The main reason of this has been the continuous modifications, new designs and new technologies applied by the main ESP service company in GSJB.
The maximum depth is associated to the temperature limit of the dielectric components. This deep limit is increasing every day with new technology and materials, but it also depends on the cooler effects of the fluid (**Figure 4- Appendix)**

For complentary information about the best practices in Golfo San Jorge Basin, the Authors recommend the paper "Artificial Lift Sistems Overview and Evolution in a Mature Basin: Case Study of Golfo San Jorge", SPE 108054, M.Hirschfeldt, P. Martinez, F. Distel,UNPSJB, 2006

## Nomenclature

$D_P$ = The pressure increase through the pump [ psi]
$Q$ = The volumetric flow rate through the pump in [bbl/day]
$P_{wf}$ = Pressure at well perforations in the formation [ psi]
$P_r$ = Reservoir pressure [ psi]
$\Delta P_{reservoir}$ = Diferencial reservoir pressure [ psi]
$\Delta P_{linepipe}$ = Diferencial line pipe pressure [ psi]
$\Delta P_{tubing}$ = Diferencial tubing pressure [ psi]
$P_{sep}$= Suface separator pressure [ psi]
$Kw$ = Input power in kilowatts
$P_{discharge}$ = Pump discharge pressure [ psi]
$P_{intake}$ = Pump intake pressure [ psi]
$D$ = Nominal rotor diameter [in]
$e$ = Pump eccentricity [in]
$D_{rod}$ = Rod string diameter [in]
$W_r$ = Rod string unit weight [lbf/ft]
$L_v$ = Rod string vertical length [ft]
$P_{lift}$ = Net lift required [ psi]
$V$ = Pump displacement [bbl/day/RPM]
$\sigma_e$ = Efective strees [ psi]
$L_{rodstring}$ = Rod string axial load [lbf]
$T_{rodstring}$ = Rod string torque [ft.lbf]

$F_{TB}$ = *Axial loadon thrust bearing*
$P_{max}$ = *maximum internal pressure in the pump [ psi]*
$d$ = *Pump shaft diameter [in]*

## Acknowledgments

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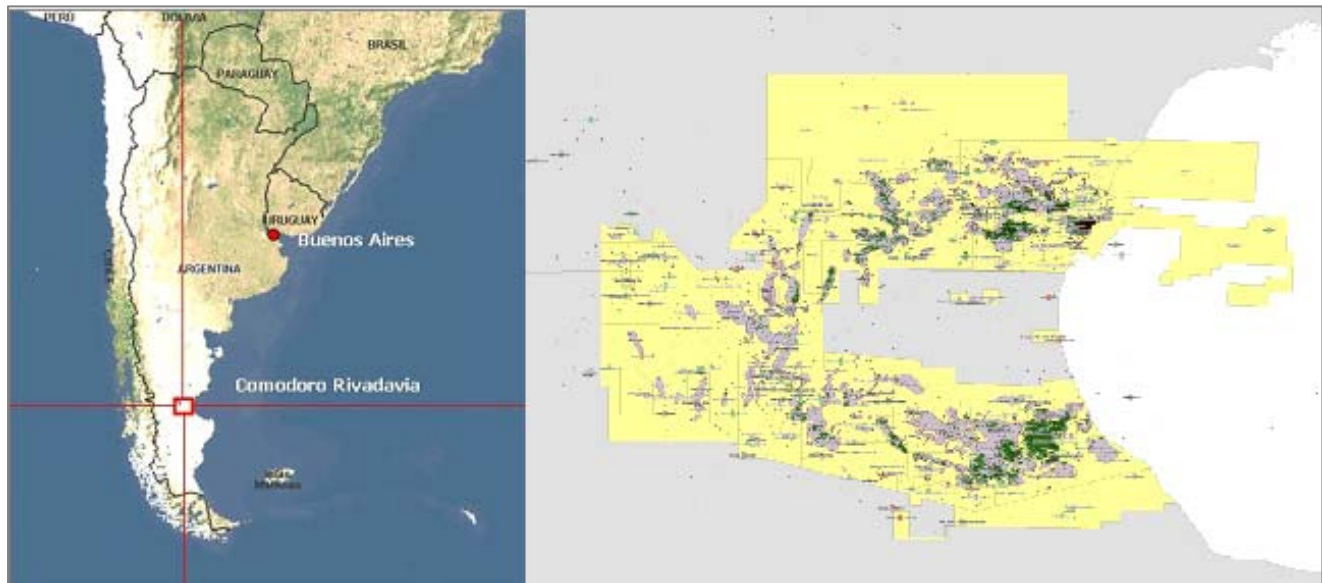17. Norris Sucker Rod Catalog
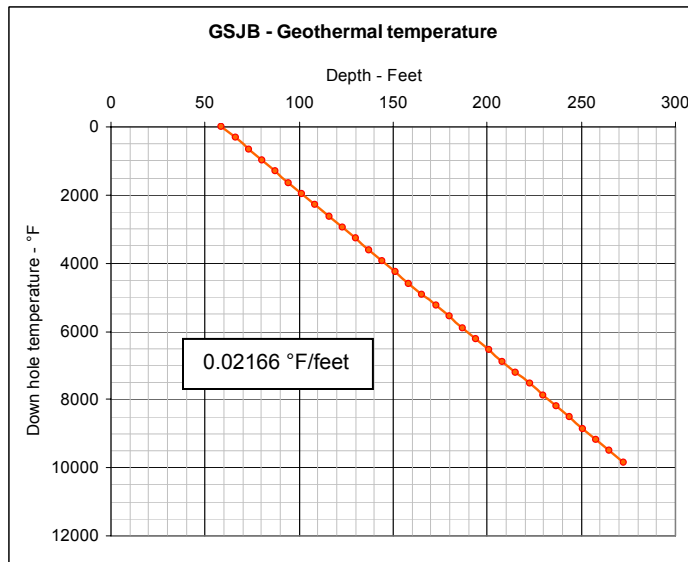
**APPENDIX**



**Figure 1**- The Golfo San Jorge Basin



**Figure 2**- GSJB Geothermical temperature
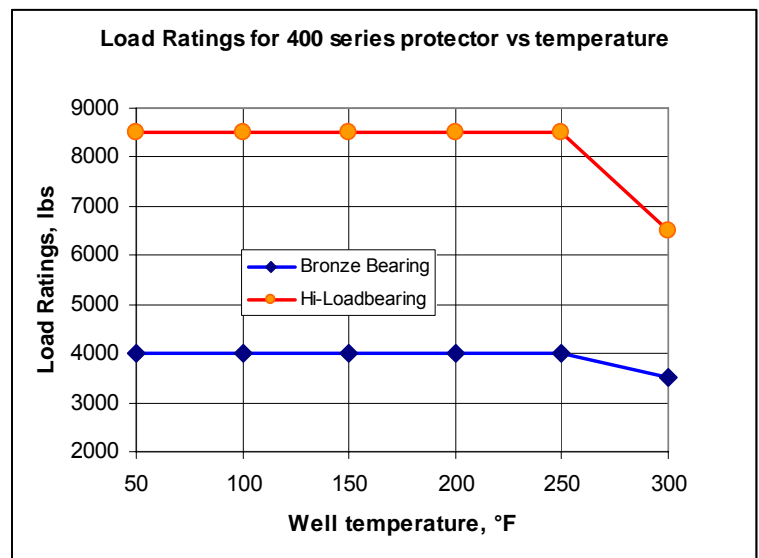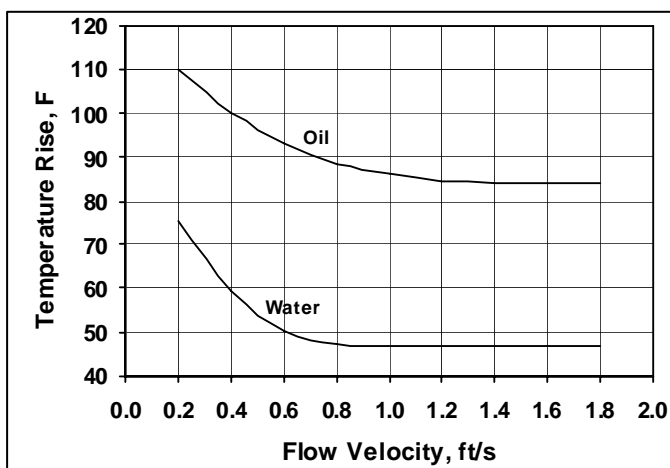


**Figure 3**- Protector Load Rating's vs temperature



**Figure 4**- Cooler effect of the fluid in ESP motors