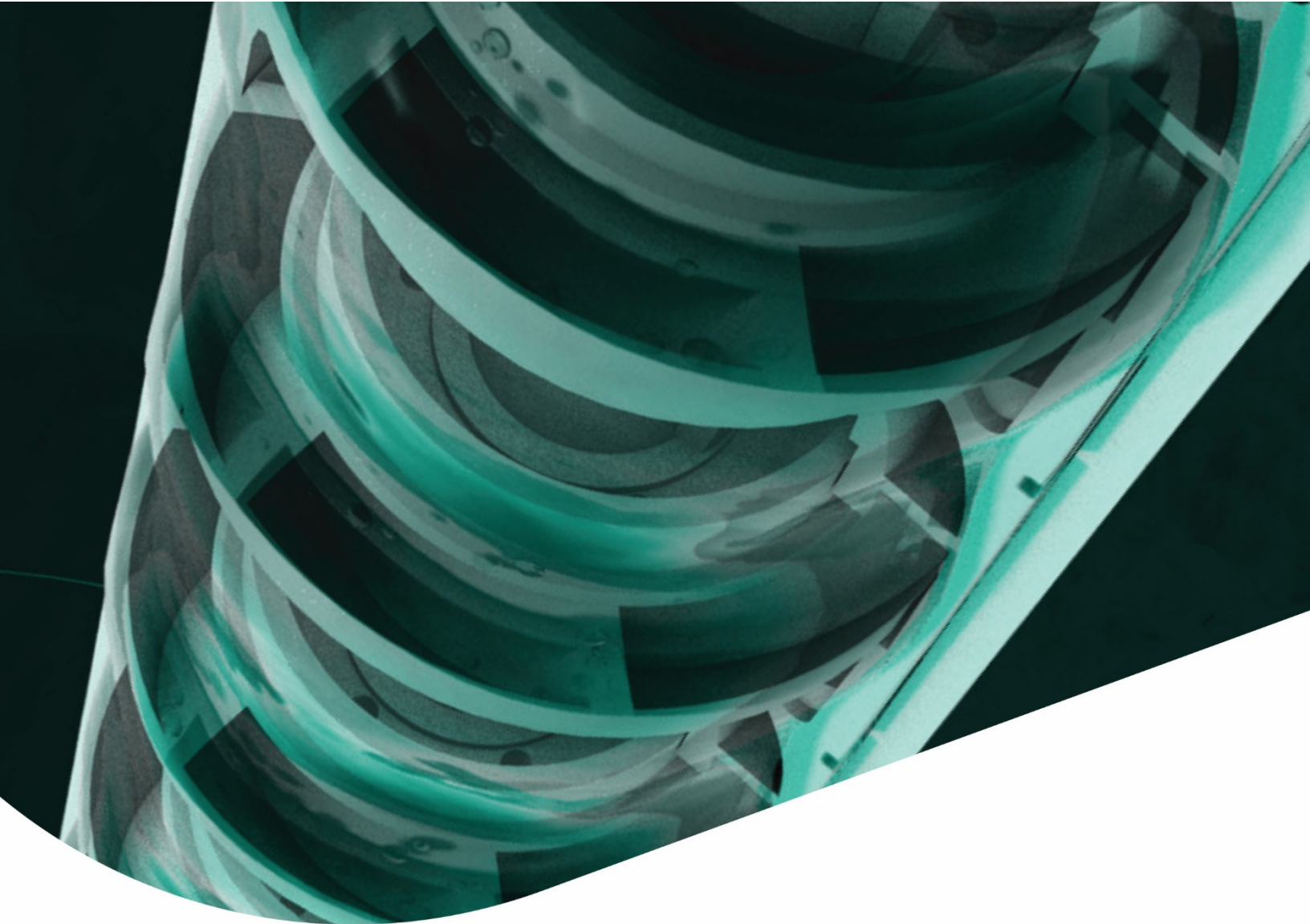




Submersible Pump Handbook

VERSION 13

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Baker Hughes 

Preface

The Baker Hughes *Submersible Pump Handbook* was designed to help readers understand the basic concepts associated with electrical submersible pumping (ESP) systems. This handbook covers fundamental principles involving the sizing and operation of ESP equipment. Also included are tables, data, and general information valuable to ESP users.

Much of the material in the *Submersible Pump Handbook* has been published previously and is conveniently reassembled in this single volume. However, there is also a considerable amount of new material included that will assist with ESP selection and operations.

Any future additions or editions will include information and revisions suggested by *Submersible Pump Handbook* users. Comments and suggestions are welcome.

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Section 1: Industry overview

Chapter 1: The Petroleum industry

Chapter 2: The Geothermal industry

Chapter 3: Baker Hughes Oilfield Services product lines

Notes:

Chapter 1

The Petroleum industry

Electrical submersible pumping (ESP) systems are a form of artificial lift developed to help petroleum companies maximize their production for the least amount of investment. This chapter provides a basic understanding of the petroleum industry in order to better understand the role artificial lift and submersible pumps play in the production of well fluids, as well as the role each Baker Hughes product line plays.



Figure 1-1: The petroleum industry

This overview of the petroleum industry includes all events from the exploration of hydrocarbons to the production from the earth. This process can be long and challenging, as oil rarely appears naturally on the surface of the earth. Often, some form of artificial lift will be required to achieve desired production rates. The petroleum industry involves many complex and elaborate techniques, including seismic and wireline exploration. From geoscience to artificial lift methods, Baker Hughes provides the service and support that operators depend on during the life cycle of a well.

Geology

Geology is the study of the physical earth, its history, structure, composition life forms, and the processes that continue to change it. In the petroleum industry, geology refers to the study of rock formations. Understanding the geology of the formation where the oil is located will help you understand the harsh conditions in which ESPs operate.

Rock formations

There are three types of rock formations: igneous, sedimentary, and metamorphic. Igneous rock is formed by the cooling of magma deep inside the earth's crust. An example is granite, a very hard and impermeable rock. Sedimentary rock is composed of materials that were transported by wind or water. Examples of this type of rock are sandstone, shale, and limestone. Layers of sedimentary rock form what is called "strata." Metamorphic rock is, in simple terms, a rock derived from pre-existing rocks. Both igneous and sedimentary rocks can "morph" into metamorphic rock after pressure and heat from the Earth is applied to them.

Oil was formed from dead organisms in ancient seas between 10 million and 600 million years ago. As the organisms fell to the sea floor, some were absorbed by the sediments at the bottom. The heat and pressure deep within the earth turned the organic matter into crude oil and natural gas. The rock formations that hold these hydrocarbons are referred to as "reservoirs."

Contrary to what most people think, oil reservoirs are not pools or lakes of oil beneath the earth's surface. In actuality, the oil is found in tiny pores within the rocks. The porosity of a rock refers to the ratio of empty space to the volume of rock in a formation. "Permeability" refers to the ease of which fluid flows through the connecting pore spaces of a rock formation. A highly permeable and porous formation makes a good oil reservoir.

Hydrocarbons

A hydrocarbon is an organic compound consisting entirely of hydrogen and carbon. The majority of hydrocarbons found naturally occur in crude oil. Hydrocarbons are located in the sedimentary rock formation. Oil reserves in sedimentary formations are the principal source of hydrocarbons for the energy, transportation, and petrochemical industries.

Hydrocarbons are initially contained in a source rock. Over a period of time, hydrocarbons migrate upward. The migration route is simply the permeable path in rock through which the oil and gas can move from source rock to cap. Figure 1-2 illustrates how the hydrocarbons continue to migrate upward until they reach the cap rock, an impermeable rock that stops upward

movement. Oil reservoirs are formed when enough hydrocarbons are trapped under a cap rock. The rock that the hydrocarbons are trapped in is referred to as the “reservoir rock.”

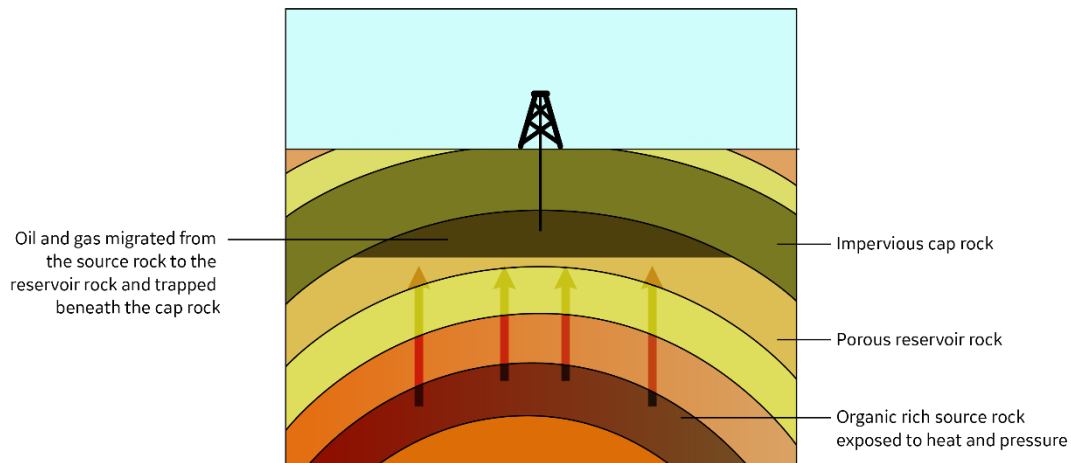


Figure 1-2: Migration of oil in formation

The life cycle of a well

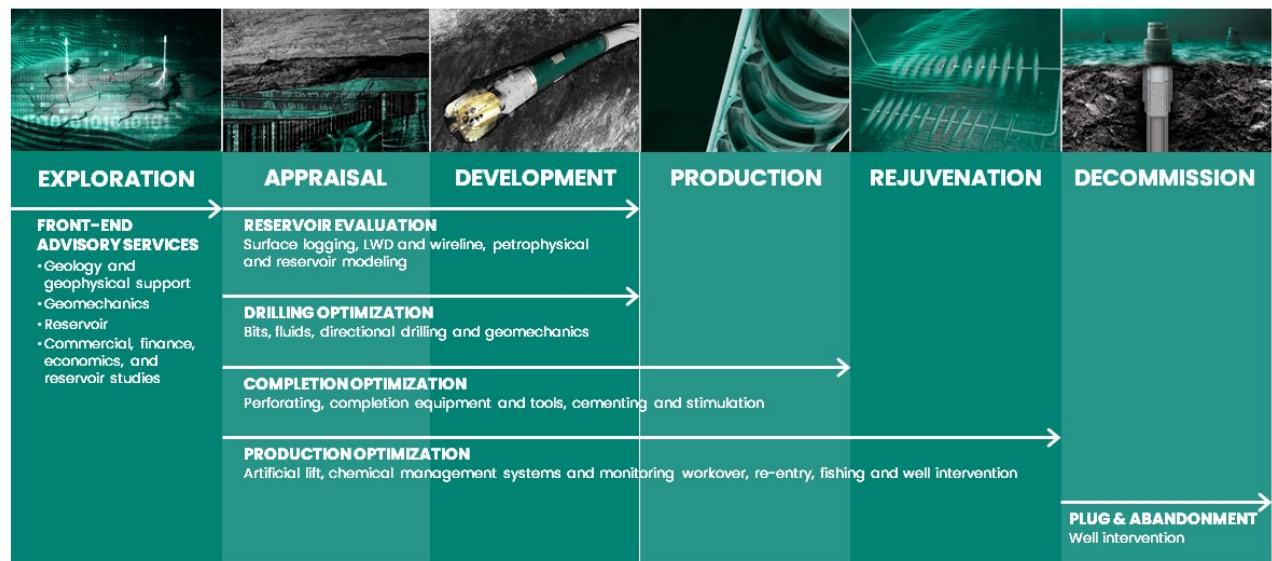


Figure 1-3: The Baker Hughes Oilfield Services portfolio spans the life cycle of a well.

Exploration: Front-end advisory services

The purpose of exploration is to find reservoirs that contain hydrocarbons for oil and gas extraction.

Seismic technique

Seismic technology creates shock waves that are radiated downward through the Earth's surface. The shock waves pass through rock layers and are reflected back to the surface. Geophysicists read the seismographs (charts which contain the seismic data) and decide if the conditions are favorable for the existence of a reservoir.

Appraisal and development: Reservoir evaluation and drilling optimization

Once a prospective location for an oil well is determined and the land has been prepared, holes are drilled to confirm the presence of hydrocarbons and facilitate hydrocarbon extraction. The well is created by drilling a hole that is anywhere from 5 to 36 in. (127.0 mm to 914.4 mm) diameter into the Earth using a drilling rig, which rotates a drill bit. Baker Hughes provides innovative and technically advanced drill bits made of durable materials.

During the drilling process, drilling fluids (also called "mud") are required to clean the bottom of the well, transport rock cuttings to the surface, cool and lubricate the drill bit, and reduce downhole friction. By reducing downhole friction, the drilling process is made more efficient. Baker Hughes provides environmentally friendly drilling fluids.

When drilling, it may not always be possible to reach the reservoir by drilling straight down. Many wells deviate from a vertical orientation and terminate with a long horizontal, or near horizontal section. Baker Hughes provides products that enable wells to be directionally drilled along complex 3-dimensional paths. In some cases in which the wells have an angle with the ground from the starting point, the wells are known as "slant wells." They are drilled with Slant Rigs.

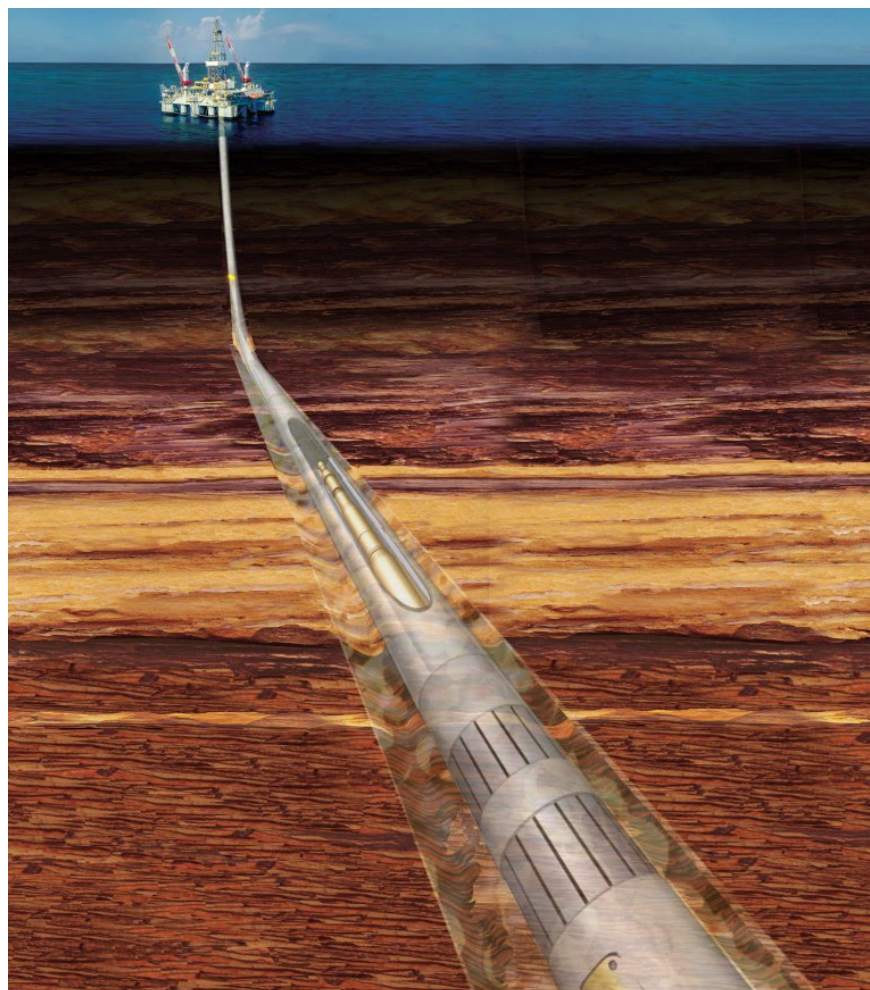


Figure 1-4: **aXcelerate™ high-speed telemetry**

Oil well depths vary based on the location of reservoir rocks. Most wells are between 7,000 and 20,000 ft.; however, some have been drilled to nearly 40,000 ft.

Evaluation

The evaluation process determines if the well has found economically producible hydrocarbons. Then the decision is made to either produce hydrocarbons or plug the well. While drilling, records are kept of the geologic formations penetrated by the drill. This process is known as well logging. Well logging provides information that helps find and quantify the amount of oil and gas in reservoirs. During the evaluation phase, Baker Hughes products and advanced technologies are used in well logging to help oil and gas producers evaluate their reservoirs. Baker Hughes gathers measurements regarding resistivity and porosity using natural gamma radiation to evaluate the reservoir.

Baker Hughes uses surface logging systems, coring services, drilling engineering services, well site data processing, and communications and geoscience services to evaluate formations surrounding a reservoir.

Wireline logging employs an electrical cable to lower tools into the borehole and to transmit data. A wireline is a metal line with a gauge attached to the end, which can be run into the borehole. The gauge records information that is sent to the surface. By interpreting this data, the logging specialist can evaluate formations and determine if the existence of a reservoir is likely.

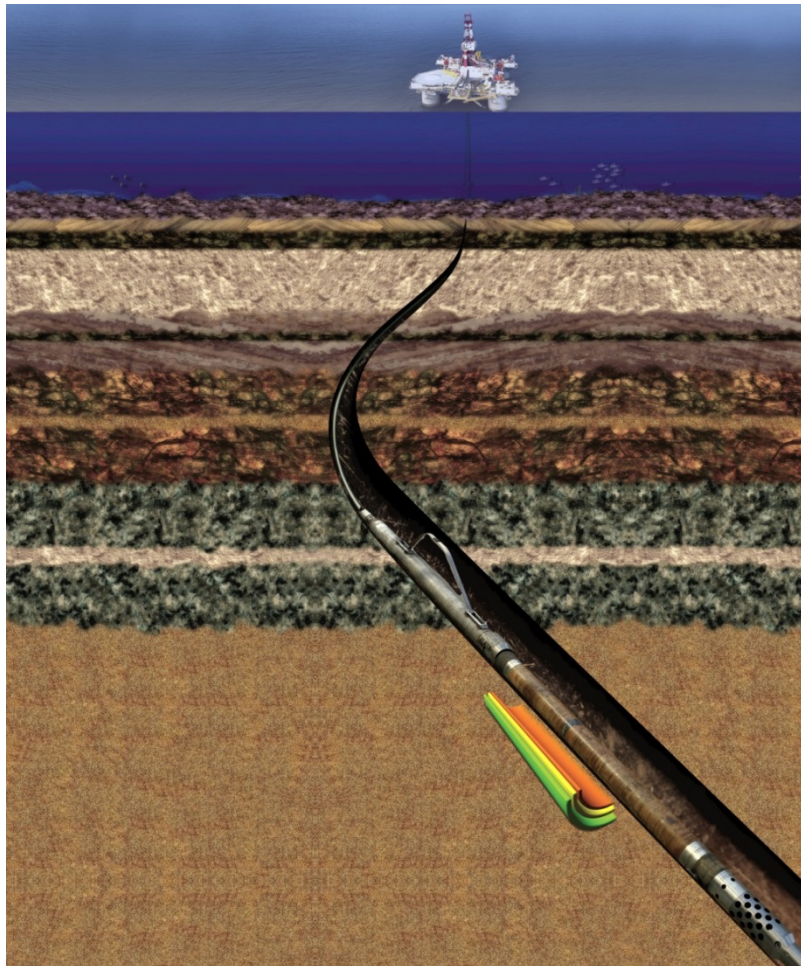


Figure 1-5: **MREX™ wireline logging tool**

Appraisal, development and production: Completion optimization

The completion phase includes the activities and methods of preparing a well to produce oil and gas. Logging information gathered by Baker Hughes is used in the completion process to prepare the well for production. During completion, Baker Hughes provides equipment to case, cement, and perforate the well. All these stages are important to the final production of a well.

Casing

After the hole is drilled, a steel pipe or “casing” slightly smaller than the hole is placed in the hole and secured with cement. The casing provides structural integrity to the newly drilled wellbore and protects surrounding formations such as freshwater reserves from being polluted, so that the well can be drilled deeper.

Cementing

Cement is used to bond casing to the walls of the borehole and to prevent fluid from migrating between permeable zones. The cement is pumped to the bottom of the well and rises upwards between the casing and borehole.

Perforating

Once the drilling process reaches its final depth a perforating gun is lowered into the well and fired to create holes in the casing, cement, and formation, allowing fluids to flow into the well (Figure 1-6).

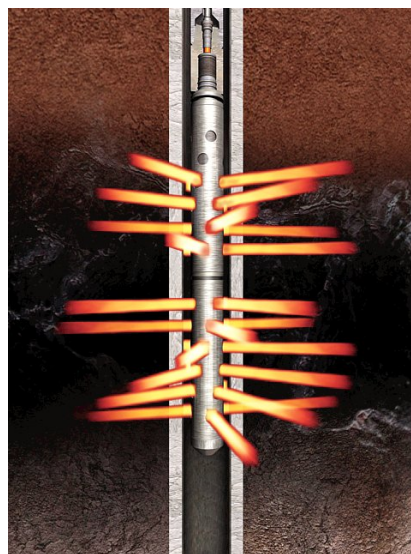


Figure 1-6: Perforating gun

Open Hole

Another practice to produce the reservoir is to leave the producing zone as open hole, without casing, based on the integrity of the formation.

Appraisal, development, production and rejuvenation: Production optimization

Production is the process of bringing hydrocarbons to the surface. By this time, the drilling rig has been removed and replaced by a wellhead. A wellhead (Figure 1-7) is a collection of valves that regulate pressures, control flow, and allow access to the wellbore in case further completion work is needed. The wellhead is commonly referred to as a “Christmas tree.”



Figure 1-7: Wellhead

When there is sufficient pressure in the reservoir, the hydrocarbons can naturally surface. When the energy declines or is low, an artificial lift method is used. The artificial lift method provides additional energy or pressure to increase the flow of well fluids to the surface. Examples of artificial lift include rod pumps, gas lift, and electrical submersible pumping systems. Artificial lift is needed

in wells when there is insufficient pressure in the reservoir to lift the liquid to the surface, but is often used in naturally flowing wells to increase the flow rate. Artificial lift is discussed in more depth in Section 2.

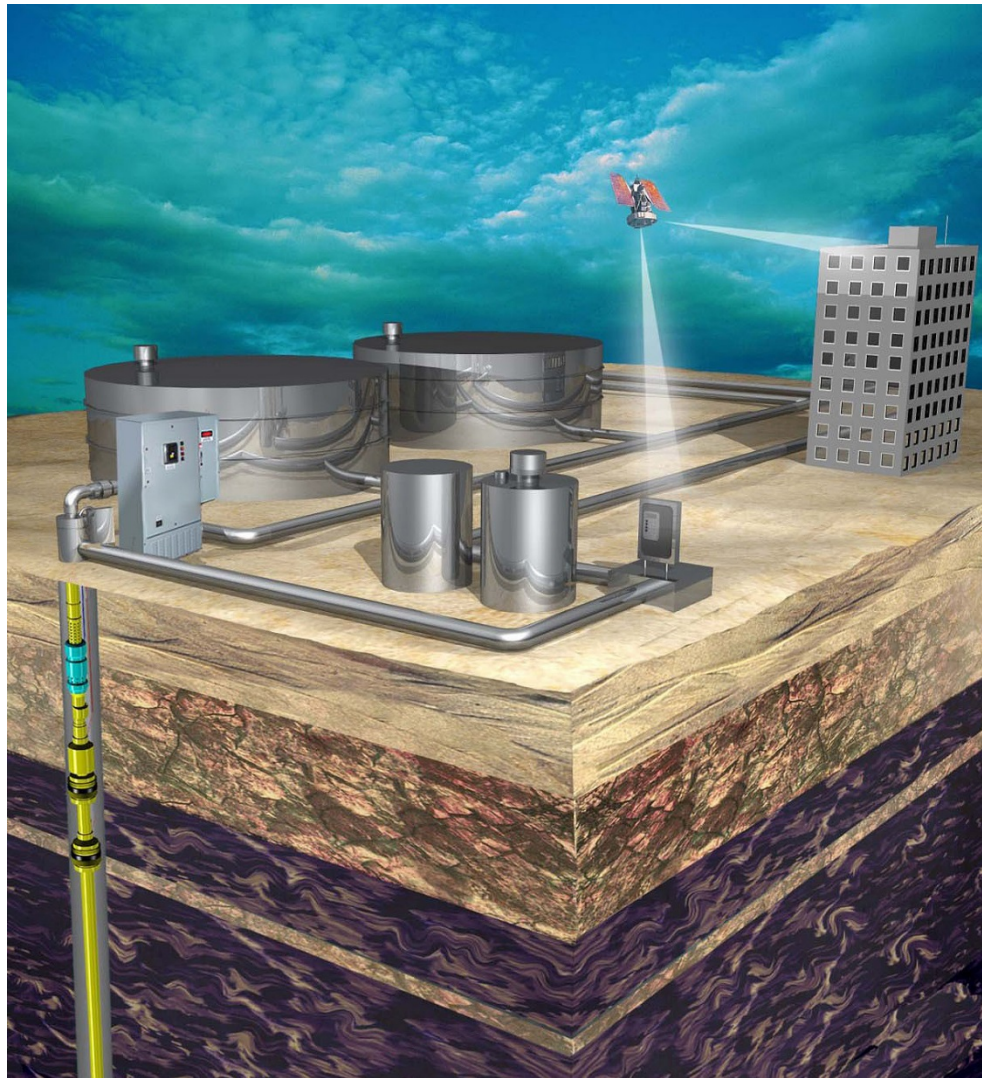


Figure 1-8: Baker Hughes well monitoring

Among other artificial lift methods, Baker Hughes provides electrical submersible pumping (ESP) systems to recover the production fluids. Baker Hughes is the only provider that designs and manufactures the complete ESP system. Baker Hughes provides oilfield chemical programs for well stimulation, production, and maintenance reduction. Baker Hughes is focused on providing technically advanced, value-adding production optimization products and services that help

operators accelerate production, increase the ultimate rate of recovery, and reduce the total cost of ownership.

Figure 1-8 shows how Baker Hughes can monitor the wellsite. Wellbore monitoring provides an early warning system to detect any issues that arise inside the wellbore. This early detection enables wells to be kept in production longer. This increases production performance and reduces the lifting cost.

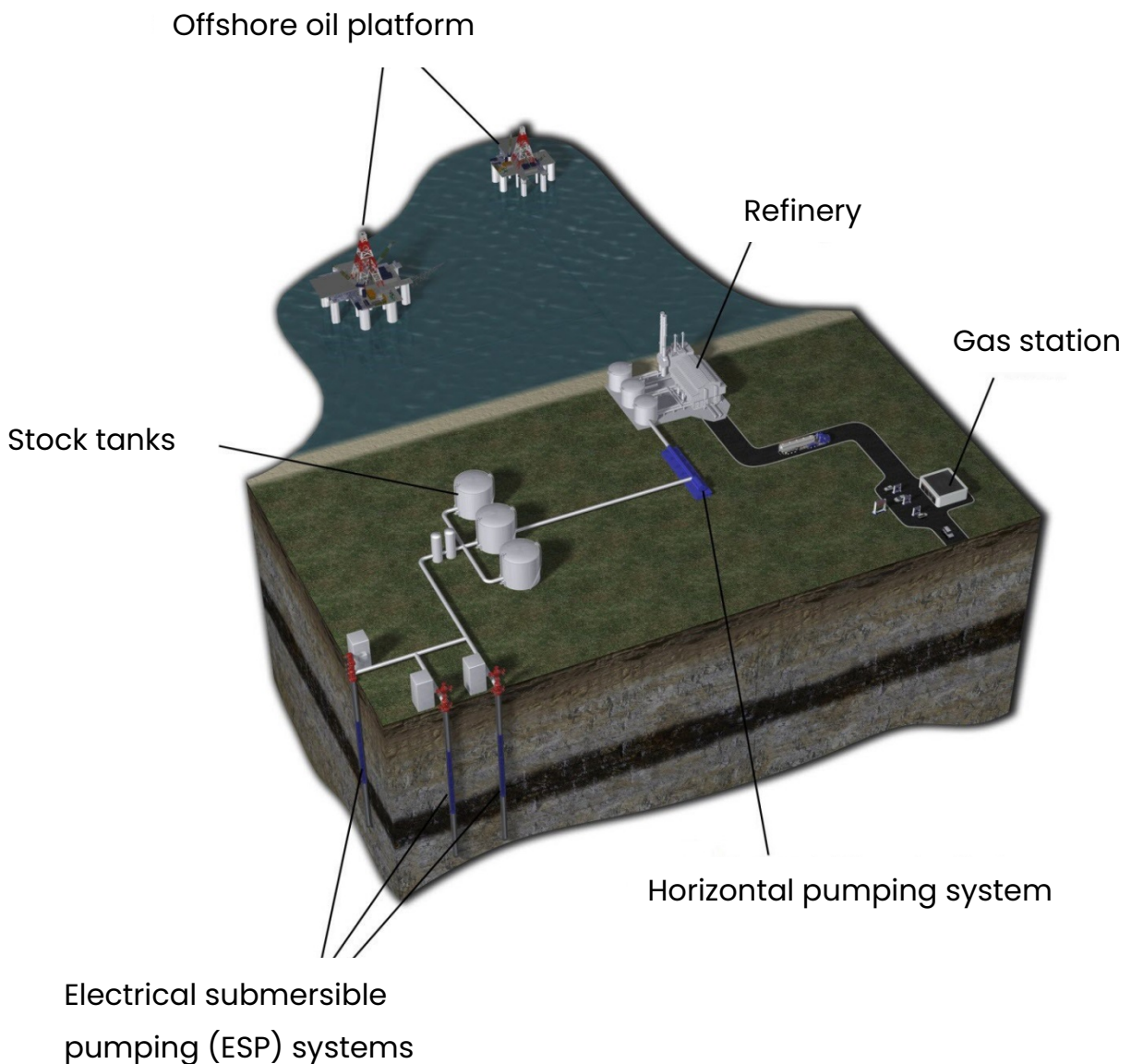


Figure 1-9: Oil production illustration

Refining

Raw or unprocessed oil is not useful when it comes out of the ground. For most of its uses, oil needs to be separated and refined. This process happens at a refinery. Refineries are large industrial complexes that process and refine crude oil into petroleum products. Once crude oil is brought to the surface, it is transported from the field to the refinery in a variety of ways. Tank trucks, railroad tank cars, and barges are used to transport the petroleum to some extent, but pipelines are the dominant mode of transportation. Refineries use heat, pressure, or other catalysts to refine the crude oil into products such as gasoline, diesel, and kerosene.

Petroleum-based products

Refined petroleum products go to market as fuel or many everyday objects that we use. The main groups of petrochemical end products are plastics, synthetic fibers, synthetic rubbers, detergents, and chemical fertilizers. The American Petroleum Institute came up with a list including more than 130 products. Perfumes, trash bags, ice chests, paintbrushes, sunglasses, umbrellas, roofing, and cosmetics are just a few examples. Life as we know it today would be extremely difficult without crude oil and its byproducts.

Notes:

Chapter 2

The Geothermal industry

As the world continues its efforts to decarbonize its economy and energy generation, the spotlight is naturally moving toward renewable and green energy. One method of renewable energy that is rapidly expanding around the world is the use of geothermal energy. By definition, “geothermal” simply refers to the natural heat of the earth that is generated by either magmatic and volcanic activity, or the natural radioactive decay happening within the crust. The idea of using geothermal heat is certainly not new, but up until the early 1900s, geothermal water flowing to the surface was only used for bathing and medicinal purposes. In 1904, the first geothermal power generator was built in Larderello, Italy, and was able to power four light bulbs. A power station was built there seven years later. Today, the heat from geothermal resources is extracted from the crust via high-temperature water/brine or steam.



Figure 2-1

Exploration methods for geothermal resources closely mirror that which are used for oil and gas resources. When searching for new fields to produce from, there can sometimes be surface features indicating a hot reservoir below ground. Some examples of these are hot water geysers, geothermal hot water pools, steam vents and/or the smell hydrogen sulfide (similar to rotten eggs), which is common in geothermal applications. Whereas oil and gas reservoirs have a finite amount of resource that can be produced, geothermal reservoirs typically benefit from resource

recharge from one of more of the following methods: a pre-existing aquifers, oceanic fluid ingress or brine reinjection.

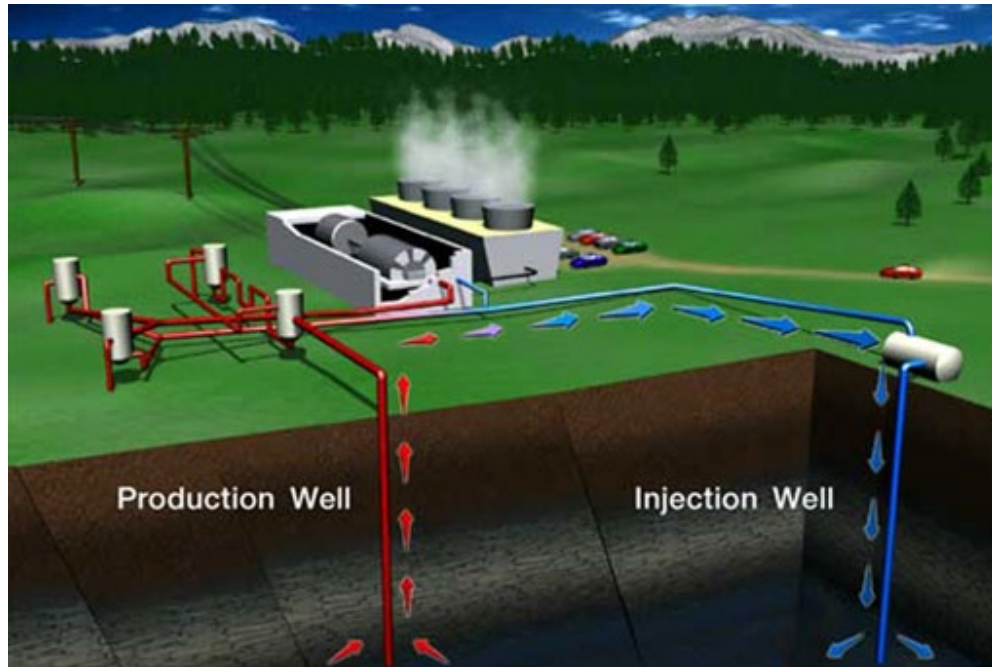


Figure 2-2

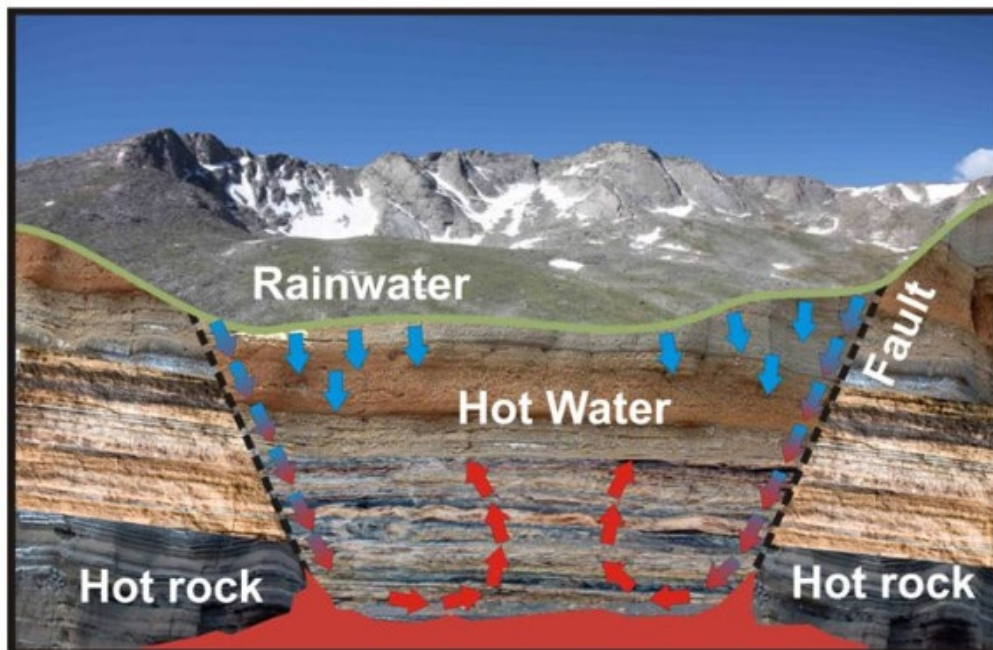


Figure 2-3

Once produced, the heat from the fluid is used in a variety of applications including power generation, residential heating, timber drying, greenhouse heating, and bathing, among other things.

Much like in the oil and gas industry, most of the artisanal geothermal sources, the “low hanging fruit,” have already been exploited. Also similar to the oil and gas industry, there is an incredible amount of opportunity for geothermal systems that are produced artificially. The primary method of artificially producing geothermal resources is with an ESP. Baker Hughes is the only service company with an ESP large enough to produce the massive volumes of water needed by geothermal operators.

One major difference in the design of geothermal wells is the need for large-diameter wellbores, typically using 13 3/8-in. casing. These large production wells make it possible to produce a greater volume of fluid can be produced – but they also have the disadvantage of high drilling costs. The other advantage of large casing diameters is the ability to set larger and more power ESPs downhole. Overall, geothermal projects tend to have a large up-front capital cost but low operating cost over the life of the well. It is as if one is buying 30 years of “fuel” all at once.

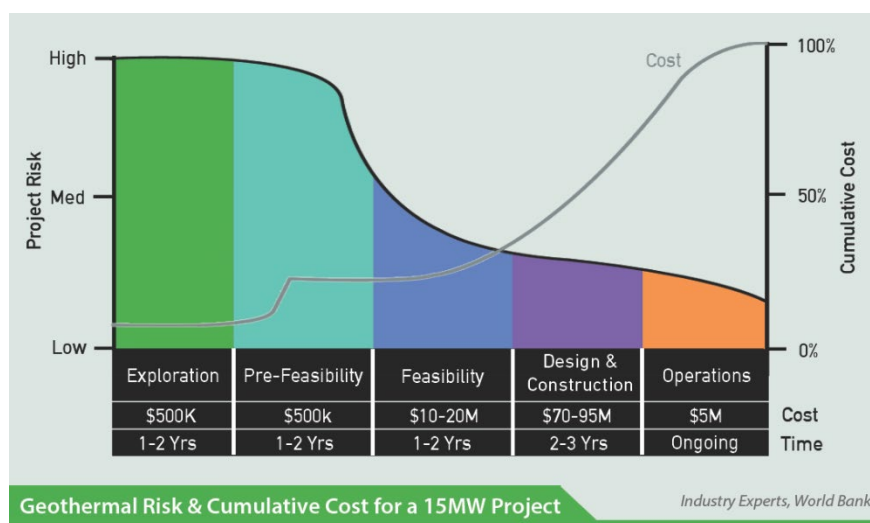


Figure 2-4

Baker Hughes operates its Center for Geothermal Excellence out of Celle, Germany. There, the research into geothermal ESP development has resulted in the most robust line of downhole geothermal pumps that the industry has to offer. Research at this facility is partially subsidized by the German government.

Chapter 3

Baker Hughes Oilfield Services product lines

Baker Hughes Oilfield Services helps operators maximize return on investment by enabling them to:

- Lower capital expenditures during exploration and development
- Minimize operational expenditures during production
- Keep pipelines and process plants operating at peak efficiency

The product lines which comprise the Oilfield Services portfolio deliver:

- **Quality**, through precisely placed wells, optimized completions and maximum production flow.
- **Efficiency**, through rapid well construction, fewer personnel on-site, and greater recovery from fewer wells drilled
- **Consistency**, from safe and predictable operations, lower HSE risks, and minimized production downtime

Drill Bits

The Drill Bits product line helps operators to:

- Drill faster and farther in efficient, uninterrupted drilling runs
- Reduce drilling cost-per-foot in every application

Product categories

- Polycrystalline diamond compact (PDC) drill bits
- Roller cone drill bits
- Hybrid drill bits
- Digital and in-bit sensing

Drilling and Completion Fluids

The Drilling and Completion Fluids product lines helps operators to:

- Safeguard against excessive drilling risks and costs by ensuring wellbore stability
- Drive drilling operations through fluid flow for downhole power and reliable hole-cleaning
- Improve drilling speed by cooling and lubricating the drill bit, bottomhole assembly and drill pipe

Product categories

- Emulsion fluids
- Water-based fluids
- Specialty drilling fluids
- Drill-in fluids
- Waste management
- Completion fluids

Drilling Services

The Drilling Services product line helps operators to:

- Quickly and precisely place wells in the most productive portions of the reservoir
- Improve drilling performance and reservoir knowledge by capturing critical downhole data
- Support safe, predictable wellsite operations by monitoring real-time drilling and formation data

Product categories

- Directional drilling systems
- Logging-while-drilling and coring systems
- Surface logging systems
- Digital and remote operations

Reservoir Technical Services

The Reservoir Technical Services product lines helps operators to:

- Understand the subsurface challenges in hydrocarbon-producing basins globally
- Design strategies and implement programs to maximize the value of the asset

Core competencies

- Geoscience
- Well integrity and corrosion analysis
- Formation evaluation

- Petroleum engineering
- Digital
- Geology
- Product knowledge

Wireline Services

The Wirelines Services product line helps operators to:

- Find and book more reserves
- Confirm well integrity to protect people and the environment
- Identify and address production issues to keep more oil flowing longer

Product categories

- Openhole logging services
- Cased-hole logging services
- Perforating and drill stem testing services

Completions and Well Intervention

The Completions and Well Intervention product line helps operators to:

- Construct dependable pathways engineered to last the life of the well
- Minimize production risks while maximizing oil and gas flow
- Capture accurate downhole data
- Limit downtime during well interventions

Product categories

- Wellbore construction
- Upper completions and lower completions
- Unconventional multistage completions
- Intelligent production systems
- Gas lift systems
- Workover systems
- Fishing services
- Thru-tubing intervention

Pressure Pumping (outside the USA)

Outside of the USA, the Pressure Pumping product line helps operators to:

- Support safe operations and protect the environment by constructing dependable barriers
- Maximize oil and gas recovery by stimulating reservoirs and increasing access to proven reserves
- Improve production with workovers and wellbore cleanouts

Product categories

- Production enhancement services
- Cementing services
- Coiled tubing services
- Tubular services

Artificial Lift Systems

The Artificial Lift Systems product line helps operators to:

- Maintain production flow and maximize recovery for the life of a well
- Limit production interruptions
- Extend a well's economic life by monitoring well conditions and optimizing operational parameters

Product categories

- Electrical submersible pumping systems
- Surface pumping systems

Oilfield and Industrial Chemicals

The Oilfield and Industrial Chemicals product line helps operators to:

- Maximize production flow and recovery for the life of a well
- Protect against production interruptions and extend a well's economic life
- Increase downstream operational efficiency, improve plant safety and equipment reliability

Product categories

- Upstream chemicals
- Downstream chemicals
- Specialty polymers

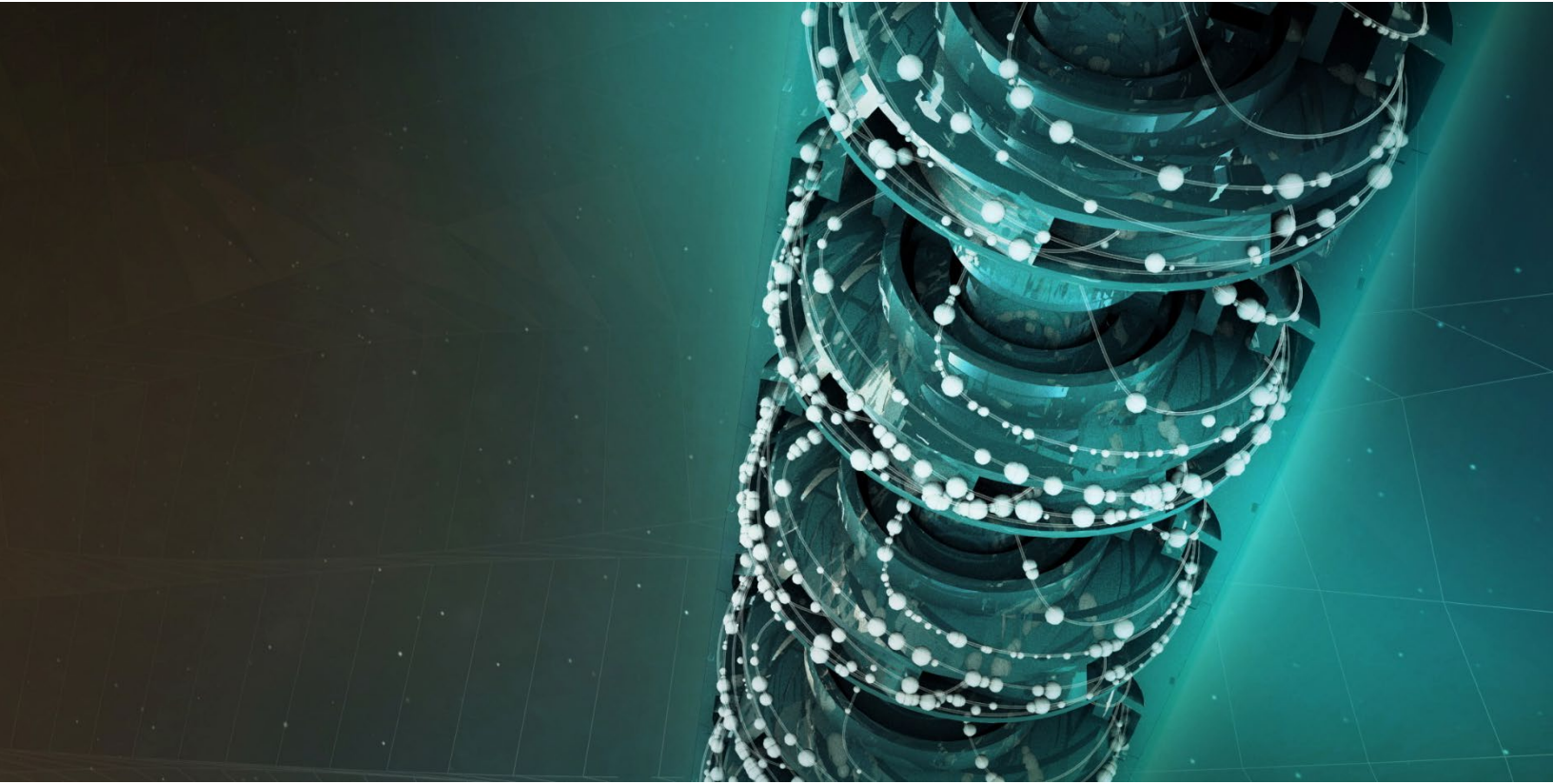
Integrated Well Services

The Integrated Well Services product line helps operators to:

- Lower total cost of ownership through an unmatched HSE focus and full alignment with goals, objectives, and KPIs
- Deliver lean operations with a focus on efficiency and repeatability
- Support optimized operations and flawless execution via detailed planning and leveraging digitalization and automation
- Maximize value creation by offering flexible commercial models

Core competencies

- Well construction
- Well engineering
- Risk management
- Project management
- Field supervision
- Contractor management



Section 2:

ESP downhole equipment

Chapter 4: Electrical submersible pumping systems

Chapter 5: ESP system pumps

Chapter 6: Gas handler

Chapter 7: Gas separator

Chapter 8: Seal

Chapter 9: Motor

Chapter 10: ESP cable

Notes:

Chapter 4

Electrical submersible pumping systems

Purpose

Baker Hughes electrical submersible pumping (ESP) systems (Figure 3-1) are state-of-the-art artificial lift systems designed to lift large amounts of fluid from oil and water reservoirs. Baker Hughes designs and manufactures ESP systems that are built for performance and reliability in a wide range of applications. Applications include conventional, unconventional, harsh gas environments, high temperature, and offshore/subsea.

Over the years, Baker Hughes, in partnership with major oil companies, has designed, engineered, and manufactured ESP technology that lasts longer and pumps more fluid. Baker Hughes ESP systems perform in previously impossible well conditions, producing well fluids in even the following extreme environments:

- Extreme temperatures
- High gas
- High viscosity
- Abrasive
- Corrosives
- Highly deviated/horizontal wells

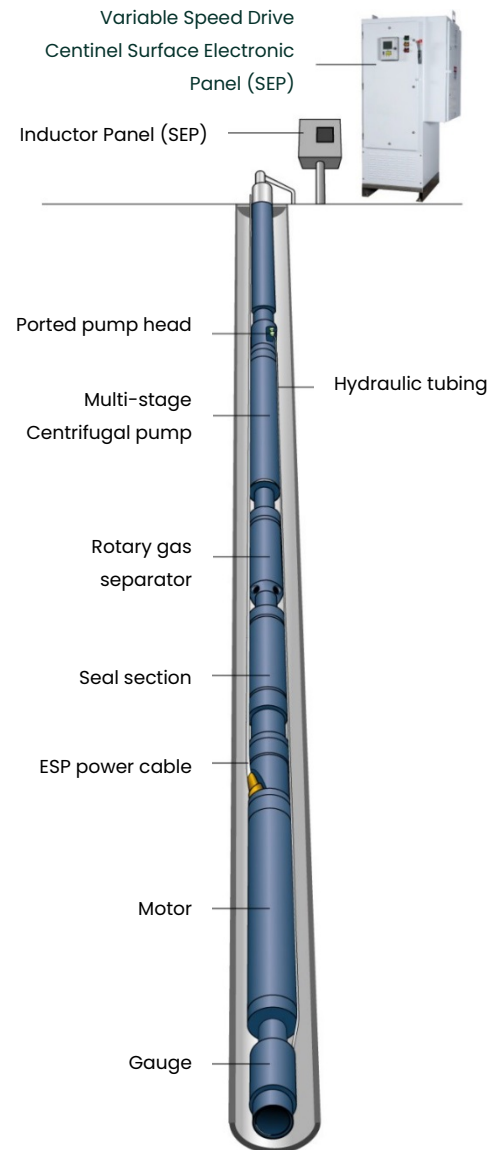


Figure 3-1:
Electrical submersible
pumping system

Components

ESP systems (Figure 3-2) include all the necessary components to transfer power from the surface, convert the power into shaft rotation, and impart energy to the produced fluids. ESP system components are custom-manufactured based on customers' well data and application requirements. They are manufactured in modular sections in a standardized set of diameters and lengths. Each component is typically less than 40 feet in length to enable transportation to the field. The modular system uses tandem sections to allow for longer length systems. If well conditions and production requirements require a longer system, two tandem systems are connected together in the field. A typical ESP system includes:

- Multi-stage centrifugal pump
- Intake/gas separator
- Seals section
- Electric motor
- Power cable
- Motor lead extension
- Motor controller
- Downhole sensor

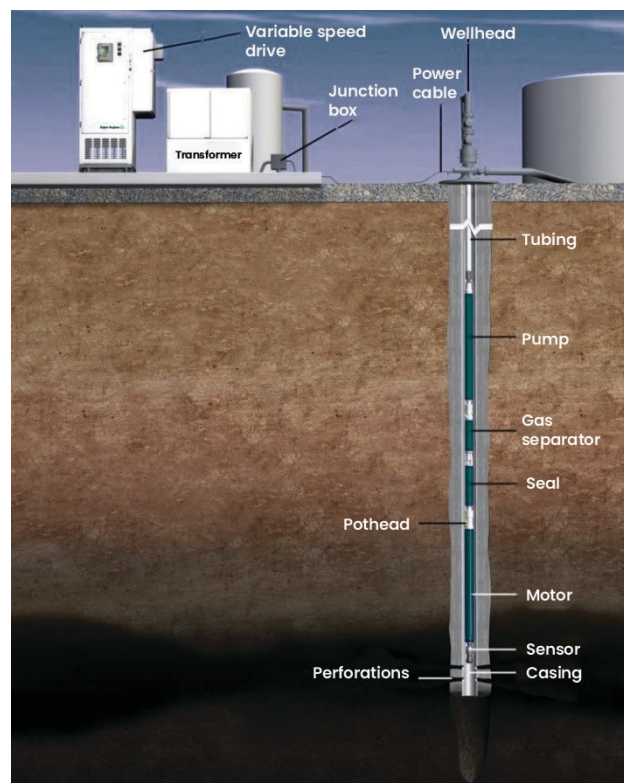


Figure 3-2: ESP system components

Support equipment

Additional support equipment is required at most wellsites. The support equipment necessary depends on the power available and the conditions of the well.

Transformer

Electrical power is usually distributed to oilfields at an intermediate voltage (6,000 volts or higher). Because ESP equipment operates at voltages between 250 and 4,000 volts, voltage transformation is required.

Transformers are available in either three single-phase units or a single three-phase configuration. Transformers used in the oilfield are oil-filled, self-cooled units. They contain a substantial number of secondary voltage taps, which allows a wide range of output voltages. Multiple transformer voltage settings are required to adjust the surface voltage to account for the range of cable voltage drops that occurs due to varying application setting depths.

Junction box

A junction box (vent box) performs three functions:

- It provides a point to connect the power cable from the controller to the power cable from the well
- It provides a vent to the atmosphere for gas that might migrate through the submersible power cable
- It allows for easily accessible test points for electrical checks of the downhole equipment.

Wellhead

The wellhead supports the weight of the subsurface equipment and maintains surface annular pressure of the well. It must be equipped with a tubing head bonnet or pack-off to provide a positive seal around the cable (or feed-through mandrel) and the tubing.

Check valve and drain valve

When an ESP turns off, the fluid in the production tubing will fall back down through the ESP system. As the fluid flow reverses through the pump, it causes reverse pump rotation. If the unit is turned on while the pump is in reverse rotation, it can cause electrical failure or mechanical damage to the equipment. A check valve installed two to three joints above the pump prevents fluid from reverse flowing through the ESP system, eliminating the associated risk of operating during

backspin. If a check valve is not used, sufficient time must be allowed for fluids to drain through the pump before the motor is restarted. A minimum of 30 minutes is recommended for most wells. A drain valve installation is recommended above a check valve to prevent pulling a wet tubing string. A drain valve installed alone is unnecessary, as the fluid in the tubing will drain through the pump during pull operations.

Note for backspin relay: *In some ESP applications, the installation of a check valve would be impractical; for example, if the well contains high amounts of scale, sand, or asphaltenes, it may be desirable to pump produced fluids, acids, or other chemicals down the tubing. These solutions would not be possible with a check valve installed in the tubing string. Instead, an electronic back-spin relay utilizes reading from the power cable to determine if the ESP system has mechanical rotation. The back-spin relay unit detects power generated by the motor due to shaft rotation. Since the unit is installed in the controller, it prevents the controller from starting in the presence of shaft rotation.*

Centralizer

Centralizers are used in ESP applications to place the equipment in the center of the wellbore. This is especially useful in deviated wells to eliminate external damage and support proper cooling of the equipment. Several centralizers are designed to protect the ESP cable from mechanical damage due to friction during installation. Centralizers prevent mechanical damage to the coatings, designed to protect the motor in corrosive environments, during the installation of the equipment.

Theory of operation

ESP systems are used to produce fluid from oil and water wells. They are used to aid production when the well no longer has the energy to produce on its own or to increase production.

ESP systems are typically installed above the perforation zone, allowing fluid to flow from the perforations past the motor. This fluid movement over the motor enables heat dissipation for heat generated in the motor. ESP systems convert electrical power into hydraulic power to lift the production fluid.

The following steps outline this energy conversion

1. Production and system performance is optimized utilizing variable speed drives to change the supply power frequency and resulting ESP rotation.
2. Long runs of power cable with copper conductors connect the motor with the surface power.
3. The motor converts electrical energy into mechanical energy.
4. The mechanical energy is communicated through the ESP system to the pump impellers via the coupled shaft.

5. The rotating impellers convert mechanical energy into velocity energy.
6. The pump diffusers convert the velocity energy into head energy or hydraulic power.
Hydraulic power or work performed by the pump equals the flow rate times the pump pressure differential.

The following individual sections detail each ESP component.

Notes:

Chapter 5

ESP system pumps

Purpose

Baker Hughes ESP system pumps are multistage centrifugal pumps that convert the energy from the rotating shaft into centrifugal forces that lift well fluids to the surface. The pump is normally attached to, or hangs from, the production tubing.

Components

ESP pumps (Figure 4-1) are made up of the following basic components:

- Shaft
- Impeller
- Diffuser
- Housing

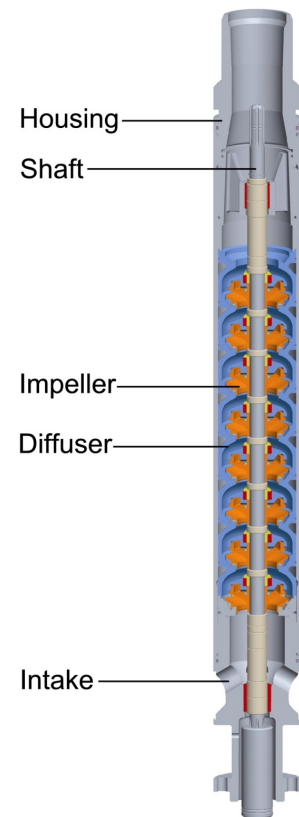


Figure 4-1: ESP pump cutaway

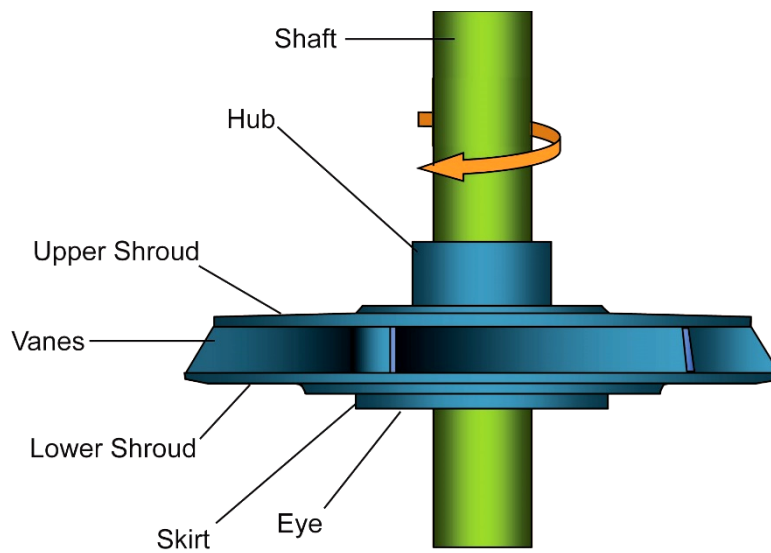


Figure 4-2: Illustration of impeller and subcomponents

Impeller

The impeller is keyed to the shaft and rotates at the motor RPM. As the impeller rotates, it imparts centrifugal force on the production fluid. Figure 4-2 is an illustration of an impeller keyed to a shaft, and identifies key sub-components of the impeller. Figure 4-3 is a cutaway illustration of a pump impeller identifying various subcomponents.

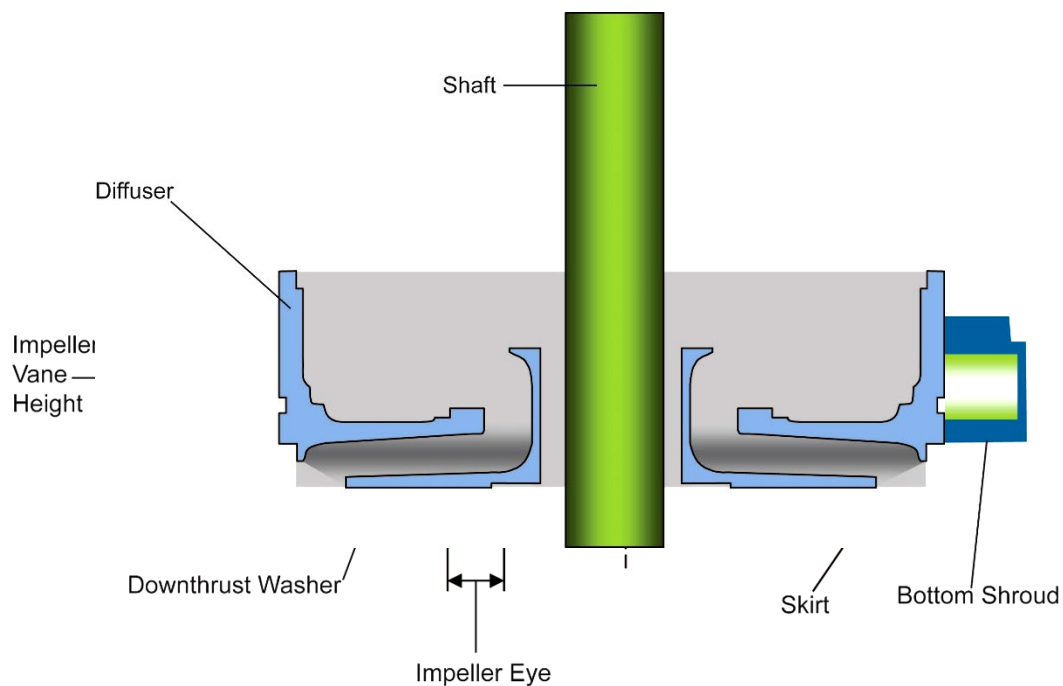


Figure 4-3: Cutaway Illustration of impeller and subcomponents

Diffuser

The diffuser (Figure 4-4) turns the fluid into the next impeller and does not rotate.

Pump stage

A pump stage is formed by combining an impeller and a diffuser. Figure 4-5 is an illustration of a pump stage cutaway, showing the impeller mated to the diffuser, the fluid flow path, and shaft rotation. Figure 4-6 is a photograph of a Baker Hughes pump stage.

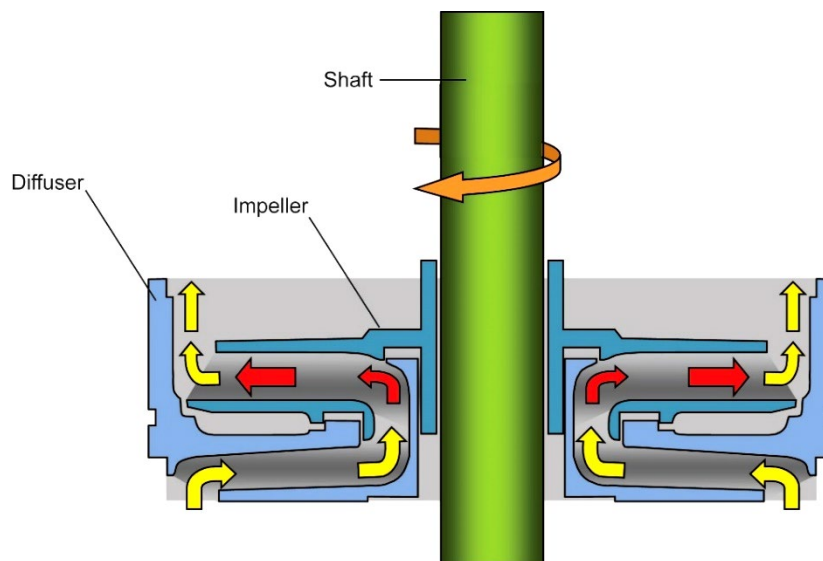


Figure 4-5: Illustration of a pump stage (Impeller and diffuser)

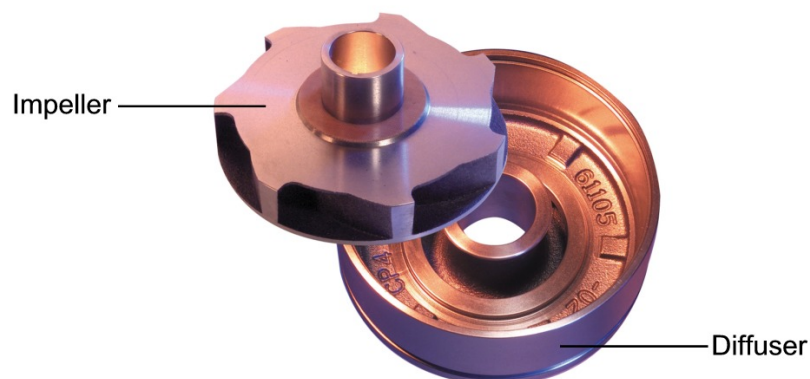


Figure 4-6: Baker Hughes pump stage (impeller and diffuser)

Shaft

The pump shaft is connected to the motor (through the gas separator and seal section) and spins with the RPM of the motor. Figure 4-7 is a cutaway of an assembled Baker Hughes pump stage with the shaft and optional abrasive resistant bearings.

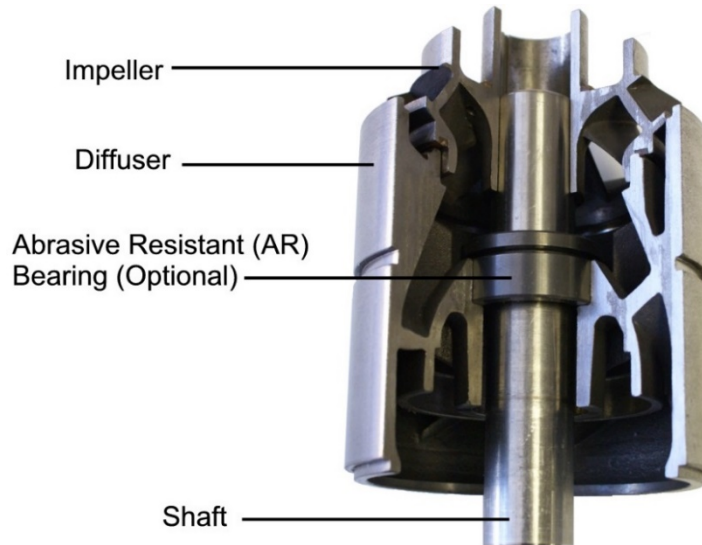


Figure 4-7: Shaft and pump stage cutaway

Intake

The pump intake (Figure 4-8) attaches to the lower end of the pump housing and provides a passageway for fluids to enter and a flange to attach to the ESP seal.



Figure 4-8: Pump intake

Theory of operation

Baker Hughes manufactures multiple stage (rotating impeller and stationary diffuser) centrifugal pumps. As the impeller spins it imparts centrifugal force to the fluid and increases the velocity. This is indicated by the red arrows in Figure 4-9.

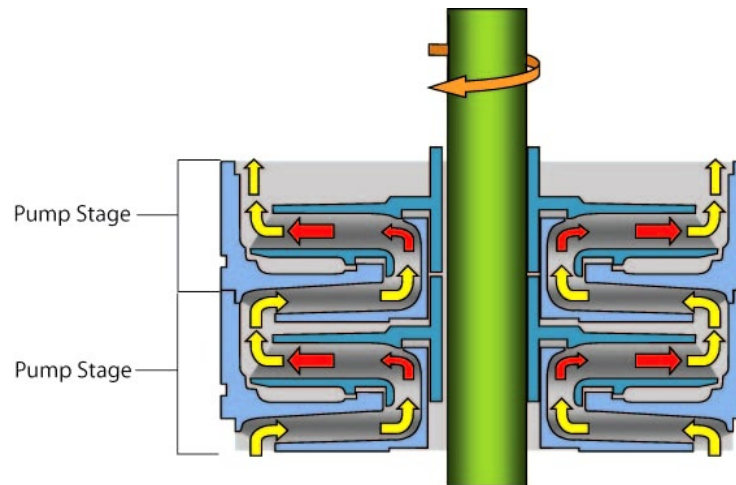


Figure 4-9: Direction of flow-through stages

The diffuser then directs the fluid into the impeller above it (indicated by the yellow arrows) and changes the velocity energy into head energy or "lift."

Radial and mixed flow hydraulic designs

The design of submersible centrifugal pump stages falls into two general categories: radial and mixed flow design. As illustrated in Figure 4-10, the smaller flow pumps are generally of radial flow design, and the higher flow rate pumps are mixed flow design. On the radial flow design, flow through the impeller travels in mostly a radial direction or perpendicular to the axis of the shaft; on the mixed flow design, the fluid travels through the stage in both an axial (parallel to the axis of the shaft) and radial direction.



Figure 4-10: Radial stage (left) and mixed flow stage (right) design pump stage

In many of the pump designs, the impeller is free to float axially on the shaft. The impellers are free to operate in the space between the diffuser, above and below it. The actual position during operation is a function of the stage design vs. the actual flow rate of the stage (which will be discussed later). In a floating stage pump design, the thrust of the individual impeller stage is absorbed on specially designed pads found on the diffuser. The thrust bearing contained in the seal section carries only the thrust of the pump shaft. This configuration is called a floating stage design. The benefit of this design is that many stages can be stacked together without having to fix the impellers axially on the shaft with precise alignment.

In compression pump designs, impellers are locked to the pump shaft in the axial direction. As a result, the thrust bearing contained in the seal section must carry the impeller thrust in addition to shaft thrust. This configuration is referred to as a fixed impeller or compression pump design.

The impellers are of a fully enclosed curved vane design, whose maximum efficiency is a function of impeller design and whose operating efficiency is a function of the percent of design capacity at which the pump is operated. The mathematical relationship between head, capacity, efficiency, and brake horsepower is expressed as:

$$BHP = \frac{Q \times H \times \text{Specific Gravity}}{\text{Pump Efficiency}}$$

Where: Q = Volume
 H = Head

Centrifugal pump hydraulics

Head or lift

Head is a measure of the pressure or force exerted by the fluid. Head is typically measured in feet but can be converted to PSI. Each stage creates a certain amount of head in order to lift the fluid to the surface. Head is created by utilizing the power created by the motor and transferred through the shaft. The impeller rotates at the same speed of the shaft and imparts centrifugal energy to the fluid. The impeller forces the fluid to the outside of the stage where it exits the impeller and enters the diffuser of the next stage in the stack. The diffuser then redirects the fluid up into the next impeller, and the process repeats. The head one stage produces is the net of the energy imparted by the impeller and the energy lost while passing through the diffuser. The head that one stage develops can then be multiplied by the number of stages to determine the total head a pump will deliver.

The discharge rate of a submersible centrifugal pump depends on the rotational speed (rpm), stage design, the dynamic head against which the pump is operating, and the physical properties of the fluid being pumped. The total dynamic head of the pump is the product of the number of stages and the head generated by each stage. Figure 4-11 is a typical 60-hertz, single-stage, centrifugal pump performance curve showing the recommended operating range, along with other pump characteristics.

The pump has, for a standard speed and fluid viscosity, a performance curve (also referred to as a pump curve), which indicates the relationship between the head developed by the pump and flow capacity through the pump.

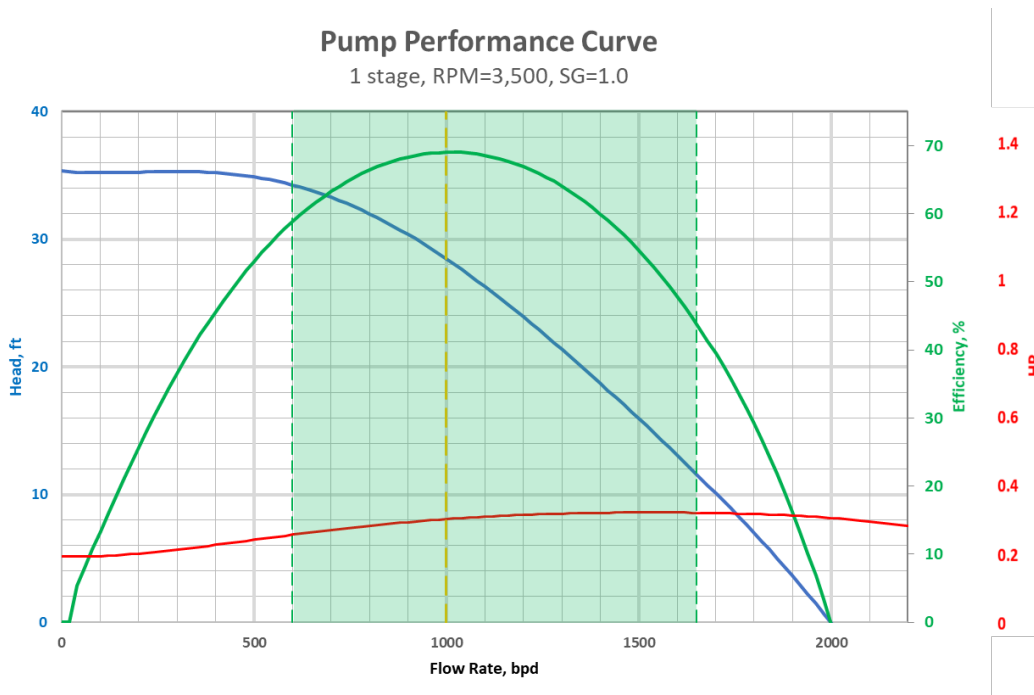


Figure 4-11: Pump curve

Pump curve

A pump curve reveals a full spectrum of pump performance characteristics including:

- Operating range
- Head capacity
- Pump efficiency
- Brake horsepower

The x-axis (flow in BPD) is the constant in each of the three curves plotted. The blue curve is head capacity, and the y-axis (head in feet) can be found to the left of the plot. The brake horsepower requirements are plotted in red. The y-axis measurement is horsepower and is located on the scale to the right of the curve (numbered in this case .5 to 2.5). The final curve, pump efficiency, is green. The y-axis is pump efficiency as a percentage, and the scale is also located to the right of the curve. The catalog pump curve is developed for one stage and assumes a specific gravity of 1.0, 3500 rpm and operation at 60 hertz. Every pump stage has its own unique pump curve based on its performance characteristics. In general, when the capacity increases, the head capacity decreases.

The highest head a pump can develop is at a point where there is no flow through the pump; that is, when the discharge valve is completely closed.

The brake horsepower (BHP) curve is plotted based on the actual performance test data. This is the actual horsepower required by the centrifugal pump, based on the same constant factors as previously discussed, to deliver the hydraulic requirement.

The efficiency of the centrifugal pump cannot be measured directly. It must be computed from test data already measured. The formula for % efficiency is:

$$\%Efficiency = \frac{Head \times Capacity \times Specific Gravity}{3,960 \times BHP}$$

Where: Head = Feet

Capacity = GPM

BHP = Brake horsepower

Each of the three parameters (head capacity, pump efficiency, and brake horsepower) can be determined for any given flow. This is done by locating the operating flow along the x-axis and following the line up to where it intersects with each of the three curves. The three points of intersection (one for each curve) are the values of head capacity, pump efficiency, and brake horsepower when producing at that rate. It is important to remember that the value is for a single stage and must be multiplied by the total number of stages in a pump.

Net positive suction head (NPSH)

Net Positive Suction Head (NPSH) is used to determine if the pressure of the liquid being pumped is adequate to avoid cavitation. The net positive suction head available (NPSHA) is the difference between the pressure at the suction of the pump and the saturation pressure for the liquid being pumped. NPSHA (available) is the net positive suction head available to a centrifugal pump intake. NPSHR (required) is the suction pressure necessary for proper pump operation. The NPSHA must be greater than or equal to NPSHR or the pump will not produce and possibly create cavitation.

Pump thrust

Pump thrust is used to describe and measure the forces acting on the components of the pump as the fluid passes through it. Pump thrust is made up of two components: shaft thrust and hydraulic thrust. The total pump thrust is the net of these two forces.

Hydraulic thrust

Total hydraulic thrust has two components: an upthrust component and a downthrust component. The upthrust component is primarily created by the velocity of the fluid as it passes through the impeller; i.e., hydraulic impact force. The downthrust is created by the pressure generated by the stage. The net of these two components make up total hydraulic thrust. The fluid characteristics, such as fluid viscosity, have an effect on hydraulic thrust.

Under normal operating conditions, fluid circulates on top and underneath the impeller shrouds. As illustrated in Figure 4-12, the pressure from the fluid acts on the upper and lower shrouds. Since the cross sectional area on the upper shroud is larger, the net force of the pressure is down. This causes the impeller to move down. This force is termed “downthrust.”

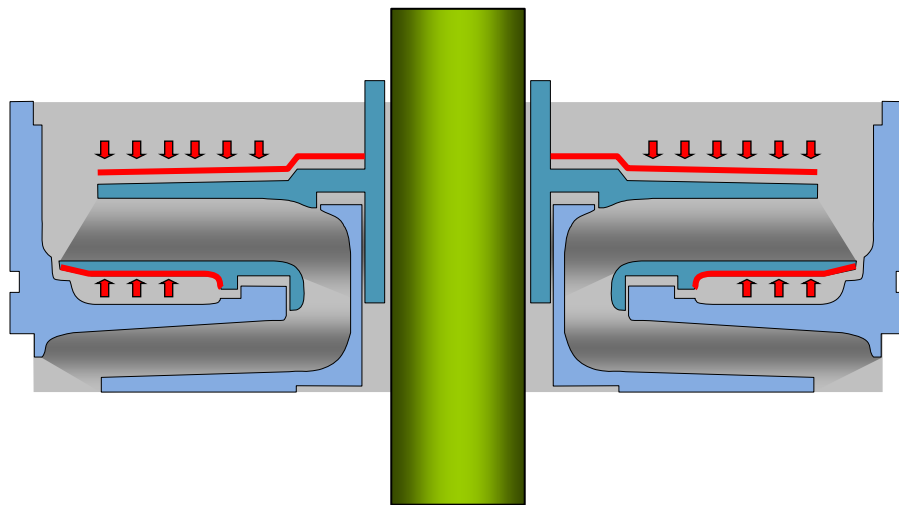


Figure 4-12: Forces acting on an impeller

Upthrust describes the force created from the speed of the fluid as it passes through the stage. While operating within the recommended range of the pump, the downthrust force is greater than the upthrust force. However, at some point the volume of fluid going up into the pump will lift the impeller up, overcoming the downthrust pressure. The downward force is now reversed (negative). It is termed “upthrust.”

Shaft thrust

There are two areas where actual thrust can be produced in a pump. The first is produced by fluid pressures (P_T and P_B) on the impeller shroud surfaces (Figure 4-13). The fluid pressure on the impeller top shroud area (A_T) produces a downward force on the impeller. The fluid pressure on the bottom shroud area (A_B) and the momentum force (F_M) of the fluid making a 90 degree turn in the inlet produces an upward force. The summation of these is called the impeller thrust force (F_I).

$$F_I = P_T A_T - P_B A_B - F_M$$

P_T and P_B are at their maximum value at shut-in (0 flow) and decline as flow rate is increased. F_M is 0 (zero) at shut-in and increases to its maximum value at the wide-open flow (maximum velocity).

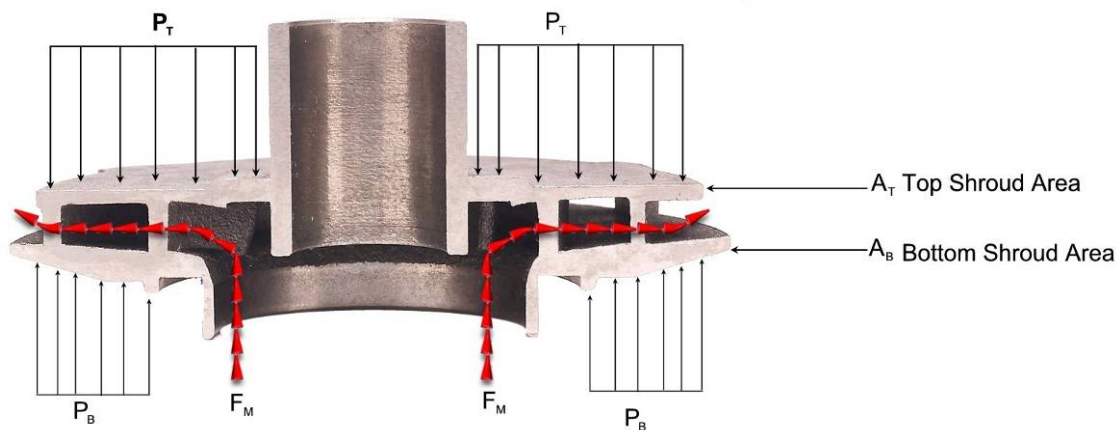


Figure 4-13: Cutaway photo of a radial stage impeller

The second is produced by fluid pressures acting on the end of the pump shaft (Figure 4-14) and is designated as shaft thrust (F_s). In this case, the pressure (P_D) produced by the pump minus pump inlet pressure (P_I) acting on the shaft area (A_s) produces a downward force (F_s).

$$F_s = (P_D - P_I) A_s$$

Fixed (or compression) vs. floating impellers

The method of handling pump thrust varies depending on the type of pump stage design. As stated previously, the fixed impeller pump stage has its impellers mounted on the shaft in such a

way that they are not allowed to slide or move axially on the shaft. The impellers are located so that they are running with a clearance between the diffuser above and below.

The floating impeller pump stage allows its impeller to move axially on the shaft and engage the thrust surfaces on the diffuser. The stage carries and absorbs the impeller thrust (F_I). The thrust is transferred through the thrust washers to the diffuser to the housing. Therefore, the seal section sees the shaft thrust only.

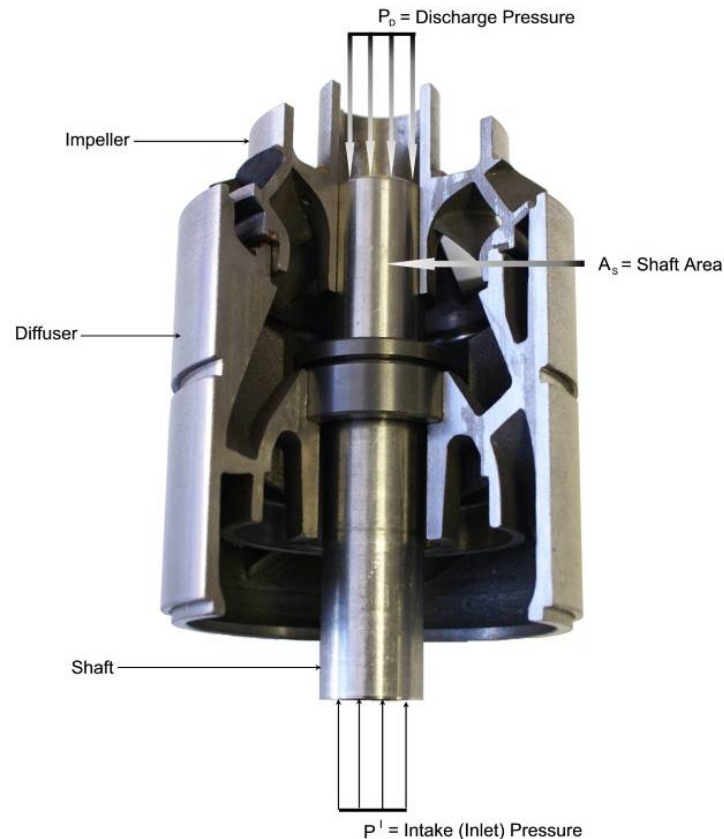


Figure 4-14: Cutaway photo of a mixed flow pump stage

One misconception is that the impeller floats between the diffuser thrust surfaces at the optimum flow rate. When the impeller reaches or nears its balanced thrust point ($F = 0$), it will become unstable and begin to oscillate up and down. Therefore, they are designed to be stable or in slight downthrust at their optimum design flow rate and to pass through this transition region at a higher flow rate. A typical centrifugal pump thrust curve is shown in Figure 4-15.

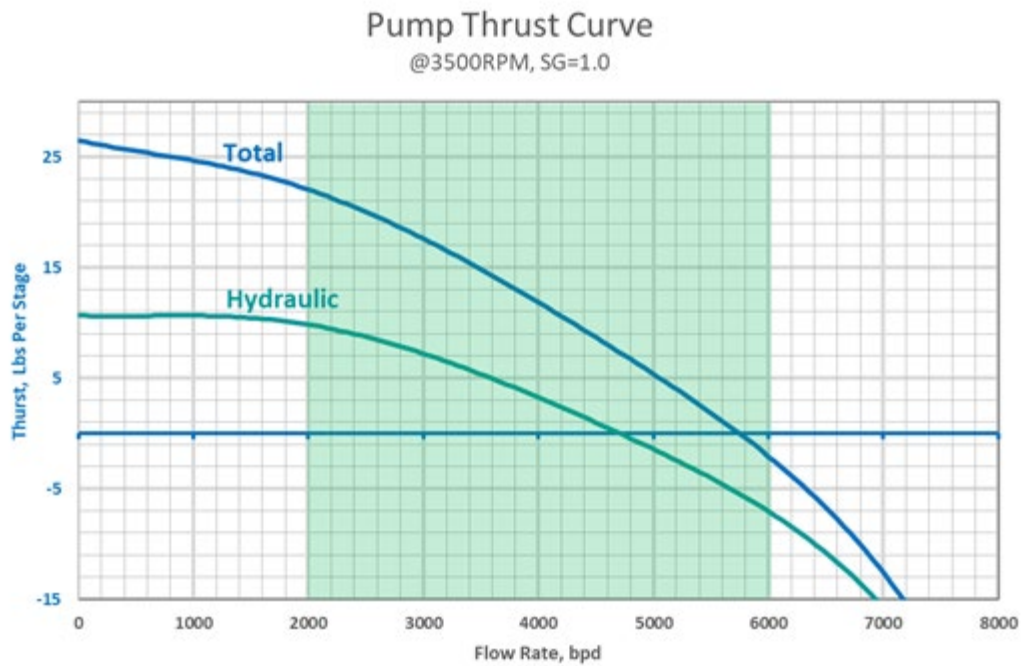


Figure 4-15: Typical centrifugal pump thrust curve

Hydraulic horsepower (water horsepower)

The energy output of the pump is derived directly from the outlet parameters (flow and head). The hydraulic horsepower for water, specific gravity 1.0, can be determined as follows:

$$HydraulicHP = \frac{Flow \times Head}{C} = \frac{GPM \times Ft.}{3960} = \frac{BPD \times Ft.}{135,773} = \frac{M^3 D \times M}{6571}$$

Brake horsepower

Total power required by a pump to do a specific amount of work.

$$BrakeHP = \frac{HydraulicHP}{PumpEff.} = \frac{GPM \times Ft. \times SG}{3960 \times PumpEff.} = \frac{BPD \times Ft. \times SG}{135,773 \times PumpEff.} = \frac{M^3 D \times M \times SG}{6571 \times PumpEff.}$$

Baker Hughes ESP system pumps

Baker Hughes manufactures a wide variety of pump types that fit in various casing sizes. The pump product line covers a broad range of flow rates and lift capacities. Figure 4-16 outlines flow range capabilities for Baker Hughes pumps.

Series	Outer diameter	Flow rates in BFPD@ 60 Hz	m ³ /day fluid @ 50 Hz
338	3.38 in.	50 to 3,400	7 to 453
400P	4.00 in.	50 to 7,500	7 to 1,000
538P	5.38 in.	750 to 14,000	99 to 1,867
562	5.62 in.	7,000 to 32,000	928 to 4,267
675	6.75 in.	4,800 to 48,000	763 to 7,631
862	8.62 in.	9,500 to 34,000	1,267 to 4,533
875	8.75 in.	12,715 to 33,429	1,695 to 4,457
900	9.00 in.	46,292 to 89,154	6,133 to 11,812
950	9.50 in.	19,000 to 45,000	2,533 to 6,000
1000	10.00 in.	20,000 to 50,000	2,667 to 6,667
1025	10.25 in.	22,286 to 54,857	3,548 to 8,736
1038	10.38 in.	50,000 to 158,000	6,667 to 21,067
1200	12.00 in.	12,758 to 72,000	1,701 to 9,600
1300	13.00 in.	34,584 to 109,999	4,611 to 14,667

Figure 4-16: Pump sizes and flow rates

Features and benefits of Baker Hughes ESP system pumps

- Baker Hughes designs and manufactures submersible pumps in a wide range of housing diameters and flow rates.
- All Baker Hughes pumps use state-of-the-art materials to mitigate the destructive effects of harsh environments.
- Each pump component is submitted to a rigorous quality procedure before assembly and is then tested to document performance.
- A broad family of patented abrasion-resistant pump designs extends run lives in abrasive well conditions.
- Under corrosive conditions, all exterior surfaces of the housings can be protected with special coatings or the complete system can be constructed from corrosion-resistant alloys.

Notes:

Chapter 6

Gas handler

Purpose

In wells with high gas volume fraction (GVF), ESP systems may suffer performance degradation with gas interference attributable to free gas. Some of the factors that can result from gas interference are listed below:

- Head reduction
- Gas head lock
- Gas blocking
- Gas locking
- Surging
- Slugging
- Cavitation

Standard pumping equipment can handle gas to a certain extent. It all depends on intake pressure. Generally, radial stages can handle up to 10–15% free gas; mixed flow stages 15–30% before seeing noticeable pump degradation. To avoid pump degradation under high GVF operation, gas handling must be considered which can be categorized as avoiding, separating, and handling. If the gas cannot be avoided or separated, the ability of the pump to handle gas needs to be enhanced to compress and move the gas with the liquid. Such specially designed pumps with high gas handling ability are categorized as “gas handling pumps.”

Gas handling pumps

Common Baker Hughes gas handling pumps include the following:

- The Gas Insurance (GI™) pump
- The **ACE PLUS™ Gas Handler pump**
- The **MVP™, a Multi-Phase pump**

Theory of operation

To determine whether a pump will operate stably with free gas in the pump, the following three factors are primarily considered.

- Intake pressure and Turpin Correlation
- Pump specific speed
- Pressure gradient in the pump

Pressure gradients in the impeller

The pressure gradients in the pump impeller point from the trailing edge to the leading edge and from the shroud to the hub. In multiphase operation, these pressure gradients oppose the motion of low density phase – gas. This results in the gas slowing, and the two phases, liquid and gas, to separate. Due to the direction of pressure gradients, the gas starts to accumulate at the impeller hub leading edge. This accumulation reduces the loading on the impeller blades which leads to lower head and efficiency of the stage. Over time, if the gas is unable to overcome these pressure gradients, it will continue to accumulate and can lead to entire vane being blocked by gas.

This would cause the stage to stop pumping and lose its entire head. This phenomenon is called “gas lock.”

Specific speed

Specific speed is defined as revolutions per minute to produce 1 gpm at 1 ft. head with an impeller. The term "specific speed" applies only at the best efficiency point; therefore, it does not change for different flow rates on the performance curve. As a stage transitions from radial to mixed flow design, its ability to handle gas increases as the specific speed increases. A higher specific speed translates to better gas handling. The following equation governs what a stage's specific speed will be:

$$N_s = \frac{n \times \sqrt{Q}}{(H)^{3/4}}$$

Where

Parameter	Units
Specific Speed	Ns
Revolutions per minute	n
Capacity in gallons per minute	Q
Head in feet	H

The following figure shows stage type transition from lower to higher specific speed, or from lower to higher gas handling ability.



Figure 5-1: Free gas handling ability by stage type

The Turpin correlation

Turpin and Dunbar were the first to publish pump gas performance, recognizing effects of the entrance pressure. Both defined a zone in which a pump would be expected to perform well. Turpin included an equation so it could be modified. Neither considered the flow rate, pump geometry, fluid properties, number of stages or pump diameter. Turpin can give the first guess as to the successful selection of the pump.

The Turpin Correlation is a simplistic representation of pump operating limits in gassy wells. It includes the wellbore intake pressure along with the free gas percentage by volume.

Understanding the Turpin Correlation is key to successful gas handling strategies.

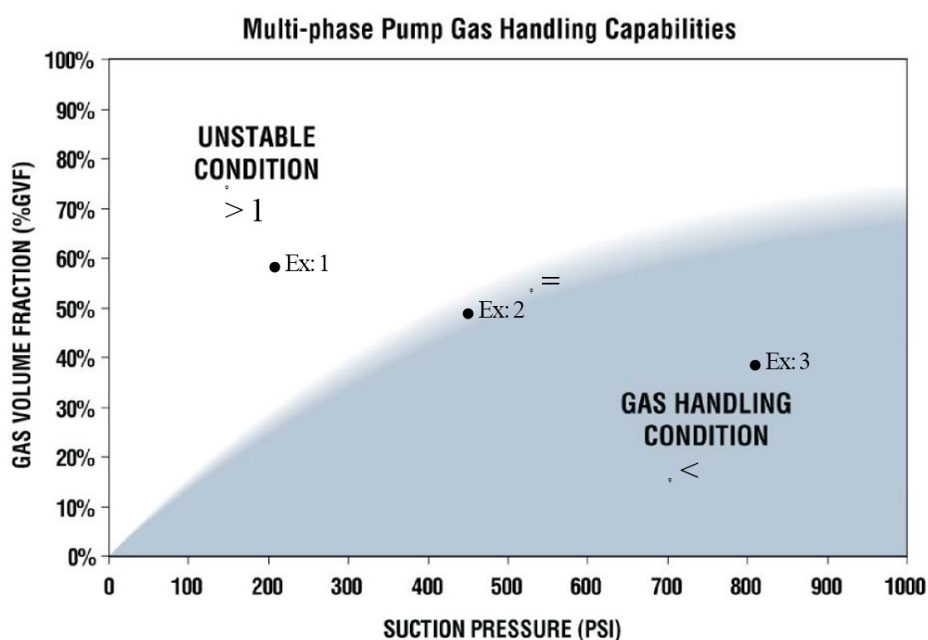
The Turpin Correlation presents an equation based on pump suction pressure and gas-to-liquid volume ratio. The equation was written in terms of Φ and is shown below.

$$\Phi = \frac{2000 \left(\frac{q_s}{Q} \right)}{3 P_s}$$

Where

Parameter	Units
Volumetric flow rate of gas, at pump inlet	q_s
Volumetric flow rate of liquid, at pump inlet	Q
Pressure at pump suction	P_s

Stable pump operation is expected when $\phi < 1.0$ and the pump is operated at, or to the right of, its best efficiency point. When $\phi > 1.0$, a significant reduction in performance can be anticipated. A graphical representation of this equation is shown below. The stable operating region is the area below the curve, while the area above the curve anticipates unstable or potential gas interference operation.



Ex. 1 – 60% GVF & 200 PSI Gas Interference	Ex. 2 – 50% GVF & 440 PSI Ideal Operation	Ex. 3 – 40% GVF & 800 PSI Ideal Operation
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Figure 5-2: Turpin curve

With the understanding of how pressure gradients, the Turpin Correlation and specific speed will determine the gas handling ability of a pump, the gas handling pump's design takes the following considerations.

- Minimize the opposing pressure gradients.
- Maximize the specific velocity to move multiphase flow.
- While the gas handling pump doesn't get gas locked itself, act as a charger pump in the bottom of the string to increase the intake pressure of the lifting pump, so that the operating point of the lifting pump can be shifted to a smaller ϕ on the Turpin curve which helps the ESP to operate stable.

The Gas Insurance (GI™) pump

- The Gas Insurance (GI) pump has the ability to handle increased amounts of gas at lower NPSHA.
- GI impellers naturally create high and low pressure regimes across each vane. The low pressure side of an impeller vane can cause gas to come out of solution, increasing the potential for gas locking.
- The GI stage is a good choice for gas handling because its unique vane angle reduces the amount of shock applied to the fluid when compared to mixed or radial stage types. The gentle sweep of the GI vane diminishes the pressure difference across the vane, ultimately reducing the probability of gas locking when increased amounts of free gas move through the pump.



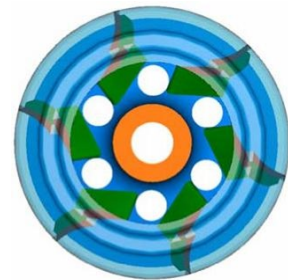
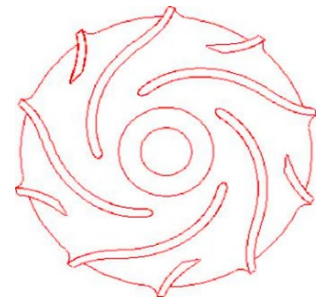
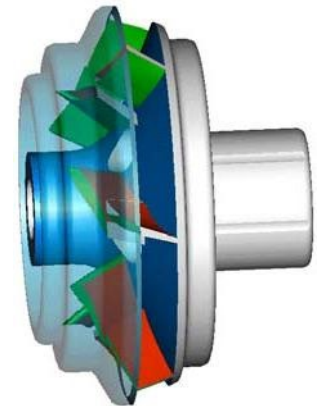
The ACE PLUS gas handler pump

- The Baker Hughes **ACE PLUS™ gas handler pumps** are designed to increase lift efficiency and extend gas production capabilities by handling up to 75% free gas.
- The ACE PLUS gas handler series is part of a suite of gas management products for high-, medium-, and low-flow rate applications. This multistage, axial-flow gas handling system is located below the main pumping system, can be used independently or in conjunction with other gas management products, and is designed to efficiently manage downhole applications with high percentages of free gas. This is accomplished by using pressure generated by the pump stages to compress the gas and produce it as part of the fluid.
- Performance tests indicate that ACE PLUS gas handler pumps are able to process up to 75% free gas without locking at extremely low intake pressures.
- Modified impellers feature low inlet angles and a high-angle discharge vane design.
- Multiple vanes on impellers increase the number of available edges to break gas bubbles.
- Axial stage design manufactured to prevent fluid from separating when passing through the stages.



The MVP, a multi-phase pump

- The innovative MVP gas handling pump design expands the operating range of ESP systems and is the most efficient gas handling pump of its kind in the industry, allowing continuous operation of ESP systems in extreme gas conditions and reducing the tendency for underload shut downs due to gas interference in the pump.
- MVP pump features a unique, patented impeller design that enables the pump to continually operate while producing substantial lift in fluid conditions up to 70% free gas, subject to the constraints of the Turpin Correlation. The MVP pump technology was extensively tested in Baker Hughes's high pressure gas test loop. This unique, highly instrumented state-of-the-art testing facility is the only one of its kind in the industry and is used to aid the design development and evaluation of gas handling technology. MVP can be used alone or employed as a charge pump in a standard ESP system.
- MVP can be combined with the Baker Hughes's GM Series gas separator for applications with greater than 90% free gas.
- The MVP pump stage is the latest technology in Baker Hughes's gas handling solutions. The MVP integrates the three principles of gas handling.
 - Balancing holes mitigate the pressure difference and thrust loading. If gas forms because of low pressure areas, it can easily escape through these holes and prevent gas pockets.
 - It has a split vane design. As a general rule, when dealing with gas, the more homogenous the fluid, the better. The split vane design allows turbulent mixing to occur, which is favorable for flow capacities to carry the gas without becoming stagnant.
 - The steep discharge angle of the MVP transmits a greater amount of kinetic energy onto the liquid, increasing lift at lower flow rates.The patented MVP stage has established a new level of gas handling where it was otherwise limited.



Baker Hughes ESP system gas handling pumps

Baker Hughes manufactures a wide variety of gas handling pump types that fit in various applications and casing sizes. Below is more information outlining the Baker Hughes gas handling pump capabilities.

Series	Outer Diameter	Flow Rates in BFPD@ 60 Hz	m ³ /day fluid @ 50 Hz
338	3.38 in.	400 to 2,900	53 to 384
400	4.00 in.	250 to 10,125	33 to 1,341
538	5.38 in.	500 to 14,000	66 to 1,855
562	5.62 in.	12,000 to 24,000	1,590 to 3,180
1025	10.25 in.	10,000 to 52,000	1,325 to 6,889

Figure 5-3: Gas Handling Pump Sizes and Flow Rates

Features and benefits of Baker Hughes ESP system gas handling pumps

- Handles up to 75% free gas without gas lock
- Works under low intake pressure
- Minimize gas lock and pump performance degradation due to gas
- Best-in-class abrasive protection options
- Uses state-of-the-art materials to mitigate the destructive effects of harsh environments

Chapter 7

Gas separator

Purpose

In wells with high gas-oil ratio, gas separators replace standard pump intakes and helps improve pump performance by separating a portion of the free gas before it enters the first stage. This helps eliminate gas locking and extend the application range of ESP systems.

Baker Hughes is an industry leader in handling gas with electrical submersible pumping systems. Baker Hughes introduced the first rotary gas separator for oilfield applications in 1978. Baker Hughes gas separators are the perfect complement to the downhole pump when large amounts of gas are present at the pump intake.

Components

The ESP gas separator (Figure 6-1) is made up of the following major components:

- Gas vent port
- Guide vane
- Inducer or high-angle vane auger (patented)
- Separation chamber
- Intake
- Shaft

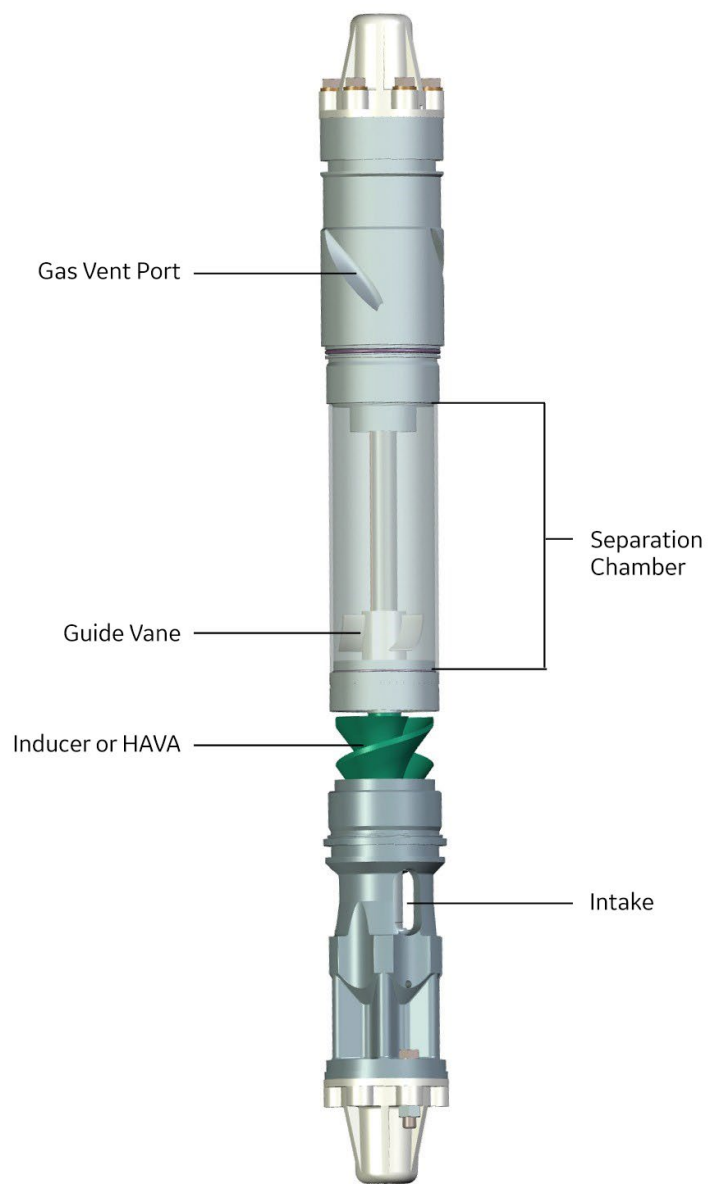


Figure 6-1: Gas separator

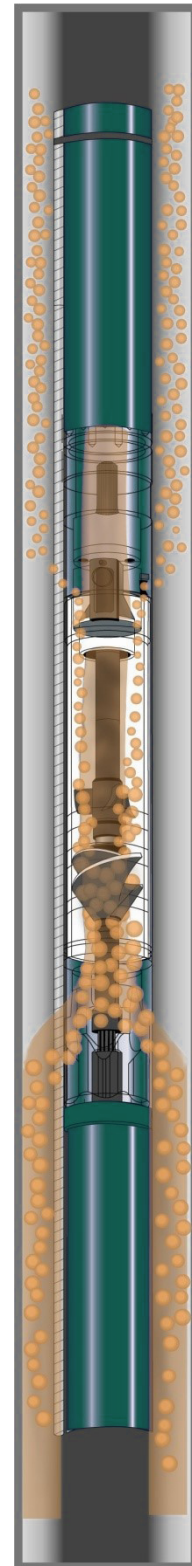


Figure 6-2: Gas separator

Theory of operation

The fluid enters through the intake and passes through the rotating inducer or high-angle vane auger (HAVA). The HAVA passes the fluids to the separation chamber where the higher specific gravity fluid is forced to the outer wall and the lighter gas in the center. The separation is caused by centrifugal force created with either a separator rotor or induced vortex stage. The gas is removed from the fluid stream by the diverter at the top of the separation chamber. The gas is vented through the gas ports and produced up the annulus. The fluid is passed into the lower end of the pump where stages lift the separated liquid to the surface.

Gas separator efficiencies typically reach 80% or higher. The separation efficiency is affected by fluid flow rates, liquid viscosity, and % of free gas vs. total volume produced. In extremely high gas conditions, tandem gas separator assemblies are installed to further improve pump performance.

There are two technologies for providing centrifugal force for separation.

The first uses a separator rotor (rotary). The rotor, which acts as an enclosed centrifuge, forces the higher density fluid to its outer diameter, leaving the lighter gas in the center. This design produces the highest possible separating force and is a superior solution when good separating efficiency is required and in cases where highly viscous fluids are produced.

The second uses an induced vortex stage. Vortex separator uses a modified impeller to induce a vortex in the fluid. This vortex provides the centrifugal force that separates the two phases of a gassy fluid. Although the fluid rotation speed is slower than a rotary design, the fluid is separated and vented in a similar fashion as previously described. The slower rotation and reduced rotating mass make this design better suited for abrasive applications. The vortex is recommended for a wider range of flow rates than the rotary separator.

Baker Hughes ESP system gas separators

Baker Hughes gas separators are available in two designs: the rotary and the vortex. Figure 6-3 lists the gas separator designs and maximum volume for each series. For more information on Baker Hughes gas separator ranges and options, please consult the latest Baker Hughes product catalog.

Feature	338 Single Rotary	400 Series GM™ Rotary	400 Series GM™ Vortex	538 Series GM™ Rotary	538 Series GM™ Vortex	675 Single Vortex
Outer Diameter (Inches)	3.38 in.	4.00 in.	4.00 in.	5.38 in.	5.38 in.	6.75 in.
Max. Intake Volume (BPD)	2,700	5,000	8,000	10,000	15,000	25,000

Figure 6-3: Baker Hughes gas separator models

Features and benefits of Baker Hughes ESP system gas separators

- Prevents deterioration of pump performance because of free gas effects
- Avoids motor load fluctuations and cycling due to gas interference
- Two product designs are available: rotary and vortex
- Best-in-class abrasive protection options
- Uses state-of-the-art materials to mitigate the destructive effects of harsh environments

Notes:

Chapter 8

Seal

Purpose

The seal chamber section connects the motor shaft to the pump intake or gas separator shaft.

Seal sections also perform the following vital functions:

- Provides an area for the expansion of the ESP motor oil volume
- Equalizes the internal unit pressure with the wellbore annulus pressure
- Isolates the clean motor oil from wellbore fluids to prevent contamination
- Supports the pump shaft thrust load

Components

Seal chamber sections are made up of the following chamber types with key components:

- Bladder type chamber(s)
- Mechanical seal
- Elastomer or plastic bladder
- Relief valve
- Labyrinth type chamber
- Mechanical seal
- Labyrinth tube (pipe)
- Thrust chamber
- Down thrust bearing
- Thrust runner
- Up thrust bearing
- Circulation pump
- Heat exchanger
- Filter screen

Seal chamber sections are normally constructed of two or three redundant barrier chambers.

Two sections are sometimes combined to form a tandem seal section. Various chamber arrangements can be customized to meet specific application requirements.

Labyrinth type chambers have an oil communication path, which reverses vertical direction twice.

This arrangement, combined with the density difference between motor oil and most well fluids,

causes the lighter motor oil to reside in the top of the labyrinth chamber. The heavier well fluid is transferred to the bottom of the labyrinth chamber through a pipe. The well fluid volume in the bottom of the chamber must displace the clean motor oil above it in order to communicate with the next chamber below.

Bladder type chambers physically isolate the motor oil from the well fluid. The bladder is a positive barrier between the clean motor oil inside and the well fluid on the outside. A bladder chamber has three main sealing components: the mechanical shaft seal, the bladder, which can be elastomer or a special high temperature thermoplastic, and the relief valve. All three must be functioning properly to prevent well fluid from migrating into the chamber. This type of chamber functions in deviated or vertical wells. Unlike the labyrinth chamber, a bag chamber does not rely on the stratification of the motor oil and well fluid for isolation.

The thrust chamber performs many functions. The down thrust bearing carries the pump shaft thrust load, and in combination with the up thrust bearing, positions the thrust runner and shaft to maintain proper function of the mechanical seals. A circulation pump creates a flow past the thrust bearing around the outside of the heat exchanger and through the filter screen. This maintains a clean oil supply and provides cooling for the thrust bearing area.

A thrust bearing consists of multiple individual shoes which are mounted on a pedestal or pivot mechanism. The operation of the bearing is dependent upon maintaining an oil film across the surface of the bearing, which is stationary, and the rotating thrust runner. If the oil film is compromised due to contamination, reduced viscosity, heat, etc., catastrophic failure can occur. Figure 7-1 shows the construction and major components of a typical seal section.

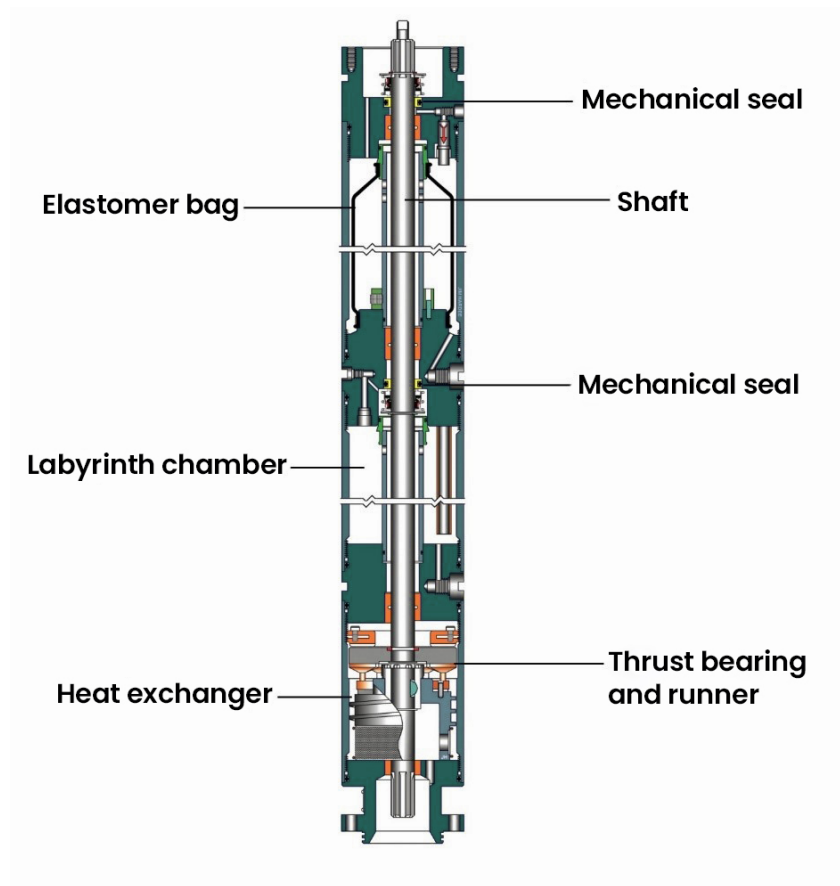


Figure 7-1: ESP Seal components

Theory of operation

As stated earlier, the seal section provides four major functions:

- Provides an area for the expansion of unit's motor oil volume
- Equalizes the internal unit pressure with the wellbore annulus pressure
- Isolates the clean motor oil from wellbore fluids to prevent contamination
- Supports the pump shaft thrust load

Expansion

Seal section allows for expansion and contraction of the dielectric oil contained in the rotor gap of the motor. Temperature gradients resulting from both the ambient bottom hole and motor temperature rise will cause the dielectric oil to expand and contract. This expansion and contraction must be absorbed by the seal section. The bladder and labyrinth chambers perform this function.

Equalization

Seal sections equalize the casing annulus pressure with the internal unit pressure. This equalization of pressure across the unit helps keep well fluid from leaking past the sealed joints of the motor and seal section. Well fluids, which may get into the motor, can cause early dielectric failure. Well fluid is allowed to migrate into the top chamber of the seal section effectively equalizing the pressure within the unit. The well fluid is contained in the upper chamber and cannot migrate into lower chambers unless there is a mechanical seal, relief valve leak, or a breach in the bag.

Isolation

Seal sections isolate the well fluid from the clean dielectric motor oil. As previously stated, contamination of the motor insulation with well fluid can lead to early insulation failure. The seal section contains multiple mechanical shaft seals which keep the well fluid from leaking down the shaft. The bladder provides a positive barrier to the well fluid. Labyrinth chambers provide fluid separation based on the difference in densities between well fluid and motor oil. Any well fluid that gets past the upper shaft seals or the top chamber is contained in the lower labyrinth chambers as a means of secondary protection. Several chambers are positioned in series to provide redundant protection. Over time, as one chamber may be compromised by well conditions or operation, additional chambers maintain isolation and protect the motor.

Thrust load support

Seal sections absorb the downthrust load produced by the pump. This is accomplished by a thrust bearing. As described earlier, the bearing utilizes a hydrodynamic film of oil to carry the load and provide lubrication for the bearing and thrust runner during operation.

Baker Hughes ESP system seals

Seal assemblies come in various sizes and options based on well conditions, motor and pump size, and well diameter.

Seal sections range from 338 series to 875 series and are generally available in a wide variety of bag and labyrinth chamber configurations. There are generally two or three thrust bearing options in each series depending on the thrust load produced by the pump. This load is a function of the lift capacity of the pump (number of stages) and the construction of the pump (fixed impeller or floating impeller).

Features and benefits of Baker Hughes ESP system seals

- Best-in-class protection for submersible motors
- Bladders are available in a variety of elastomer options that can be tailored for specific downhole conditions
- Designed with a short axial-span between shaft bearing provides better rotational stability and less vibration
- Proven check valve system that improves the reliability of expansion bladder chambers
- Thrust bearings available in standard, high load and enhanced high load as pump selection and head requires
- Forced oil circulation system through the heat exchanger section, which aids both cooling and filtering of the thrust bearing lubricant
- Available with standard or premium mechanical seal designs

For more information on Baker Hughes seal section product ranges and options, please consult the latest Baker Hughes product catalog.

Notes:

Chapter 9

Motor

Purpose

The main purpose of a motor is to convert electrical energy into mechanical energy through rotation of the shaft. The shaft is coupled to the seal, gas separator, and pump to turn the pump impellers.

Components

ESP motors are made up of the following major components:

- Rotors
- Stator
- Shaft
- Bearings
- Insulated magnet wire
- Winding encapsulation
- Rotor and stator laminations
- Housing
- Thrust bearing

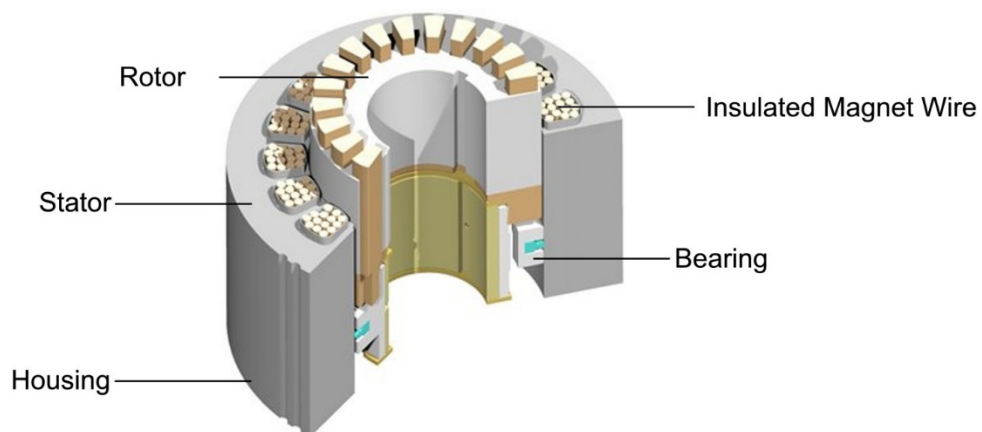


Figure 8-1: ESP motor cutaway illustration

Theory of operation

ESP applications use induction motors (IM) and permanent magnet motors (PMM). ESP applications have a long history of using induction motors, but permanent magnet motors have seen increased usage in recent years (since 2010). IMs and PMMs are three-phase squirrel cage construction and are mechanically very similar using the components outlined in Figure 8-1. The primary difference is that induction motors use induction to energize the conductive elements in the rotors to generate the secondary magnetic field. PMM rotor construction incorporates rare earth magnets to provide a permanent secondary magnetic field. The magnetic field generated by the stator works with these secondary magnetic fields to rotate the rotor and shaft.

IMs (asynchronous motors) are typically two-pole construction for ESP applications and mechanically spin somewhat slower than the electrical generated magnetic field to account for slip associated with induction/asynchronous machines. IM rotation is estimated at approximately 3500rpm with a 60 Hertz power supply but varies depending on motor load and associated slip. Considering two pole motors, 60 cycles per second electrical power multiplied by sixty seconds should result in 3600 rotations per minute. Asynchronous refers to slip or this difference in electrical frequency and mechanical rotation.

Slip is a critical factor in the physics of how IMs work. If the rotor and stator magnetic field were to rotate at the same speed, there would be no relative motion, and induction would cease. Slip refers to the lag between the rotor and the induced rotor's magnetic field. This phenomenon results in robust control for IM control due to slip's self-regulating response to torque changes. Any torque change to the motor will increase or decrease the slip and increase or decrease the associated current draw and magnetic field strength to normalize the motor's torque delivered. This relationship between the stator's and rotor's magnetic field allows induction motors operation with across the line starters and V/Hz variable frequency drives (VFD).

PMMs (synchronous motors) are typically four-pole construction for ESP applications. PMMs run at synchronous mechanical speed and electrical supply frequency. For example, a 120 Hertz power supply will drive a four pole permanent magnet motor at precisely 3600rpms. Please note that the 120 Hertz power supply is twice that needed in the two pole induction motor example. This 2x multiple is strictly related to the change in pole count. Synchronous refers to the 3600 rpm operation and no indication of slip. All motors can be constructed in higher pole constructions (10, 12, and 14 poles), but this is more practical for PMMs.

PMMs are mechanically very similar to IMs; the primary difference is the rotor construction. The rotor construction incorporates permanent rare earth magnets. The surface control system (VFD) regulates the stator's magnetic field and aims to maintain synchronous operation with the permanent magnets. Loss of synchronous operation would result in instability and vibration. PMM operation requires a VFD for optimal motor performance and reliable operation in changing loads. It is recommended to use a VFD with a modern vector control.

The PMM and IM stators are comprised of the housing, winding, and laminations. Three-phase two-pole motors have three separate coils of wire, known as windings, one for each phase, distributed uniformly around the inner circumference of a cylindrical stack of steel laminations. Higher pole constructions typically have dedicated coils for each phase and pole; i.e., 4-pole constructions have six separate coils, and 6-pole constructions have nine separate coils. One cycle of AC power will make a full magnetic cycle (north to south to north) in each coil. Graph 8-1 denotes the coils for various poles as N_1 , N_2 , S_1 and S_2 . Note, there is only an N_1 and S_1 for a two pole construction. One AC cycle through coil in a 4-pole motor construction will only move the rotor one half of a revolution. This concept can be expanded on for higher pole configurations. Graph 8-2 further shows the relationship with AC power cycles and mechanical rotation for varying pole constructions.

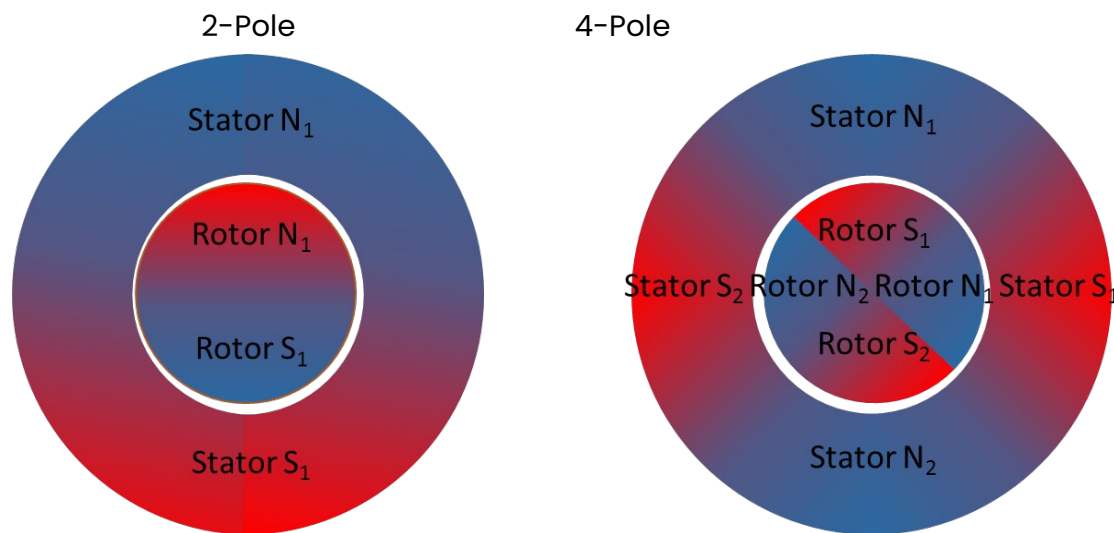
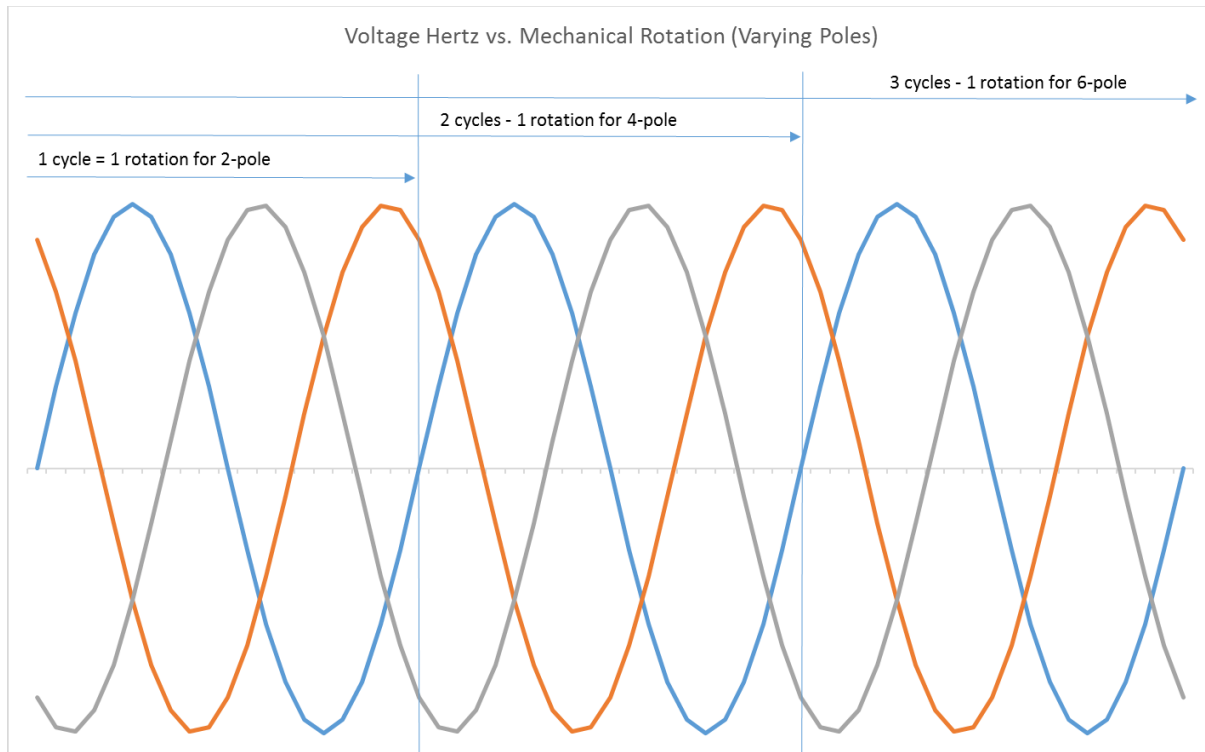


Figure 8-1: Motor rotor's and stator magnetic poles



Graph 8-2: AC cycles vs mechanical rotation for various pole counts

Equations 8-1 and 8-2 below shows the relationship between mechanical speed (rpm), power supply (Hz), slip and pole count.

$$\text{MotorRPM} = \text{DriveFrequency} * \frac{2}{\text{PoleCount}} * \frac{3600\text{rpm}}{60\text{Hz}} - \text{slip (NA for PMM)}$$

Equation 8-1: Motor rotations per minute as a function of supply electrical efficiency, pole count and slip

$$\text{SupplyFrequency} = (\text{MotorRPM} + \text{slip (NA for PMM)}) * \frac{\text{PoleCount}}{2} * \frac{60\text{Hz}}{3600\text{rpm}}$$

Equation 8-2: Supply frequency as a function of motor rpm, pole count, and slip

Inside the stator's inner circumference (stator bore) are the rotors. The rotor is also typically made of a cylindrical stack of steel laminations. The mechanical clearance between the rotor OD and the stator ID is known as the air gap. The air gap is required to prevent friction between the two

components and is full of oil to lubricate the bearings and conduct heat which is generated by the various motor losses. The air gap is optimized to balance the friction and fluid loss within the air gap with magnetic power across the air gap.

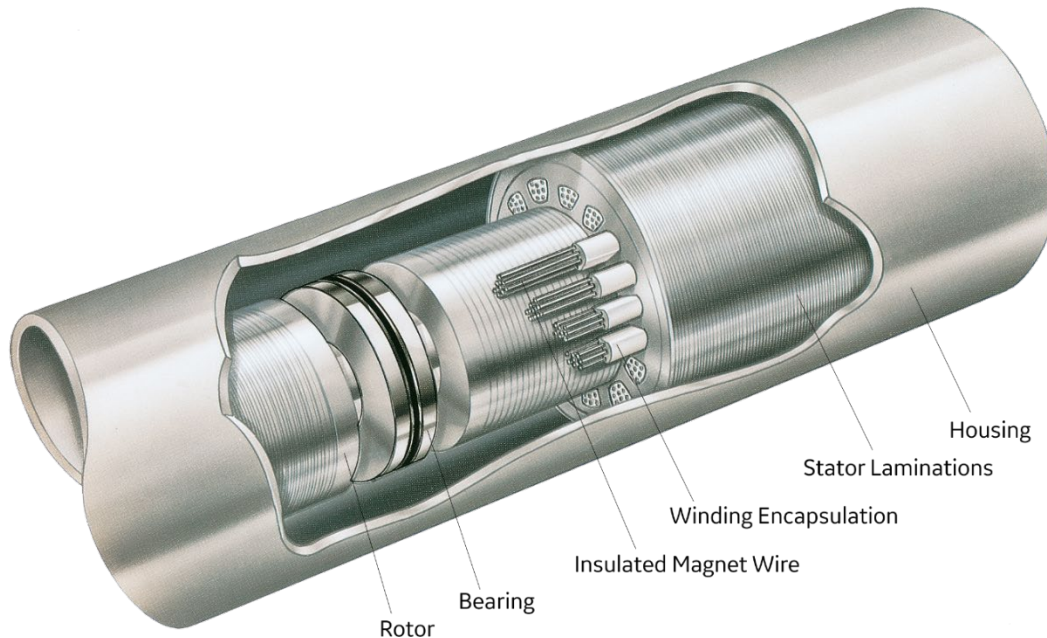


Figure 8-2: ESP motor IM cutaway illustration

IM and PMM stator windings are connected to an alternating three-phase voltage source, which generates currents in the windings producing a rotating magnetic field in the air-gap. The interaction between this magnetic field and the rotors is where IM and PMM physics diverge.

For an IM, the rotating magnetic field in the air gap causes a three-phase current to flow in the rotor bars, which, in turn, results in torque delivered by the rotor to the shaft. The amount of induced magnetic field and current in the rotor bars is determined by the load required. For current to be flowing in the rotor, it is necessary to have relative motion between the synchronous magnetic field in the air-gap and the rotor (slip). The synchronous speed of the magnetic field in the air-gap is given by the expression:

Embedded in the outer regions of the induction rotors are electrical conductors, or bars, running parallel to the stator windings, which are joined, or shorted, at each end by electrical shorting rings known as end rings or resistance rings. This is referred to as a squirrel cage design. Squirrel cage derives its name by the shape formed by the rotor bars and end rings.

For a PMM, the rotors have a permanent magnet field from the arrangement of rare earth magnets. The stators rotating magnetic field drives the rotor's permanent magnetic field at a synchronous speed without slip. The variable speed drives estimates the position of the rotor's magnetic field. It makes fast adjustments to the stator's magnetic field to provide synchronous operation. Asynchronous operation for permanent magnet motors indicates a step-out and unstable operation. This further results in undesirable vibration and currents.

Embedded in permanent magnet rotors are rare earth magnets. There are two typical rotor constructions for permanent magnet motors; surface permanent magnets (SPM) and internal permanent magnets (IPM). SPM have magnets close mounted on the surface of the rotor, and IPMs have the magnets embedded deeper inside the rotors. The most commonly used rare earth magnets are Samarium Cobalt and Neodymium. Typically Neodymium is a more energy-dense (higher flux density) magnet but has a lower maximum temperature rating than samarium cobalt. It is important to note that there are varying grades of these magnet materials.

Nameplate motor HP is the manufacturer's recommended rated HP for the operating conditions allocated to that motor. All squirrel cage induction motors have nameplates which, as a minimum, indicate their rated HP, rated voltage, and rated current. The same size (length) motor and same winding has a wide range of HP. The main factor in determining the load capability of the motor is its operating temperature. The operating temperature, in turn, is determined by the losses of the motor and how effective the fluid passing over the outside surface of the motor is in removing the heat, as well as the bottomhole temperature. To gain further understanding of this phenomenon, contact Baker Hughes regional engineers or the motor engineers at Baker Hughes worldwide headquarters in Claremore Oklahoma.

Nameplate voltage Nameplate voltage is the voltage that should appear at the motor terminals to generate the rated HP. Allowance is to be made for cable voltage drop to determine the proper surface voltages. A motor operating at the appropriate voltage for its operating load will operate at minimum current for the required load, which minimizes cable loss and heat rise, and maximizes system efficiency.

Nameplate current is the current the motor will demand when operating at nameplate horsepower (HP) and nameplate voltage. If the current is less than nameplate current, it follows that the motor is not fully loaded. Likewise, if the current is in excess of nameplate current, the motor is either overloaded or the terminal voltage is incorrect, or both. However, when the system is first energized, it is not unusual for the motor to draw current several times the nameplate current. This is known as the "startup current."

In some cases, for example, where sand is being produced, the running current may be higher than expected by as much as 10% to 20%. In this instance, it is recommended that the system be left energized for two to three hours and, if the overcurrent condition still persists, the manufacturer should be contacted to determine the advisability of continuous operation.

Rated motor torque is the value of torque the motor will produce when fully loaded at its rated speed. Torque is essentially the turning force of the motor. If there is excessive torque the shaft can break. The relationship of torque to mechanical speed is as follows

$$T = \frac{\text{BHP} \times 5,252}{\text{rpm}}$$

Where: T = motor torque (ft-lb)

BHP = Brake horse power (hp)

Motor efficiency is the ratio of the power output to the power input and is usually expressed as a percentage. Motor efficiency is the ratio of mechanical power output at the end of the shaft to input electrical power, expressed as a percent. Fortunately, there is a simple relationship:

$$\text{BHP (hp)} = \frac{\text{rpm} \times T}{5232}$$

$$\text{Motor Input Power (hp)} = \frac{V \times A \times 1.732 \times pf}{746}$$

$$\text{Motor efficiency} = \frac{\text{BHP}}{\text{Motor Input Power}}$$

Where: BHP = Brake horse power (hp)

T = motor torque (ft-lb)

V = motor terminal voltage

A = line voltage

Pf = power factor

The efficiency of electrical submersible induction motors range from around 80% to above 90% at the rated load and voltage. IM efficiency typically increases with motor diameter. The efficiency of the motor will vary with the load. Providing optimal voltage based on load will enable the highest efficiency at varying load.

The efficiencies of electrical submersible PMMs are typically between 90% and 95%. Motor diameter is less impactful to PMM efficiency than to IM efficiency. Efficiency is relatively constant over the full load range of the motor. This is primarily because there is no energy required to induce current into the rotors. This is further reflected in constant relationship between load and current for PMMs.

Figure 8-3 is a voltage optimization curve, more commonly referred to as a load saturation curve. It illustrates change of speed (RPM), efficiency, power factor (PF), current, and kilowatt (kW) input for a constant pump load with varying voltage. It can be seen that operation at less than nameplate voltage results in lower speed and higher current. Lower speed means lower pump output, since volume varies directly with speed and pump head varies as the square of the speed.

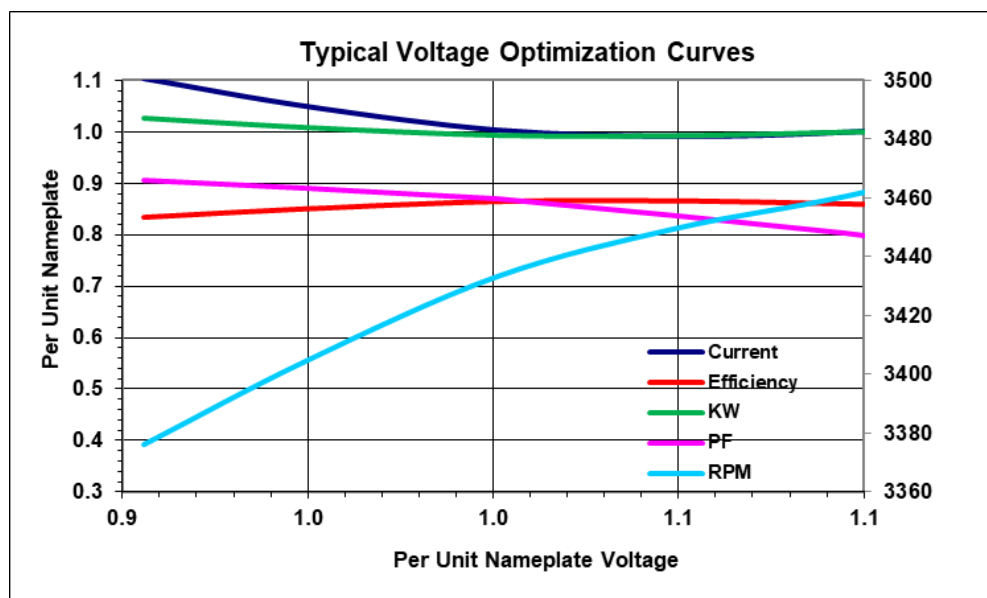


Figure 8-3: Voltage optimization curve

It is also apparent that operation at higher than nameplate voltage affects current and kW with a reduction in power factor. If there is a power factor penalty provision in utility rate schedule, this is an especially important consideration. The ideal practice is to aim at 100% required motor terminal voltage. Figures 8-4 and 8-5, are motor composite characteristic curves for IMs, and PMMs, respectively, more commonly referred to as a motor performance curve, based on loading, for a typical electric submersible motor. This generalized curve is based on output dynamometer measurements. This typical induction motor performance curve illustrates how the motor behaves through the load range of the motor.

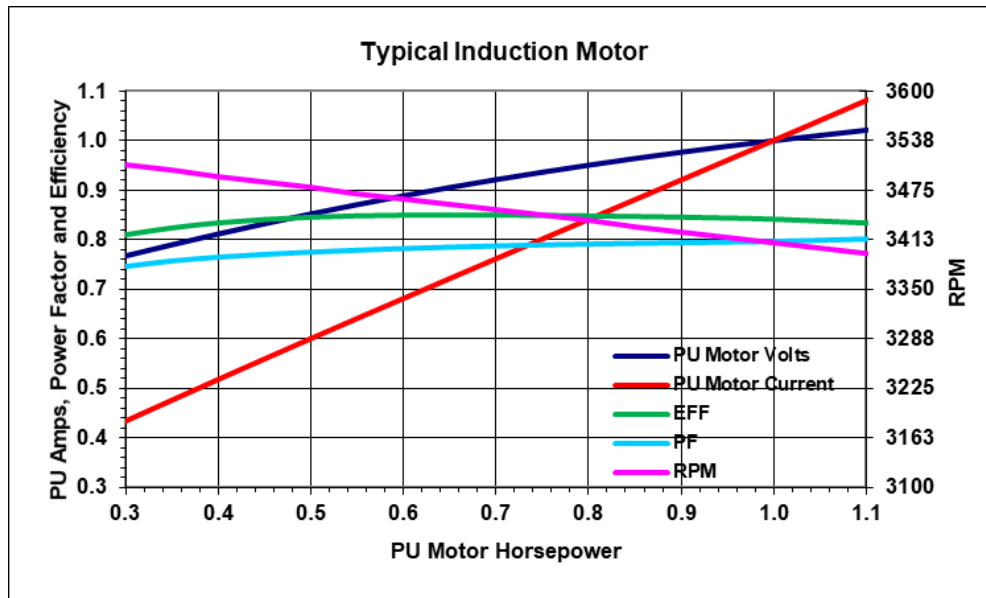


Figure 8-4: Induction motor composite characteristic curve @ 60 Hz

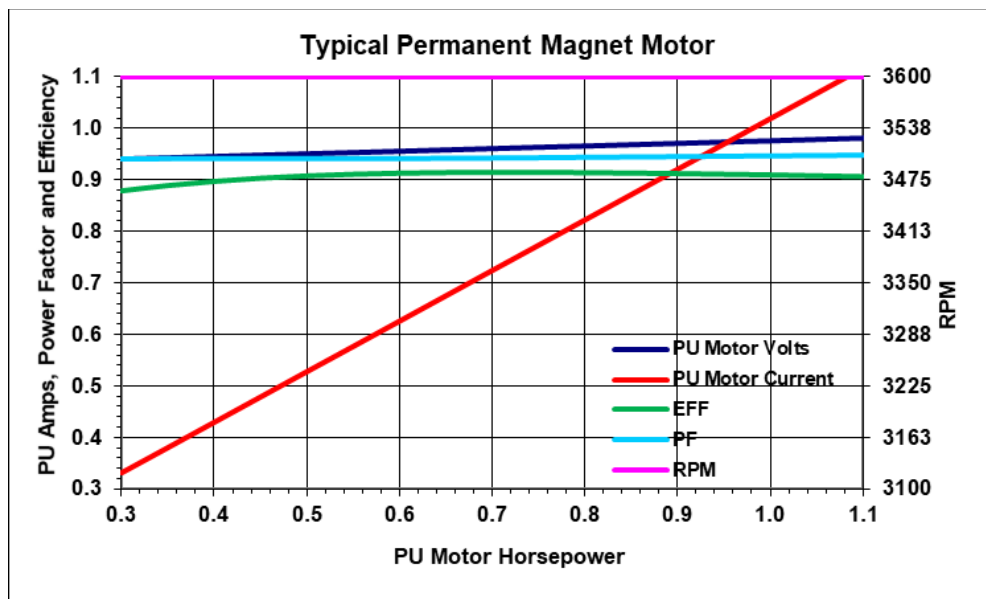


Figure 8-5: Permanent magnet motor composite characteristic curve @ 120 Hz

Figure 8-6 is a generalized curve showing motor temperature rise versus velocity of flow by motor. Two curves are plotted for a motor loaded 100%, one using water (specific heat 1.0) and the other a typical crude oil (specific heat 0.4). From this curve it is obvious that fluid velocity is as important as fluid specific heat.

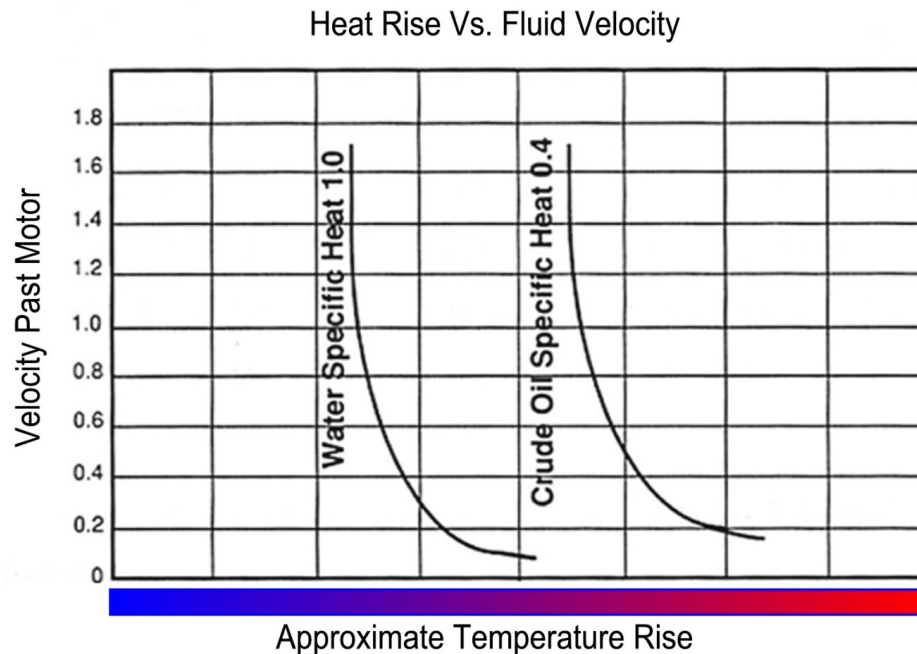


Figure 8-6: Generalized motor heat rise chart

Baker Hughes ESP system motors

Motor assemblies come in multiple frame sizes to maximize equipment diameter for operation in various casing sizes. Maximized equipment diameter allows design for shorter motors, higher maximum power, and increased surface area for cooling. Motors range from 375 series to 875 series. They are available in a wide variety of configurations to support operation in harsh well conditions, including high temperature, corrosive fluid, sour gas, and more. Table 8-1 summarizes Baker Hughes motors.

API casing OD	Equipment series application motor	Horsepower range	
		60 Hz (hp)	50 Hz (hp)
4 ½ in. (114.3 mm)	375	20-275	17-230
5 ½ in. (139.7 mm)	450	22-576	18-480
7 in. (177.8 mm)	562	50-1254	42-1045
8 ⅝ in. (219.1 mm)	725	100-1600	83-1330
10 ¾ in. (273 mm)	880	700-2800	583-2330

Table 8-1: Baker Hughes ESP system motor portfolio

Features and benefits of Baker Hughes ESP system motors

- Full line of 3 phase squirrel cage induction and permanent magnet motors available
- The Magnefficient™ PMMs have high efficiency and power factor over the full operating range of the motor. The Magnefficient PMM provides all the power in half the length of an induction motor.
- XP motors feature epoxy encapsulated windings for higher temperature tolerance and better heat rise characteristics
- SP motor feature open windings with varnish retention with an application range to handle most ESP applications
- The **Vanguard™ construction motors** for high-cost intervention applications where long life is the most important factor
- The **CENTigrade™ motors** for high-temperature applications like SAGD or high temperature geothermal
- Induction motors have shaped bar design to improve rotor efficiency, resulting in higher operating speeds
- 300 and 400 series 3 phase 4 pole permanent magnet motors (other sizes under development)
- Closed slots reduce windage and friction, improving efficiency
- Stator lamination designed to optimize the magnetic circuit for improved performance
- Optimized air gap for efficiency and power factor
- T-ring bearing design prevents bearing spin at start-up and during operation. Mechanical keys are available for high-temperature applications and in the large 725 and 880 Vanguard bearings
- Motors are filled with the proper viscosity of highly refined, synthetic, high dielectric strength oil to enhance operating life
- Plug-in pothead connection allows easier field installation

Notes:

Chapter 10

ESP cable

Purpose

Baker Hughes ESP cable is the critical link between the downhole equipment and the power source. Power is transmitted to the submersible motor by banding a specially constructed three-phase ESP electric power cable to the production tubing. This cable must be of rugged construction to prevent mechanical damage and be able to retain its physical and electrical properties when exposed to hot liquids and gasses in oil wells.

Components

Baker Hughes cables are constructed in both round and flat configurations (Figure 9-1). Most cables are composed of at least four components: conductor, insulation, jacket, and armor.

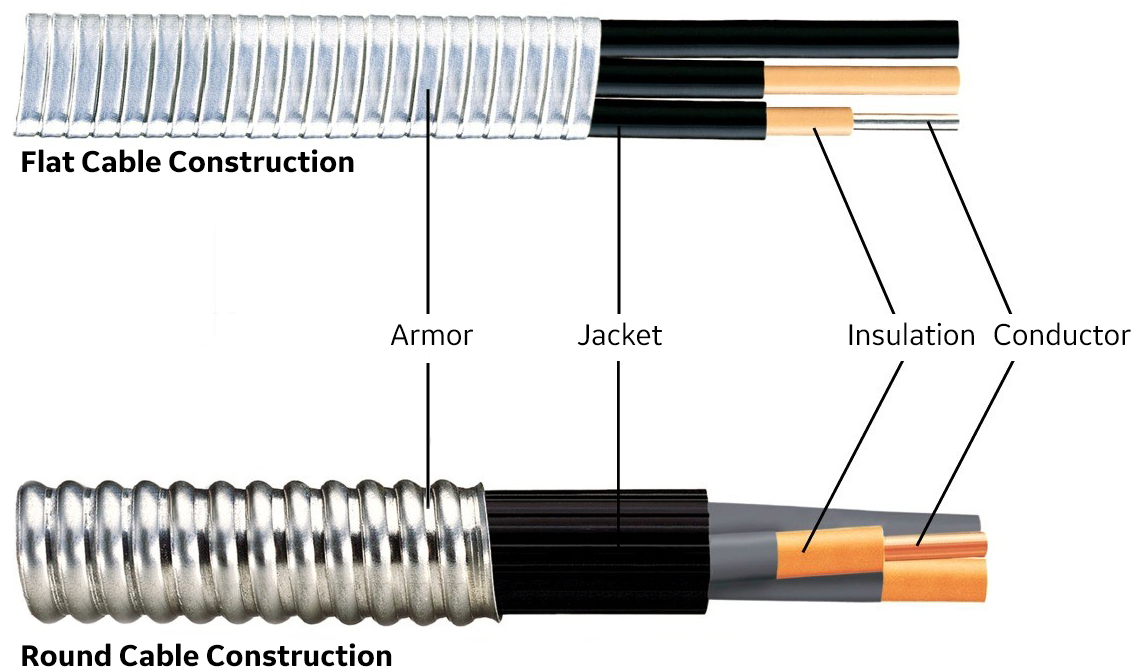


Figure 9-1: Flat and round cable cutaway

Power cable

Choosing the correct cable for specific well conditions is very important to long service life. The most basic requirements of the cable is that it be capable of delivering the amount of current required by the ESP motor at a sufficiently high voltage at the motor terminals to start and run the motor. The larger the cable, the more power it can supply to the motor. Conversely, as the cable gets smaller so does its ability to transmit power. There are many different ESP cable designs with a variety of conductor sizes, voltage ratings, temperature ratings, and physical dimensions. Below is an overview of the factors involved in selecting the correct cable for specific applications.

The ability of a cable to carry current is referred to as the ampacity of the cable. The amount of current a cable can carry depends on how hot the conductor gets when the current passes through it. This conductor temperature depends on many factors, most importantly the amount of current, the size of the conductor, the temperature at the bottom of the well, and the physical construction of the cable. Refer to Section 6 for sizing and selection. Different conductor sizes and cable designs will have different conductor temperatures during operation. Calculating the conductor temperature, while taking into account the amount of voltage drop, allows selection of the cable insulation with a properly matched temperature rating.

Other factors that affect ESP cable design selection include, but are not limited to, the space available in the well for the cable, the concentration of corrosive gasses such of hydrogen sulfide, the amount of gas in the produced fluid, weight limitations imposed by surface handling equipment, and the amount and type of corrosive agents in the well fluid.

Because the service life of the ESP system is directly dependent on the life of the ESP cable and because ESP cable represents a large portion of the capital investment in any ESP installation, it is very important to make an informed and correct cable selection. Baker Hughes application engineers are experienced in assisting with this process and consulting them is highly recommended.

Motor lead extension

A motor lead extension (MLE) performs the same basic function as a plug on a lamp cord; it connects the motor lead cable directly to the motor. Commonly referred to in the industry as a pothead, MLEs are available in a variety of temperature and power ratings and are specifically designed to fit a wide range of ESP motors and applications. MLEs are highly engineered products and special care must be taken during handling and installation to prevent damage to the internal seals due to excessive pulling or twisting. Pre-manufactured MLEs offer a quick and effective means of connecting power to the motor, offering the advantage of less rig time than splicing to the motor leads and greater reliability due to controlled manufacturing and testing procedures.

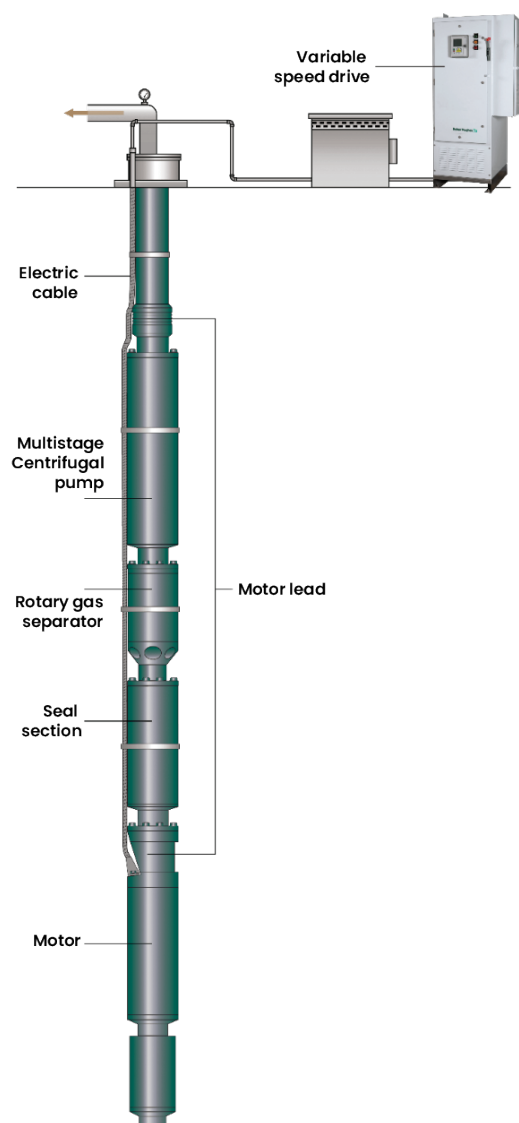


Figure 9-3: ESP system

Motor lead cable

A specialized motor lead cable connects the main ESP power cable to the motor. The motor lead cable is spliced to the power cable and banded to the pump and seal assembly all the way down to the pothead, which is plugged into the motor. The motor lead always has a flat profile so the pump can be sized as large as possible, allowing the ESP system maximum flow capacity and efficiency. All the factors involved in selecting the main ESP power cable, as described later, apply to the motor lead cable. As with power cable, consulting an applications engineer can be very helpful in selecting the appropriate motor lead cable for the application.



Figure 9-2: Motor lead extension

Theory of operation

Due to the extreme and varying nature of oil wells, cable must be durable in a wide range of conditions. Long cable life is most effectively achieved by preventing decompression damage and mechanical damage resulting in durable long-lasting ESP cables.

Withstand rapid gas decompression

Most oil wells have a high concentration of dissolved gasses referred to as the gas-to-oil ratio (GOR). These gasses readily dissolve into the synthetic rubber cable jacket and insulation materials because they are derived from oil. When the pressure on oil inside a well is reduced bubbles begin to form within the oil: this is referred to as the bubble point of oil. When the bubble point is reached in the ESP cable insulation, i.e. when the pressure on the cable is rapidly reduced, such as when the pump lowers the liquid level in the well or when the cable is pulled from the well, bubbles form inside the insulation. Rapid reduction in pressure is referred to as decompression and the resulting damage to the cable insulation is called decompression damage. ESP cable designers use several different methods to prevent damage from rapid gas decompression.

One popular design approach is to cover the cable with an impermeable layer of lead to keep the insulation from ever being exposed to oil well gasses. This design works well as long as no pinholes or other forms of damage ever compromise the lead layer. A second and widely used method of preventing decompression damage is called containment. By tightly containing the insulation so it cannot swell up when pressure is reduced, gasses inside the insulation are prevented from forming into bubbles which would damage the electrical properties of the insulation. A third and even more effective method is to cover the insulation with an extruded **Fluro-Barrier™** layer of low permeability material so the gasses trapped inside the insulation escape very slowly from the cable causing no damage to the insulation even at the molecular level. Containment of the insulation and barrier layers in round cable is accomplished by tightly wrapping the cable with a layer of metal armor. In flat cables containment is achieved by braiding a layer of strong fibers around the insulated conductors. Proper selection of the armor and braid materials, that can withstand the oil well environment, is essential to preventing decompression damage which is the key to extending ESP cable life.

Protect from mechanical damage/corrosion

During transport and installation at a wellsite, ESP cable can be damaged in many ways. Even after the cable is successfully installed in the well it can be weakened by corrosive fluids and gasses. As emphasized above, the outer metal armor in round cable plays a critical role in preventing decompression damage as well as physically protecting the cable during handling

and installation. Many different types of armor materials are available including, galvanized steel, stainless steel, and Monel®. Armor is also available in a range of thicknesses to meet the physical and corrosive demands of the well environment.

Baker Hughes ESP system cable

As the leading designer and manufacturer of ESP cable, Baker Hughes offers a diverse line of cable manufactured to withstand the many different and challenging well environments. Selecting the right ESP cable extends system run life and prevents lost production and costly premature pulls due to cable failure.

ESP system cable is available in a wide range of conductor sizes (Figure 9-4), which permits efficient matching to motor requirements. They are manufactured in either round or flat configurations using galvanized steel, stainless steel, or Monel® armor that is capable of withstanding the hostile environments of an oil well. All cables are made to strict specifications using specially formulated materials for different operating environments. Baker Hughes uses propriety insulation to protect the conductor and give the cable the highest temperature rating in the industry. Solid conductor construction is recommended because of its superior decompression resistance. Stranded conductor construction is available upon special request.

Description						
Product	Conductor	Insulation	Covering	Jacket	Configuration	Armor
CPE	Copper	PolyPropylene		PolyEthylene	Round	N/A
CTT	Copper	Thermoplastic		Thermoplastic	Flat	
CPN	Copper	PolyPropylene		Nitrile	Round or Flat	
CEN	Copper	EPDM		Nitrile	Round or Flat	Galvanized steel, stainless steel, or Monel®
CEB	Copper	EPDM	Barrier	EPDM	Round	
CEBE(-HT)	Copper	EPDM	Barrier	EPDM	Round	
CEE	Copper	EPDM	Tape and Braid	EPDM	Round or Flat	
CPL	Copper	PolyPropylene	Lead		Flat	
CEL	Copper	EPDM	Lead		Round or Flat	

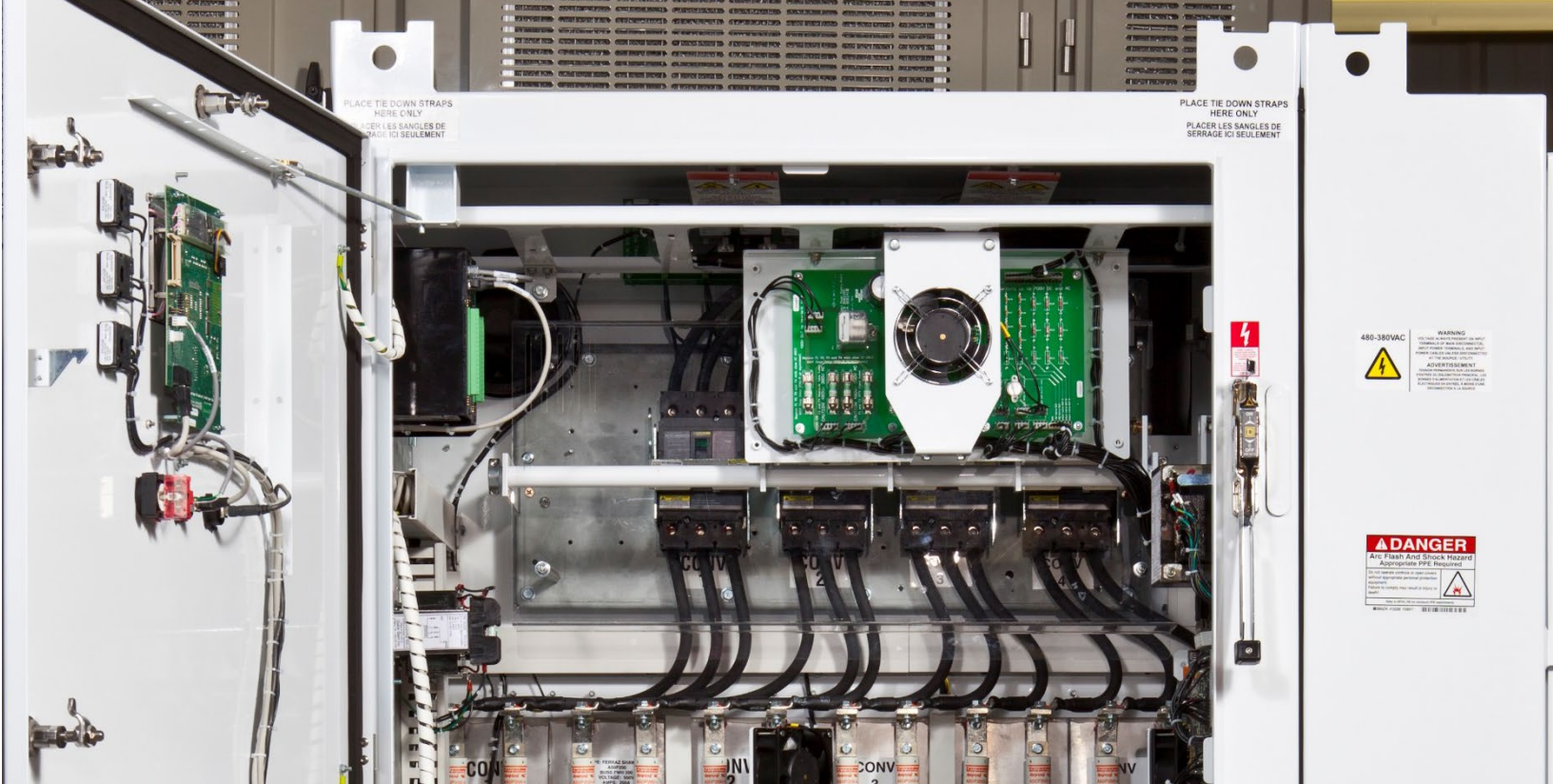
Product	Min temperature	Max conductor temperature	Gas service
CPE	-30 ° F/ -34 ° C	176 ° F/ 80 ° C	Standard <3% H ₂ S
CTT	-30 ° F/ -34 ° C	205 ° F/ 96 ° C	
CPN	-30 ° F/ -34 ° C	205 ° F/ 96 ° C	
CEN	-30 ° F/ -34 ° C	280 ° F/ 138 ° C	
CEB	-40 ° F/ -40 ° C	300 ° F/ 149 ° C	Barrier <3% H ₂ S
CEBE (-HT)	-60 ° F/ -51 ° C	400 ° F/ 204 ° C	Very High GOR gassy wells
CEE	-60 ° F/ -51 ° C	400 ° F/ 204 ° C	
CPL	-40 ° F/ -40 ° C	257 ° F/ 125 ° C	Moderately gassy wells
CEL	-40 ° F/ -40 ° C	500 ° F/ 260 ° C	High H ₂ S > 3%, High GOR High CO ₂ Corrosive fluids

Figure 9-4: Cable temperature rating

Features and benefits of Baker Hughes ESP system cable

- Full line of reliable power cables for any ESP application
- Manufacturing flexibility allows for specific configurations and construction materials
 - Integrated chemical injection line(s)
 - Armor options
- Efficiently provide electrical power to downhole motors
- Unmatched patented designs
- Provides an unmatched wide operating range covering production dynamics
- Delivers robust design and rigorous testing for the most challenging environments
- Extends cable run life in extremely abrasive applications

Notes:



Section 3:

ESP surface controllers

Chapter 11: Electrical power fundamentals

Chapter 12: ESP system variable speed drives

Chapter 13: ESP switchboards (fixed speed)

Notes:

Chapter 11

Electrical power fundamentals

Electrical power distribution

Most power stations use either hydraulic energy, heat energy produced by uranium, or heat energy produced by burning fossil fuels such as coal, oil, or natural gas to produce steam to drive a turbine coupled to a generator. Figure 10-1 shows a typical power distribution system.

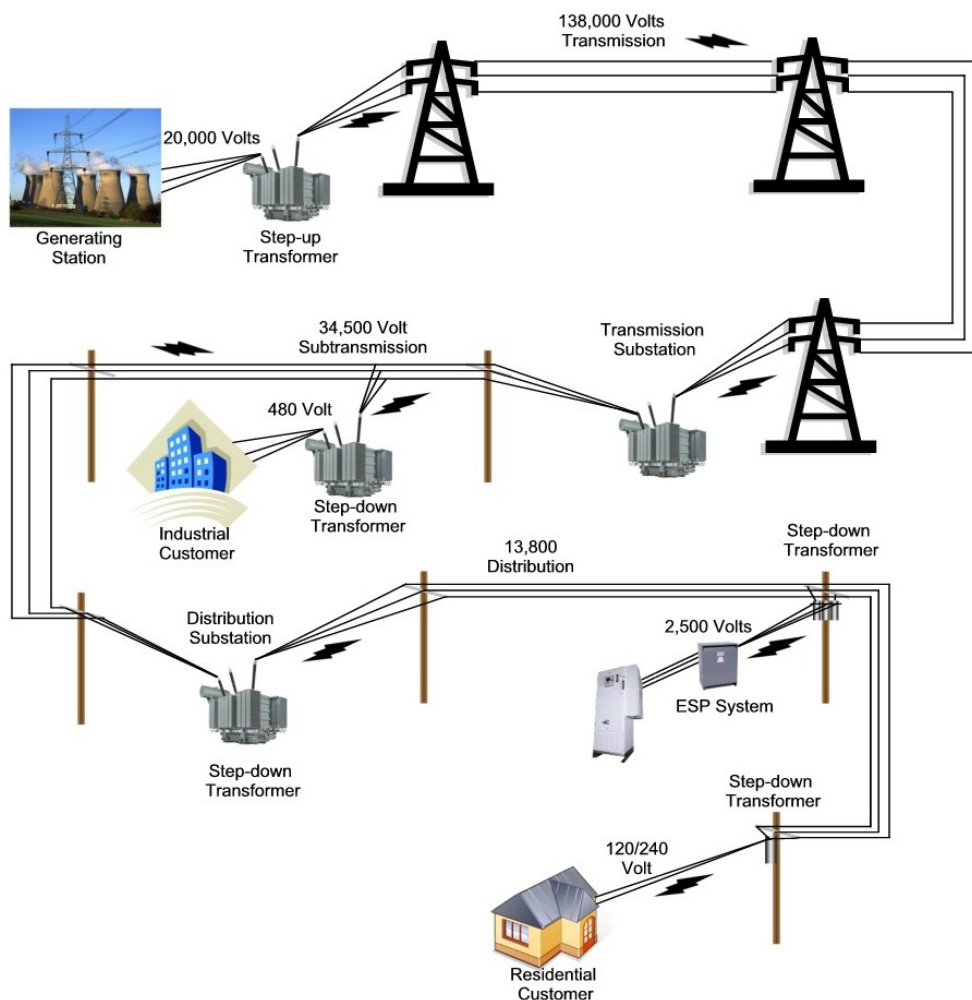


Figure 10-1: Typical electrical power distribution system

The alternating current (AC) generator is the most important means for the production of electrical power. All AC generators convert mechanical energy into electrical energy. This energy

conversion depends on the action of a coil rotating through a magnetic field and of a magnetic field rotating through a coil for their operation. Relative motion between a conductor and a magnetic field generates a voltage. Therefore, the generator converts mechanical energy into electrical energy, which is then directed to the consumer by the transmission and distribution system.

High voltage AC power minimizes transmission losses, making AC power the best suited for long-distance power transmission. Transformers increase and decrease AC voltages to accommodate suitable optimal voltage requirements throughout the distribution system. AC power is generated at low to moderately high voltages, transmitted at very high values, and consumed at lower voltages. The higher the voltage (electrical pressure), the smaller the wire required to carry a given amount of power, hence, the advantage of high-voltage transmission. The following are some basic electrical fundamentals to help better understand the principles of electrical power generation and distribution systems.

Voltage (V)

Since the electrons are typically distributed evenly throughout a substance, a force or pressure called electromotive force (EMF) is required to detach them from the atoms and make them flow in a definite direction. This force is also often called potential or voltage. The unit for measuring this electromotive force is the volt.

Current (I)

When a sufficiently strong potential or voltage is applied to a conductive substance, it causes the flow of electrons. This flow of electrons is called an electrical current. The rate of this flow of current is measured in amperes. An ampere is the rate of flow of electric current represented by the movement of a unit quantity of electrons per second.

Resistance (R)

Resistance is analogous to the friction encountered by a flow of water through a pipe. A straight pipe with a smooth inside surface conducts water flow with little loss of pressure. If the same length pipe is rough inside and has many bends, the required pressure differential increases to force the same flow rate. Similarly, a material having low resistance allows electricity to flow with small voltage losses; a material with high resistance causes an increased drop in voltage. The energy used in overcoming resistance is converted into heat.

Ohms law

The voltage required to make a current flow depends upon the resistance of the circuit. One volt forces one ampere through a resistance of one ohm. This relationship is known as "Ohms Law."

$$I = \frac{V}{R}$$

Where: I = Current (amperes)

V = Voltage (volts)

R = Resistance (ohms)

Alternating current sine wave

In a single-phase AC power system, the voltage and current follow an approximate sine wave. They build up from zero to a maximum in one direction, then diminish to zero, builds up to a maximum in the opposite/negative direction, and again diminish to zero, thus completing one cycle or two alternations and 360 electrical degrees (Figure 10-2).

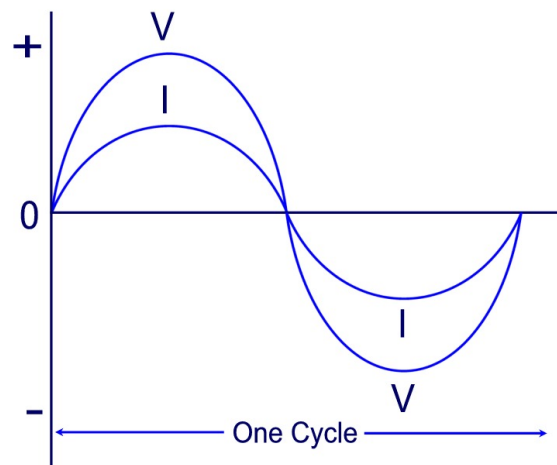


Figure 10-2: Alternating current sine wave

Power

Power is defined as the rate of doing work, abbreviated (P). In electrical terms, it represents the energy necessary to maintain the flow of current. Electric power is measured in watts. 746 watts is equal to one horsepower. One watt is a rather small unit of power; consequently, when speaking of power required by motors, the term kilowatt (kW) is used, one kilowatt is a thousand watts. True or real power refers to the amount of power consumed in a circuit. In a purely resistive circuit, when voltage and current are in phase, power can be defined as:

$$P = V \times I$$

Where: P = Power (watts)
I = Current (amperes)
V = Voltage (volts)

A three-phase AC power distribution system, as the name implies, has three single-phase AC power systems. These single-phase systems are spaced, so the voltage generated in any one phase is displaced by 120 degrees from the other two (Figure 10-3). The total power delivered by a balanced three-phase system is equal to three times the power delivered by each phase.

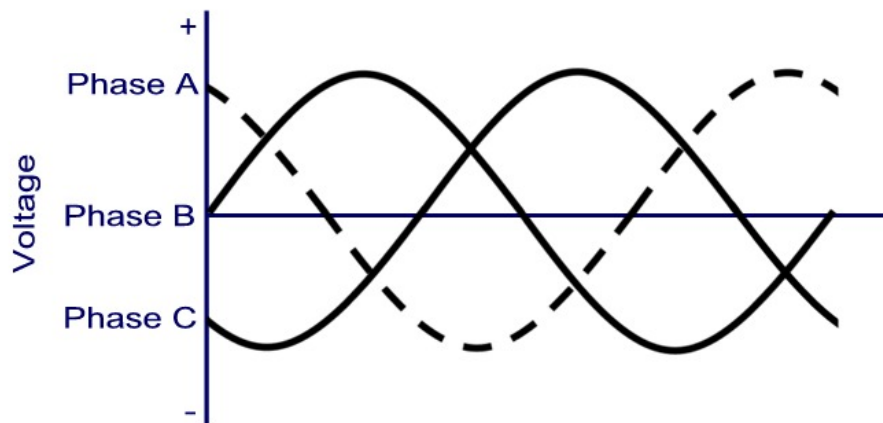


Figure 10-3: Three-phase sine wave

To obtain the power delivered to an alternating-current motor, you cannot merely multiply effective amperes by effective volts. If the circuit contains inductance and/or capacitance, and motor circuits always do, the product of the effective current and effective voltage is greater than the true power. Apparent power refers to this higher than true power value, ignoring the circuits phase angle. Apparent power is measured in volt-amperes or more often in a unit 1,000 times as large, the kilovolt-ampere, abbreviated kVA.

Frequency (Hertz)

When a generator rotates through 360 degrees, one complete revolution, the generated voltage completed is one cycle. If the generator rotates at a speed of 60 revolutions per second, the generated voltage completes 60 cycles in 1 second, it can then be said that the generated voltage has a frequency of 60 cycles or 60 hertz.

The following formula describes the relationship between the supplied electrical frequency, the mechanical frequency of the rotor, and the number of poles in the motor.

$$f = \frac{N * P}{120}$$

Where: f = electrical frequency (hertz)
N = mechanical frequency (rpm)
P = motor pole count (2, 4, 6,)

Inductance (L)

Many AC circuits contain coils, transformers, and other electrical apparatus that produce magnetic effects. Once the current increases, the circuit stores energy in the magnetic field. When the current decreases, the circuit gives up this energy from the magnetic field. Therefore, these magnetic effects react upon the current. They impede the current and cause it to lag behind the voltage, as illustrated in Figure 10-4, where it may be seen that the voltage has reached its maximum and started to fall some time before the current reaches a maximum. Some current flows in the circuit at the instant when the voltage is zero. This magnetic reaction is called inductance and is measured in henrys.

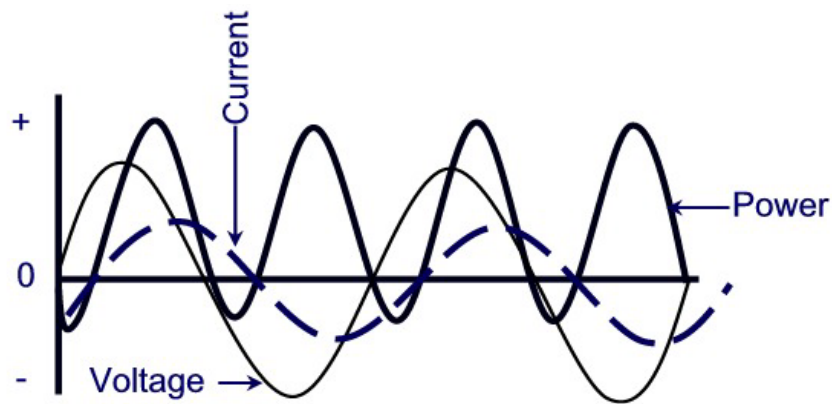


Figure 10-4: Diagrammatic Illustration of Magnetic Effects on Current

Inductive reactance is the action of inductance in opposing the flow of alternating current and in causing the current to lag the voltage. It is measured in ohms and symbolized by X_L . In a purely inductive circuit, the true power is zero. The formula used to calculate inductive reactance is:

$$X_L = 2 * \pi * f * L$$

Where:

X_L = inductive reactance (ohms)

f = frequency (hertz)

L = inductance (henries)

Capacitance (C)

The presence of capacitance causes another kind of influence on current in an AC circuit.

Capacitance exists between any nearby conductive materials (plates) separated by insulation.

This phenomenon is used to store energy in devices referred to as capacitors. A capacitor charges its plates with energy from the circuit, and then returns that charge to the circuit when the circuit energy is removed. Capacitance is the ability to accumulate a charge from the circuit and to give it back to the circuit. It is measured in farads. Capacitance opposes any change in voltage, and its effect on the current is to cause it to lead ahead of the voltage. It tends to counteract the inductance in a circuit and is useful in overcoming the inductive lag in the current inherent in most alternating current motors.

Capacitive reactance is the action of capacitance in opposing the alternating current and causing the current to lead the voltage. It is measured in ohms and symbolized by X_c . In a purely capacitive circuit, the true power is zero. The formula used to calculate capacitive reactance is:

$$X_c = \frac{1}{2 * \pi * f * C}$$

Where: X_c = capacitive reactance (ohms)
f = frequency (hertz)
C = capacitance (farads)

Impedance (z)

In an AC circuit, resistance, inductance, and capacitance affect the current. The impedance of the circuit is the combination of any two or all three of these effects. Resistance is a concept primarily used in direct current, and impedance is the AC equivalent of resistance. The impedance is the opposition to current flow when a voltage is applied. The unit of measurement of impedance is the ohm. The unit for the measurement of very low impedance is the microohm and is equal to one-millionth of an ohm. The unit for very high impedance is the megohm and is equal to one million ohms.

All electrical, electronic, and many other types of scientific measurement make use of standard prefixes, which are attached to the front of the word that is used as the standard unit of measure. The prefixes indicate the precise multiplier or fraction of that standard unit. The range of prefixes in common use is as follows:

Measurement conversion			
Prefix	Abbreviation	Meaning	Mathematical equivalent
pico	p ($\mu\mu$)	1 millionth of 1 million part of	10^{-12}
nano (millimicro)	m ($m\mu$)	1 thousandth of 1 million part of	10^{-9}
micro	μ	1 millionth part of	10^{-6}
milli	m	1 thousandth part of	10^{-3}
centi	c	1 hundredth part of	10^{-2}
-	unit	unit standard of measurement	10^0
kilo	k	1 thousand times	10^3
mega	m	1 million times	10^6
giga	g	1 thousand million times	10^9

Figure 10-5: Measurement conversion table

Conductors

A conductor is a substance that permits electrons to flow freely through it. Every substance is a conductor of electricity, but electrons flow very easily through some materials such as gold, silver, copper, aluminum, iron, and other metals. Wire and cables are the most common forms of conductors.

Insulators

An insulator is a substance through which electrons have great difficulty traveling. Materials such as rubber, glass, certain plastics, fiber, and dry paper allow almost no electrons to flow through them. These materials are called insulators, non-conductors, or dielectrics. When an insulator is continuous, for instance, around a wire, it is commonly called insulation.

Power factor

Power factor is the ratio of true power (kW) to the apparent power (kVA), the former measured by a wattmeter and the latter by a voltmeter and ammeter; therefore, power factor (pf) can be defined as follows:

$$\text{Power factor} = \frac{\text{TruePower (kW)}}{\text{ApparentPower (kVA)}}$$

Rewriting this equation, you can see that the kilowatt input to any machine may be found by multiplying KVA input by the power factor:

$$\text{TruePower (kW)} = \text{ApparentPower (kVA)} * \text{PowerFactor}$$

The power factor is said to be 1.0 or unity if the voltage and current reach their respective maximum values simultaneously. However, as discussed previously, in most alternating current systems, the voltage reaches its maximum value in a given direction before the current attains its maximum value. In this case, the current lags behind the voltage. This lag is measured in degrees. Various ESP components in the electricity's path, such as but not limited to transformers, induction motors, and variable speed, drives cause this current lag.

The actual current drawn by an apparatus of this class may be considered as having two components. One component is known as the magnetizing current, or that current which must overcome the choking effect produced by the characteristics of the apparatus, and which lags 90 electrical degrees behind the voltage. The value of this lagging current is zero when the voltage has reached its maximum value. This lagging or magnetizing current is called the reactive current. The other component is known as the real current, and it is in phase with the voltage. This real current and the voltage reach maximum values simultaneously.

The actual line current is the vector sum of the reactive and real currents; furthermore, it is the current that would be registered if an ammeter was connected in the circuit. Since there is one component lagging 90 electrical degrees or at right angles to the voltage, the resultant or actual line current of which this component is a part must, consequently, be out of phase with the voltage and lag behind it. The degree, or amount that it lags depends upon the magnitude of this reactive current component and is a measure of power factor.

Transformers

A transformer changes the voltage in an alternating-current system. It consists of an iron core surrounded by coils of insulated wire. Usually, both core and coils are immersed in oil, which serves as an insulator and helps cool the transformer.

A simple transformer (Figure 10-6) consists of two windings very tightly coupled together, usually with an iron core, but electrically insulated from each other. The winding to which an AC voltage source is applied is called the primary. It generates a magnetic field that cuts through the turns of the other coil, called the secondary, and generates a voltage in it. The windings are not physically connected. They are, however, magnetically coupled to each other. Thus, a transformer transfers electrical power from one coil to another by using this alternating magnetic field.

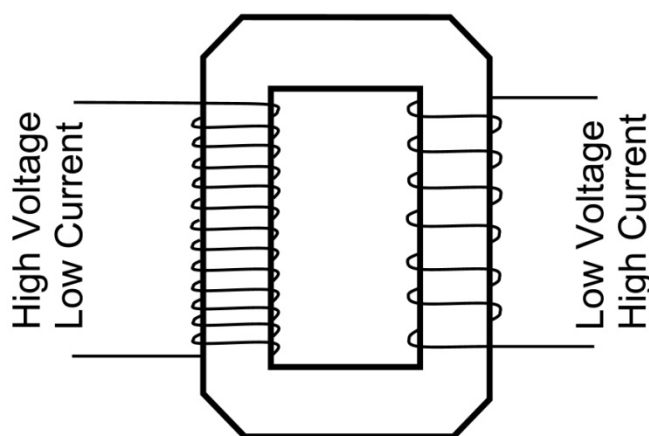


Figure 10-6: Simple Transformer Illustration

For simplicity, assume all the primary magnetic lines of force cut through all the secondary turns. The voltage induced in the secondary (V_s) depends on the ratio between the number of turns in the secondary (N_s) and primary (N_p). This is mathematically expressed as:

$$V_s = \left(\frac{N_s}{N_p} \right) * V_p$$

Where: V_s = secondary voltage (v)
 N_s = secondary turns
 N_p = primary turns
 V_p = primary voltage (v)

The transformer voltage increase or decrease is proportional to the transformer turn ratio. For instance, if the primary winding has 1,000 turns and is connected to a 4160V circuit, a secondary winding of 100 turns provides 416V. In this case, the transformer ratio is 10:1.

In an auto-transformer, there is only one winding, part of it being for low voltage and all of it being connected in the high-voltage circuit, as shown in Figure 10-7. The high voltage circuit is not isolated from the low-voltage circuit in this transformer.

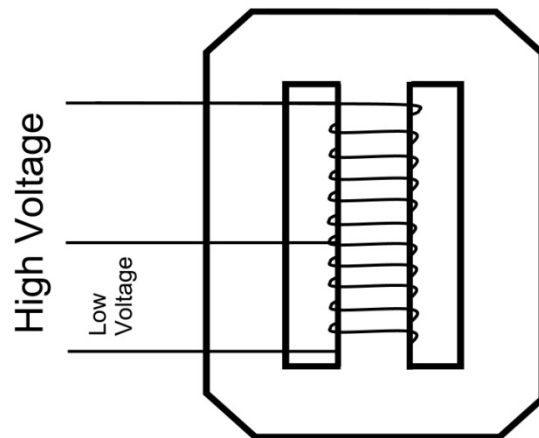


Figure 10-7: Auto-transformer illustration

A transformer does not generate electrical power. It merely transfers electrical power from one winding to another by magnetic induction. Although transformers are not 100% efficient, they are very nearly so. Remember, power is the product of voltage and current. Therefore $V_P I_P$ represents the primary power, and $V_S I_S$ represents the secondary power. The transformer's primary power equals the secondary power (assuming 100% efficiency). Expressing these statements in equation form for the 100% efficient transformer, we have:

$$V_P * I_P = V_S * I_S$$

Where: V_P = primary voltage (V)
 I_P = primary current (A)
 V_S = secondary voltage (V)
 I_S = secondary current (A)

Wye and delta connections

Wye and delta connections are the two primary methods of connecting three-phase AC devices, specifically generators and transformers. These connections got their names because their circuit resembles the Latin letter wye "Y" and the Greek letter delta "Δ." Figure 10-8 illustrates windings in wye and delta connections.

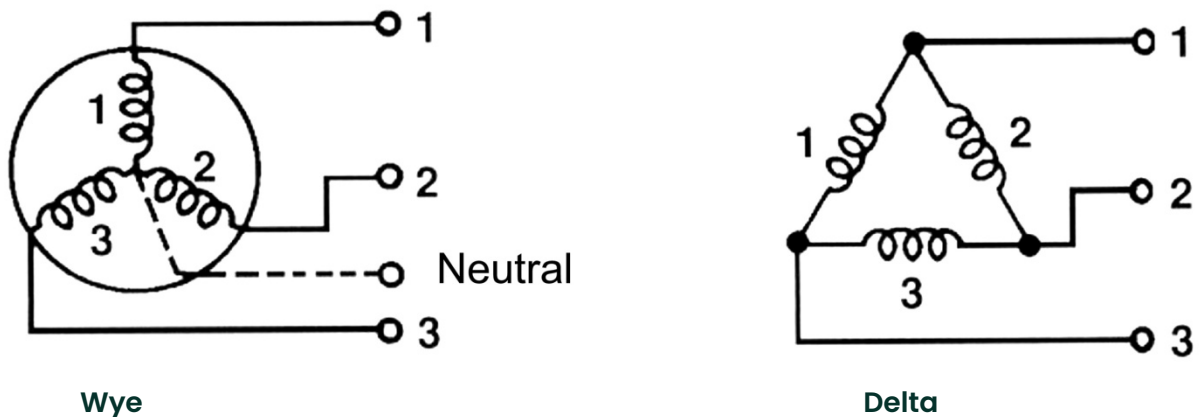


Figure 10-8: Wye and Delta connections

Three winding generators produce three-phase alternating current. As previously mentioned, these windings occupy positions such that the voltage produced in each winding becomes displaced 120 electrical degrees from voltages produced in the other two windings. Electrical degrees differ from our usual concept of degrees. A four-pole generator, for example, produced two cycles, or 720 electrical degrees, for a single mechanical revolution (360 degrees) of its rotor.

For delta connection, the line voltage is equal to the voltage produced in any one of the three windings, assuming that the system is without loads or that the load is equally distributed among the three phases. For a wye connection, the line voltage is greater than the voltage produced in one winding by a factor of 1.732 (the square root of 3). Vectorially adding the instantaneous voltages in the three windings derives this 1.732 factor. In a balanced system, the current in a wye system is equal to the current in each winding. However, in the delta system, the line current is 1.732 times the current in each winding of a balanced system.

By connecting three single-phase transformers, you can configure a three-phase transformer in either a wye or delta configuration. The wye connection configuration requires three transformers to provide three-phase power, which is necessary to power a three-phase device such as our ESP motors. The wye connection produces a higher voltage than the delta connection, which is

sometimes a considerable advantage. A delta connection configuration has the unique advantage that three-phase power can be delivered using only two transformers, although at a sacrifice of considerable capacity. The transformers connected in what is called an open delta can deliver only 57.7 percent of the power of three transformers connected in a closed delta. ESP applications utilize multiple transformer configurations to optimize electrical performance.

Notes:

Chapter 12

ESP system variable speed drives

Purpose

Electrical submersible pumps have limited flexibility when operated at a fixed speed. Baker Hughes variable speed drives (VSD) allow operators to optimize production by controlling the speed of the pump and protect the ESP system by monitoring equipment performance. This allows operators the ability to use the full range of the centrifugal pump to manage dynamic well conditions. The VSD has gained acceptance as the ESP controller to alleviate these restrictions. Variable speed drives offer operators the most flexibility for controlling their ESPs.



Figure 11-1: Baker Hughes variable speed drive

Components

ESP variable speed drives are made up of the following major components

- Enclosure
- System control
 - Human Machine Interface – Graphical Control System (GCS)
 - Motor controller
 - Expansion module i/O modules
- Power Module
 - Converter
 - DC BUS link
 - Inverter

Enclosure

Whether operating in the desert, tropics, arctic, or a controlled environment, Baker Hughes VSD enclosures are engineered to perform in the most demanding environments. Oil field operations typically require the VSD to be outdoors in the elements. Baker Hughes offers a full line of NEMA4/IP56 rated enclosure to provide maximum protection against rain and dust. Baker Hughes also provides an industry-leading 55 Celsius temperature rating for the hottest outdoor environments. Packages can be customized to meet individual customer requirements, as well as local regulations. Packages include hazardous area modules, severe climate modules, specialized protective modules, mobile modules, and complete control room modules.

System control

The Baker Hughes graphics control system (GCS) motor controller provides protection, monitoring, and control for ESPs. Use of the latest digital electronics and graphic display technology allows for an intuitive human interface that delivers ease of set-up, operation, and diagnostics.

When combined with available sensors, the GCS controller is configurable for use in many types of programmable motor control applications. The GCS provides additional flexibility with system expansion and customization. The display unit is common to all modules of the GCS family, offering a familiar interface for a variety of control and measurement products.



Figure 11-3: Graphical control system (GCS) display

Power module

Most variable speed drives (power modules) consist of three fundamental components; converter, dc bus, and inverter. The converter converts the incoming alternating current into direct current and voltage. The dc bus briefly stores the dc power in capacitors. The inverter converts this stored energy into a new alternating current of a desired frequency. There are few variations of this process, but this AC to DC to AC process is fundamental to most drives.

The converter of the variable speed drive can be configured in various ways to reduce harmonics; 6-pulse, 12-pulse, 18-pulse, and 24-pulse. The GCS Electrospeed variable speed drive offers 6-pulse or 12-pulse converters as standard options. For improved input power harmonics, Baker Hughes provides a full line of GridSync 24-pulse VSDs to help operators meet IEEE standards.

The inverter can be configured in a variety of ways to reconstruct the waveform. The GCS Electrospeed is the only VSD in the industry to offer FPWM™ or ESP-mode (six-step) output waveforms. The Electrospeed VSD is programmable for variable torque, constant torque, and constant voltage with extended speed range. Baker Hughes was an early adopter applying variable speed drives to ESP application and develop the GCS Electrospeed specifically for ESP application.

Theory of operation

The basic operation of the VSD is to convert the incoming three-phase AC power, typically at 480 volts, to a single DC power supply. Then, using power semiconductors as solid-state switches, it sequentially inverts the DC supply to regenerate three AC output phases of pseudo-sinewave power. The frequency and voltage of the output wave are controllable.

Controlling motor speed offers equipment fine-tuning ESP operation through changing well conditions; decreasing system stresses at start-up, managing well drawdown, and improving ESP gas and solids handling capabilities. The variable speed drive delivers reliable operation by monitoring and responding to key equipment parameters, including motor current, motor temperature, pump pressure differential, and vibration. The variable speed drives further supports maximum production by maintaining a desired bottom hole pressure or reservoir pressure.

The ESP operation is restricted to points on a fixed speed pump curve (See Figure 4-1: Pump Curve). At a fixed speed, centrifugal pumps have a unique head delivery at a given flow. The total dynamic head requirement of the application will set the pump flow rate and resulting efficiency. Centrifugal pump performance curves change with pump speed according to affinity laws (see tornado curve). By allowing the pump speed to be varied, the rate and/or head can be adjusted (depending on the application) with no modification of the downhole unit.

Variable speed drives control the pump speed to protect the pumping system. Baker Hughes drives shut down the system if conditions develop that could potentially damage the ESP. If operating parameters go outside a set point, but are still within a critical limit range, the VSD will slowly make step changes to return to the initial set point. The unit also provides up to 200% starting torque to overcome hard start situations.

Although pumping flexibility is typically the original purpose of applying a VSD, there are additional benefits to the operator. Particularly, the VSD extends downhole equipment life, provides soft start capabilities, controls wellbore drawdown, automatically controls speed, provide line-transient suppression, and may eliminate the need for surface chokes. The VSD also helps prevent electrical failures. VSD controllers do this by isolating the load from incoming switching and lightning transients, balancing output volts to reduce motor heating, ignoring frequency instability from generator supplies, compensating for brownouts, and minimizing starting stresses. In addition, VSDs can improve overall system efficiency, reduce the required generator size, avoid the need for a choke, reduce downhole unit size, and provide intelligent control functions to maximize production.

The best combination of drive features and benefits must be selected and combined based on the application.

VSD effects on ESP system components

Effects on centrifugal pumps

As previously discussed, the performance of the centrifugal pump is described by a curve of head versus rate for a given speed. Changes in speed generate a new curve. The head values are larger if the speed is increased and smaller if the speed is decreased. As the operating frequency of a three-phase induction motor varies, the pump's speed changes in direct proportion to the frequency. Thus, the speed of the pump and its hydraulic output can be controlled simply by varying the power supply frequency. This remains true provided that voltage and motor loading limits are properly observed.

The technique of combining the performance characteristics of the centrifugal pump and the three-phase induction motor, allows a multiple frequency performance curve (tornado curve) to be developed (Figure 11-4). The following equations were derived based on these conditions:

Derived from affinity laws

$$\text{New Rate} = \frac{\text{New Hertz}}{60 \text{ Hertz}} \times 60 \text{ Hertz Rate}$$

$$\text{New Head} = \left(\frac{\text{New Hertz}}{60 \text{ Hertz}} \right)^2 \times 60 \text{ Hertz Head}$$

$$\text{New BHP} = \left(\frac{\text{New Hertz}}{60 \text{ Hertz}} \right)^3 \times 60 \text{ Hertz BHP}$$

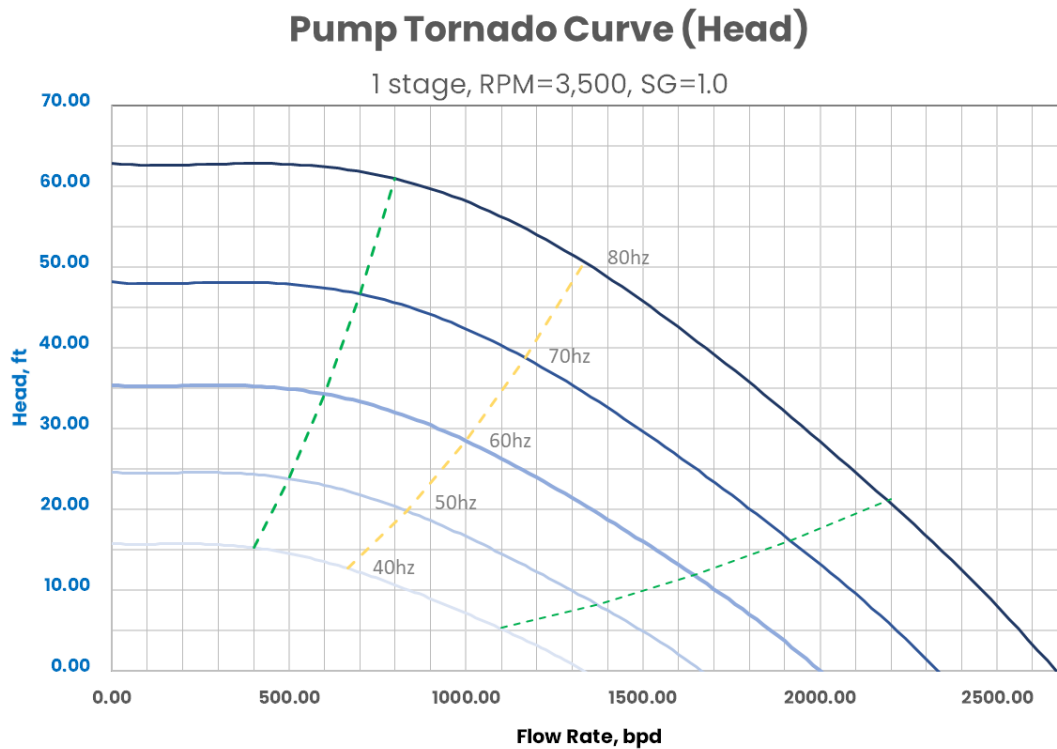


Figure 11-4: Variable speed (tornado) pump curve

Effects on motor

A fixed frequency motor of a particular frame size has a specified maximum output torque for the specified voltage that is supplied to its terminals. This same torque can be achieved at other speeds by varying the voltage in proportion to the frequency. This allows the magnetizing current and flux density to remain constant and so the available torque will also be constant (at nominal slip rpm). As a result, power rating is obtained by multiplying rated torque by speed. Power output rating is directly proportional to speed. It should be noted that this rerating of motors increases the maximum horsepower available to fit a particular size casing.

$$\text{New Power Output} = \left(\frac{\text{New Hertz}}{60 \text{ Hertz}} \right) \times 60 \text{ Hertz Power Output}$$

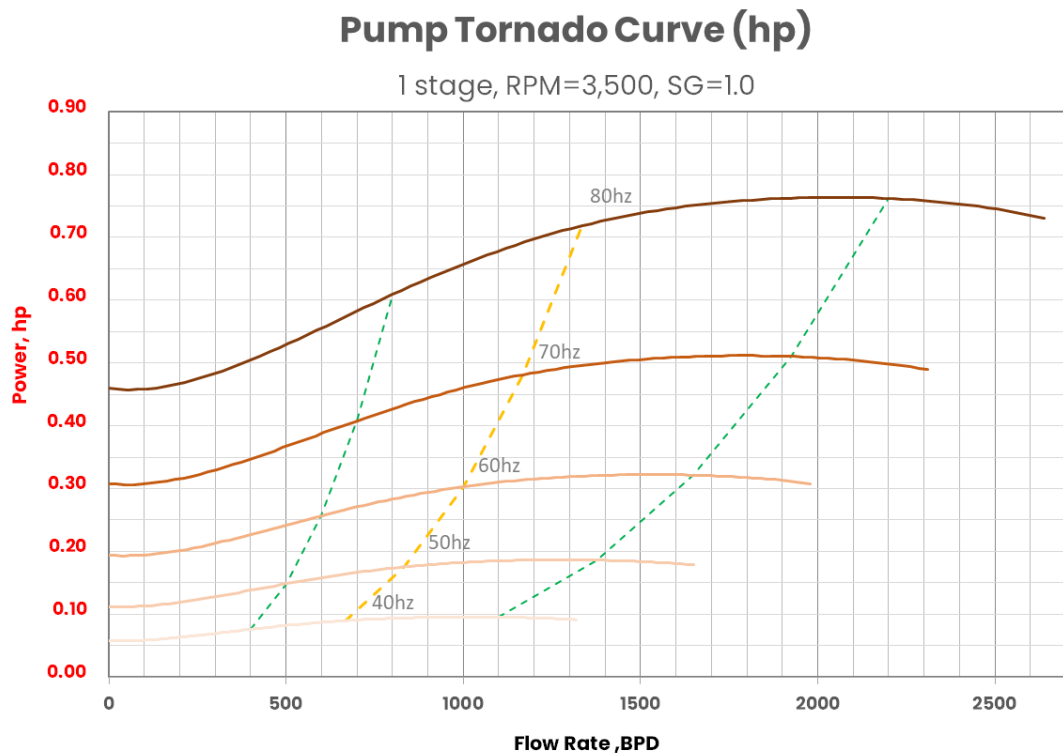


Figure 11-5: Variable speed (tornado) pump curve

Matching motor, pump, and VSD

Normally the pump is chosen to deliver a certain hydraulic output at a particular speed. A motor is chosen so that the capacity matches the pump when operating at the maximum anticipated speed. Any frequency above that speed will overload the motor due to the cubic nature of the pump load. Similarly, the motor will operate in underload at lower frequencies. This relationship is reflected in the current drawn by the motor as the motor nameplate amps will only be drawn at the chosen speed.

The surface kVA requirement is calculated to include the resistive loss in the power cable and motor requirements at maximum frequency since this represents the peak requirement of the system. A VSD unit is selected if its rated kVA capacity matches or exceeds the requirements. The linear characteristic of the motor HP capability intersects the cubic pump BHP characteristic at the design maximum frequency. Higher operating frequencies would generate a motor overload situation (Figure 11-6). These principles lay out the theory, but in practice, there are several additional details that also need to be considered when designing a full VSD system.

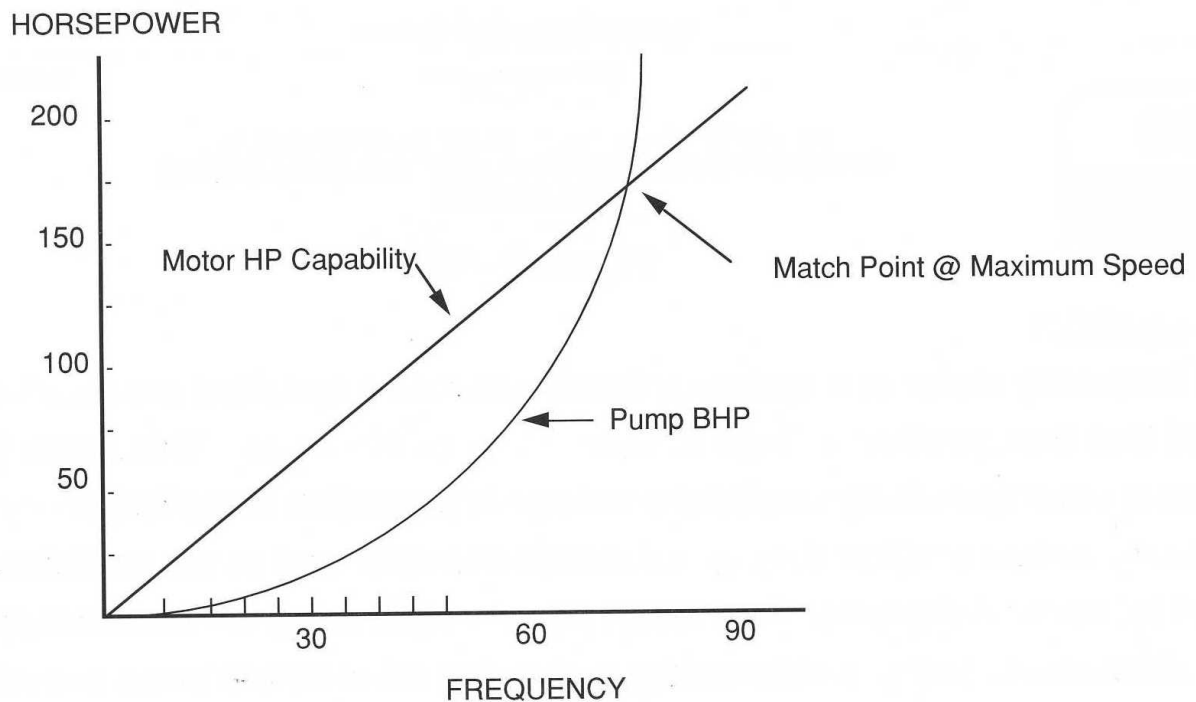


Figure 11-6: Horsepower versus brake horsepower chart

Pump shaft limitation

The horsepower capacity of the shaft is proportional to speed while the brake horsepower is a cubic function of speed. Therefore, there will be a speed above which the pump shaft rating will be exceeded. This rating should be checked at maximum frequency. It should be recognized that running a pump shaft at high frequency maximizes its capability to deliver power and this can be significant in installations where shaft strength is a limiting factor.

Vibration

The ability to change rotational speed provides the opportunity for vibration problems to occur. There are two modes of vibration that can have an effect on ESP systems. First is lateral vibration, which is vibration occurring sideways with respect to the length of the ESP. Second is torsional vibration, or vibration that is a twisting of the ESP shaft. Vibration may be a result of forces caused by unbalance, rubbing, or unit position in casing. These forces are found in any machine that has moving parts. In other words, any machine may vibrate. Other factors that affect vibration are the type of motion in the machine, the mass, speed, stiffness, and damping of the machine.

Natural vibration frequencies are generally related to length, diameter, and mass of the system. In general, due to the long length and small diameter of the electrical submersible pumping

equipment, the natural frequency of the system is very low. Experience has shown that, in this condition, the lower the natural frequency the lower the vibration levels.

Damping is another effect that reduces the amplitude of vibration at natural frequencies. ESP systems generally have high damping due to the fluid being pumped and the motor fluid in the motor and the seal. Except in very special conditions, natural frequencies do not result in vibration.

The higher operating speed produced by a variable speed drive will increase vibration due to unbalance. The forces due to an unbalanced weight are proportional to the operating frequency squared. Manufacturers take steps while machining parts to maintain required concentricity to prevent unbalance. They also balance the heavier rotating parts to minimize the effects of unbalance on ESP equipment. Excessive unbalance, and the resulting vibration, will result in bearing and stage seal ring wear.

Wear

Wear increases exponentially with surface speed. Therefore, speed increases will result in an accelerated wear rate. If abrasive wear is a problem in a well, the higher operating speeds will make the wear greater. On the other hand, lower operating speeds will make the wear much less. The VSD can be used in these cases to operate at lower speeds at the expense of using an oversized pump and motor. Since this enhances run life, a lower overall operating cost results in areas where pulling costs are high.

Motor efficiency

The voltage waveform generated by the VSD is generally a six-step pseudo-sinewave. Although the current waveform is nearly sinusoidal, the harmonic content does generate increased motor losses (in the order of 10%). However, accurate balancing of the three-phase voltages reduces losses. Most ESP manufacturers assess that these two factors cancel out. The proportional increase in losses due to harmonics is much more significant in surface motors because of their higher base efficiencies.

Running at higher frequencies also increases efficiency losses. In the constant flux case, resistive heating in the windings and all rotor losses remain constant. These three factors actually contribute a smaller loss percentage at higher speeds. Stator iron losses are roughly proportional to frequency and do not contribute to a percentage change. The friction losses in the oil gap however, are approximately proportional to the square of speed. Therefore, there is an increase in the total percentage losses at higher speeds.

Motor heating

Even if motor efficiency remains constant, rerating a motor to a higher than nameplate horsepower means that more kilowatts are dissipated through an unchanged surface area. This causes internal motor temperature to increase. The motor temperature in an actual ESP installation is determined by many factors. The main variables are the velocity and viscosity of the fluid as it passes by the motor housing since this is how motors are cooled. To compensate for the extra heat generated in a high frequency VSD application, manufacturers normally recommend a higher minimum flow rate past the motor.

Starting

In the oil field, a normal across-the-line start is a rather poorly controlled event. Typically there are two desirable modes of starting. A soft start is preferred under clean fluid conditions. If sand or scale is present, the system may require the highest torque possible. With an across-the-line start, neither cable impedance nor power supply regulation can be altered. This controller can deliver excessive torque at shallow setting depths with strong power supply installations.

In contrast, the VSD can use low frequencies to shift the speed-torque curve of the motor to achieve low starting torques at low currents. When desired, it can be adjusted to deliver peak torque at quite modest starting currents by raising the starting frequency a little higher.

There is a voltage drop effect dependent on the length of cable between the VSD and motor. The cable voltage drop becomes a large percentage of required surface volts at low frequencies. In this case, a boost to the volts/hertz ratio of the VSD is required to deliver the necessary starting amps downhole. Since this would saturate a standard transformer, special low flux density designs are supplied for the output transformer to deliver the high volts required downhole.

Baker Hughes variable speed drives

The **GCS Electrospeed™ 3** is available in two standard enclosures: general purpose NEMA 1 and weatherproof NEMA 4. Each of these enclosures is offered in three frame sizes: 2000, 4000, and 8000 series. The GCS Electrospeed 3 features all stainless steel fittings to provide maximum durability, even in harsh environments.

The Baker Hughes GCS Electrospeed 3 variable speed drive is TUV certified to UL specifications in both the United States and Canada. These drives also bear the CE mark for European Union approval.

In most series, the GCS Electrospeed 3 offers a standard choice of 6-pulse, 12-pulse, or IEEE compliant converter options. IEEE 519-1992 is the recommended practice for increased harmonic reduction.

The GCS Electrospeed 3 is the only VSD that offers a choice of output waveforms. The industry standard is the traditional 6-step output waveform, which has been successfully used in thousands of ESP systems for more than two decades.

The GCS Electrospeed 3 also offers the option of FPWM (filtered pulse width modulation) output. This option provides an output waveform that closely replicates a sine wave, which can be a benefit to system run life. The GCS Electrospeed 3 continually monitors the output filter. Filtering is important to systems to prevent harmful voltage spikes that are present in certain situations with unfiltered PWM outputs. In the event of a filter failure, the filter is automatically disconnected from the output and the VSD switches from FPWM to 6-step output mode without shutting down the ESP. The GCS Electrospeed 3 is designed to seamlessly interface with downhole monitors and data communications systems. The GCS interface is engineered to gather and log data from both drive performance and downhole ESP monitors. Information can then be observed, downloaded to a computer, or communicated for remote monitoring and control. Operational parameters can then be analyzed or compared to the simulator in the AutographPC software program for measuring and analyzing data retrieved from wells. When parameters move outside maximum efficiency envelopes, equipment performance can be adjusted through the GCS Electrospeed 3 to optimize well and field performance.

Features and benefits of Baker Hughes variable speed drives

- Unit RPM can be increased to counteract ESP wear and maintain maximum production for a longer system life
- Improves power quality to the motor by isolating downhole equipment from damaging power fluctuations and balancing all three phases of the output voltage
- Soft starts the unit which reduces starting stress by controlling current levels during start-up
- Allows motor speed adjustments to match fluctuating well conditions for maximum production
- Increases remote operation capabilities by interfacing with downhole sensors and communications
- Reduces well lifting costs by reducing generator size, power consumption and downhole equipment requirements
- Controls motor speed to maintain critical operating levels in the presence of high GOR, high viscosity, or sand

Notes:

Chapter 13

ESP switchboard (fixed speed)

Purpose

Baker Hughes ElectroStart™ switchboards are full voltage pump panels specifically engineered for use with electrical submersible pumping (ESP) systems. ElectroStart switchboards include a fused disconnect, a vacuum contactor, and a full range control power transformer housed in a NEMA 3R enclosure with separate high and low voltage compartments.



Figure 12-1: Baker Hughes ElectroStart ESP switchboard

Components

The switchboard (across-the-line starter) is comprised of a motor starter, solid-state circuitry for overload and underload protection, a manual disconnect switch or circuit breaker, time delay circuitry, and a recording ammeter. Many control systems have surface equipment for use with bottomhole pressure and temperature monitoring equipment installed within the motor controller cabinet. Fuses are provided for short circuit protection.

Theory of operation

Switchboards provide full voltage and current when the contactors are engaged. As previously stated, the power (voltage, current, and frequency) applied to the switchboard is also the output voltage, current, and frequency. Step-up or step-down transformers may be used in line with the switchboard to change the voltage to a level suitable for the ESP electrical components (motor and cable).

When starting an ESP system with a switchboard, the frequency and voltage are the same at the input and output terminals. This results in a fixed speed operation. When started, the motor will ramp up to its rated speed within a fraction of a second. During starting, a motor can draw 5 to 8 times its rated current. This high starting current allows the motor to deliver several times its rated torque. This can cause excessive electrical and mechanical stress on the ESP equipment, especially in shallow set applications.

Generally, an ESP is placed into operation at a depth that requires several thousand feet of power cable. During start-up operations, this piece of cable causes a voltage drop to the motor. This reduced voltage start decreases the initial starting current and torque.

Time-delayed underload protection and automatic protection against voltage or current imbalance on all three phases is offered in most solid state controllers, underload, or some type of pump off protection, is necessary since low flow past the motor will not give adequate cooling. Circuits designed for automatic restart after shut down are normally included.

External control devices should be interfaced with the controller as recommended and/or approved by the pump manufacturer to give dependable and trouble free operation. All external control devices are connected to a time delay, which activates or deactivates the controller after a short time delay. Usual external control devices are tank hi-lo level controls or line pressure switches.

Baker Hughes switchboards

GCS electroStart switchboard – The GCS ElectroStart switchboard is a full voltage pump panel specifically engineered for ESP equipment. The standard switchboard package includes the advanced GCS Vortex programmable solid-state motor controller.

The Baker Hughes family of switchboards provides application specific solutions.

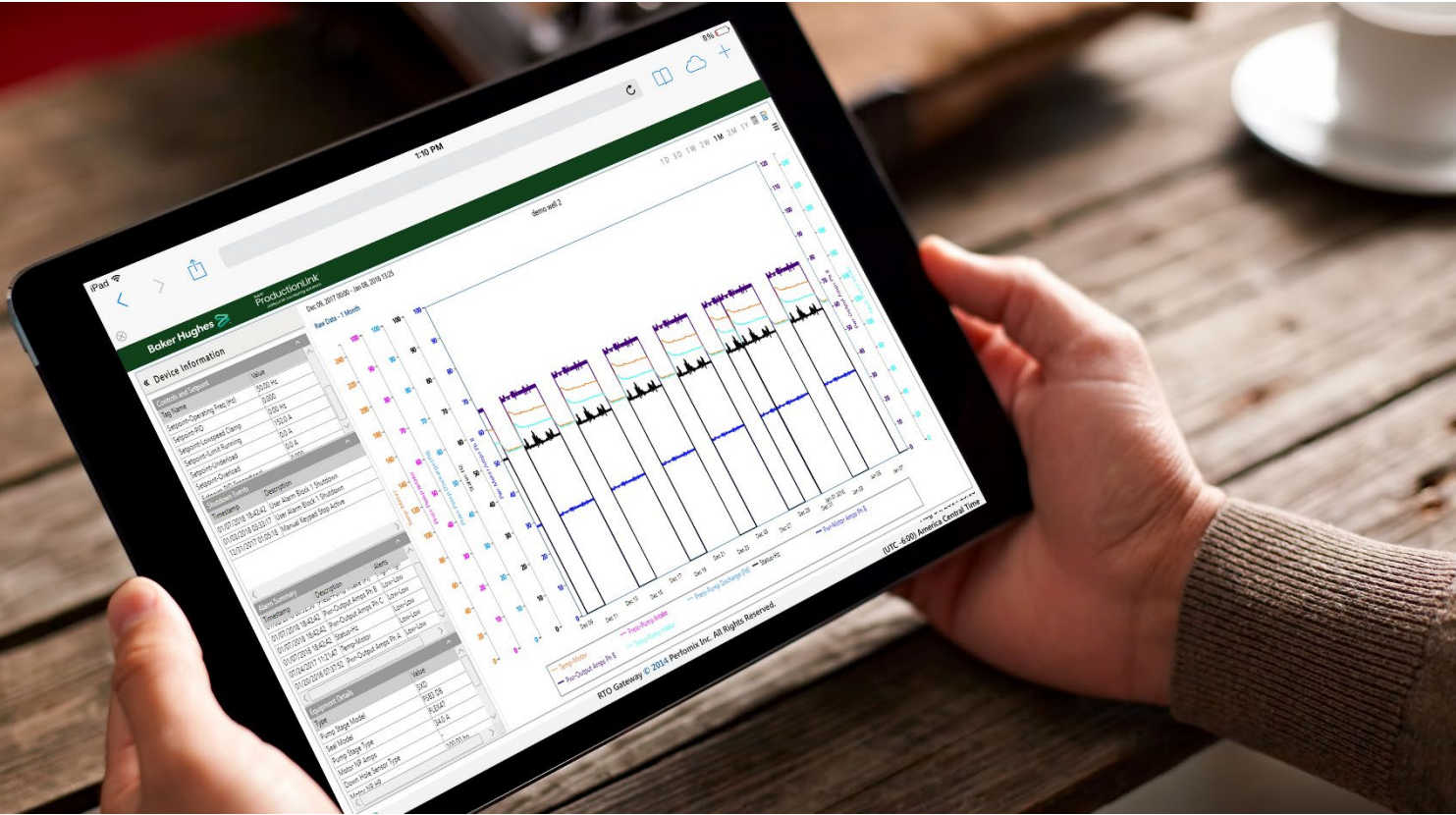
- Electrostart SP – Available with either a graphic control system or a Vortex motor controller, but no additional upgrades, and is rated for up to 3,600 volts.
- Electrostart SP1 – A full-featured model with the graphic control system and rated for up to 3,300 volts. Optional equipment configurations are also available.
- Electrostart SP2 – The most full-featured, state-of-the-art switchboard in the industry features the graphic control system and is rated to 4,800 volts.

Optional equipment configurations are available based on the application.

Features and benefits of Baker Hughes ESP system switchboards

Feature	Benefit
GCS electronic ammeter	Provides superior accuracy and reliability versus standard chart recordings
Input disconnect	Reliable arc extinguishing system
Vacuum contactor	Effective arc containment and quenching, reducing risk of fire and/or explosions
NEMA 3R Enclosure	Allows for outdoor installations
Control power transformer	Several taps provide customers full flexibility of operation voltages

Notes:



Section 4: Monitoring and automation

Chapter 14: Downhole sensor

Chapter 15: ProductionLink artificial lift monitoring service

Notes:

Chapter 14

Downhole sensor

Purpose

Downhole sensors are used to monitor physical characteristics of the oil well and pumping system, delivering '*real time*' data to surface which enables operators to make fast, appropriate and confident assessment of oil production and system performance. Reliable insight into downhole operations can deliver enhanced ESP system efficiency, reliability, run life and production rates whilst improving well longevity, safeguarding pumping equipment and reducing operating costs.

As part of the Baker Hughes artificial lift portfolio, the **Zenith™** line of downhole monitoring systems deliver quality and reliability for our customers. Continual product improvement delivers a sensors portfolio that offers the best technology and highest level of service.

Zenith gauges are available to address a full range of artificial lift monitoring applications including high temperature and high pressure rated solutions. Offering a selection of ESP gauges to suit individual economic and technical requirements, and a full range of slimline sensors, rigless-deployed gauges, and permanent cable-to-surface solutions enables Baker Hughes to offer a wider range of solutions than our competitors.

Components

A typical Zenith E-Series ESP monitoring system includes the following basic components:

- Downhole gauge
- Surface inductor panel (choke)
- Surface panel (ZSP)

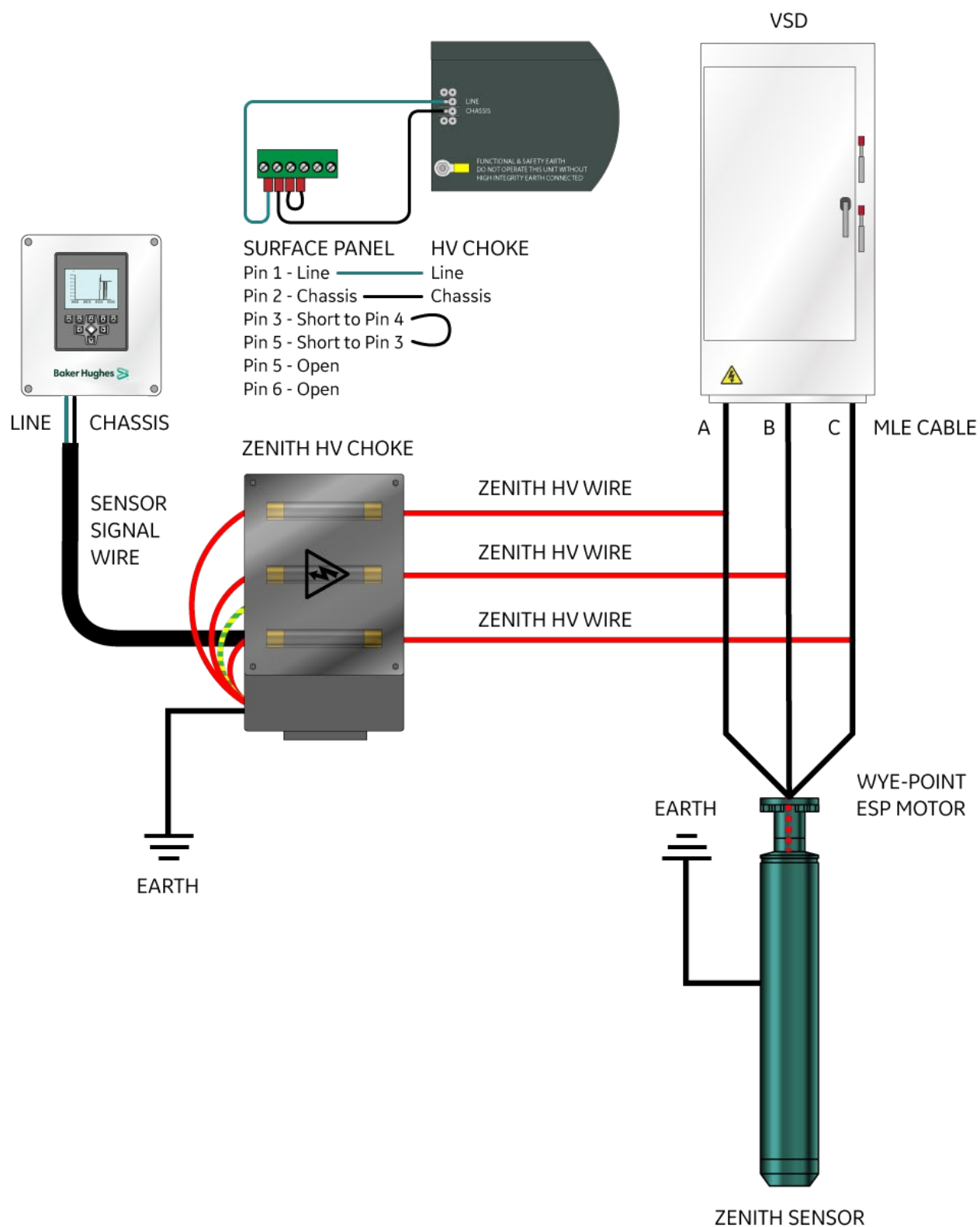


Figure 14-1: Zenith E-Series wiring diagram

A typical Zenith C-Series cable-to-surface monitoring system includes the following basic components:

- Downhole gauge
- Gauge carrier or mandrel
- ¼-in. Mono-core cable
- Surface panel (ZSP)

The downhole gauge acts as the nerve center of the monitoring system. It contains a myriad of electronics, including sensors to measure parameters such as pressure, temperature, and vibration.

The E-Series gauge is installed below an ESP motor using a flange connection and connected electrically to the wye point of the motor. A motor base crossover may be required.

C-Series gauges are installed in a clamp, carrier sub or mandrel in the tubing string above or below the pump and use an electric instrument line to power and communicate signals to surface.

The surface inductor panel, or “choke,” is a 5,000V interface module that enables the surface panel to communicate with the downhole gauge. The choke allows DC power and data-carrying current to be safely superimposed on the high voltage AC downhole power cable that powers the AC motor of the ESP. This is where we get the term “comms-on-power,” as the DC current provides the communications by travelling unimpeded on the AC power cable.

The choke contains very high AC voltages during operation and acts as a buffer between the high voltage AC power and the low voltage DC signals and should at no time be opened unless the downhole AC power has been locked out and tagged out.

The surface panel or “ZSP” provides the interface for communication with the downhole gauge by accepting a low voltage signal from the choke and converting that signal into industry standard data streams that can be viewed locally, stored for future evaluation or transmitted via SCADA or other data management systems.

The panel contains a display and keypad for local information and can be connected to surface drives to provide automated shut-down signals in addition to alarms protecting lift systems and well integrity.

Theory of operation

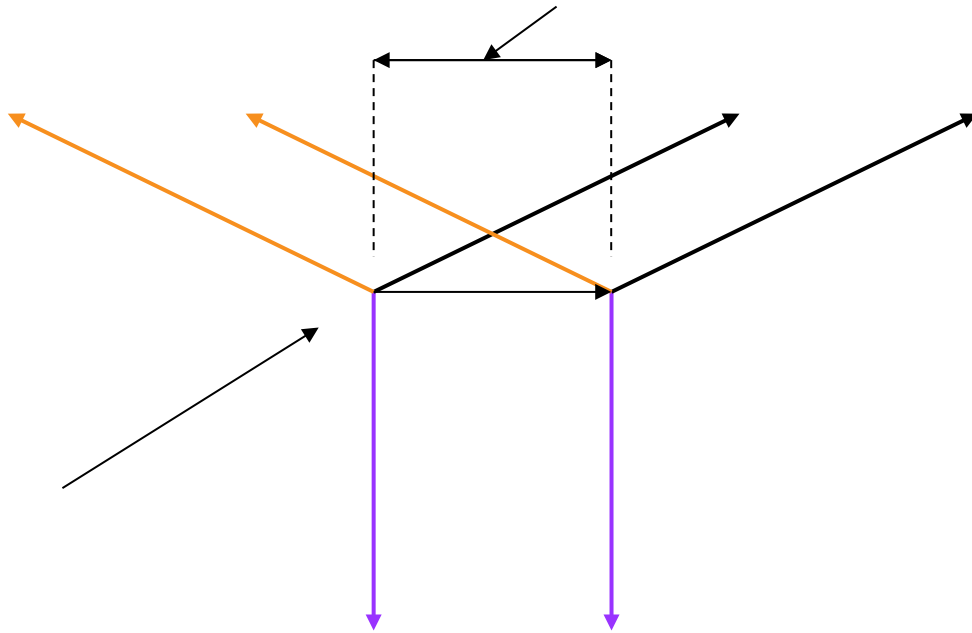
Comms-on-power ESP gauges (Zenith E-Series)

Downhole sensors for ESP wells communicate with the surface via the 3-phase conductor power cable. These sensors used to monitor ESPs are broadly termed “comms-on-power” sensors. The term refers to communicating with the downhole sensor over the power cable and through the motor.

The ability to communicate with the downhole gauge over the same power cable that is sending thousands of volts of AC power to the ESP motor is made possible by a phenomenon of electrical transmission. At the base of the motor, after the AC current has passed through the motor and provided power, all three phases are brought together in what is known as the “star point” or “wye point”. At this point there are 0 volts of AC power present, assuming all three conductors of the power cable are equally balanced. The downhole sensor is AC-coupled to the conductors of the power cable through the wye point at the base of the motor assembly.

In the surface inductor panel, or “choke,” a virtual star point is created and through this star point a low- to mid-voltage DC current is superimposed on each of the three conductors of the downhole power cable. This voltage then travels to the star point at the base of the motor completely independent of the AC current. The choke is AC-coupled to the conductors of the power cable to separate the medium voltage and the low voltage to both prevent harm to personnel and protect the surface panel (HMI).

The following diagram shows how the three phases of the AC power, shown as vectors, cancel out to zero at the star points. The entire vector diagram is then shifted by the amount of DC voltage that is applied at the surface star point.

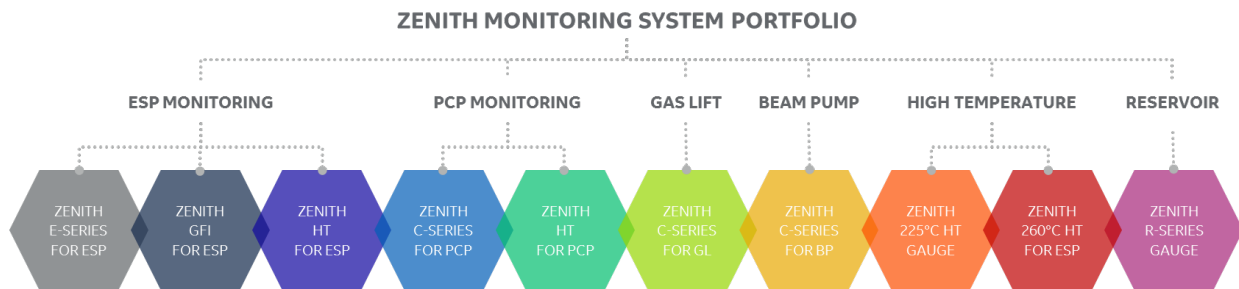


This DC voltage then is used to both power the gauge and provide data signals to the surface. For successful communications, the integrity of the downhole cable needs to be excellent. Degradation of the insulation allows current to “leak” to ground. Where Vdc power is tapped from the wye point of the motor, the communication system cannot tolerate increased current leakage or ground fault due to the sensors being of earth return signal. Such electrical noise has the ability to corrupt the sensor data stream to the surface, often referred to as a sensor failure, but can more often be related to poor grounding. When a certain threshold of leakage is reached, or any of the three phases of the downhole cable goes completely to ground, the motor can continue to operate but the comms-on-power sensor will lose communications.

Cable-to-surface (CTS) Zenith C-series

An alternative method of termination to the sensor for telemetry is on monocoil tubing encapsulated cable (TEC) lines. The metallic sheathed inductor cable is connected to the tool via a modified motor base crossover allowing normal fitment to the motor base. The cable can either be bare or encapsulated for further protection.

The cable is terminated at a junction box at surface after exiting through the well head penetrator – such terminations do not require the use of a surface choke as there is no contact with the ESP medium voltage. It is terminated direct to the surface panel operating on a nominal 120Vdc.



Zenith E-Series ESP Gauge: Reliable downhole monitoring systems for electrical submersible pumps

Accurate, real-time measurements enable fast, appropriate and confident assessment of well and artificial lift system performance; optimize uptime, run life, pump performance and oil production whilst protecting the lift system and reducing operating costs.

E-Series gauges are available in multiple specifications to suit the application and economic impact of deploying a downhole monitoring system.

Low production wells with small economic impact: Measure intake pressure and intake temperature to prevent pump-off and provide well pressure surveillance.

Prolific wells or difficult conditions: Add discharge pressure, discharge temperature, motor winding temperature and vibration to enable full well analyses to assess performance and optimize production.

Gauge options are also available for reliable operation in HIGH-PRESSURE and HIGH-TEMPERATURE environments.

E-Series monitoring system options	E6	E7	E8
Primary Parameters for essential pump and well surveillance and protection			
Pump intake pressure	●	●	●
Pump discharge pressure	–	●	●
Intake temperature	●	●	●
Discharge temperature	–	–	●
Motor oil or motor winding temperatures	●	●	●
Vibration X axis	●	●	●
Vibration Y axis	●	●	●
Predictive parameters for preventative maintenance and effective workover management			
Current leakage	●	●	●
Wye point voltage	–	○	○

● Parameter included as standard | ○ Optional alternative or additional parameter

Zenith GFI ESP gauge: Industry-first ESP gauge to deliver unshakable surveillance despite ground fault conditions

Unlike traditional downhole monitoring systems, the Zenith GFI ground fault immune ESP gauge cannot be disturbed by cable ground faults, allowing maintained reliable well surveillance resulting in up to 25% more production.

Continuous reliable well data enables better decision making, optimized production and efficient well operation:

- Increase production by reducing ESPs running without data
- High speed downhole data delivery
- Improve reservoir data quality during start up and shut down
- Fault location measurement system
- Diagnostic trail and continuous monitoring of ESP cable health

Zenith GFI gauge measured parameters	
Downhole gauge	Pi, Pd, Ti, Tm, Vx, Vz, THV
Surface	PhIV, Ph2V, Ph3V
Calculated output	Fault severity, fault depth, fault resistance

Zenith high-temperature (HT) ESP gauge: Extends downhole ESP gauge temperature limitations, operating reliably up to 260°C

Installation of a Zenith HT high temperature gauge in a well delivers dependable downhole surveillance despite challenging environments, ensuring continued delivery of data from wells experiencing temperatures up to 260°C.

- Proven reliability
- No downhole electronics
- Simple deployment
- No downhole fiber optics
- Compatible with all ESPs

Features and benefits

Enabling customer reserves to be produced in the most efficient and profitable manner, the Zenith name has become synonymous with reliable downhole monitoring systems.

Recognized value

- Exacting test processes/standards.
- Multiple spec options to suit.
- Slimline, tubing-deployed, and dual ESP system designs.
- Solutions for high-pressure and high-temperature environments.
- Compatible with all pump equipment.
- ZSP / ZIU compatible with non-Baker Hughes drives.
- Refurb in country.
- Continual product improvement.

Designed for reliability

- Advanced tech welded transducers.
- Electronics mounted to absorb vibration.
- Cable encapsulation protects in harsh conditions (CO₂/H₂S)
- Rigorous testing and continuous improvement.

Prolong ESP run life and enhance oil recovery

Maximize run life while reducing costs

Alarm/trip safeguards ESP and well, protecting against:

- Unnecessary workover and expenditure
- Excessive well draw down
- High- or low-flow rates (pump upthrust or downthrust)
- Dead heading or shut in
- Resonant vibration frequencies

Optimize production

- Dual pressure gauge enables full validation and analysis of well and ESP operating conditions
- Feedback intake pressure level to VSD frequency setting to provide automated control of draw down
- Fast sampling and accurate gauges enable analysis of draw-down and build-up pressure transients

Deliver reliable data and analysis

- Identification of pump wear issues.
- Validation of inflow/outflow data.
- Field-proven reliability.
- Fast sampling and accurate.
- Long service life for repeated deployment.

Notes:

Chapter 15

ProductionLink artificial lift monitoring service



The **ProductionLink™ artificial lift monitoring service** provides real-time transmission, visualization and monitoring of artificial lift operational data to effectively and efficiently optimize production. These services deliver an integrated field connectivity solution, bringing wellsite data to the user through a secure web-based interface. ProductionLink monitoring service minimize health and safety risks (requiring fewer trips to the field), reduce well intervention costs and downtime, and maximize equipment run life.

The platform interface promotes communication and collaboration between engineers and operators with built-in, real-time diagnostics and analytical capabilities. This enables real-time decision making with data tables and trend data visualization, tracks operational changes, and allows users to quickly assign and resolve tasks.

The dashboard features trending and alarming options that notify users by email or text message of any changes that may affect the system or well health. Advanced alarms trigger escalation workflows and send notifications to key personnel to take appropriate actions. Key performance indicators (KPIs), diagnostic, and analytical features provide reference data for well performance and device efficiency, which can be analyzed to improve production optimization decisions. The system can generate customizable, automated reports that can be sent based on ongoing subscriptions or emailed on demand. There is also a ProductionLink mobile application so users can remotely monitor wells on iOS and Android devices. The interface is viewable in multiple languages, including English, Russian, Chinese, and Spanish.

Technical description

Enterprise deployment model (ProductionLink private cloud)

The following schematic illustrates the network topology for ProductionLink Private Cloud, which provides a dedicated server which storage real-time data at operator offices and provides a web-based real-time visualization using customer network.

NOTE: Server administration, maintenance, IT and network support should be provided by customer who will be trained by Baker Hughes experts. Otherwise, Baker Hughes can provide an additional quote for these support services.

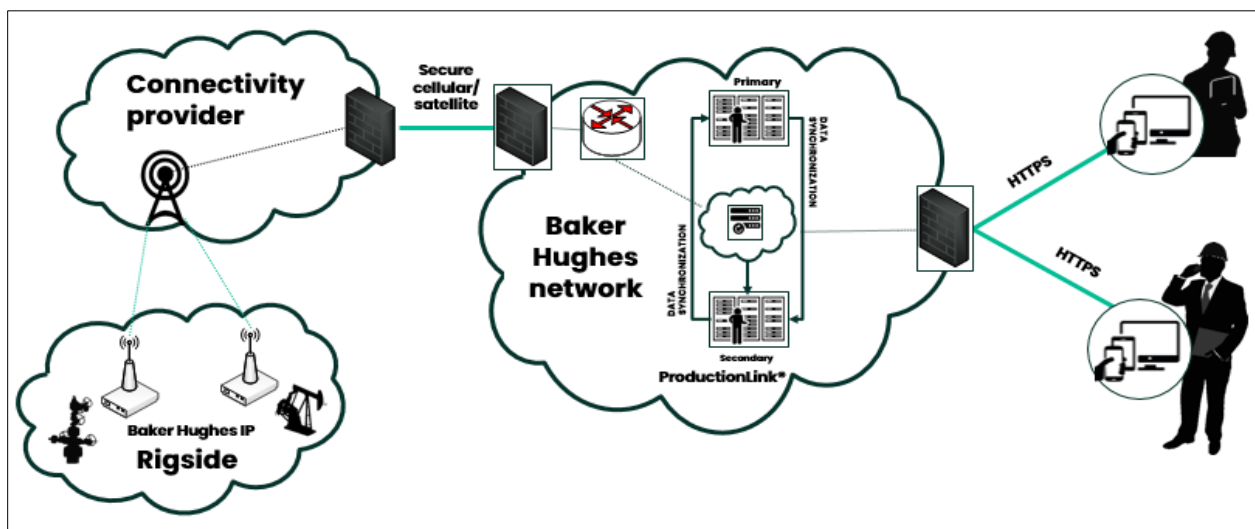


Figure 15-1: Baker Hughes cellular/satellite communications – data flow

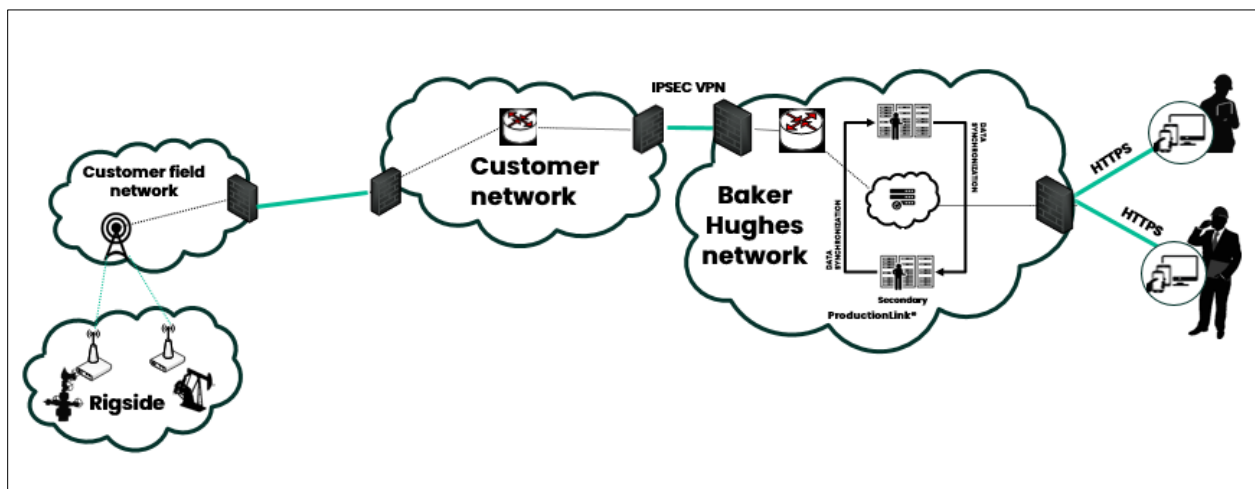


Figure 15-2: Data access from customer SCADA – control option

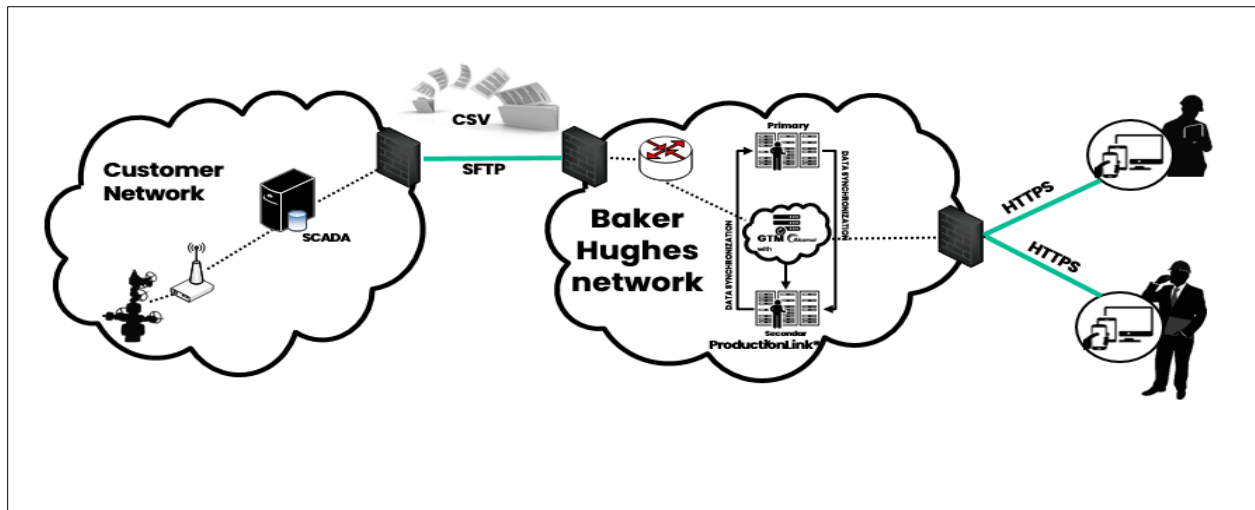


Figure 15-3: Data access using CSV files – data flow

Key platform features

- Grid enabled production data hub (PRODML Server) 'Big Data' platform with elastic scalability
- High-volume data managed through data compression and interpolation
- Scalable architecture supports versatile deployment scenarios
 - Embedded field systems
 - On premise server hosting and storage
 - Private or public cloud based environment
- Industry and IT standards based compliance and certification
 - PRODML, OPC/OPC-UA, Modbus TCP/RTU
 - HTML 5, BPMN, BPEL
- OSIsoft PI adaptor
- Device independent HTML5 visualization
- Service oriented architecture to support application interoperability
 - Published API
 - SDK
- Secure data management
 - HTTPS transport layer security
 - WSS message level security
 - Password object level security

Architecture overview

The ProductionLink platform combines state-of-the-art architecture with oil and gas and IT standards for seamless data exchange and integration to promote interoperability across customer and third-party applications, and to simplify the information flow between operators and regulatory agencies. It provides comprehensive collaborative workflows, real-time visibility, reporting and knowledge management framework, and tools to support the continuous improvement process; ensuring consistent performance and maximized revenue throughout the asset lifecycle.

The ProductionLink platform has a multi-tiered componentized architecture that facilitates elastic scalability at each tier and component levels based on the implementation requirements. The diagram below shows the various layers and capability of the ProductionLink platform. It utilizes the latest and most relevant technology at different layers and components to consistently provide agility and flexibility to adapt to changing business needs.

Data flow

The ProductionLink service can support end to end data aggregation and visualization to enable real-time visibility of field operations to end users. It also utilizes the power of Big Data management, multi-dimensional data analysis and reporting to create a comprehensive and easy-to-use business intelligent solution to maximize operational performance.

Our production data hub is compliant with the Energistics standard PRODML, and can aggregate all production and field measurement data at the enterprise level and supply standardized data to the consuming applications with the relevant level of granularity. The data flow of the ProductionLink platform is illustrated in the figure below.

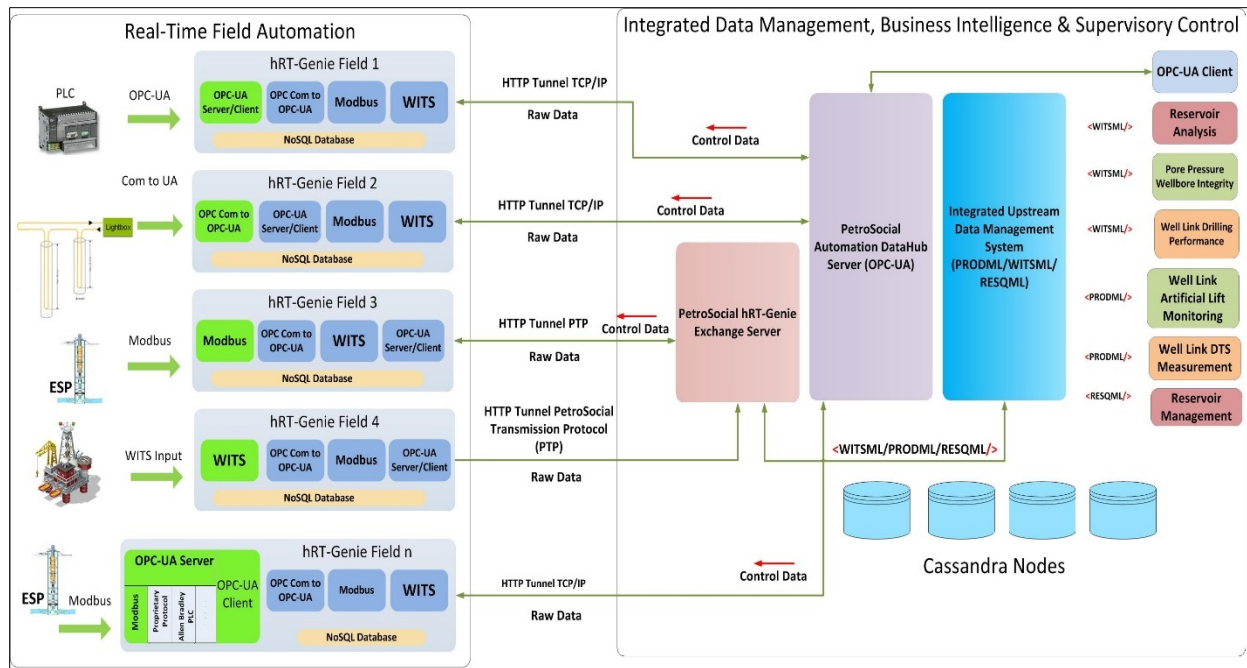


Figure 15-4: End-to-end data flow

High-availability deployment

Redundancy for hot failover and high availability is engineered into the solution software, hardware and power systems. The VMWare VMotion technology enables the application modules to float across the hardware stack to balance system load and recover from hardware and operating system failures.

All components of the ProductionLink service are deployed in a load balanced, high availability mode to enable scalability and maximum uptime. All components can be individually scaled up or down without impacting the other running components or causing service interruption; e.g., if the number of concurrent users increases then the production gateway and data hub can be scaled accordingly. If the volume of data increases above the threshold then the DB (Cassandra & Oracle) can be scaled without impacting the production gateway or data hub.

Automated failover is achieved through Global Traffic Management (GTM) with two geographically redundant data centers. It also helps in application load balancer without impacting the end users. Similar load balanced architecture can be used for on premise deployments.

Service quality management

The ProductionLink service has a mature ISO 9001 certified Quality Management System (QMS). We strive to deliver highest service quality for superior user experience. Our QMS includes the following areas:

- Service Quality Incident Investigations and Reporting
 - Investigation of critical service issues with audit/compliance or contractual related violations
 - Creation of incident reports
 - Implementation of corrective actions in timely manner to mitigate incident re-occurrence
- Continual Service Improvement Initiatives
- Execution of improvement projects to increase efficiency and streamline processes
- Creation and enforcement of standardized processes, best practices, and policies

Information security

The ProductionLink service has a mature ISO 27001 certified Information Security Management System (ISMS). It complies with the following standards:

- SAS 70 confirmation of physical and basic infrastructure controls at the data center
- Three-tier VLAN-based server architecture (web, application, database)
- Systems management and administration functions over a separate management network which does not have access to the Internet
- Commercially-proven fine-grained, role-based security
- Enterprise security standards specify standard operating procedures for:
 - Entitlements management
 - Authentication control
 - Account management
 - Password management
 - Encryption
 - Testing
 - Security patching
 - Virus protection
 - Administrative access control
 - Coding practices

Authentication/authorization

- Authentication of users with federation capabilities (SAML 2.0) and local identities where customer federation services are not available
- Authorization is managed by a robust data entitlement system with detailed audit trails

Integrated portal and user management

The ProductionLink service is available on any PC/Laptop with 2GB of RAM with Microsoft Internet Explorer® 8.0+ / Mozilla Firefox® 10.0+ / Google® Chrome 20+ / Safari® 5.1+, as well as iPad or Android tablets with compatible browsers. The application user authentication system seamlessly integrates with existing LDAP/AD enabling user authentication process in one centralized location within the company.

The ProductionLink service provides flexible and configurable user roles and supports role based access management. User accounts are categorized into roles and access managed in multiple categories including a basic user with only view only capability, power user with basic control capability and an administrator role to manage users, make changes to user roles, and customize entitlement settings. The role titles provided are just examples and are customizable based on company standards.

All view/modify/delete actions (users and widgets) are tracked and stored with detailed audit trails. Interactions between users and resources are controlled based on user access and permissions. Roles are assigned to users and control access is assigned to system resources; therefore, users can only access the resources and tools based on entitlements.

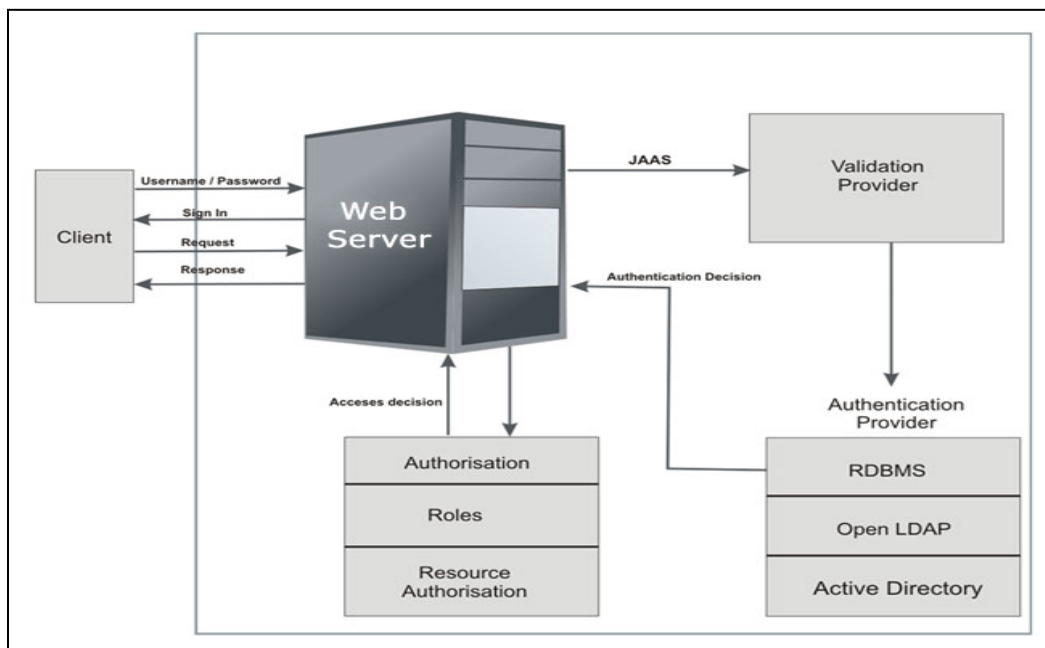


Figure 15-5: Authentication and authorization process

The ProductionLink service interface enables communication and collaboration among engineers and operators. This allows real-time decision making with data tables and data visualization, track operational changes, and enables users to quickly assign and resolve tasks.

The ProductionLink service supports all Lift type application (ESP, RLS, HPump, PCP, GL etc.) with the following product service tier levels:

- The ProductionLink Insight service
- The ProductionLink Expert service

The ProductionLink Insight service

The ProductionLink Insight service interface enables communication and collaboration between engineers and operators. This allows real-time decision making with data tables and data visualization, track operational changes, and enables users to quickly assign and resolve tasks. It supports all lift type applications (ESP, PCP, BPU and gas lift).

Key features

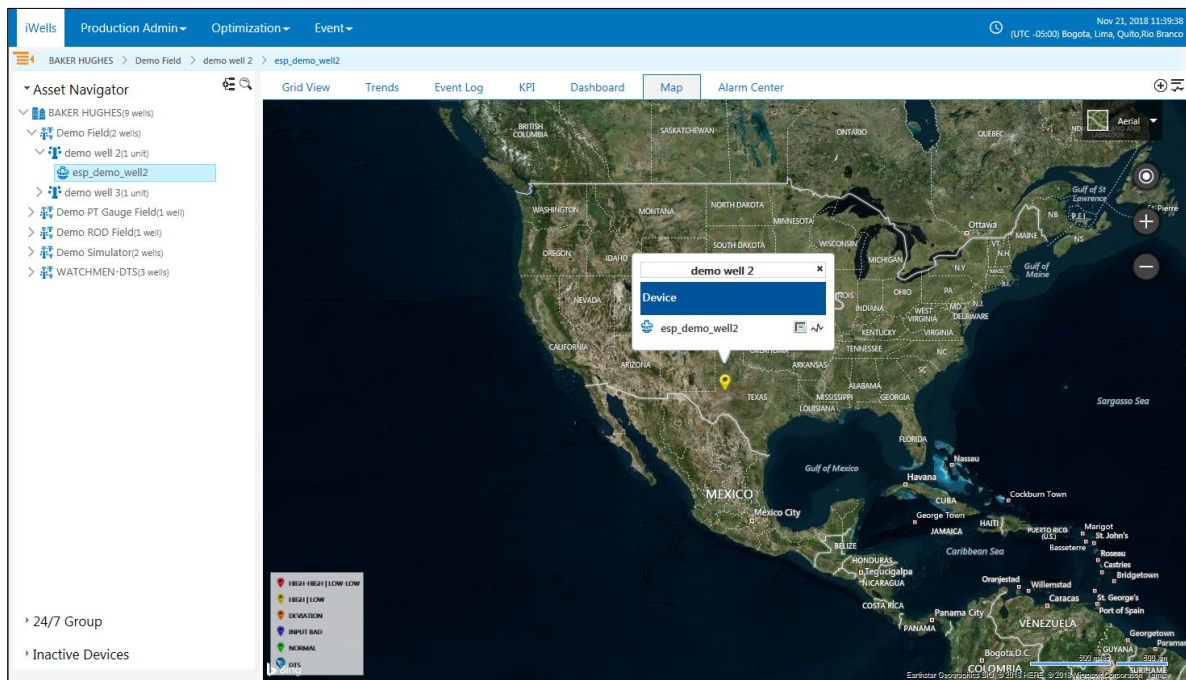
- Secured two-way communication; i.e., encrypted communication; remote control; support satellite, cellular, radio and data mining
- Multi-tenant application
- Flexible platform unit system with capabilities for customization.
- Customized system time zone.
- Flexible visualization and data capture
- Integrated and automated reporting system
- Integrated alarming system and customization i.e. Threshold, rate of change, deviation, stagnant and capabilities to receive this alarms via Email, SMS, Sound and Visual
- Integrated case management with automated case management report.
- Integrated and automated data export
- Capabilities to integrate with other optimization tools both internal and external
- Mobile application

Summary listing

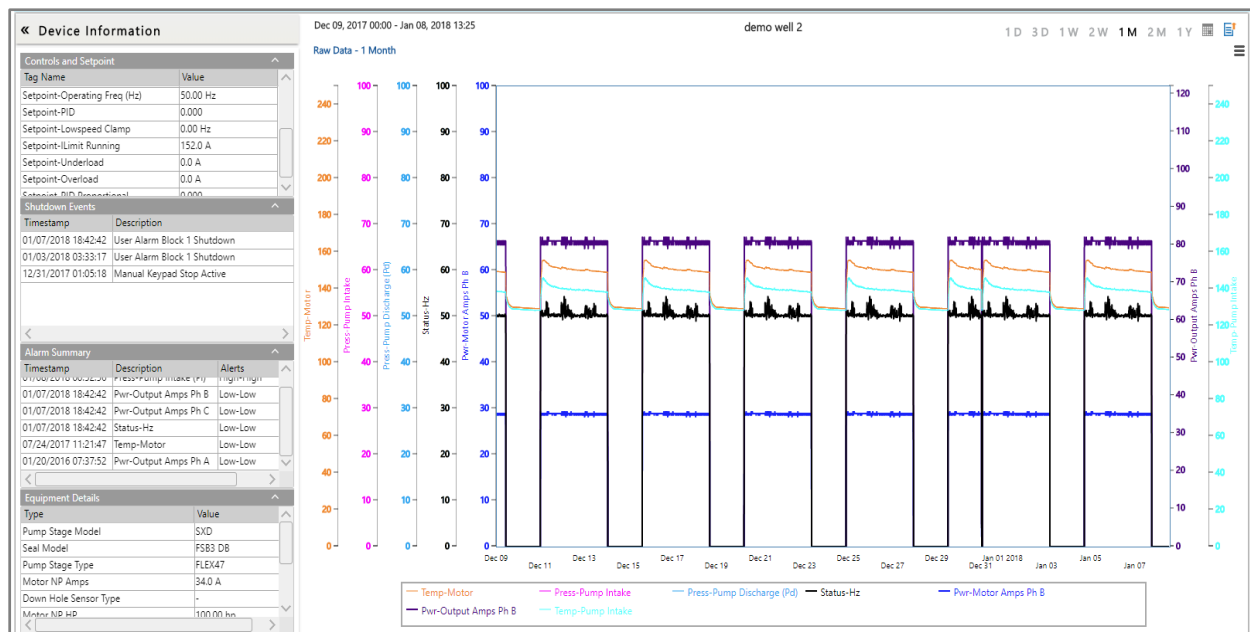
A tabular view of all the data associated with the well and field, including active alarms and direct access to trends,

Grid View										Trends	Event Log	KPI	Dashboard	Map	Alarm Center	System Health	Analytics			
Device - ESP										Device - ROD		Device - GL		Device - HPUMP						
Facility Parameters										Static Parameters		Control Parameters								
Alerts		Comm.	Well	Device	Status-Motor [-]	Status-Hz [Hz]	Press-Pump Intake (Pi) [psi]	Temp-Motor [degF]	Pwr-Motor Amps Ph B [A]	Pwr-Output Amps Ph B [A]										
4			demo well 1	esp_demo_well1	Stopped	0.00	3789.50	216.50	0.00											
7			demo well 2	esp_demo_well2	Stopped	0.00	149.80	129.60	0.00											
			demo well 3	esp_demo_well3	Stopped	0.00	17.20	0.00	0.00											
3			Ehimario	ESP_Ehimario	Stopped	0.00	0.00	0.00	0.00											

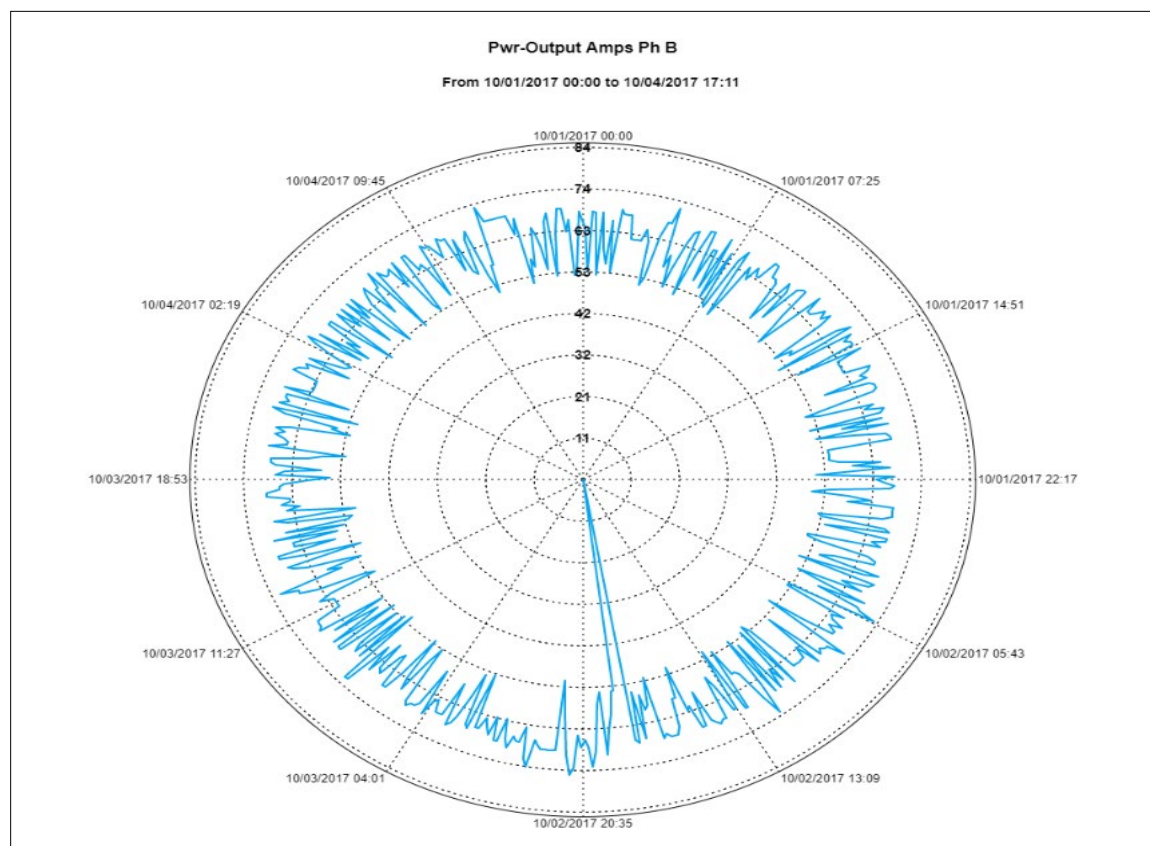
Map view. Displays of all wells alongside critical alarms/data



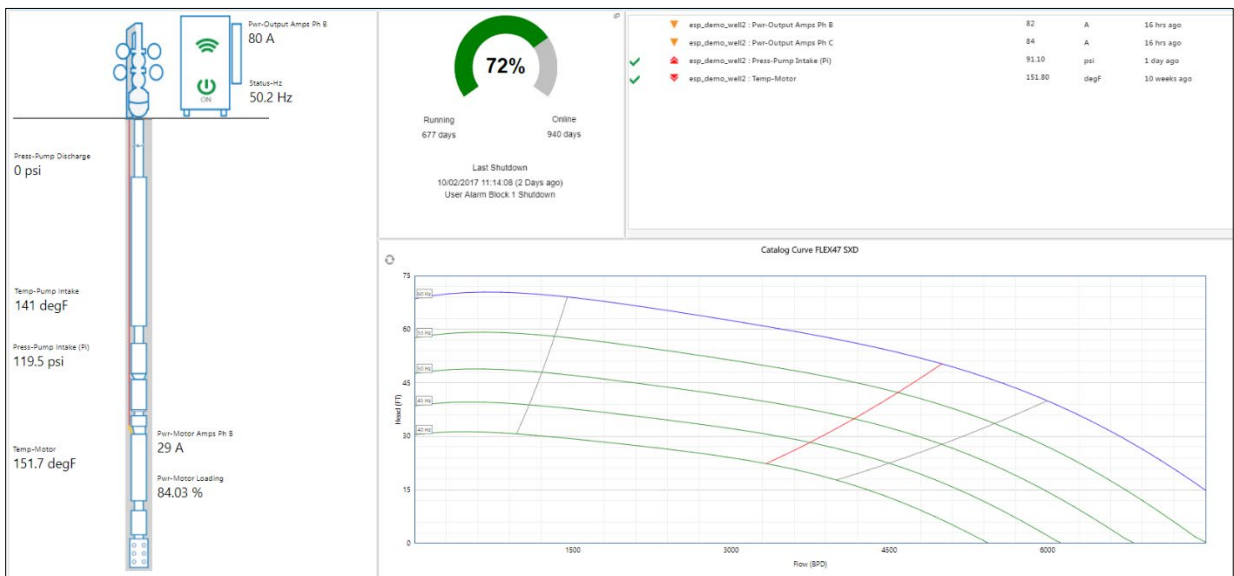
Data trending. An integrated trending package customizable to the needs of the individual well and user. The trending visualizes the data at full resolution (typically 1 or 10 minute data) to easily understand the details of the pump and reservoir behavior.



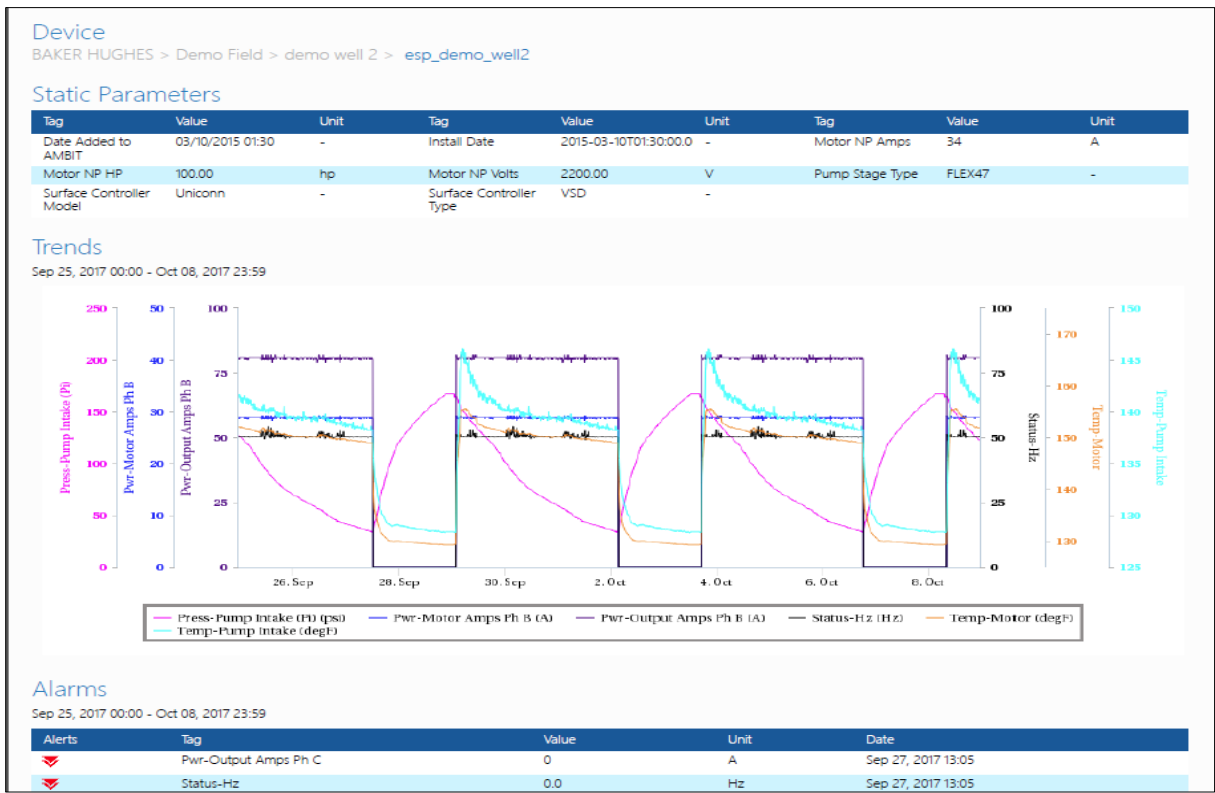
Amp chart. Presents the data in the traditional circular chart



ESP dashboard. A quick overview of measured data, last shutdown event, alarms summary and inclusive catalog curves



Reports. Several configurable reports provide you with the required details of your critical wells directly by e-mail. These reports include well and details, trends, alarms, memos and KPIs.



Mobile app. Enable informed production decisions by monitoring of artificial lift equipment "on the go" with mobile device or tablet for field operations and events in real time. Make remote control changes and modify flow measurements, frequency, power data, and status data, among others.



Collaboration. One of the most critical aspects of monitoring is to establish clear communication lines between engineering staff, field personnel, and the equipment supplier. The ProductionLink service provides the following

- Document attachment
- Memos
- Tasks

The ProductionLink Expert service

The ProductionLink Expert service features a calculation engine that allows definition of customized calculations based on static and real-time data. The calculated results can be trended and used for alarming. Key performance indicators (KPIs), diagnostic, and analytical features provide reference data for well performance and device efficiency, which can be analyzed to improve production optimization decisions.

Lift diagnostics and optimization

- Well optimization
- Multi-well optimization – Field cluster optimization with constraints (i.e. assuming WC & GOR wont vary).
- Operation and communication KPI optimization with customization of asset/field/well/device.
- Artificial lift diagnostics module using fuzzy logic.

- Lift cost analysis
- Real time Performance curves, IPR Curves and Pressure vs Depth curve using physics base model
- Real time model calibration
- Well level physics base model recommended potential asset optimization
- ESP vs Gas lift physics base model analysis
- Smart Gas Lift performance curve
- Dynacard visualization with automatic pattern matching, displaying percentile matching of events according to each dynacard polled
- Display and overlay 5,10 previous cards for surface and downhole cards
- Various optimization reports i.e. Production variance report; Deferred production report; Physics model field level sensitivity report.

Well optimization and diagnostics –offers real time asset production optimization to effectively manage customer field asset, extending ESP run life and providing the best field practice for setting up operating equipment's.

Diagnostic module

ESP diagnostic is a module within the ProductionLink designed to assist the ESP professional in analysis of steady state conditions associated with a standard ESP installation and in diagnosis of conditions that may adversely affect production. It uses a rule based Artificial Intelligence engine that utilizes fuzzy logic to identify adverse condition when real time measured values start to deviate from the expected values based on baseline model. The module brings together measured data from SCADA and simulated values from data modeling tool called "AutographPC", which provides a simulation of the well and the installed equipment.

ProductionLink Expert can diagnose the following conditions:

When looking at a graph or a table of data, it is not always easy to troubleshoot and diagnose what is happening or perhaps conduct a full ESP operational stress analysis in regards to why ESP performance is not as expected. The ESP diagnostic module helps with diagnosing the following conditions:

- | | | |
|---------------------|--------------------------|--------------------------|
| • Pump plugged | • Tubing leak | • Choke open |
| • Draw down | • Tubing plugged | • Motor overloaded |
| • Main valve closed | • Pump speed down and up | • Shutdown |
| • Gas locking | • Pump off | • High and low frequency |
| • Broken shaft | • Pump wear | |



Well Optimization Visualization showing all the modules

ESP_EHIM-1				
espExpert				
Potential Asset Optimization				
	Current Operation	Low Risk Optimization Recommendation*	Medium Risk Optimization Recommendation*	High Risk Optimization Recommendation*
Frequency (Hz)	52Hz	52.51Hz	53.99Hz	56.92Hz
Prod-Total Fluids per Day	6014.048BPD	60278BPD	6065.18BPD	6141.928BPD
Press-Pump Intake	1763.06Psi	1734.5Psi	1650.17Psi	1478.66Psi
Limiting Factor	None	Motor internal temperature is too high f more...	Motor internal temperature is too high f more...	Motor internal temperature is too high f more...
Net Possible Asset Gain (BOPD)	0	12.168BOPD	47.98BOPD	119.958BOPD
Today's Est. Oil Value (\$/BBL)	47.9	47.9	47.9	47.9
Estimated Daily Net Additional Income	0 \$US	582.27	2294.32	5745.51
Estimated Monthly Net Additional Income	0 \$US	17468.12	68829.68	172365.16
Estimated Annual Net Additional Income	0 \$US	212528.85	837427.81	2097109.4

* - Need to verify surface equipment limitations prior to changing frequency of the pump. It is the responsibility of the operator to weigh the risks of changing the frequency to the potential gains that may be seen in asset returns. espExpert output data is only as accurate as the input data accuracy. It is intended to identify possible areas for increased asset Production. The user must insure all data is accurate and reasonable prior to taking any action noted above.

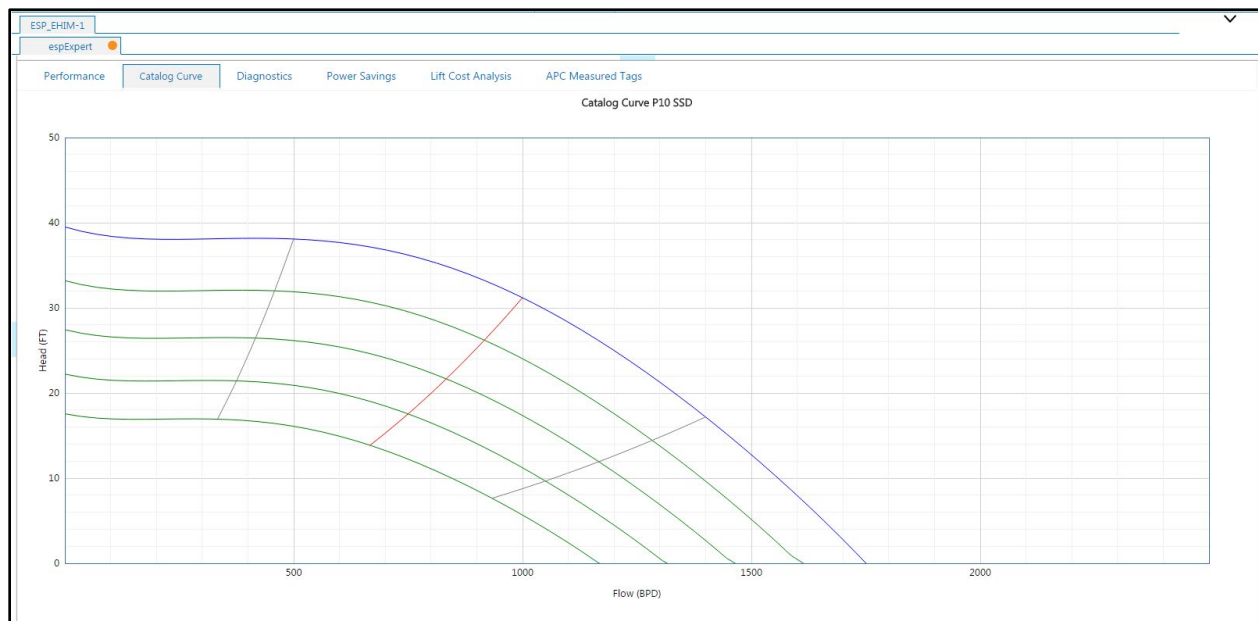
Potential Asset Optimization module. Shows the optimized production with all the risk equipment limiting factors and the estimated income.



Real-time **Pump Performance Curve** (This is the pump performance curve that graphs what the operating conditions are in comparison to what the design parameters where. Using this chart one can identify if the pump is starting to wear or if it is operating at a point that is undesirable i.e. upthrust or downthrust. A lot of actions can be taking from this chart which could include speeding up or slowing down the motor as well as increasing back pressure.), **IPR curve** (IPR Curve shows your inflow performance based on your pump intake pressure) and **Pressure vs Depth curve** (Shows your intake pressure, discharge pressure, and surface pressure).

	Current Operation	Optimization Recommendation
Applied Voltage	2054V	2014V
Net Power Savings	3KW	3KW
Cost per KWH	.05\$/KWH	.05\$/KWH
Expected Daily Savings	3.6	3.6
Expected Monthly Savings	108.04	108.04

Power saving module. Gives you the optimized power recommendation



Catalogue Curve. Shows the well equipment downhole water base/catalogue curve

ProductionLink NeuraX virtual sensor and flow meter

NeuraX is a soft sensing virtual meter, where X stands for variables such as Flow, Pump Intake Pressure, Discharge Pressure, GOR, WC, etc. Precise measurements are critical to optimize electrical submersible pumping (ESP) system operation. The ability to measure different parameter and most specially flow accurately and consistently is required for well diagnostics, ESP Diagnostics, production allocation, sizing facilities requirements, and government reporting. However, standard flow monitoring techniques are expensive and often are available only at periodic intervals.

NeuraX™ virtual meter, the newest soft sensing monitoring technology from Baker Hughes, changes that paradigm. This flow-monitoring sensor that combines real time operating parameters acquired from downhole sensor with neural network machine learning capabilities to yield real-time, accurate flow and operating parameters. Since downhole sensor and surface equipment already installed in most ESP completions, different measurements such as intake pressure, discharge pressure, Motor Amps and pump frequency acquired from sensors can be used as inputs to feed into a trained machine learning neural network model for soft sensing purpose. When properly calibrated and maintained, the NeuraX virtual meter delivers variables estimates i.e. flow with a greater than 95 percent accuracy rate when compared to actual flow rate measurements.

NeuraX virtual meter is made possible by combining two technologies:

- Built – in static and dynamic simulator from industry leading ESP modeling tool – AutographPC can generate thousands of ESP operating scenarios as training data set for neural network model setup purpose.
- Neural Network utilize training dataset generated from AutographPC and generalize a model which can predict how ESP and reservoir will behave in new situation.

Using Baker Hughes AutographPC software, the industry standard for ESP sizing, as the main physics base model & mathematical engine, NeuraX produces real-time measurements as accurately as the most expensive virtual meters at a fraction of the cost.

Benefits

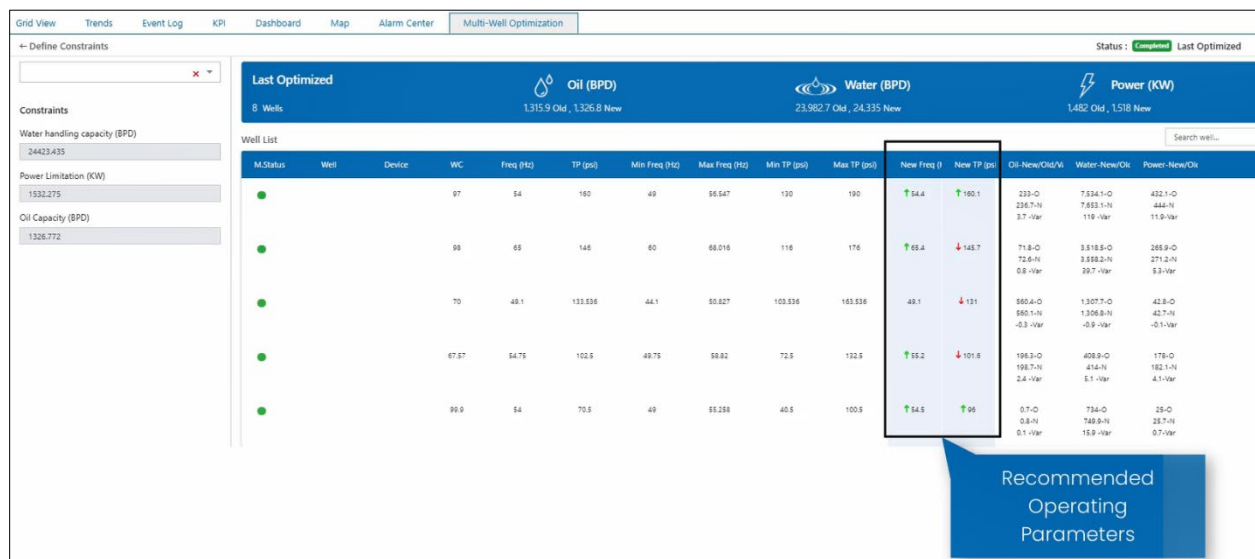
- **Hardware cost saving:** Providing inferred production data or reservoir characteristics (e.g. PI and Pr) based on physics based model and data driven/machine learning methodology so no need for a physic flow meter
- **Reducing the frequency for well test:** With VFM, customer can reduce the frequency for paying third party to conduct well test. Results from real well testing will only be used to calibrate the model
- **Less NPT and impact to surface equipment:** No need to shut in production just for gathering production data for a single ESP.
- **Production allocation:** some local governments require oil producer to report production for each individual well. It is very hard for customer to allocate production for each ESP if they do not have a multiphase flow meter for each ESP.
- **Troubleshooting:** If customer uses a single separator for a few ESPs, it will be very difficult to identify the ESP that could deviate from its expected production. With the help from VFM, customer can narrow their focus on ESP that is under producing.
- **Data source for other analysis or analytics:** For the ESP application that does not have multiphase flow meter, VFM can be used in conjunction with other analytic tool to further improve advanced analysis. For example VFM can be used to examine if ESP is running in up or down thrust condition.
- **Edge Device ready:** Model based on physics based model and machine-learning method can be executed vary fast from an Edge device. This makes this VFM technology edge-device ready

Multi-well optimization

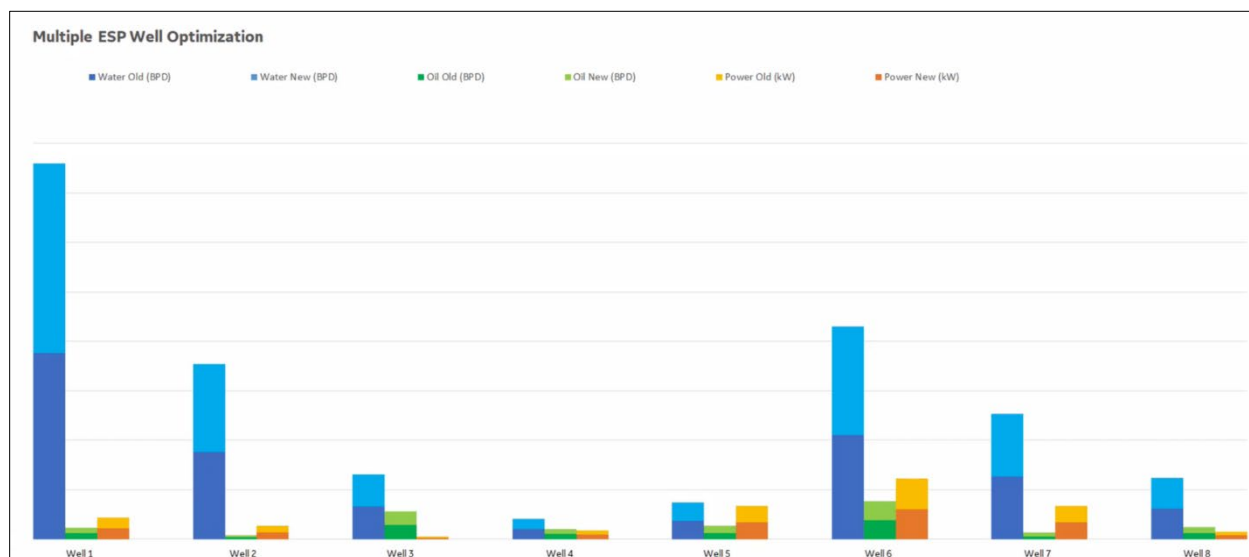
The goal of the multi-well optimization is to maximize oil production from a group, a set of groups or the entire field, subject to constraints. The optimization can also be multi-objective, i.e., maximize oil production and minimize power consumption and this is achieve by honoring all mechanical and electrical limitations.

Problem statement example;

- When the water flow & power consumption constraints are benign
 - In this case, MWO algorithm finds a solution equals the intrinsic potential of each well
- When the water flow constraints is stringent and the power consumption constraint is benign
 - The algorithm finds a solution that penalizes wells that produce a lot of water, while maximizing production from well with lower water-cut
- When Both water flow and power constraints are stringent
 - In this case, wells with significant amount of water, as well as consume a lot of power are penalized. Production from wells with low water cut continue to be maximized

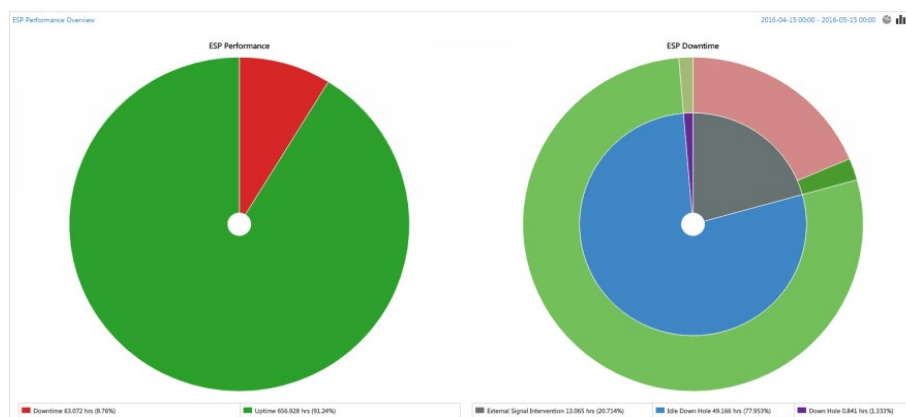


Optimized field of wells showing the recommended operating parameters



Graphical result of the MWO

Uptime and downtime KPIs and trend analysis – Optimize uptime and availability with KPI Shutdown Reason Analytics. Monitor and track well operation events in real-time, and proactively take actions by using trend analysis, enabling quick identification of trends, patterns, and anomalies to diagnose downhole conditions, enhance production, and improve overall recovery.



Analytics: Predictive, prescriptive and descriptive solutions – Maximize production recovery in daily operations by using a wide array of analytics to predict ESP failure and extend pump run life. Using a variety of statistical techniques (including machine learning, predictive modelling and algorithms) for both historical and real time data to estimate, or 'predict', future outcomes and recommend the most optimal solution.

- Prescriptive analytics
- Predictive analytics
 - Event prediction
 - Shutdown prediction (Underload, Overload, High Motor Temp prediction)
- Descriptive Analytics using shutdown reason codes

Well Name: demo well 1		Time Occured: 10/06/2017 14:21:11 - 10/06/2017 17:21:11	
		Rule Name: No rules triggered.	
Press-Pump Discharge	Status-Hz	Temp-Motor	Pwr-Motor Amps Ph B
↑	↑	↓	↓
Press-Pump Discharge	INCREASING		Status-Hz
Temp-Motor	DECREASING		Pwr-Motor Amps Ph B
Press-Tubing	CONSTANT		Press-Pump Intake (Pi)
Prod-Flow Rate	CONSTANT		Temp-Pump Intake

Well Name: demo well 2		Time Occured: 10/06/2017 14:21:11 - 10/06/2017 17:21:11	
		Rule Name: PLUGGED PERFORATION	
Press-Pump Discharge	Status-Hz	Temp-Motor	Pwr-Motor Amps Ph B
↓	○	○	↓
Press-Pump Discharge	DECREASING		Status-Hz
Temp-Motor	CONSTANT		Pwr-Motor Amps Ph B
Press-Tubing	CONSTANT		Press-Pump Intake (Pi)
Prod-Flow Rate	CONSTANT		Temp-Pump Intake

Description			
PLUGGED PERFORATION			
1. Contact BHGE or Company Field Service Tech. 2. Contact BHGE application Engineer to simulate plugged perforation. 3. Take fluid sample to check for scale,paraffin i.e. wellbore conditions, identify and notify operator and engineering. 4. Plan for wellbore acidizing and do well clean out.			

Prescriptive analytics – The prescriptive analytic is an automatic event-driven (advisory) model that can be used in improving ESP operations decision making and management. Prescriptive model has been modeled using industry field experience best efficiency practice in picking event pattern and after the events is matched to a particular pattern; a customized rule of thumb message is automatically prescribed. The prescriptive model is aimed at giving guidance to the operators on taking alternative action having the highest expected benefit or lowest expected cost during the ESP system operation.

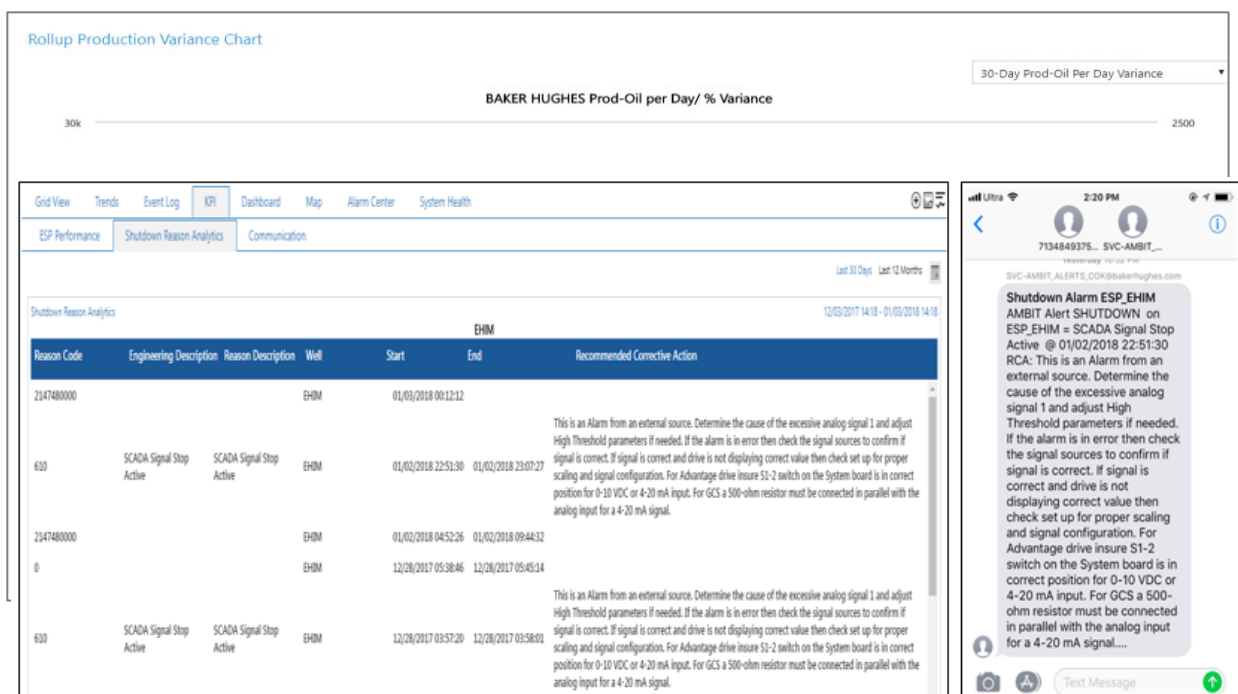
Methodology – The machine learning linear regression algorithm and fuzzy logic method was used both to predict the output of a dataset and to predict output from a pre-computed model. Important operating parameters that are typically monitored include:

- Frequency
- Pump intake pressure and temperature
- Pump discharge pressure and temperature
- Internal motor operating temperature
- Flow rate
- Surface current and voltage
- Voltage imbalance
- Tubing pressure and casing pressure
- Current leakage
- Unit vibration

Currently detect up to 26 operational events and below are examples of the event detected from prescriptive analytics with a recommended prescribed corrective actions;

- Overloaded motor
- Worn out pump
- Reverse pump rotation
- Gas locking
- Broken pump shaft
- Closed valve
- Pump plugged
- Tubing leak
- Flow line leak at the surface
- Tubing plugged

Rollup production variance report – understand the variation in production in oil, gas, water and total fluid per day for the last 30 days, 60 days and 90 days.

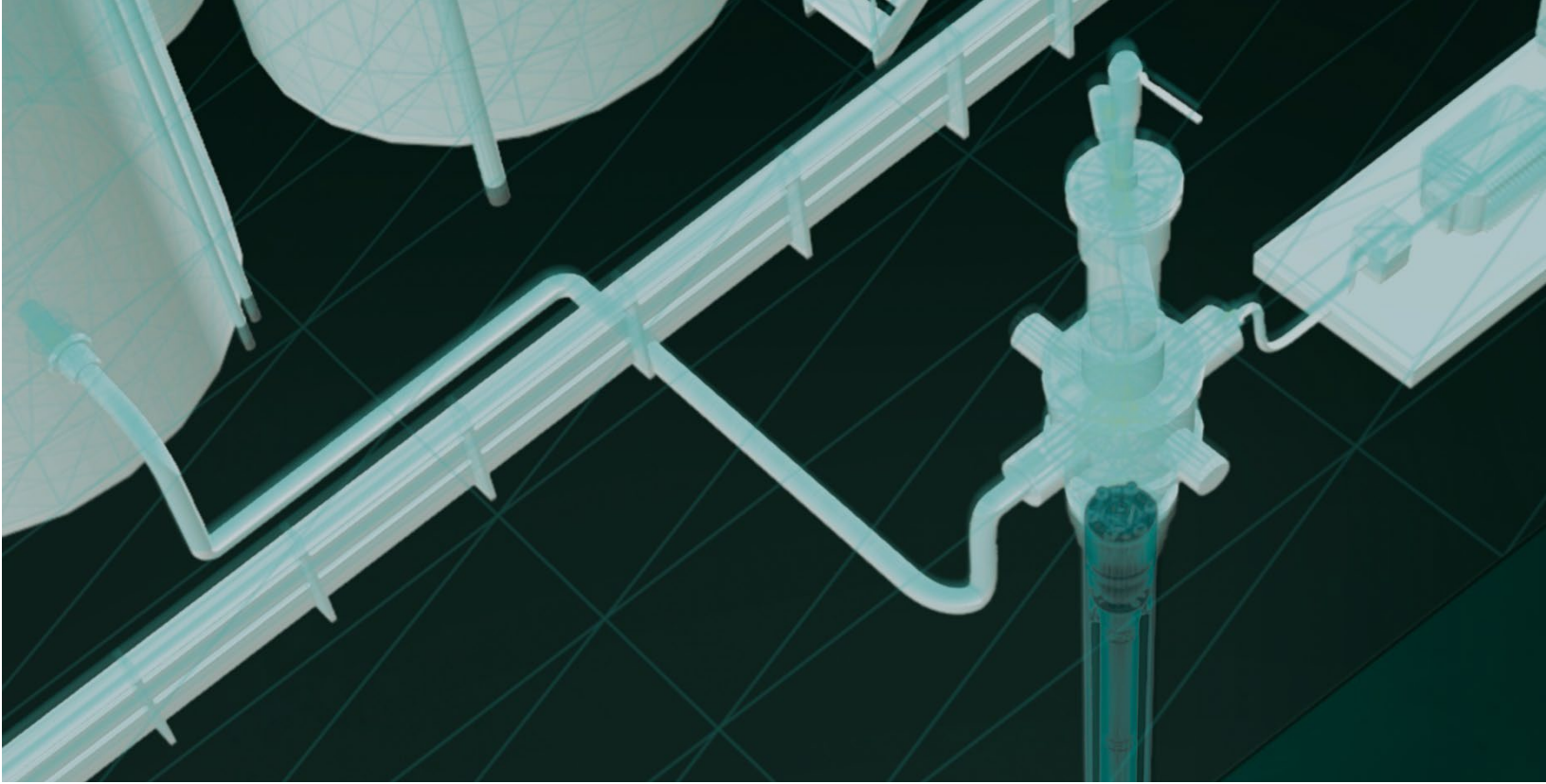


Shutdown reason analytics – Shutdown predictive is an analytics model solution that uses advanced machine learning algorithm to predict ESP shutdown. Shutdown prediction is achieved by both analyzing the trained history data set and calculation strategies.

Conclusion

ProductionLink artificial lift optimization solutions combine leading technology, premium customer service, and flexible commercial deployment options to deliver data, optimize production, manage costs, and increase ultimate recovery. Contact your Baker Hughes representative today to find out how our ProductionLink artificial lift optimization solution can help you easily access the information you need to make the best decisions for your artificial lift systems.

Notes:



Section 5: ESP application

Chapter 16: Well fundamentals

Chapter 17: Typical ESP completions

Chapter 18: Geothermal application

Chapter 19: ESP run life

Notes:

Chapter 16

Well fundamentals

Well characteristics play a critical role in the proper design and deployment of an ESP system. They directly affects the performance, efficiency, and longevity of the ESP system. This chapter covers the following well characteristics:

- Dimensions
- Hydraulics
- Fluid characteristics
- Well performance
- Temperature

Dimensions

Wellbore diameter

The well diameter can vary anywhere from approximately 5 to 36-in. (13 cm to 71 cm). The ESP equipment must be sized or selected based on the smallest diameter of the well that it must pass through. For sizing purposes, the casing (Figure 16-1) inner diameter (ID) is the smallest diameter of a well that the ESP system will have to pass through to operate.

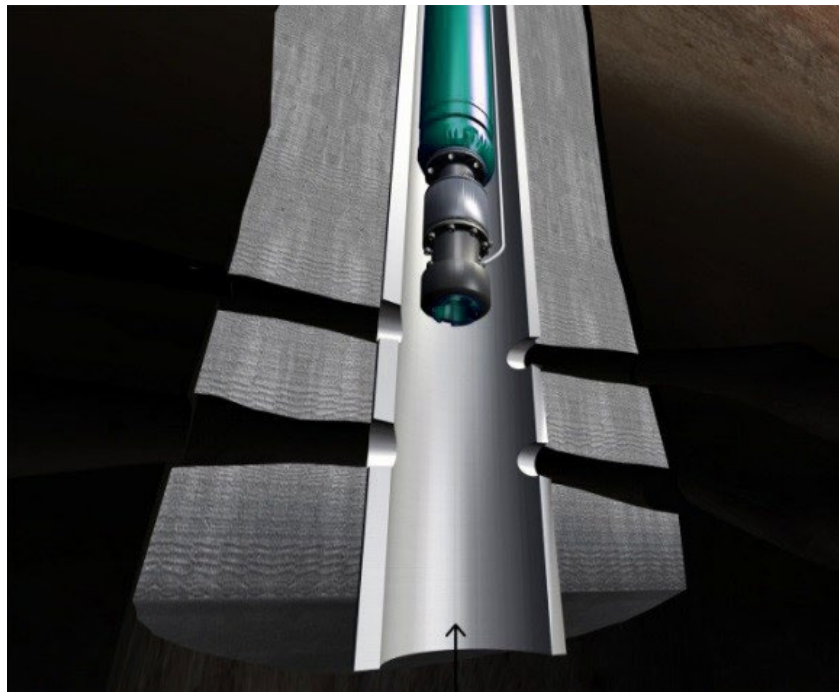


Figure 16-1: Typical ESP completion (above the perfs)

Casing

Casing (Figure 16-1) is the support structure in the well. It typically comes in lengths of approximately 30 ft and the pieces are screwed into each other as it is run to the bottom of the well. The entire casing string is then anchored and cemented to the wellbore. The inside of the casing is the internal diameter in which the ESP system must fit.

Tubing

Tubing is run inside the casing and connects to the pump discharge. It serves as the flow path for the well fluids to reach the surface. The tubing length is also the measured depth corresponding to the pump setting depth. There are two methods to run tubing. The first is to screw rigid sections of tubing called joints together piece by piece when running it in the well. The other is to use coiled tubing, which is one continuous flexible steel pipe that comes on a reel. Coiled tubing allows for quicker tubing installation.

Well depth

There are numerous terms used to describe the various depths of a well, but three of the most common used in ESP applications are total vertical depth (TVD), measured depth (MD) (Figure 16-2) and pump setting depth. TVD is the vertical distance from a measured surface reference (usually the wellhead) to the bottom of the well. TVD does not take deviations into account. MD is the distance measured from the surface along the wellbore path. Finally, pump setting depth is the setting depth, either vertical or measured, as measured from a surface reference (usually the wellhead) to the pump intake.

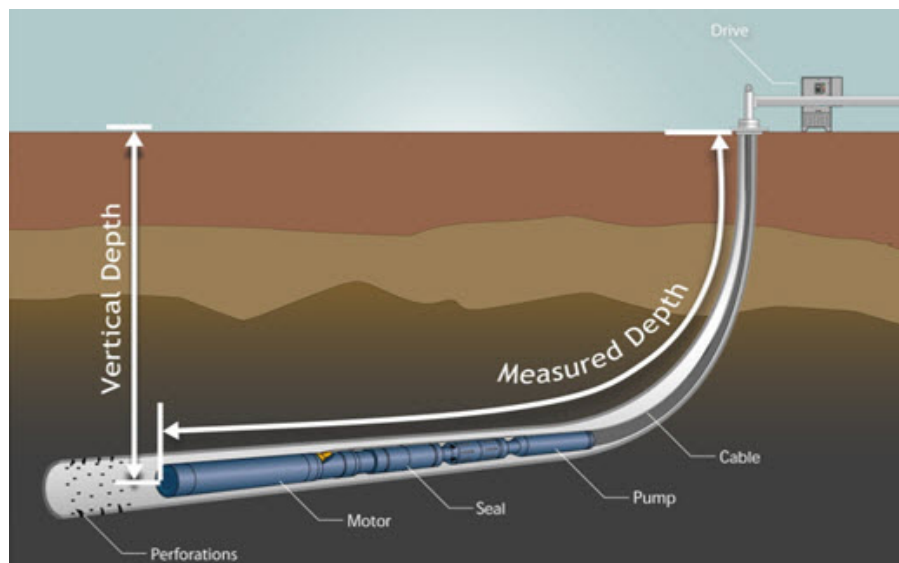


Figure 16-2: Vertical and measured depth

Well types

Wells are generally classified into three types: vertical, directional or deviated (illustrated in Figure 16-2), and horizontal. A vertical well is any well drilled perpendicular from the surface location. A directional (deviated) well is purposely deviated from the vertical, using controlled angles to reach a targeted location other than directly below the surface location. A horizontal well is any well drilled either from the surface or from an existing wellbore where a portion of the well is drilled parallel to the surface (horizontally) or near horizontal.

Perforations

Perforations are a series of holes blasted through the casing, cement, and formation that allow fluid to flow into the wellbore. The perforations are created using a perforation gun, (Figure 16-3) which contains charges that are lowered into the well by wireline. Perforations are usually shot in a series.

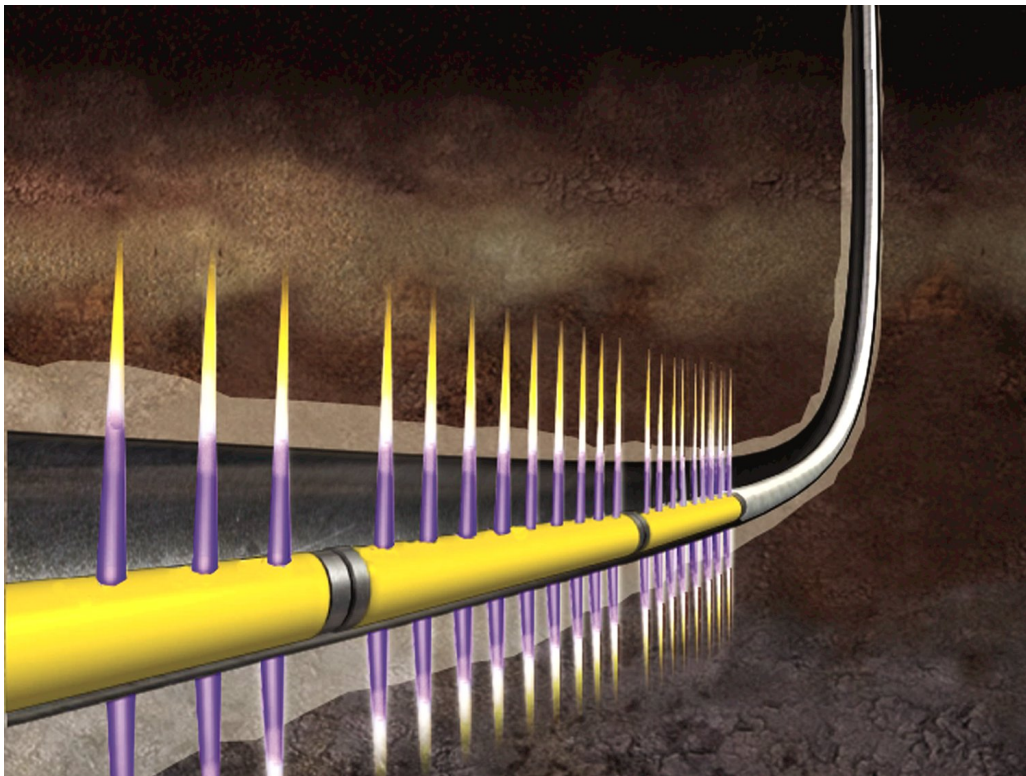


Figure 16-3: Illustration of a perforating gun firing in well

The location of the perforations is important when sizing an ESP system. The perforation vertical depth (perfs VD) represents the depth at which the hydrocarbons enter the well. This depth is normally associated with a range of depths. For example, the perfs VD could extend from 5,500 to 6,000 ft. The top (5,500 ft in this example) of the perfs VD is most often used for calculations. The

ESP should normally be set above the top of the perforations to make sure that all the flow passes the motor for cooling purposes.

Hydraulics

The science of hydraulics is the study of the behavior of fluids at rest and in motion. A fluid is a substance capable of flowing; therefore, both liquids and gases are considered fluids. A general understanding of hydraulics is necessary to aid in the solution of problems involving the flow of fluids—viscous fluids, multiphase fluids, or any fluids that are handled by pumps.

Density, or specific weight, is the weight per unit volume of substance. The density of water is 8.328 pounds per gallon, or 62.4 pounds per cubic foot (at standard pressure and temperature or sea level and 60° F or 16° C). The density of air is 0.0752 pounds per cubic foot at standard conditions of pressure and temperature.

Gradient is the pressure exerted by a fluid for each foot of fluid height. For example, fresh water exerts a gradient pressure of 0.433 psi/ft. Therefore, a column of water 50 ft high would exert a pressure of 21.65 psi (50 ft x 0.433 psi/ft). To increase the pressure one (1) psi requires 2.31 feet increase in depth.

$$\text{Gradient (psi/ft.)} = \text{Specific gravity} \times 0.433 \text{ psi/ft}$$

Specific gravity is the ratio of the density, or specific weight, of a given material to the density of some standard material. For liquids, the standard is water at 60° F or 16° C. For gases, the standard is air at standard pressure and temperature.

Although specific gravity is a dimensionless number, in certain industries scaled graduations are arbitrarily made in degrees. In the petroleum industry, American Petroleum Institute (API) gravity is used; 10 degrees API corresponds to a specific gravity (SG) of 1.00. The following equation relates API gravity to specific gravity.

$$\text{Specific Gravity @ } 60^{\circ} \text{ F} = \frac{141.5}{131.5 + \text{Degrees API}}$$

$$\text{Gradient (psi/ft.)} = \text{Specific gravity} \times 0.433 \text{ psi/ft}$$

Viscosity is a measure of a liquid's internal resistance to flow. The viscosity of petroleum products is commonly expressed in terms of the time required for a specific volume of the liquid to flow through an orifice of specific size.

Absolute (or dynamic) viscosity is usually expressed in centipoise in metric units. Kinematic viscosity is the ratio of absolute viscosity to density and is expressed in centistokes in metric unit or S.S.U. (Saybolt Seconds Universal).

Viscosity varies with temperature change, decreasing as the temperature is increased. A report of viscosity, therefore, must always state the temperature at which the determination was made.

Pressure is the force per unit area of a fluid. The most common API unit for designating pressure is pounds per square inch (psi). Metric units for pressure include kilograms per square centimeter, bar, and Pascals. According to Pascal's principle, if pressure is applied to the surface of a fluid, this pressure is transmitted undiminished in all directions.

Pressures

Gauge Pressure (PSIG)

Atmospheric Pressure

Absolute Pressure (PSIA)

Gauge Pressure + Atmospheric Pressure = Absolute Pressure

Gauge pressure is the differential pressure indicated by a pressure gauge, as opposed to absolute pressure. Gauge pressure and absolute pressure are related; absolute pressure being equal to gauge pressure plus atmospheric pressure.

Atmospheric pressure is the force exerted on a unit area by the weight of the atmosphere. The pressure at sea level is 14.7 psi. One bar is equal to 14.7 psi.

Absolute pressure is the sum of gauge pressure and atmospheric pressure. The absolute pressure in a perfect vacuum is zero.

Head is commonly used to represent the vertical height of a static column of liquid referenced to a specific point at a specific pressure. When used regarding pumps, it is the vertical height a pump can raise the fluid being pumped.

Pressure and head are different ways of expressing a pump's performance capability. In the submersible pump and petroleum industry, when the term "pressure" is used, it generally refers to units in psi, whereas "head" refers to feet or height of a fluid column. These values, being mutually convertible, can be found using these simple formulas:

$$Psi = \frac{Head\ in\ Feet \times Specific\ Gravity}{2.31\ ft./\ psi}$$

$$Head\ in\ Feet = \frac{Psi \times 2.31\ ft./\ psi}{Specific\ Gravity}$$

Or

$$Head\ in\ Meters = \frac{10.01 \times Kg / Cm}{Specific\ Gravity}$$

Pump intake pressure (PIP)

In submersible pump operations, we are interested in feet of fluid over the pump or pump intake pressure. To correctly define this point, it is important to know the specific gravity or gradient of the liquid in the casing annulus. If the fluid gradient or specific gravity is known, we can estimate the pump intake pressure from the fluid level over the pump.

An accurate determination of the pump intake pressure may be derived by establishing feet of annular fluid over the pump intake and adding any casing pressures imposed at the surface. Figure 16-4 illustrates a cased well with a pump installed. The pump intake is located 5,000 ft from the surface. From a sonic log, the fluid level is located 3,000 ft from the surface. The average specific gravity of the fluid in the annulus is 0.950, and the casing pressure is 100 psi. What is the unit pressure (psi) at the pump intake?

Solution:

$$5,000 \text{ ft (Datum)} - 3,000 \text{ ft (Fluid Level)} = 2,000 \text{ ft (Submergence)}$$

Therefore, the pressure at the pump intake is:

$$\text{Pump Intake Pressure} = \left(\frac{2,000 \text{ ft.} \times 0.950}{2.31 \text{ ft./ psi}} \right) + 100 \text{ psi} = 923 \text{ psi}$$

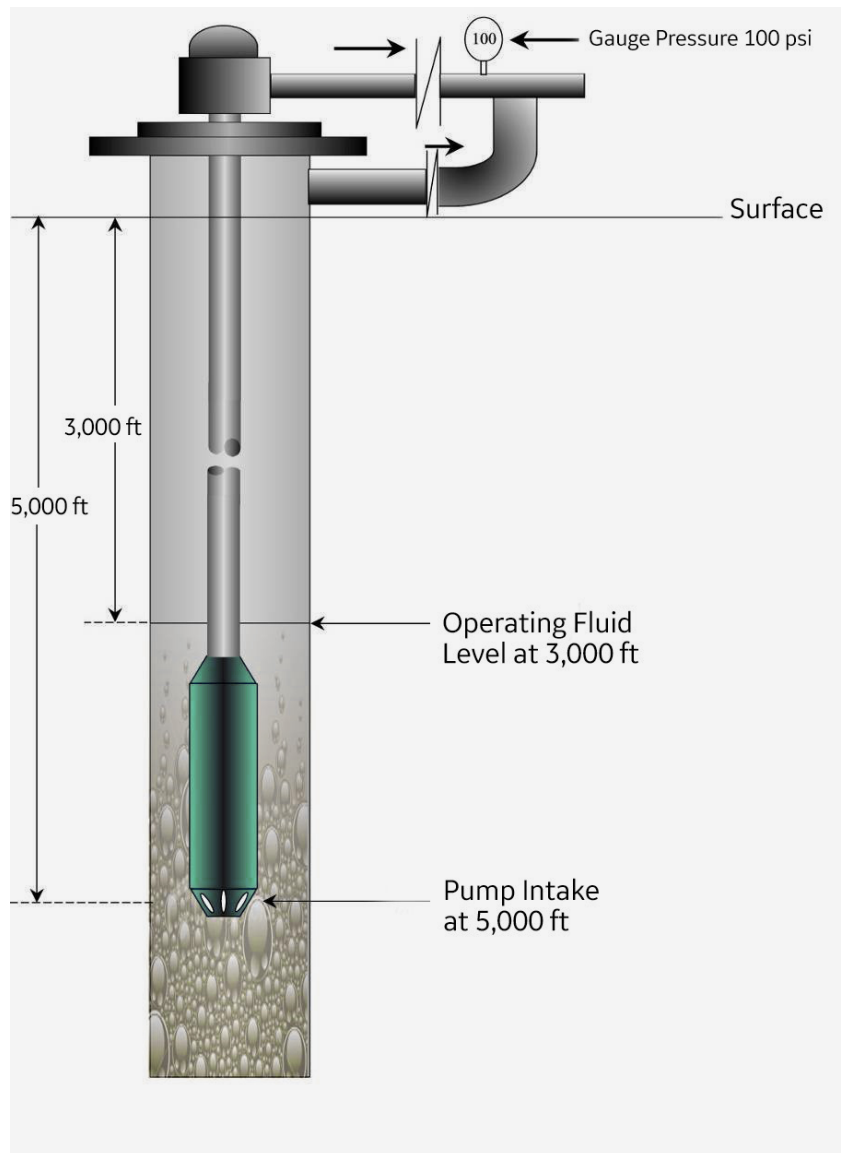


Figure 16-4: Pump intake pressure

Required PIP

This is the intake pressure necessary to properly feed the pump and prevent cavitation or gas locking. This is also known as required NPSH (net positive suction head). This value varies with well fluid conditions and this variance will be discussed later in the pump design section.

Available PIP

This pressure is a function of the system in which the pump operates. The available PIP is the operating submergence characteristics of each individual installation.

Pipe friction

Friction in pipe will vary with the pipe size, capacity, length, and viscosity. Tables for calculating the friction through a piping system are available in the *Hydraulic Institute Standards*, pump manufacturer's literature, and many handbooks. Following is the Hazen-Williams formula for calculating pipe friction loss:

$$\Delta P = 4.524 \left(\frac{Q}{C} \right)^{1.85} \frac{1}{D^{4.87}}$$

- Where:
- Friction = Tubing friction loss, feet
 - P = pressure loss due to friction, psi per ft of pipe length
 - Q = flow rate, gal/min
 - D = pipe inside diameter
 - C = Hazen-Williams roughness coefficient factor, dimensionless
 - C = Friction coefficient
 - C = 100 for old tubing (more than 10 years)
 - C = 120 for new tubing (less than 10 years)
 - C = 130 for fiberglass lined tubing
 - C = 140 for plastic lined tubing

Well performance

The methods discussed in this section are a simplification of procedures for predicting well performance. It is assumed that the downhole reservoir conditions remain in a constant state, although, in reality, changes occur over time. These changes include wellbore skin damage, fluctuating reservoir pressures, and changes in fluid composition.

Production tests are usually performed on initial completion of a well to determine the capability of the well to produce oil, water, and/or gas. From the standpoint of well and reservoir operations, they provide periodic physical evidence of well conditions.

There are two basic methods used in predicting well inflow performance. They are the **Productivity Index (PI)**, and Vogels¹ **Inflow Performance Relationship (IPR)**. These basic approaches are often combined to create a composite inflow performance model.

Productivity index (PI)

The productivity index is defined as:

$$PI = \frac{Q}{\bar{P}_r - P_{wf}}$$

Where: Q = Test rate of liquid production stbpd

$\bar{P}_r$ = Static Reservoir pressure

P_{wf} = Well flowing pressure (@ Test Rate Q)

$\bar{P}_r - P_{wf}$ = Pressure drawdown

This simplistic IPR model implies a directly proportional relationship between pressure drawdown at the well perforations and the flow rate from the reservoir. Experience has validated the PI model for many reservoirs as long as the flowing pressure is above the bubble point pressure. In other words, there is not free gas flowing, only liquid.

The above equation can be transformed to solve for new rates of production (Q_d) based on a new well flowing pressures (P_{wfd}). The equation would then be defined as:

$$Q_d = PI(\bar{P}_r - P_{wfd})$$

168_____

¹ Vogel, J.V. "Inflow Performance Relationship for Solution Gas Drive Wells." *Journal Petroleum Technology*, Jan 1968, pp. 83-93

Furthermore, to predict the well flowing pressure (P), based on a new rate of production (Q), the equation can be transformed as:

$$P_{wfd} = \bar{P}_r - \left(\frac{Q_d}{PI} \right)$$

All three equation forms of the PI model are used extensively depending upon which parameter is being determined.

Vogel IPR model

When the well flowing pressure falls below the bubble point pressure, gas comes out of solution and interferes with the flow of oil and water. The end result is that the actual inflow performance curve is not a straight line, it usually declines at greater drawdowns. An accurate well test should consist of test points at several production rates in order to provide a better representation of the true inflow performance of the well.

Vogel developed a dimensionless reference curve that has become a very effective tool in defining well inflow performance (Figure 16-5). This technique, based on a computer simulation of dissolved gas drive reservoirs, provides a more realistic indication of the well's producing potential. The equation of the curve that gives a reasonable empirical fit is:

$$Q_{o \max} = \frac{Q_o}{1 - 0.2 \left(\frac{P_{wf}}{P_r} \right) - 0.8 \left(\frac{P_{wf}}{P_r} \right)^2}$$

Where:

Q_o = Test rate of liquid production stbpd

P_r = Static reservoir pressure

P_{wf} = Well flowing pressure (@ Test Rate Q_o)

Q_o = Maximum production rate ($P_{wf} = 0$)

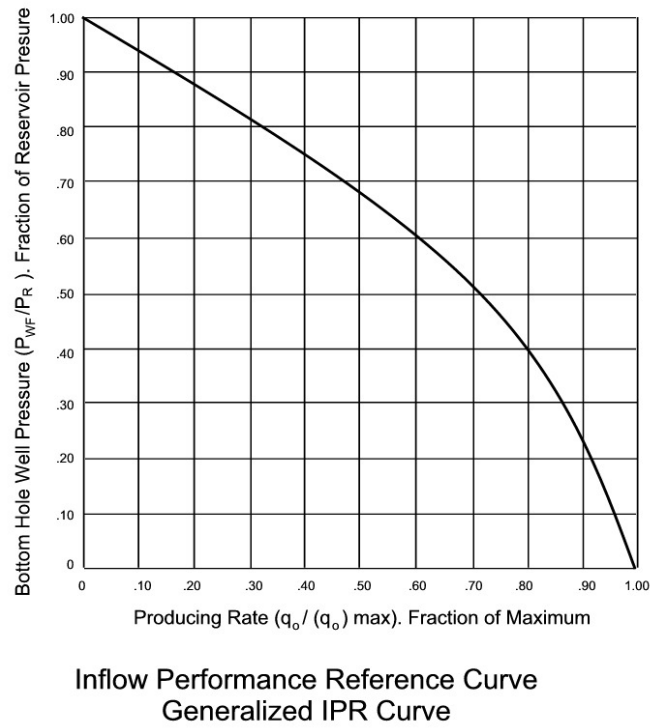


Figure 16-5: Inflow performance reference (IPR) curve

If we assume that constant reservoir conditions exist, we can transform Vogel's mathematical statement to solve for the anticipated production (Q_{od}) based on changes in the well flowing pressures (P_{wfd}). The transformed equation would then be defined as:

$$Q_{od} = Q_{o \max} \left\{ 1 - 0.2 \left(\frac{P_{wfd}}{P_r} \right) - 0.8 \left(\frac{P_{wfd}}{P_r} \right)^2 \right\}$$

Furthermore, to predict the well flowing pressure (P_{wfd}), based on changes in the production rate (Q_{od}), the equation can then be transformed as:

$$P_{wfd} = 0.125 \left\{ \bar{P}_r \left[-1 + \sqrt{81 - 80 \left(\frac{Q_{od}}{Q_{o \max}} \right)} \right] \right\}$$

The time taken to correctly identify well performance is a critical part in designing any type of artificial lift system. Effective well testing and the use of these inflow performance formulas can support a reliable and efficient artificial lift system.

Production fluid characteristics

Typically, production fluid is a combination of salt water (brine), natural gas, and oil. Commonly, mixed in with the production fluid are solids from the formation, predominately sand. From this point forward, the mixture will be referred to as production fluid. The characteristics of the production fluid are of vital importance to an ESP system. Without going into extensive detail, these characteristics will be discussed.

In order to figure out the size of any pumping system, certain characteristics of the production fluid to be pumped must be identified in a way that can be measured against a standard. In the case of a liquid the standard is water, for a gas the standard is air. Before getting into the standardization process, a trait must be defined that is unique to a particular substance. In the case of production fluid, that trait is its weight per unit volume, more commonly known as its density. The density of water is 8.328 pounds per gallon, or 62.4 pounds per cubic foot (at standard pressure of 14.7 psia and standard temperature of 60° F). The density of air is 0.0752 pounds per cubic foot at standard conditions.

Pressure and temperature will be discussed later in this chapter. With density defined as the unique factor for each fluid, it is then standardized by creating the ratio of the density, or specific weight of the production fluid, to the density of water or air. This ratio is known as the specific gravity of a fluid. The petroleum industry goes one step further in the standardization process and uses American Petroleum Institute gravity. API gravity is also commonly referred to as oil gravity.

Another important fluid parameter is the viscosity of a fluid. Viscosity is the resistance of a fluid to movement because of internal friction (shear rate). It can be determined by measuring the time required for a specific volume of the liquid to flow through an orifice of specific size. Production fluid is a mixture of oil, gas, and water. The fraction of water in the production fluid at surface conditions is known as the percentage H₂O, also commonly referred to as the water cut. The amount of gas in the production fluid in ratio to the amount of oil at surface conditions is known as the production gas – oil ratio, or prod GOR. When the gas oil ratio is referred to downhole conditions; it is called Gas Volumetric Factor (GVF). This is the reference of what the pump have to avoid, separate or handle.

Gaseous production fluids

The presence of free gas has the potential of adversely affecting the performance of the pump. The basic problem is that a centrifugal pump is not an efficient gas compressor. Therefore, progressive deterioration of the head generated by the pump can be expected with increasing

free gas fractions. Research and tests have shown that as the free gas reaches approximately 10% by volume at the pump intake, the performance of the pump starts to deteriorate. At lower gas fractions, the pump should perform close to catalog performance. Several potential solutions to gas interference have been described in published literature:

- Incorporate the use of a rotary centrifugal or vortex gas separator.
- Increase the pump intake pressure by lowering the unit deeper into the hole, reducing the production rate, or a combination of both.
- Locate the pump intake below the casing perforations. This will take advantage of the natural separation of the gas and liquid due to gas bubble buoyancy. When this method is used, a motor shroud is required to cool the motor.
- Incorporate the use of tapered pump designs. Tapered pumps utilize two or more stage types. Usually, the stages at the intake are specially designed gas handling stages. These stages have better gas handling performance and handle higher fractions of free gas before gas locking.

It has been demonstrated over many applications that a combination of one or more of these solutions allows submersible pumps to effectively produce oil wells having substantial gas fractions. Gas becomes a limiting factor only in those applications where the well makes mostly gas and only a small amount of fluid.

Temperature

There are two temperature readings that are important when choosing an ESP system: the surface fluid temperature, and the bottomhole temperature. With these temperatures, a fluid temperature gradient for the well can be modeled. These temperatures affect the characteristics of the production fluid and the run life of the components in the ESP system.

Bottomhole temperature (BHT)

The BHT is the temperature of the well at the perforations.

Fluid surface temperature

The fluid surface temperature is the temperature of the flowing fluid stream at the surface. If the fluid surface temperature is not available, many computer programs can estimate a fluid temperature if the Earth surface temperature is known. This temperature is normally measured 10 ft below the actual surface or offshore wellhead. It is typically a constant temperature for every region.

Notes:

Chapter 17

Typical ESP completions

An electrical submersible pumping unit basically consists of an electric motor with seal section, multistage centrifugal pump with an appropriate intake, round and/or flat power cable, motor lead extension, motor controller, and power transformer. Many installations also add a downhole sensor and surface package. In addition to the basic equipment, depending on application, several accessories may be required, such as tubing and couplings, swage nipples, cable guards, clamps, reels and supports, check-valve, drain valve, centralizers, etc.

Baker Hughes ESP systems are available in various sizes, configurations, and types to meet specific well or production requirements, such as casing size; well productivity; hydraulic lift required; available power supply; and health, safety, and environmental regulations. The equipment can be modified, assembled, and installed using different designs and deployment methods. The following are examples of common configurations used in the industry.

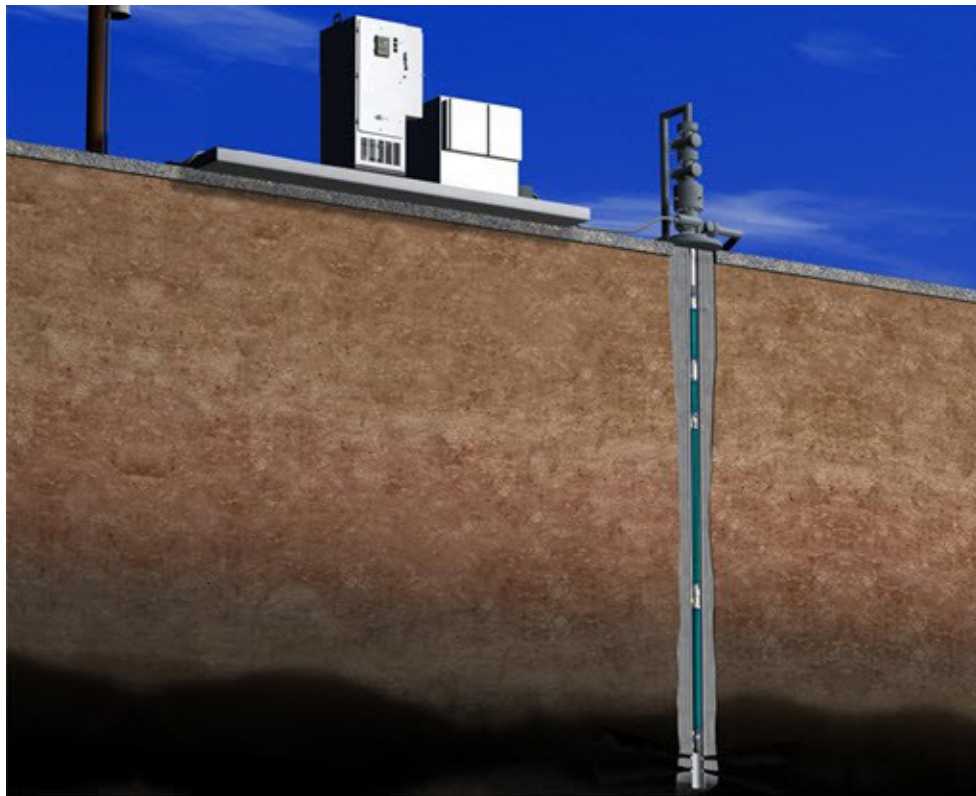


Figure 17–1: Typical ESP completion

ESP installation with deep-set packer

Many ESP systems are deployed with packers (Figure 17-2). This is especially true in offshore installations and where regulations mandate barriers between the producing zone and the surface.

The packer serves several functions, including isolating producing zones without comingling fluids, isolating the casing above the packer from damaging wellbore fluids, and preventing cable damage due to gas saturation in a high pressure well. The packer would be equipped with an electrical feed through penetrator to provide a pressure rated electrical connection between the motor lead (below the packer) and the power cable (above the packer).

To prevent cable damage, it is recommended to install an adjustable union below the packer to remove the excess slack from the motor lead cable. If packers are set hydraulically, pressure should be reduced slowly to prevent cable damage due to rapid decompression.

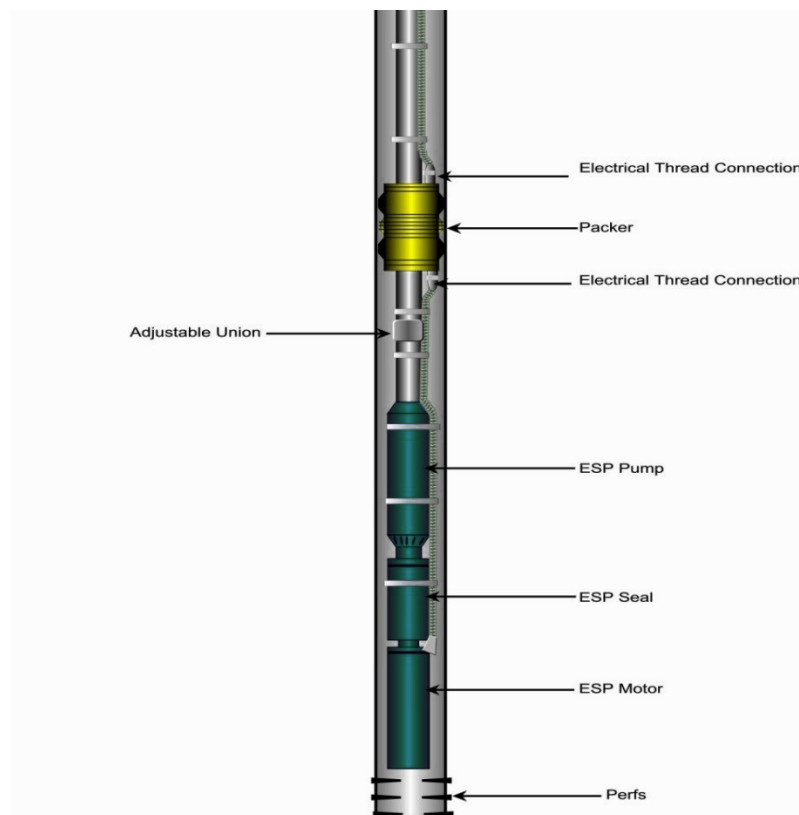


Figure 17-2: ESP with deep-set packer

ESP installation with "Y" tool

The "Y" tool is a production tool that allows access below the ESP with wireline equipment when an electrical submersible pump is in the well. The tool would be run just above the pump and designed not to affect the normal operation of the pump. Figure 17-3 illustrates how the "Y" tool is installed with a submersible pump.

The basic principle of the tool is to provide a piping arrangement whereby the pump is offset to allow a straight, smooth run for the wireline tools to pass through. The "Y" tool assembly has three major parts: the tool itself, designed to allow flow from the pump into the production string with minimal flow restriction; a blanking plug, standing valve, or logging plug is used to isolate the by-pass tubing when the well is in production; and the bypass tubing itself, which is securely attached to the ESP assembly.

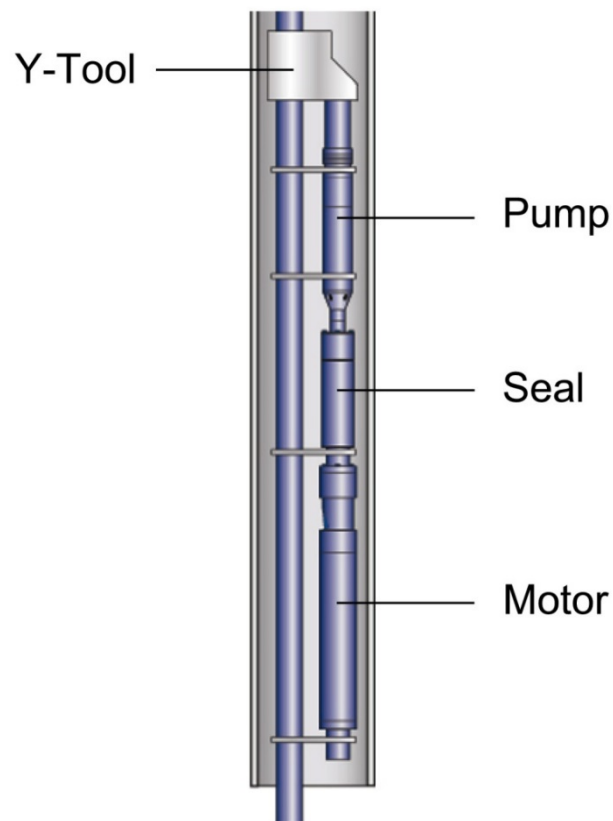


Figure 17-3: ESP with "Y" tool

In many ESP installations, especially offshore, both a packer and a “Y”-tool are used together.

Shrouded configuration

When an ESP is set in or below the perforation zone, motor cooling is achieved by surrounding the motor with a shroud (motor jacket), with the top of the shroud located just above the pump intake and the open-ended shroud bottom extending below the motor (Figure 17-4). Thus, the shroud completely covers the pump intake, seal section, and motor. The produced fluid is directed from the perforations downwards along the outside of the shroud to the bottom of the shroud and upwards to the pump intake through the annular space between the motor and the inside of the shroud.

The most common applications and reasons for using a motor shroud are:

- The ESP is set below the perforations to separate gas at the perforations.
- The ESP is set below the perforations to maximize pressure drawdown and pump rate.
- The ESP is set above the perforations but a motor shroud is used to increase fluid velocity past the motor. This improves heat transfer and reduces the motor operating temperature.
- The ESP is set above the perforations but a motor shroud is used to prevent excessive motor temperature during start-up.

It is also possible to invert the shroud and install the unit above the perforations and use it as a gas separator (Figure 17-5).

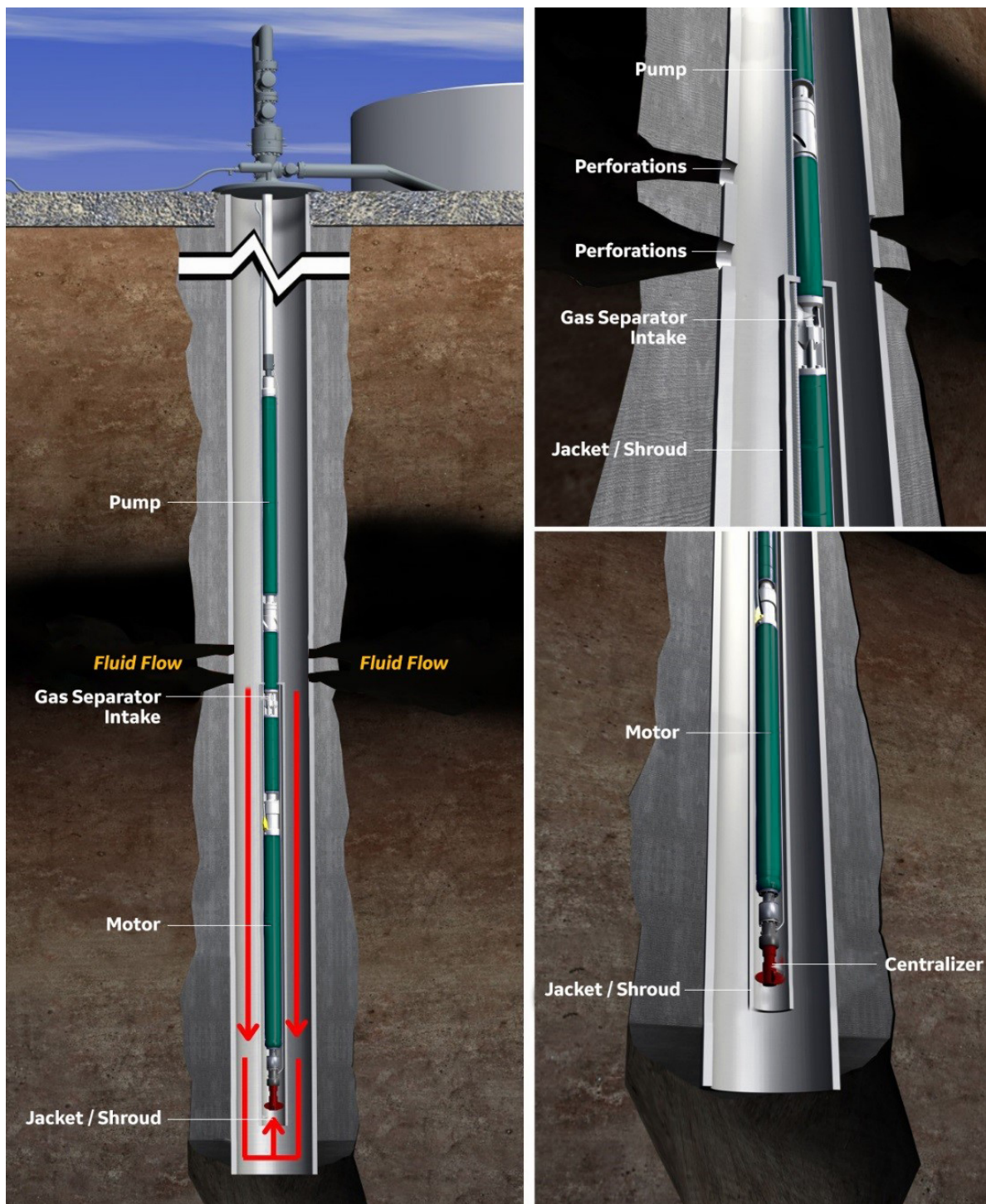


Figure 17-4: Shrouded configuration (viewed from 3 angles)

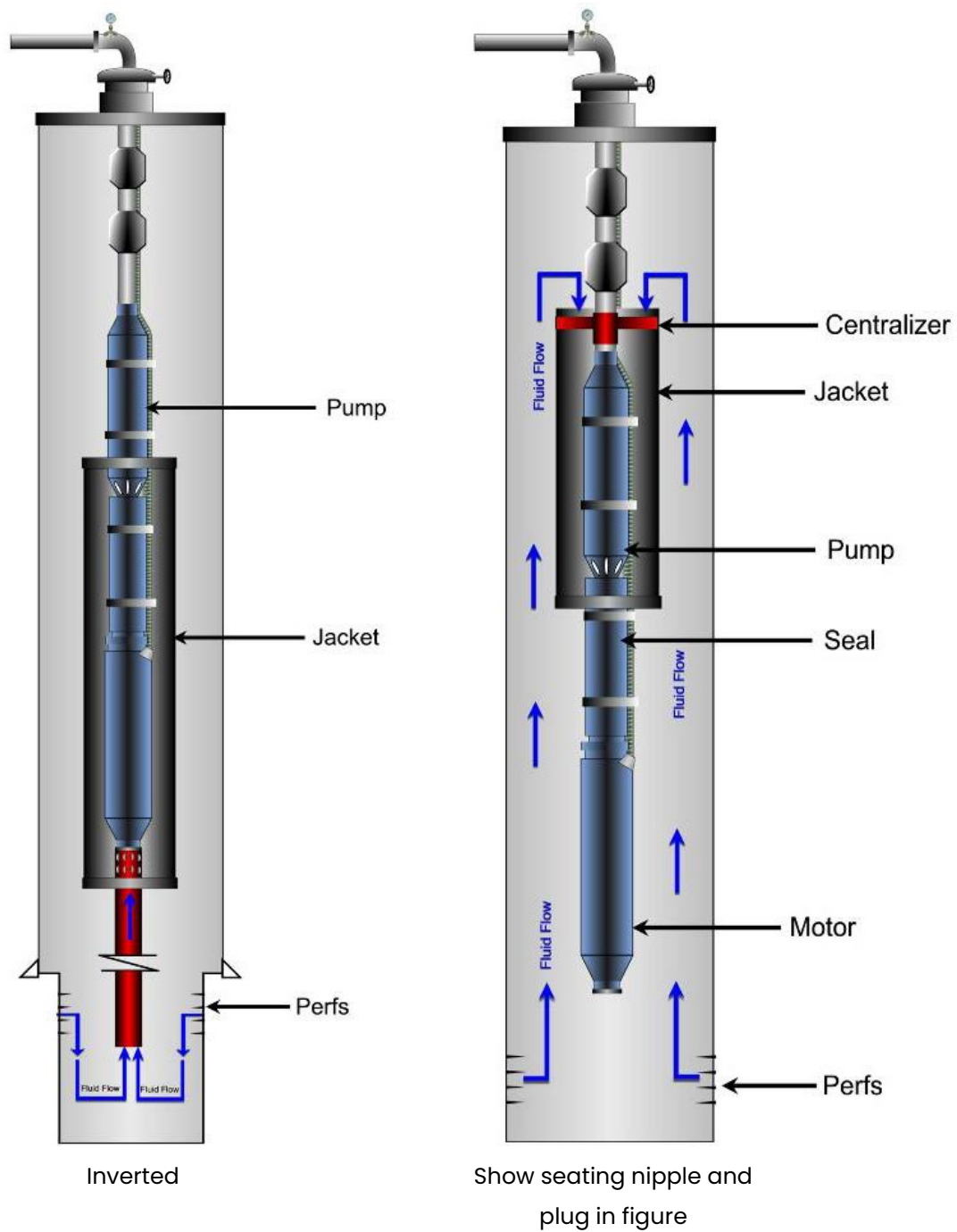


Figure 17-5: Shrouded configuration

Booster pump

In this application, the ESP is used as a booster pump to increase the incoming pressure. The unit is installed in a shallow set vertical section of casing popularly known as a can and the systems are sometimes called “canned pumps.” Connected to the can is an incoming line which feeds fluid into the can and to the pump. The unit is assembled in shrouded configuration (Figure 17-6) with the shroud supported from the surface.

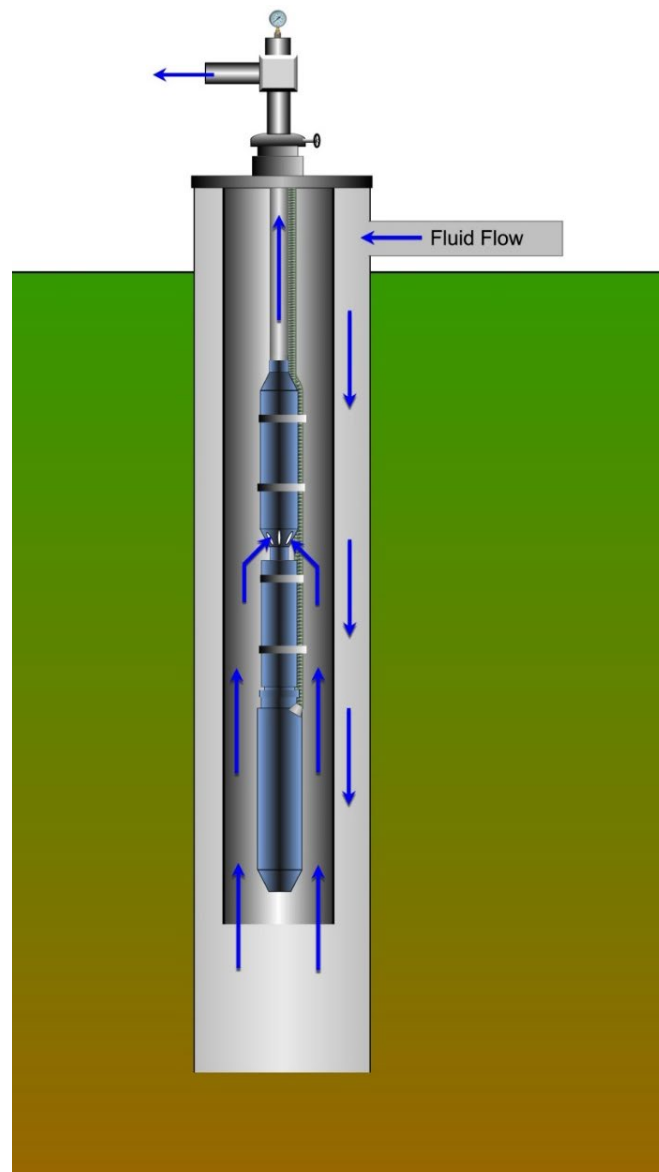


Figure 17-6: Booster pump configuration (With stinger inverted)

Depending on the application, several booster pumps can be connected together in series or in parallel. In series connection, the discharge from one booster is connected to the feed of the second pump. In such a system, the flow rate through various pumps stays the same while the pressure increases as the fluid flows from one booster to the next. In a parallel connection, the boosters are connected to a common discharge manifold whereby the discharge pressure is the same, but the production rates are additive.

ESPs as boosters are frequently used to add pressure to long pipelines for pumping produced fluid to storage and processing facilities. Such a system is also used for increasing the pressure of water injection systems in water flood projects. Because the internal pressure in the motor is equalized, the mechanical shaft seals operate at very low pressure differentials. Consequently, the seal problems typically encountered in horizontal or vertical shaft turbine pumps, are eliminated and very high intake pressures can be accommodated. Also, the system provides a vibration and noise free operation as all the rotating equipment is installed below the surface.

Direct production-injection-system

In this application, the conventional electrical submersible equipment is installed in a water supply well and the produced water is directly injected into an injection well (Figure 17-7). It is also possible to inject the produced water into several injection wells simultaneously.

Such an approach can considerably reduce capital expenditures since the system does not require surface storage facilities, surface pumps, and associated auxiliary equipment. As the system is closed, corrosion control is considerably simplified.

Another significant advantage of the system lies in the fact that the inherent head-capacity curve of a centrifugal pump conforms to the injection requirements of a typical water flood. In the early stages of water flood, the reservoir requires large flow rates at low injection pressures. However, as the reservoir fills, the flow rate declines and injection pressure increases. The whole system can be efficiently designed by keeping in mind the future requirements. In such a case, the equipment can be economically modified to meet the varying reservoir conditions.

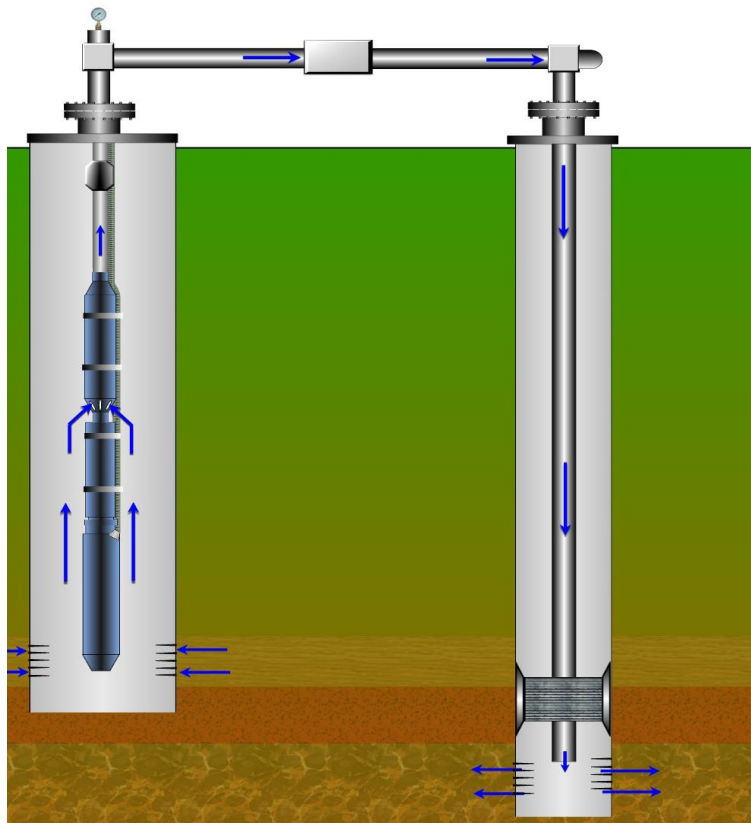


Figure 17-7: Two-well system

Horizontal pumping system

The horizontal pumping system (Figure 17-8) is a high-volume, high-pressure pump ideally suited for use in waterflood operations, in transfer wells, and as a pipeline booster pump. It moves fluid with an ESP centrifugal pump, driven by a standard class A or B electric motor, through a specially designed thrust chamber.

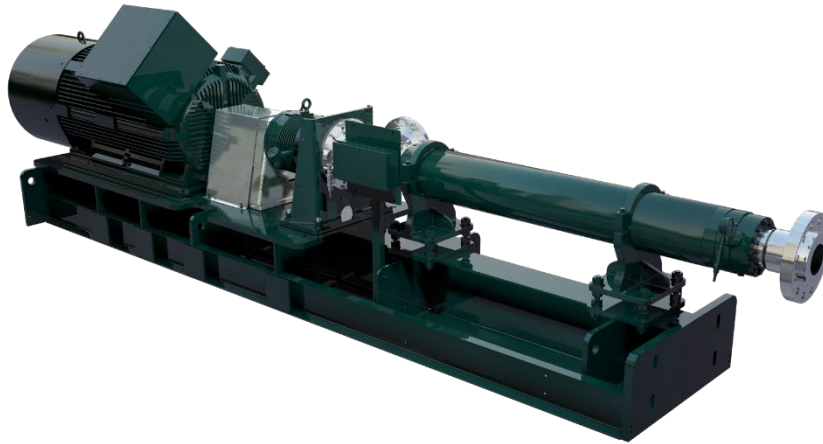


Figure 17–8: Horizontal pump

The horizontal pumping systems are available in a wide range of sizes, volumes, and discharge pressures. The rugged skid-mounted design and laser alignment provides for a highly economical, low maintenance surface pump solution in many applications.

For more information on horizontal pumping systems, please contact your local Baker Hughes representative.

Harsh environment applications

High gas applications

The presence of free gas has the potential for causing detrimental performance with regard to the pump. The basic problem is that a centrifugal pump is not an efficient gas compressor. Therefore, progressive deterioration of the discharge head of a pump can be expected with increasing free gas. Research and tests have shown that as the free gas-fraction reaches approximately 10% by volume at the pump, the performance of the pump deteriorates. At lower free gas fractions, the pump should perform according to catalog performance.

Types of gas interference include head reduction, cavitation, gas blocking, and gas locking. Head reduction is caused by the volumetric change and lighter specific gravity of gassy fluid. This causes the pump's head capacity to be reduced, which results in lower flow at the surface. Cavitation is the implosion of gas bubbles on stage surfaces. The bubble implosion causes a localized pressure pulse which can result in stage casting damage. Due to the relatively high impeller RPM and velocity through the vanes, this phenomenon generally does not occur in oilfield ESP stages.

Gas blocking is a collection of gas bubbles on the low pressure side of the impeller vane, partially blocking the flow area. This reduces the impeller's flow capacity.

Gas locking is a more severe form of gas blocking where the gas collects in the impeller eye (inlet). This effectively stops or "locks" the pump flow.

Many wells also produce slugs of gas which must be handled by the pump or separated. This can cause unstable operation of the unit while the gas slug is being produced by the pump. This type of interference is generally called "slugging" or "surging."

Solutions

Several solutions are available to help address the operation of ESPs in high-gas environments. In general, the solution must either avoid the gas, separate the gas, or produce (handle) the gas. The following is a list of the most common solutions:

- Incorporate the use of a rotary or vortex gas separator. Tandem gas separators can also be used in extremely gassy applications.
- Increase the pump intake pressure by lowering the unit deeper into the hole or by reducing the production rate or a combination of both.
- Locate the pump intake below the casing perforations. This will take advantage of the natural separation of the gas and liquid due to gas bubble buoyancy. When this method is used, a motor shroud or recirculation pump (Figure 17-9) is required to cool the motor.
- Incorporate the use of tapered pump designs with specially designed gas handling stages at the intake. In extremely gassy applications, a combination of solutions may be required to address the gas interference in the ESP system.

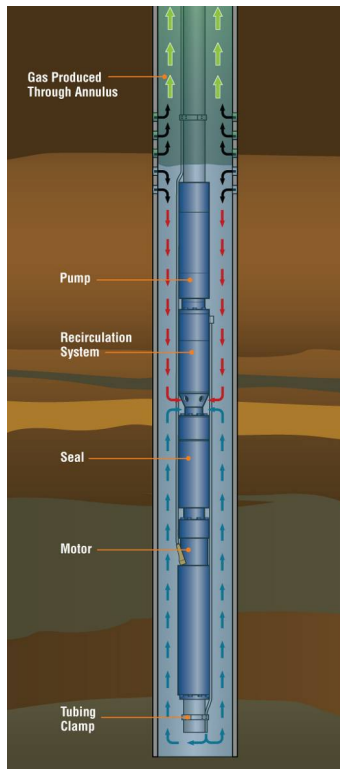


Figure 17–9: Recirculation pump

High-temperature applications

The trend in the application of ESPs has been toward installation in higher temperature reservoirs. These higher temperature reservoirs are typically found as the installation depths become deeper or equipment is applied in geothermal or steam assisted gravity drainage (SAGD) (Figure 17–10) reservoirs.

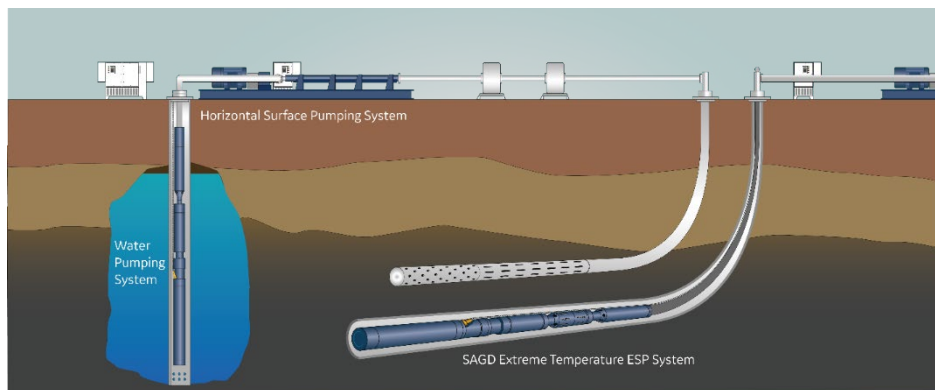


Figure 17–10: SAGD production system

ESPs of standard design are commonly applied to ambient well temperatures of approximately 220° F (105° C) to 300° F (150° C). The upper limit for application has reached as high as 428° F (222° C). In order to maintain adequate equipment life at this high bottomhole temperature, important changes have been made to the material and design of the motor.

The insulation system has been improved by careful selection of the phase-to-phase and phase-to-ground dielectric materials. Epoxy materials have been found to provide superior performance as a winding encapsulation material as compared to the more conventional varnish winding coatings.

Various rotating clearances in the motor have been changed to provide for additional thermal expansion made necessary by the high motor temperatures. Substantial development and testing have been required to predict the extent of thermal expansion and to make final adjustments in the design.

Because of the high magnetic and electrical stresses in the motor leads, as well as the higher temperatures, the trend has been toward utilization of special fluoropolymer materials. Processes have been developed to provide reliable lead connections to the motor windings which can endure the high temperatures.

In order to properly apply an ESP motor, it is important that the combination of the well temperature and motor temperature rise not exceed the insulation thermal rating of the motor. The dielectric life of the insulation system follows the Arrhenius Rule. That is, life is reduced by one-half for each 10° C above insulation rated thermal life.

Four factors (in addition to the ambient well temperature) affect motor heat rise. They are:

- Motor load percent of nameplate rating
- Fluid velocity past the motor
- Fluid composition (oil percent, water percent, gas percent, scaling tendencies)
- Power quality (full three-phase nameplate voltage, sine wave distortion)

For a given ESP motor, the higher the horsepower load its rotor delivers, the higher the temperature rise in the motor, given a constant well environment. Therefore, the temperature rise in the motor can be decreased by reducing the horsepower load as a percent of motor rating. In fact, the use of a larger horsepower motor than what is required by the pump load is the most utilized method of reducing heat rise to acceptable limits in harsh applications.

Three motor design factors impact motor temperature rise. The first design factor is efficiency. The higher the efficiency, the less heat generated in the motor and the less heat rise for a constant environment. The second factor is the thermal conductivity. Epoxy encapsulation enhances thermal conductivity, thereby improving heat dissipation of the motor windings as compared to a varnished coating of motor windings.

The final element that affects motor temperature rise is the heat dissipation (cooling) characteristics of the well environment. How effectively the motor is cooled by the well environment is largely a function of the following parameters :

- Water cut
- Fluid velocity past the motor
- Fluid viscosity
- Free gas fraction
- Scale deposits on motor surface

Since variable speed drives do not provide a pure sinusoidal voltage output, some degree of current harmonics exist. These harmonics generate additional motor heat (about 10%) which in average applications are insignificant. In more complex and hostile applications, the temperature rise from the harmonics must be taken into account so that adequate motor life can be achieved. The proper motor oil should also be selected to provide adequate viscosity for bearing lubrication at the motor operating temperature.

Besides the motor, modifications are required in the seal section, pump, and cable. The rotating clearance considerations used in the motor must also be used in the seal section and pump at critical bearing locations. Rubber elastomers must be carefully selected and will be different than those used on ESPs of a standard design. The use of ethylene propylene diene monomer (EPDM) type elastomers have provided the best performance in the high temperature applications. Certain fluorocarbon-based elastomers have also proven to be effective.

EPDM elastomers have provided the best performance for both the insulation and jacketing on the power cable. In many cases the lead-sheathed jacketed cables are required because of corrosive gasses found downhole. The combination of EPDM insulation with lead sheath provides the highest cable performance for high temperature systems.

Abrasive well applications

Many well fluids contain abrasive solids. Solids are more prevalent in flow from unconsolidated sand stone formations where sand particles tend to become dislodged from the formation and are ingested into the pump. Failure of the centrifugal pump from solids is due to both abrasive grinding wear and cutting wear due to erosion. ²

Many factors go into selecting the proper abrasion-resistant (AR) options for an ESP in a particular abrasive environment. Since all wells are different, specialized designs are needed to fit the application and well economics. This is why Baker Hughes offers a wide range of abrasion-resistant pumps.

There are generally three types of wear patterns that pumps see in an abrasive environment:

- Radial wear in the head and base bushings, as well as the stage shaft supports
- Upthrust or downthrust wear on the stage thrust surfaces
- Erosive wear in the flow path area of the stages due to the high velocity and abrasive fluid

Because most pumps are of the floating impeller design, primary wear first occurs on the thrust surfaces of the impeller and diffuser. Severe wear in this area ultimately destroys the thrust washers and causes metal-to-metal contact, which destroys the stages and locks up the pump. Radial wear also starts to take place in the bearing areas causing eccentric rotation of the impeller and results in increased pump vibration. If the thrust surface wear does not cause the failure, then the vibration caused by radial wear will ultimately result in fluid leakage by the mechanical seals in the seal and the motor will ultimately fail.

The following characteristics are used to determine the abrasive nature of a particular sample:

- Quantity of sand produced
- Acid solubility - percentage of sample not soluble in concentrated acid
- Particle size distribution - percent of sample which will fit within the pump tolerances
- Quantity of quartz - percentage of the sample that is quartz
- Sand geometry - the sand grain shape (angularity), determined by microscopic examination.

The sharper the sand, the more aggressive it will be with respect to abrasive wear.

² Dr. Ing Dieter-Heinz Hellman, *The Influence of the Size of Submersible Motor Pumps on Efficiency and Erosion Wear*, "World Pumps, September 1984, p.332

Solutions

Several options are available to enhance the overall operation of the ESPs in abrasive environments. The following pump configurations will slow down the pump wear process of one or more of the wear types described:

- Compression (fixed impeller) designs
- Stabilized designs
- Modular designs
- Premium designs

Most standard stages now incorporate particle swirl suppression (PSS) ribs that mitigate the erosive swirl damage in diffusers. This protection is incorporated in all abrasive resistant pump solutions.

Compression designs

This design is suitable for mild abrasive environments. Compression (fixed impeller) designs provide downthrust protection by hub-to-hub contact of the impellers, which are locked in position on the shaft between each diffuser. By properly setting the shaft extension, the impellers are lifted off of the diffuser downthrust pads when the unit is coupled to the seal section. This prevents downthrust wear and allows for extended pump operating range at lower rates. Compression pump construction transfers all the stage thrust load to the seal thrust bearing. This results in a significant increase in the seal thrust bearing load. In addition, compression pumps provide no radial shaft bearing support.

Stabilized designs

This pump is suitable for mild to moderate abrasive applications. It provides radial shaft support through hardened bearings placed throughout the unit. Hardened radial inserts are imbedded in the bearing areas in the top and bottom of the pump assembly (head and base). Additional hardened bearings can be inserted in the stages or in separate bearing carriers. Standard stages are used between each bearing location. The spacing between hardened bearings is determined by the stage type and design specification.

Stabilized designs do provide enhanced radial support for the pump shaft. This limits shaft vibration resulting from abrasive wear. However, this design does not provide enhanced downthrust protection.

Modular designs

This type of pump is for moderate to aggressive abrasive environments. It provides both downthrust and radial support. This design utilizes hardened bearing sets in a carrier or pump stage that are spaced throughout the pump assembly. In this type of construction, a number of stages above transfer downthrust to the hardened bearing inserts. This is also known as a “module.” These inserts also provide enhanced radial support for the shaft. The number of stages in the “module” is determined by diffuser height and shaft diameter.

This pump design provides excellent downthrust and radial support in abrasive well environments. Because of the enhanced downthrust support, modular pump designs can also extend the low-end operating range of a system.

Premium designs

This type of pump design is well suited for moderate to aggressive abrasive environments. This design utilizes hardened bearing inserts in each stage, and has been widely used throughout the industry and offers superior downthrust protection and radial support.

Erosion

As ESP run lives have increased in abrasive applications, erosion of the pump stage flow surfaces has become more of an issue. Hard coatings have been utilized extensively in recent years to address the erosive effects of the abrasive fluid production. Coatings come in a wide variety of material and application methods.

For more information on available abrasive resistant technology, contact your local Baker Hughes representative.

Corrosive well fluid applications

As submersible pumps have been extended to deeper wells, the presence of corrosive fluids has become more dominant. In addition, the expansion of tertiary recovery methods to include the use of CO₂ injection has increased the problems associated with corrosion. Since the materials comprising the outside surface of a submersible pumping unit have been low carbon steel, such aggressive environments have created substantial problems with failures due to corrosion. Early solutions included the application of a coating to the surface of the low carbon steel comprised of an epoxy or polyester resin. Additional techniques included the utilization of metalized coatings where stainless steel or monel was applied to the surface of the equipment using a flame spray method. Each of these solutions had the disadvantage of being susceptible to

coating damage caused by mechanical rubbing during installation into the well. Where this occurred, accelerated corrosion actually took place in the unprotected areas where the coating was lost. For this reason, additional solutions were sought.

Because of problematic corrosion in wells where CO₂ was present, a submersible pump was developed in the late 1970s using metallurgy with high chromium content. These metals were either of the 400 series stainless steel family or at the least contained chrome at a level greater than 7% or 8%. Today this solution continues to be the preferred approach to solving severe corrosion problems in CO₂ and heavy brine applications.

Other corrosion problems can be caused by low to medium concentrations of H₂S at intermediate to high temperatures and pressures. The basic problem caused by H₂S is aggressive corrosion of all copper parts contained in the submersible pump and cable. The solution to this problem is to remove the copper-based parts from all downhole components where direct well contact is possible. This generally becomes a concern at H₂S concentrations of 3% or greater in combination with temperatures 180° F (82° C) or more.

The cable conductor is protected by shielding the insulated copper conductor from the H₂S by a lead sheath. As long as the lead sheath does not crack, effective protection is provided. Lead sheath is also effective in blocking gasses from penetrating the insulation, which can result in decompression damage.

Subsea

Baker Hughes innovative production solutions boost fluids from deepwater subsea fields to maximize production and minimize costs—ultimately expanding the economic development limits of subsea technology. As subsea development water depths and step out lengths increase, operators require more technologically advanced and cost-effective methods to produce reserves over the life of deepwater fields. Baker Hughes electrical submersible pumping ESP system technology is the optimum solution for these challenging conditions.

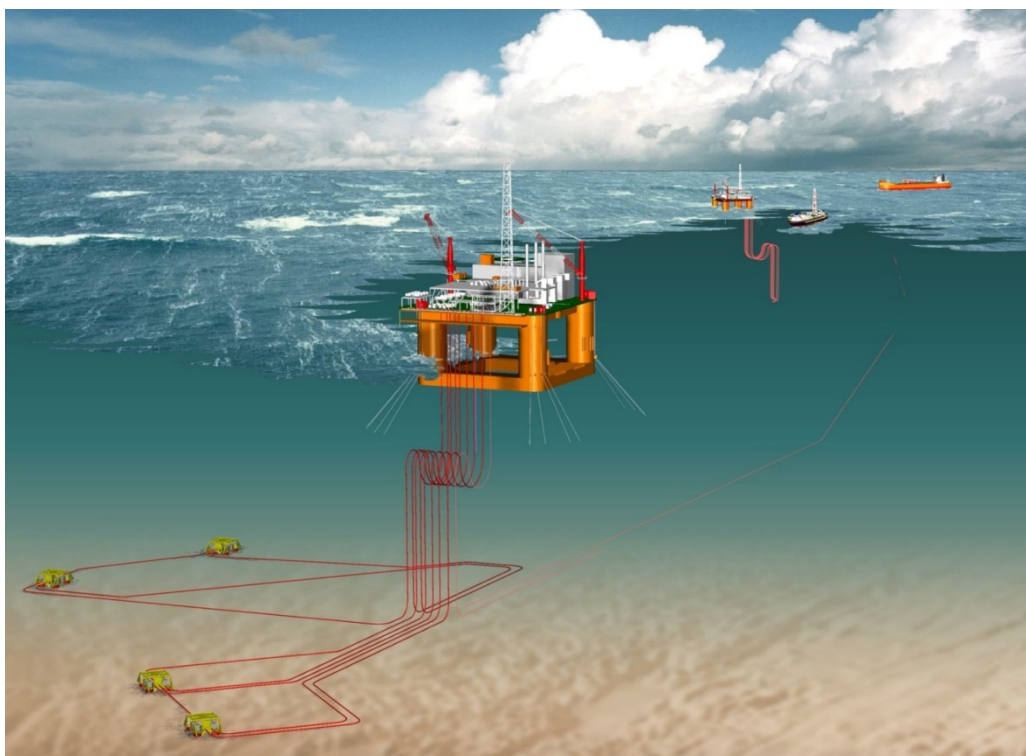


Figure 17–11: Subsea applications

Baker Hughes ESP boosting solutions are more efficient than many other artificial lift systems and have a proven track record of operating in high-pressure and high-temperature conditions, making them ideal for subsea environments. ESP technology can produce high fluid volumes (up to 150,000 BPD), has a wide operating range, and can provide the necessary boost (in excess of 5000 psi) to deliver the production stream to the host platform.

Baker Hughes offers in-well dual ESP systems, seabed booster systems, and riser deployed booster systems. Each option provides distinct advantages, depending on the overall production needs of subsea fields.

In-well dual ESP systems located close to the reservoir maximize overall reserve recovery and the redundant systems provide maximum reliability to reduce overall costs. The in-well system can be combined with seabed boost systems for maximum production.

Seabed ESP boost systems are a cost-effective alternative to in-well systems. Deployment and intervention of seabed systems (Figure 17-12) can be accomplished with multipurpose vessels, negating the need for expensive drilling rigs.

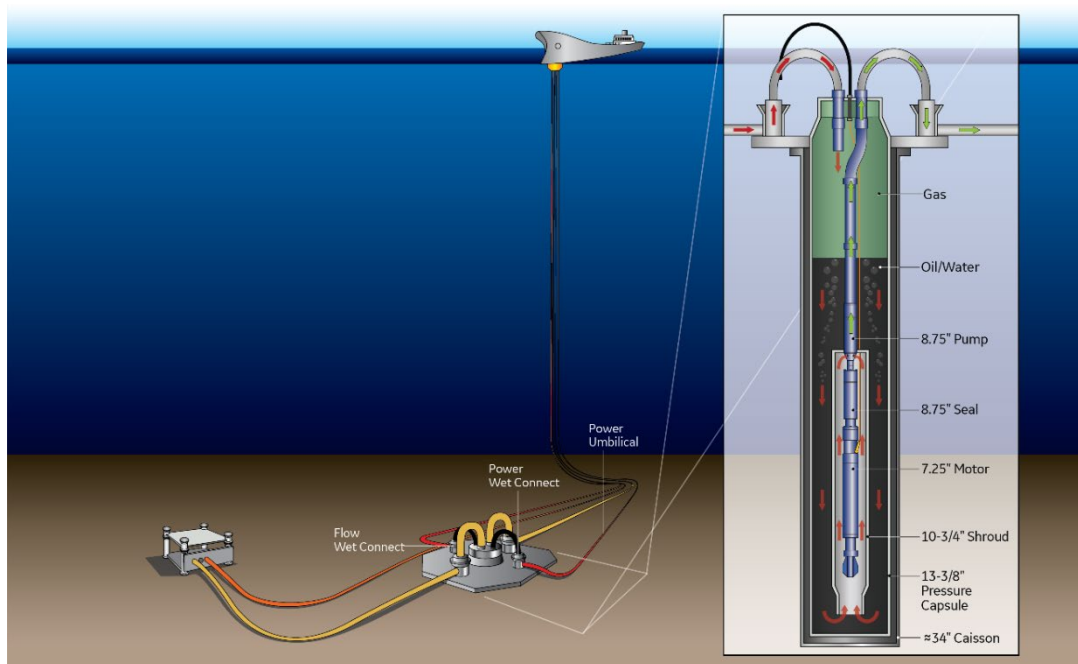


Figure 17-12: ESP boost system

Conclusion

The electrical submersible pump is a uniquely designed machine that has played a vital role in the high volume production of petroleum resources. This equipment has been applied to higher temperature and more aggressive oil wells over the last several decades. During that time significant developmental trends have provided solutions to the difficult problems of maintaining and improving equipment operating life in such environments.

Identification of the major contributors to operating problems in these harsh applications has yielded equipment design changes and improved materials capable of increasing overall performance. Application of these solutions have maximized oil production and increased ESP run life.

Notes:

Chapter 18

Geothermal application

The most common method of artificially producing geothermal systems is to use an ESP. Only with this method is an operator able to achieve the massive amount of flow that is normally needed for surface operations. The development of a system that is able to pump brine with the necessary horsepower and at the high wellbore temperatures has been a key piece in the overall growth of the modern day geothermal market, making projects possible that previously were not.

However, by their very nature, the well environment that these ESPs have to operate in are some of the harshest and most difficult in the world. On top of the high temperatures that can cause thermal expansion of materials inside the pump, the brine from geothermal fluid can have a variety of compositions containing naturally-occurring toxic elements like arsenic, high levels of dissolved solids and scale as well as corrosive compounds like H_2S .

In almost all instances, geothermal brine produced by an ESP is run through a heat exchanger and then reinjected back into the reservoir. The brine is normally kept under pressure to prevent gasses and solids from coming out of solution. Where applicable, chemical inhibitors can be injected into the brine below the ESP to mitigate issues that may be caused by corrosion and scale formation. The Baker Hughes CENetic™ ESPs for water and geothermal applications has been highly engineered to operate in bottom-hole temperatures up to 482°F reliably. A range of material for these ESPs are available to handle everything from high salinity and corrosive applications to scale intensive environments. Special developments have also been made to allow operation in scale and corrosive environments where chemical injection is prohibited.

In order to meet the high flow requirements by geothermal operators, large diameter pumps are used in geothermal applications and capable of producing up to 158,000 bpd as seen in Figure 18-2. While the ranges of fluids that these pumps can produce vary by the model, each stage has a specific flow rate where its efficiency is maximized; this is known as the best efficiency point or BEP.

The CENetic motors used in geothermal systems range from an outer diameter of 5.62-in. to 8.80-in. The 8.80-in. motors are the largest downhole motor that is available in the market today and is capable of producing up to 2800 HP depending on the application temperature.



Figure 18-1: An ESP being pulled from a scale intensive well in Southern Germany

Geothermal pumps			
Stage	Flow Range (bpd)	Flow at BEP (bpd)	Casing size Minimum
WJJ1200	30,000-50,000	41,000	13 ³ / ₈ -in.
WGT1300	36,000-53,000	45,000	9 ⁵ / ₈ -in.
WNE1600	46,000-68,000	55,000	10 ³ / ₄ -in.
WNE2100	62,000-89,000	72,000	10 ³ / ₄ -in.
FLEX2800	51,000-120,000	96,000	13 ³ / ₈ -in.
FLEX3800	58,000-158,000	130,000	13 ³ / ₈ -in.

Figure 18-2: Geothermal pump stage offering from Baker Hughes

In very hot applications, motors need to be “re-rated” to operate reliably and keep the internal temperature from rising above the material limits; this is achieved by using a motor in an application that is oversized in needed horsepower and run under-loaded. For example, a 900HP motor might only be run at 50% load to stay cooler versus using a 450 HP loaded at 100% in the same applications that will run at a higher temperature.

Geothermal motors			
Motor	Max HP	Max bottom hole temperature (°F)	Casing size minimum
562MXPY	264	482	7- ⁵ / ₈ -in.
562KM-VC	900	360	9- ⁵ / ₈ -in.
725HMI-VC	1600	320	9- ⁵ / ₈ -in.
880M	2800	320	10- ³ / ₄ -in.

Figure 18-3: Geothermal motor offering from Baker Hughes

Design challenges for ESPs in geothermal applications isn't also just restricted to the limitation of the equipment but also to the fluid being produced itself. Much like in oil production, there are careful considerations taken to make sure that the fluid being produced is in a single phase where possible by means of controlling the wellhead pressure. In almost all geothermal wells globally, the water being produced would evaporate into steam if exposed to atmospheric pressure, therefore, additional wellhead pressure is maintained to make sure that water being produced stays in liquid form, even at fluid temperatures as high as 400°F. Related to this is an important design consideration with regards to pressure drop near the pump intake as it is producing fluid. If, at very high temperatures, the fluid is produced too rapidly, the drop in hydrostatic head from the smaller fluid column will cause a pressure drop and the geothermal brine may flash into steam before entering the pump which will generally lead to production losses as well as reduced equipment run life.

Notes:

Chapter 19

ESP run life

Achieving maximum system run life with the least total cost of ownership is normally the goal of most ESP operators. This chapter is a consolidation of critical factors (some of which were outlined in the Harsh Environments Section) that impact the run life of an ESP system. These factors include:

- Proper sizing
- High temperatures
- Free gas
- High viscosity
- Corrosion
- Abrasives
- Foreign material
- Deposition
- Electrical failures
- Operating practices
- Troubleshooting

Each well varies and may have a combination of these factors that impact ESP run life, which is determined by the limiting factor in the well.

NOTE: See Chapter 16 for more information.

Proper sizing

Properly sizing or selecting an ESP system is the first and arguably most critical factor in achieving maximum performance and run life. ESPs must be sized to operate within the recommended operating range and the sizing must be based on accurate well productivity data. If the ESP system is not properly sized it could result in the ESP running outside its operating range, leading to accelerated component wear and decreased runtime. Additionally, inaccurate fluid data (water analyses, abrasives, scaling, etc.) can cause the brake horsepower required by the pump to be more than predicted, resulting in potential motor overload and eventually premature failure.

As illustrated in the pump performance curve in Figure 19-1, the operating range of the pump directly affects the following key operating parameters:

- Head capacity
- Flow
- Pump efficiency
- Brake horsepower

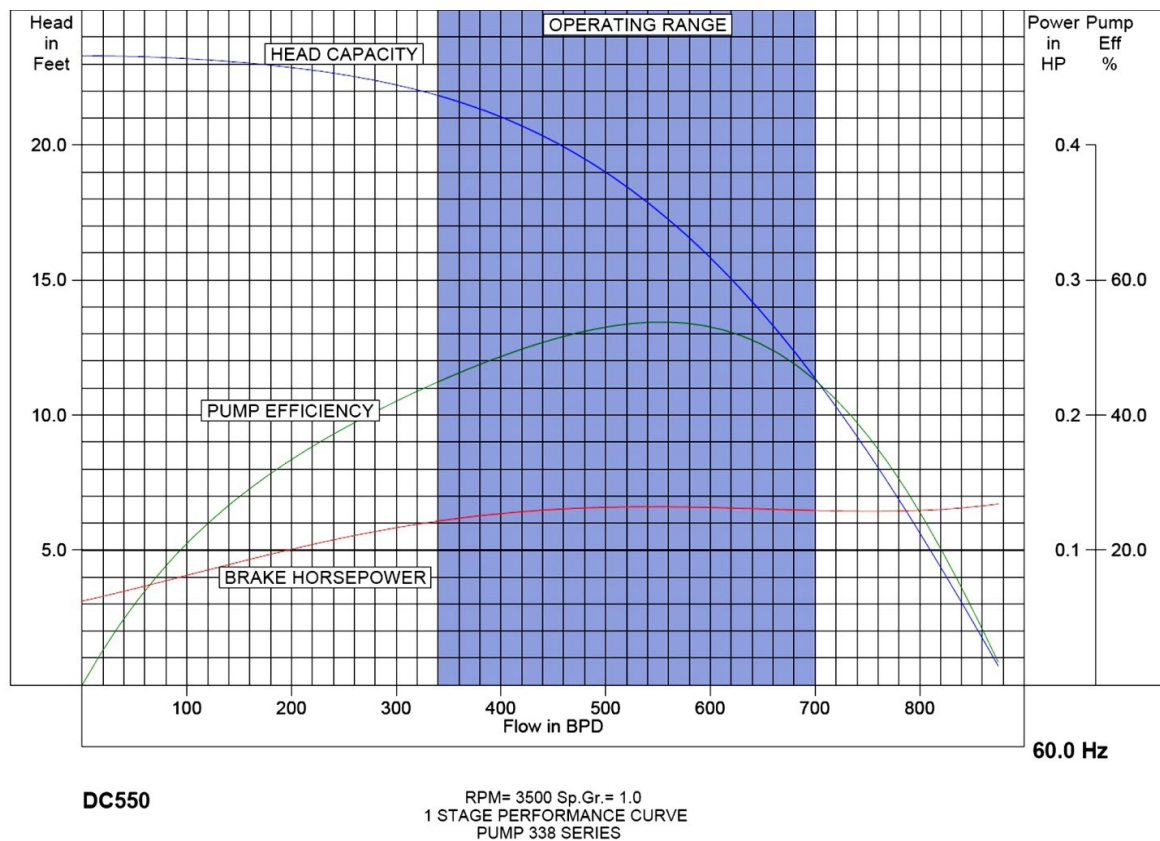


Figure 19-1: Pump performance curve

Each parameter on the pump performance chart is directly affected by fluid and productivity data.

Sizing solutions

To obtain maximum performance and extend system run life:

- Utilize accurate reservoir and inflow performance data
- Utilize accurate fluid properties data
- Computer models and correlations should reflect well parameters as closely as possible (average percent correlation error 5 to 15%)
- Compensate for sizing variables or inaccuracy by using a variable speed drive (VSD) to extend system operating range. Figure 19-2 illustrates a variable speed pump curve and illustrates how variable speeds affect pump performance.

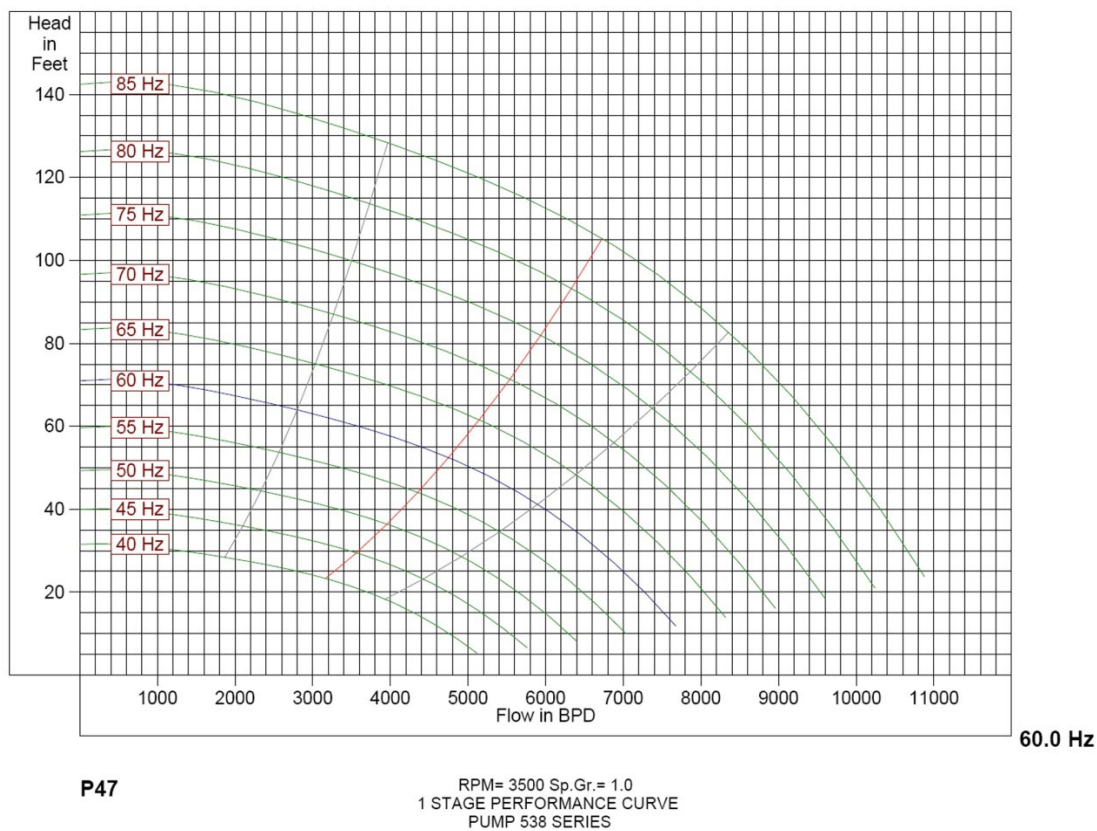


Figure 19-2: Variable speed pump curve

High temperature

High bottomhole temperatures can affect many ESP system components. These include:

- Elastomers components
- Motor oil type
- Cable type

The motor operating temperature is affected by various factors, including the following:

- Percentage of load versus nameplate motor horsepower
- Fluid velocity past the motor
- Percent water, percent oil, percent gas of well fluid past motor
- Power quality (unbalanced current, distorted wave form)

The combination of all the above factors determines the unit operating temperature.

High-temperature solutions

ESPs can run for long periods of time in high temperature wells if the proper equipment is used.

The following equipment features are recommended:

- High-temperature motor oil (retains viscosity at higher temperatures and also has good low temperature qualities)
- High-temperature elastomers (EPDM)–ethylene propylene diene monomer cable insulation and jackets, O-rings, and Aflas seal bags
- Special rotor bearings in motor for proper bearing clearances
- De-rating motors for very high temperatures

Free gas

The presence of free gas can affect ESPs in numerous ways. The pump flow will be reduced or completely stopped as the free gas increases. This is called “gas locking.” In addition, the motor will run hotter as the fluid velocity decreases past the motor and the fluid’s cooling properties will decrease as the free gas increases.

Gas solutions

Some solutions for gassy wells include the following:

- Gas separators
- Gas handling pump stages like the Baker Hughes MVP Stage
- Shroud or upside-down shroud
- Recirculation systems
- Tapered pump design

High viscosity

High fluid viscosity can cause many problems. The resistance to the viscous flow increases the pump's brake horsepower (BHP). High viscosity also reduces the pump's ability to lift the fluid and its efficiency. Viscous fluid produces more friction loss in the tubing, which causes the pump to work much harder.

Viscosity solutions

Some solutions for high fluid viscosity are to use pumps with higher flow stages and higher HP motors, but instability on the left side of the pump curve should be watched carefully. Diluting the well fluid with low viscosity crude also helps to lessen problems associated with high fluid viscosity.

Corrosion

Corrosive fluid affects ESPs in a multitude of ways. Carbon dioxide (CO_2) combined with water forms carbonic acid causing corrosion of housings, heads, bases, and fasteners of the downhole assembly. CO_2 also causes the corrosion of galvanized cable armor on the power cable, connectors, and motor lead extension (MLE). Hydrogen sulfide (H_2S) chemically reacts with copper components causing cable conductors to disintegrate. This also causes sulfide stress cracking with certain steels, especially 300 series SS, affecting shafts, bolts and couplings.

Along with the above mentioned corrosion regimes there is an additional one that is somewhat unique. This is corrosion that is influenced/caused by bacteria. This is called microbiologically influenced corrosion (MIC). In most cases, but not all, the corrosion result will appear as galvanic corrosion; in fact, this is the mechanism. Not to be confused with a dissimilar metal couple, which produces electron transfer, the bacteria can set up an electron transfer regime as well. This is more involved than can be covered here. We have produced a number of SPE presentations, which are available for additional study.

Corrosive solutions

For corrosive wells, ESPs should have:

- Corrosion resistant housings (9% Cr, 1% Mo minimum)
- Stainless steel heads, bases, and fasteners
- Stainless steel or Monel cable armor – understand chloride concentration
- Monel or Nickel Alloy 718 pump and seal shafts to address stress corrosion cracking
- Lead sheath cable for high H_2S environments (defined as 3% or above by volume)
- Corrosion inhibitors (please check elastomers for chemical compatibility)

- When dealing with MIC one can treat with chemicals, a biocide, or use an insulting coating so the bacteria does not have direct access to the metals. As well, the use of a CRA (corrosion resistant alloy) will provide extended runtimes, as opposed to carbon steel components. However, the CRA will not eliminate the MIC; but will postpone the corrosion and increase runtimes.

Abrasives

The production of sand and other abrasives results in:

- Abrasive wear on the pump stages, shafts and housings
- Excessive pump shaft vibration
- Mechanical seal leakage in the seal section
- Motor burns due to fluid migration

Abrasive solutions

Abrasion resistant pump design which provides for downthrust support and radial shaft stabilization – **NOTE:** See Chapter 16 for more information.

Slow, steady increase in production of well on initial start up to limit inflow of unconsolidated sand and frac proppant

Foreign material

The production of foreign material can lead to damage to the pump stages if the debris is harder than the pump stage material (unit fails similar to abrasion). Other damage can be caused by the plugging of pump stage vane passages if debris is softer than pump stage material or low flow by the motor due to partially or totally plugged pumps, which can result in a burn of the motor or power cable.

Foreign material solutions

Solutions to diminish damage caused by foreign material are a thorough well cleanout during the well workover, and a slow, steady increase in production of well on initial start-up to limit the inflow of unconsolidated debris and foreign material. It should be noted that screens can also be used to prevent any damage caused by foreign materials. However, screens can also plug easily in some conditions.

Deposition

Deposition on pump stages can cause high brake horsepower, locked stages, and/or restrictions on the pump or tubing. Some types of deposition are:

- Scale
- Asphaltenes
- Paraffin
- Hydrate/ice plugs

Deposition solutions

Typical ways to deal with problems related to deposition are:

- Chemical treatment
- Tubing heat
- Controlling the pump intake pressure

Electrical failures

Electrical failures are caused by factors such as surface electrical or electronic component failure, poor power (such as voltage imbalance), cable failure due to decompression damage or voltage spikes and overload of the controller or transformer due to changes in downhole or unit conditions.

Operating practices

Poor operating practices can cause the failure of ESPs. The most common are:

- Operating the unit against the closed surface valve for an extended length of time (no flow by the motor will cause the motor or MLE to burn)
- Operating the unit in a no-flow or low-flow condition with no underload protection (same as above)
- Rapid decreases in wellbore pressure (can cause decompression damage of power cable, MLE, or penetrators)
- Increasing unit production quickly causing rapid inflow of sand or foreign material

ESP operating solutions

Once an ESP system is commissioned, the operator plays a key role in the system's performance and run life. Key parameters must be monitored to make sure of proper operation of the system. Failure to properly monitor or interpret these parameters can be costly. Three basic ESP operating parameters are gross production rate, pump intake pressure, and operating motor current.

By monitoring these parameters, an operator can better determine the relative condition of an ESP and anticipate possible problems.

Monitor production rate

Loss of production is usually the first indicator of a downhole problem with an ESP. By monitoring the production rate, an operator can determine the approximate operating point on the pump curve, trend the rate of declining production, and detect possible pump wear, tubing leaks, etc.

Monitor pump intake pressure (pip)

By monitoring PIP, an operator can anticipate unit cycling, determine relative unit sizing accuracy by comparing it with the computer sizing, and look for tubing leaks, pump plugging and/or wear. Increases or decreases in PIP can indicate a change in the pump performance, well inflow, or installation integrity.

Monitor motor current

By monitoring motor current, an operator can look for trends in unit loading, spot possible motor damage due to electrical or mechanical problems, determine relative pump load or spot changes in loading, and detect changes in downhole fluid conditions. Changes in operating current indicate the motor is reacting to a new input from the pump, well, or electrical system. The motor controller should shut the unit off if the current varies beyond acceptable limits.

Additional operating parameters

Other operating parameters that may be monitored include:

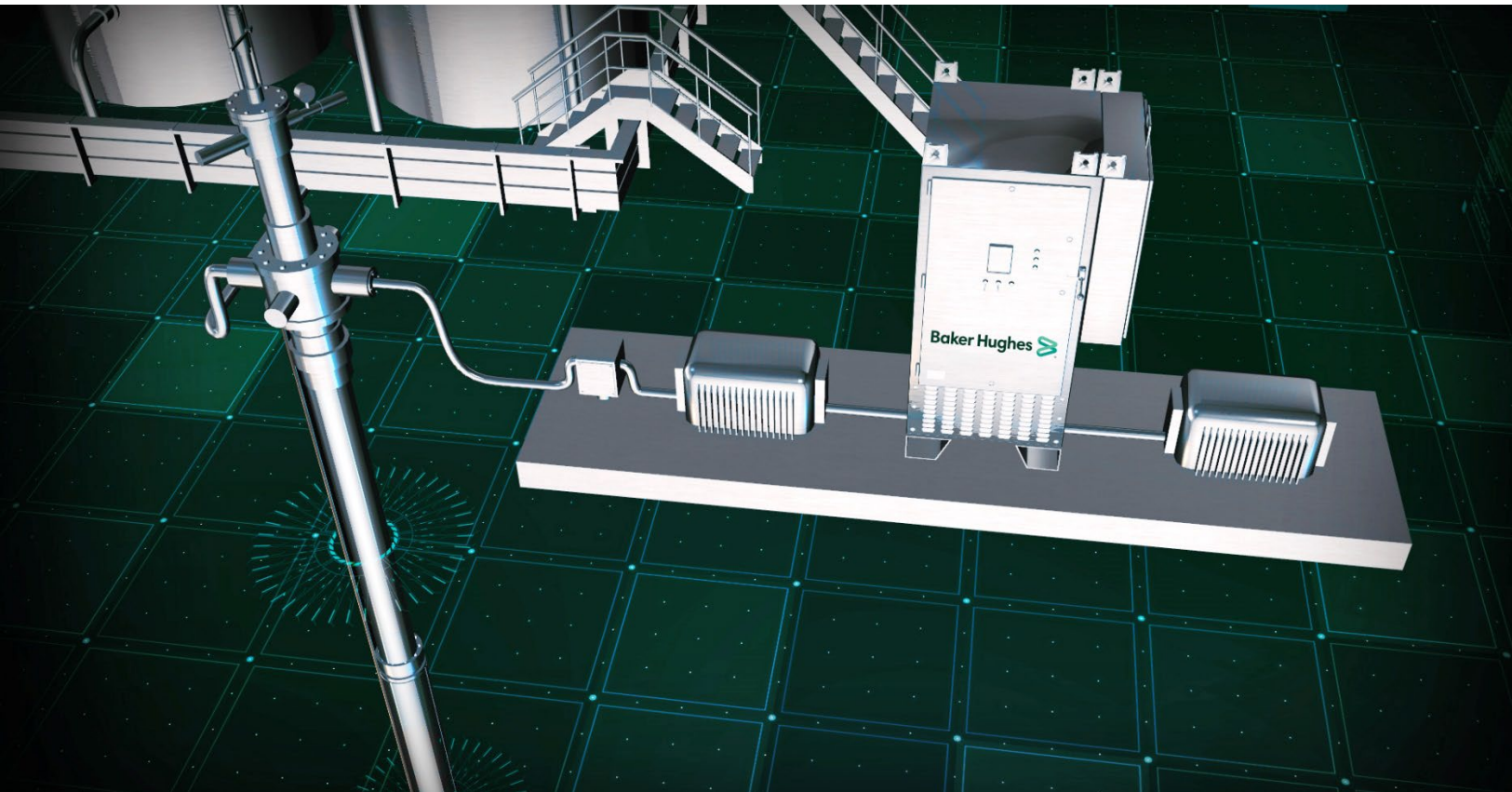
- Pump discharge pressure
- Bottomhole temperature
- Discharge fluid temperature
- Motor operating temperature
- Vibration

Troubleshooting

Troubleshooting by an operator involves looking at the unit operating parameters, as a group, to determine a possible cause. By process of elimination, a cause and effect sequence can be developed when ESP operating problems occur. Failure to check all parameters and/or call for assistance when required can result in premature failure of a unit. Troubleshooting any system requires the proper tools. In the case of ESP systems, this means information which includes:

- Well history (including workovers, treatments, etc.)
- Previous ESP run life and failure modes
- Amp charts (prior to and during time of failure)
- Production data and historic trends
- Available bottomhole and surface pressure data
- Information on starts and stops or operator intervention

Notes:



Section 6: ESP sizing

Chapter 20: Basic sizing

Chapter 21: Variable speed drive (VSD) sizing procedure

Notes:

Chapter 20

Basic sizing

Following is a list of data required for proper ESP sizing:

Well data

- Casing or liner size and weight
- Tubing size, type, and thread (new or used)
- Perforated or open hole interval
- Pump setting depth (measured and vertical)

Production data

- Wellhead tubing pressure
- Wellhead casing pressure
- Test production rate
- Producing fluid level and/or well flowing pressure
- Static fluid level and/or static bottomhole pressure
- Datum point
- Bottomhole temperature
- Desired production rate
- Gas-oil ratio
- Water cut

Well fluid conditions

- Specific gravity of water
- Oil API or specific gravity
- Specific gravity of gas
- Bubblepoint pressure of gas
- Viscosity of oil
- PVT data

Power sources

- Available primary voltage
- Frequency
- Power source capabilities

Possible problems

- Sand
- Deposition
- Corrosion
- Paraffin
- Emulsion
- Gas
- Temperature

High water cut wells

The simplest type of well for sizing submersible equipment is the high water cut well and it will be used to illustrate a simplified ESP sizing procedure.. The basic methodology is correct, but modern ESP sizing is done using computer software with much more rigorous calculations on a stage-by-stage basis. The biggest simplification in these steps is that fluid volumes and densities are assumed constant and unchanging with pressure and temperature. Accordingly, the following step-by-step procedure can be used:

- Collect and analyze the available data as outlined above.
- Determine production capacity, pump setting depth, and pump intake pressure as required.
Depending upon the data, several combinations are possible. If the desired production rate and pump setting depth are known, the pump intake pressure at the desired production rate can be estimated based on the well's inflow performance. Otherwise, the optimum production rate for a given pump setting depth can be determined by plotting a flowing pressure (or producing fluid level) flow rate curve.
- Calculate the total dynamic head required, which is equal to the sum of the net lift (vertical distance from producing fluid level to surface) friction loss in feet in production tubing and wellhead discharge pressure all expressed in terms of height of column of fluid being produced.
- Based on the pump performance curves, select a pump type so that the OD of the pump will fit inside the casing of the well and the desired production rate falls within the recommended capacity range of the pump. If two or more pumps meet these conditions, an economic analysis may be necessary before finalizing the selection. In actual practice, the pump with the highest

efficiency at the desired production rate is usually selected. From the selected pump performance curve, determine the head produced and brake horsepower required per stage.

- Calculate the number of stages required to provide the total dynamic head. The total number of stages rounded off to an integer is equal to the total dynamic head divided by the head produced per stage. Also calculate the motor horsepower by multiplying the brake horsepower per stage by the total number of stages and average specific gravity of the fluid being pumped.
- Based on the technical information provided by the supplier, select appropriate size and model of the seal section and determine horsepower requirements. Select a motor which is capable of supplying total horsepower requirements for both the pump and seal section. The selected motor should be large enough to withstand the maximum load without overloading it.
- Use the technical data provided by the submersible pump manufacturer to determine if any load limitations were exceeded (shaft loading, thrust bearing loading, housing pressure limitations, fluid velocity passing the motor, etc.).
- Select the power cable type and size based on motor current, conductor temperature, and space limitations. Calculate surface voltage and kVA requirements.
- Select accessory and optional equipment.

Example: High water cut well

To facilitate comprehension of the selection process, these various steps are discussed in greater detail and illustrated by the following example:

Collection and analysis of available data

This is the first and most important step towards selection of submersible pump equipment and the information obtained from the analysis will have a significant effect on the selection as well as actual performance of the equipment. Therefore, the significance of this step cannot be overemphasized and unfortunately, often little attention is paid to the collection and proper analysis of the data.

As an example, let us assume that the following information is available and it is required to select a suitable submersible pumping system:

Well data

- Casing – 7-in. OD, 23 lb/ft
- Tubing – 2 7/8-in. OD external upset 8 round thread (new)
- Perforations – 5,300 to 5,400 ft
- Pump setting depth – 5,200 ft (measured and vertical)

Production data

- Wellhead tubing pressure – 150 psi
- Test rate – 900 bpd
- Datum point – 5,350 ft
- Test pressure – 985 psi
- Static bottomhole pressure – 1,650 psi
- Bottomhole temperature – 180° F
- Gas-oil ratio – not available
- Water cut – 90%
- Desired production rate – 2,000 bpd (stock tank)

Well fluid conditions

- Specific gravity of water – 1.02
- A.P.I. gravity of oil – 30 degrees (0.876)
- Specific gravity gas – not available
- Bubblepoint pressure of gas – not available
- Viscosity of oil – not available

Power sources

- Available primary voltage – 7,200/12,470 volts
- Frequency – 60 Hertz
- Power source capability – stable system

Possible problems

None

Analysis

- The gas information for this application is not available. For all practical purposes, it can be assumed that only oil and water mixture flows through the pump.
- As the water cut is very high (about 90%), no emulsion problems may be anticipated. Moreover, friction loss charts based on water flow can be used (ignoring the effects of oil viscosity).

Determine pump intake pressure

In this case, the desired production rate and pump setting depth are given. The pump intake pressure, at the desired production rate, can be calculated from the present production

conditions. As the water cut is very high and the gas-oil ratio (GOR) is unknown, the productivity index will probably give satisfactory results.

$$PI = \frac{Q}{\bar{P}_r - P_{WF}}$$

Where: Q = Test Rate

$\bar{P}_r$ = Static Reservoir Pressure

P_{WF} = Well Flowing Pressure @ Rate Q

Or

$$PI = \frac{900 \text{ bpd}}{1,650 \text{ psi} - 985 \text{ psi}} = 1.353 \text{ bpd} / \text{psi}$$

Next, find the well flowing pressure (P_{wfd}) @ the desired flow rate 2,000 bpd (Q_d):

$$P_{WFD} = \bar{P}_R - \left(\frac{Q_d}{PI} \right)$$

$$P_{WFD} = 1,650 \text{ psi} - \left(\frac{2,000 \text{ bpd}}{1.353 \text{ bpd} / \text{psi}} \right) = 172 \text{ psi}$$

The pump intake pressure can be determined by correcting the well flowing pressure for the difference in pump setting depth and the datum point and by considering the friction loss in the casing annulus.

In the given example, as the pump is set just above the perforations, the friction loss, due to loss of fluid through the annulus from perforations to the pump setting depth will be small compared to the flowing pressure and can be neglected. Also, because there is both water and oil in the produced fluid, it is necessary to calculate the composite specific gravity of the produced fluids. The composite gravity of the fluid (SG_L) = $(1.02 \times 0.9) + (0.876 \times 0.1) = 1.01$.

The difference in datum depth (5,350 ft) and pump setting depth (5,200 ft) is 150 ft. To estimate the pump intake pressure (PIP) we can convert this difference of 150 ft to psi and subtract it from the well flowing pressure (P_{wfd}) calculated above at 2,000 bpd:

$$\text{Pump Intake Pressure} = P_{wfd} - \left[\frac{(\text{Datum Depth} - \text{Pump Depth}) \times SG_L}{2.31 \text{ ft./psi}} \right]$$

$$\text{Pump Intake Pressure} = 172 \text{ psi} - \left[\frac{(5,350 \text{ ft.} - 5,200 \text{ ft.}) \times 1.01}{2.31 \text{ ft./psi}} \right] = 106 \text{ psi}$$

Total dynamic head = Net dynamic lift + friction loss + wellhead tubing pressure

$$\text{Net Dynamic Lift} = \text{Datum Vertical Depth} - \left(\frac{P_{wfd} \times 2.31 \text{ ft./psi}}{SG_L} \right)$$

or

$$\text{Net Dynamic Lift} = \text{Pump Vertical Depth} - \left(\frac{PIP \times 2.31 \text{ ft./psi}}{SG_L} \right)$$

$$\text{Net Dynamic Lift} = 5,350 \text{ ft.} - \left(\frac{172 \text{ psi} \times 2.31 \text{ ft./psi}}{1.01} \right) = 4,957 \text{ ft.}$$

Determine friction loss in tubing using Hazen-Williams formula, or from Figure 20-1, and new 2 7/8-in. tubing @ 2,000 BPD (32 ft/1,000).

$$\text{Total friction loss} = 32 \text{ ft} \times 5,200 \text{ ft} / 1,000 = 166 \text{ ft}$$

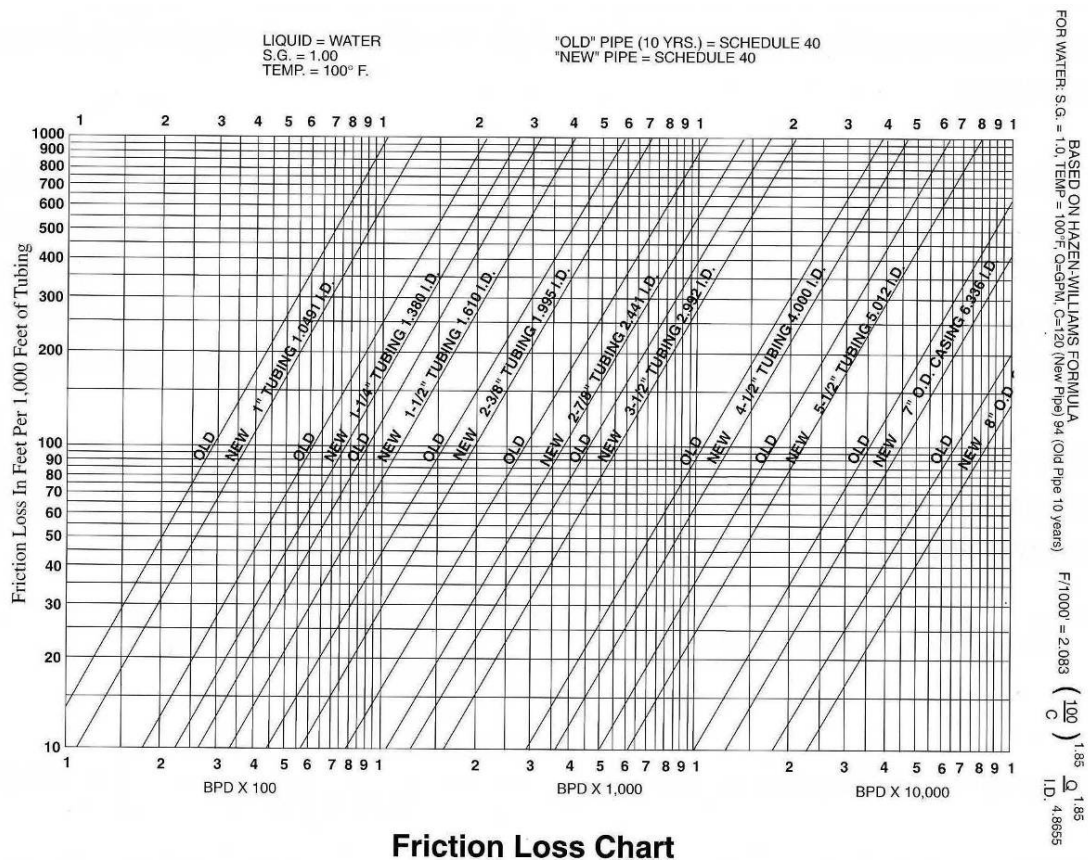


Figure 20-1: Friction loss chart

The required wellhead tubing pressure is 150 psi. Converting to Head (ft):

$$\text{Head (ft)} = \frac{\text{psi} \times 2.31 \text{ ft./psi}}{SG_L} \quad \text{Or} \quad \text{Head (ft.)} = \frac{150 \text{ psi} \times 2.31 \text{ ft./psi}}{1.01} = 343 \text{ ft}$$

Total Dynamic Head = Net Lift (4,957 ft.) + Friction Loss (166 ft.) + Wellhead Tubing Pressure (343 ft.) = 5,466 ft.

API casing O.D.	Weight		Equipment series applicable			*Maximum round cable size recommended with various tubing sizes (O.D.)								
	Lb/Ft	Kg/M	Motor	Seal	Pump	API upset			API non-upset					
						2	2 ⁷ / ₈	3 ½	2 ³ / ₈	2 ⁷ / ₈	3 ½	4½	5½	7
4 1/2" (114.3MM)	9.5	14.1	375	338	338	†			†					
	10.5	15.6				†			†					
	11.6	17.3				†			†					
5 1/2" (139.7MM)	**20.0	29.9	375, 450	338,400	338, 400	1	-	-	1	***6	-	-	-	-
	17.0	25.3				1	6	-	1	***4	-	-	-	-
	15.5	23.0				1	6	-	1	***4	-	-	-	-
	14.0	20.7				1	6	-	1	***2	-	-	-	-
6 5/8" (168.3MM)	28.0	41.7	375, 450	338,400	338, 400	1	1	6	1	1	**4	-	-	-
	26.0	38.7	450, 544	400,513	400, 513, 538	1	1	**4	-	1	-	-	-	-
	24.0	35.8			1	1	**4	1	1	1	-	-	-	
	20.0	29.9			400, 513, 538, 562	1	1	1	1	1	1	-	-	-
7" (177.8MM)	32.0	47.6	450, 544,56 2	400,513	400, 513, 538	1	1	2	1	1	1	-	-	-
	29.0	43.3				1	1	1	1	1	1	-	-	-
	26.0	38.7				1	1	1	1	1	1	-	-	-
	23.0	34.1			400, 513, 538, 562	1	1	1	1	1	1	-	-	-
	20.0	29.9				1	1	1	1	1	1	-	-	-
	17.0	25.7				1	1	1	1	1	1	-	-	-
7 5/8" (193.7MM)	39.0	58.1	450, 544,56 2	400,513	400,513,53 8,562	1	1	1	1	1	1	***4	-	-
	33.7	50.2				1	1	1	1	1	1	***2	-	-
	29.7	44.3				1	1	1	1	1	1	1	-	-
	26.4	34.4				1	1	1	1	1	1	1	-	-
	24.0	35.8				1	1	1	1	1	1	1	-	-
	20.0	29.9				1	1	1	1	1	1	-	-	-
8 5/8" (219.1MM)	49.0	72.8	450, 544,56 2,725	400,513, 675	400,513,53 8,562 and 675	1	1	1	1	1	1	1	4	-
	44.0	65.6				1	1	1	1	1	1	1	2	-
	40.0	59.4				1	1	1	1	1	1	1	1	-
	36.0	53.5				1	1	1	1	1	1	1	1	1
	32.0	47.6				1	1	1	1	1	1	1	1	1
10 3/4" (273.0MM)	55.5	82.7	450, 544, 725	400, 513, 675, 875	400, 513, 538, 562, 675, 875	1	1	1	1	1	1	1	1	1
	32.7	48.5				1	1	1	1	1	1	1	1	1
13 3/8" (339.8MM)	83.0	123.4	544, 725	400, 513, 675, 875	400, 513, 538, 562, 675, 875, 1025	1	1	1	1	1	1	1	1	1
	48.0	71.5				1	1	1	1	1	1	1	1	1

* CABLE OF FLAT CONFIGURATION IN SIZES #1, #2, AND #4 CAN BE RUN WITH LARGER TUBING SIZES IN 5 1/2", 6 5/8" AND 7" O.D. CASING TO REDUCE BOTH POWER LOSSES AND FRICTION LOSSES

** INSTALL 450 MOTOR, 400 PUMP IN 5 1/2" CASING ONLY WITH SPECIAL MOTOR LEAD EXTENSION. CONSULT SALES REPRESENTATIVE.

*** RECOMMEND INSTALLING THIS SIZE ROUND CABLE WITH FOUR JOINTS OF SMALLER DIAMETER TUBING IMMEDIATELY ABOVE PUMP.

† CAN ONLY BE USED WITH FLAT CABLE UNLESS 2" INTEGRAL-THREAD TUBING IS USED

Figure 20-2: ESP Equipment Specifications Table

Pump type

From the table in Figure 20-2, it can be seen that the 500 series pump, motor, and seal are the largest diameter units to fit the 7-in., 23 lb /ft casing. The largest diameter units are generally the first selection, if the desired production rate falls within the operating range of the pump. Three common advantages of selecting the largest diameter units are: 1) as the equipment diameter increases the efficiency increases, 2) the larger units are normally less expensive, and 3) the unit runs cooler due to higher fluid velocity.

Next, using the table in Figure 20-3, it can be seen that the desired production rate (2,000 bpd) lies well within the recommended capacity range of the 538P23 pump stage type.

Series	Type	60 Hz (BPD)		50 Hz (m³/D)	
		Rate at best efficiency	Operating range	Rate at best efficiency	Operating range
338	DC550	550	340 – 700	73	45 – 93
	DC750	750	550 – 1000	99	73 – 132
	DC950	950	600 – 1300	126	79 – 172
	DC1250	1250	950 – 1700	166	126 – 225
	DC2200	2300	1000–2760	305	132 – 366
	DC2500	2400	1200 – 3100	318	159 – 411
400	400P3	330	120 – 460	44	16 – 61
	400P4	400	300 – 600	53	40 – 79
	400P6	600	400 – 900	79	53 – 119
	400P8	800	550 – 1200	106	73 – 159
	400P10	1000	650 – 1400	132	86 – 185
	400P12	1200	850 – 1600	159	113 – 212
	400P16	1600	850 – 1950	212	113 – 258
	400P18	1800	1000 – 2500	238	132 – 331
	400P22	2200	1200 – 2900	291	159 – 384
	400P30	3000	1500 – 3800	397	199 – 503
	400P35	3500	2200 – 4500	464	291 – 596
	400P43	4450	3200 – 5400	589	424 – 715
	400P60	5600	3600 – 6800	742	477 – 901
	400G12SSD	1200	800 – 1700	159	106 – 225
	400G22SSD	2200	1000 – 3100	291	132 – 411
	400G42SSD	4200	2200 – 5800	556	291 – 768
538	538P11	1150	750 – 1500	152	99 – 199
	538P17	1750	1400 – 2100	232	185 – 278
	538P23	2300	1200 – 2900	305	159 – 384
	538P31	3100	2000 – 4300	411	265 – 570
	538P37	3700	2500 – 4800	490	331 – 636
	538P47	4750	2800 – 5700	629	371 – 755
	538P62	6200	4000 – 7700	821	530 – 1020
	538P75	7500	4750 – 8500	993	629 – 1126
	538P100	10000	5000 – 12000	1324	662 – 1589
	538G31	3100	1800 – 4400	411	236 – 583
	538G68	6800	4000 – 9500	901	530 – 1258
	538G110	10500	6000 – 14000	1391	795 – 1854
562	562P100	11000	7000 – 13250	1457	927 – 1755
	562P155	16000	11000 – 18500	2119	1457 – 2450
	562P200	19000	17500 – 24000	2516	2318 – 3179
675	HC7800	8200	5000 – 10000	1086	662 – 1325
	HC10000	10400	8000 – 12600	1377	1060 – 1669
	HC12500	12500	9000 – 16000	1656	1192 – 2119
	HC16000	15700	10000 – 17000	2079	1325 – 2252
	HC20000	20000	12000 – 23000	2649	1589 – 3046
	HC27000	28000	23500 – 33600	3709	3113 – 4450
	HC35000	36000	33500 – 48000	4768	4437 – 6358
875	IA600/WIE600	21429	13715 – 27429	2838	1817 – 3633
	IB700/WIE700	27432	13715 – 33429	3633	1817 – 4428
1025	JA1100/WJE1000	36000	22286 – 46286	4768	2952 – 6130
	JC1300/WJE1200	41143	27429 – 54827	5449	3633 – 7266

Figure 20-3: Pump operating range table

Figure 20-4, is the corresponding 60 hertz pump performance curve for the 538P23 pump. Using the performance curve find, at the desired production rate of 2,000 bpd, the head/stage (60.0 ft /stg.) and bhp/stage (1.4 bhp/stg.)

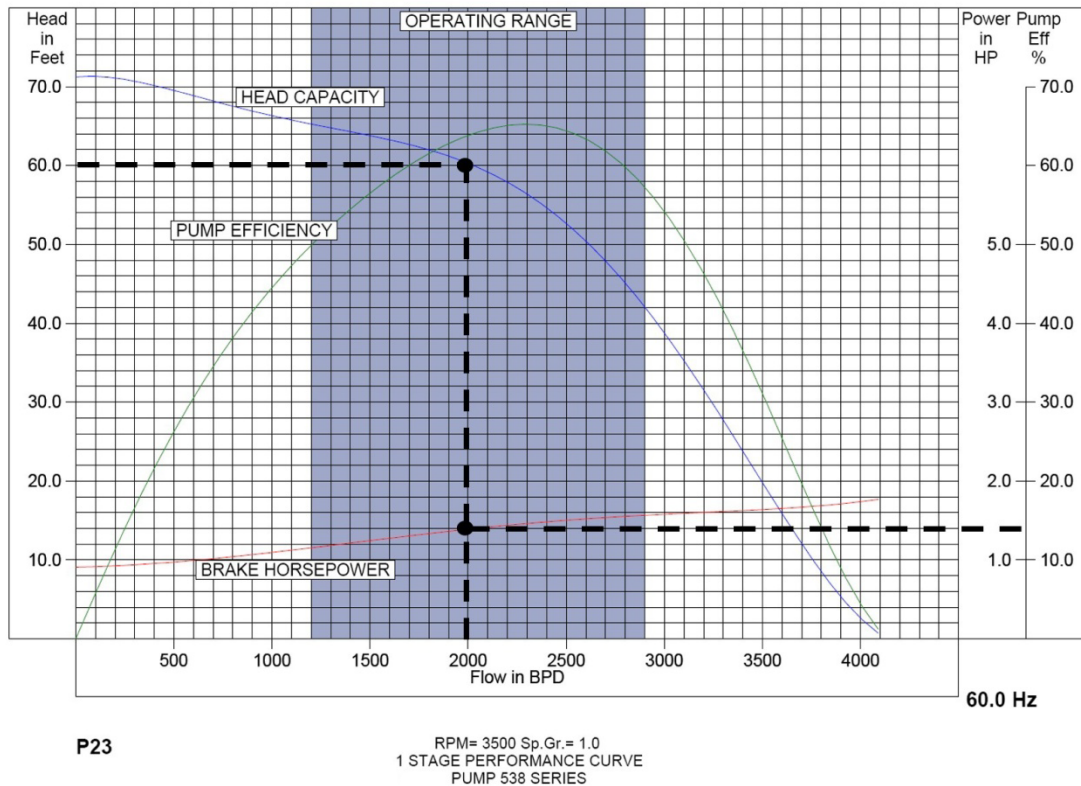


Figure 20-4: Pump Performance Curve

Determine the number of pump stages required for the application.

$$\text{No. Stages} = \frac{\text{Total Dynamic Head}}{\text{Head / Stage}} \quad \text{Or} \quad \text{No. Stages} = \frac{5,466 \text{ ft.}}{60.0 \text{ ft./ stg.}} = 91 \text{ stages}$$

Once the number of stages has been determined, we can then calculate the pump brake horsepower (BHP) as follows: BHP = BHP/Stage x Number Stages x SG_L

$$\text{BHP} = 1.4 \text{ BHP/Stage} \times 91 \text{ Stages} \times 1.01 = 129 \text{ BHP}$$

Seal section and motor selection

Normally the seal section series is the same as that of the pump, although, there are exceptions and special adapters are available to connect the units together. In this example application, we will assume that the seal section and pump are of the same series.

The horsepower requirement for the seal section is based upon the total dynamic head produced by the pump. The seal brake horsepower (BHP) has a minimal impact on horsepower requirements. It is generally less than 1 BHP per seal section. Therefore, the total horsepower requirement for this application is 129 HP for the pump, plus 1 HP for the seal, or 130 HP.

KMH				Dimensions			
Size HP		Volt/Amp		Length		Weight	
60 HZ	50 HZ	60 HZ	50 HZ	Ft.	M.	Lbs.	Kg.
38	32	435/53	363/53	5.4	1.65	383	174
38	32	875/26	729/26	5.4	1.65	383	174
38	32	1315/18	1096/18	5.4	1.65	383	174
57	48	430/81	358/81	6.8	2.08	486	220
57	48	870/40	725/40	6.8	2.08	486	220
57	48	1315/26	1096/26	6.8	2.08	486	220
76	63	865/53	721/53	8.3	2.52	590	268
76	63	1360/34	1133/34	8.3	2.52	590	268
95	79	840/69	700/69	9.7	2.95	693	314
95	79	1330/44	1108/44	9.7	2.95	693	314
114	95	860/81	717/81	11.1	3.39	796	361
114	95	1300/53	1083/53	11.1	3.39	796	361
114	95	2330/30	1942/30	11.1	3.39	796	361
133	111	830/98	692/98	12.5	3.82	899	408
133	111	1345/60	1121/60	12.5	3.82	899	408
133	111	2205/37	1838/37	12.5	3.82	899	408
152	127	1340/69	1117/69	14.0	4.26	1003	455
152	127	2325/40	1938/40	14.0	4.26	1003	455
171	143	1290/81	1075/81	15.4	4.69	1106	502
171	143	2390/44	1992/44	15.4	4.69	1106	502
190	158	1185/98	988/98	16.8	5.13	1209	548
190	158	1430/81	1192/81	16.8	5.13	1209	548
190	158	2415/48	2013/48	16.8	5.13	1209	548
209	174	1305/98	1068/98	18.2	5.56	1313	596
209	174	2385/53	1968/53	18.2	5.56	1313	596
228	190	1130/123	942/123	19.7	6.00	1415	642
228	190	1425/98	1188/98	19.7	6.00	1415	642
228	190	2305/60	1921/60	19.7	6.00	1415	642
266	222	1315/123	1096/123	22.5	6.87	1622	736
266	222	1660/98	1383/98	22.5	6.87	1622	736
266	222	2345/69	1954/69	22.5	6.87	1622	736
304	253	1505/123	1254/123	25.4	7.74	1828	829
304	253	1900/98	1538/98	25.4	7.74	1828	829
304	253	2290/81	1908/81	25.4	7.74	1828	829
342	285	1695/123	1413/123	28.2	8.61	2035	923
342	285	2575/81	2146/81	28.2	8.61	2035	923
380	317	1881/123	1568/123	31.1	9.48	2242	1017
380	317	2370/98	1975/98	31.1	9.48	2242	1017
418	348	2070/123	1725/123	33.9	10.35	2448	1110
418	348	2610/98	2175/98	33.9	10.35	2448	1110

Figure 20-5: ESP motor selection table

Referring to the table in Figure 20-5, it can be seen that a 133 HP, 562 series, motor is available. This motor will be loaded approximately 98% during normal operation. Caution should be taken when selecting a motor that is overloaded during normal operation. This overload condition will often result in a reduced run life.

The final decision is usually based upon economic considerations as well as on previous experience under similar conditions. For this application, we will select the 133 HP motor. The motor voltage can be selected based on the following considerations:

- The high-voltage (consequently low-current) motors have lower cable losses and require smaller conductor size cables.
- The higher the motor voltage, the more expensive the motor controller will be.
- The utilization of existing equipment

In some cases, the savings due to smaller cable may be offset by the difference in motor controller cost and it may be necessary to make an economic analysis for various voltage motors. However, for the application under reference, we will select the high-voltage motor (133 HP, 2,205 volts, 37 amps).

Load limits

Referring to the engineering section of the ESP manufacturer's catalog, check to see that all parameters are within recommended range (e.g. thrust bearing, shaft HP, housing pressure, and fluid velocity).

Power cable

The selection of a cable involves a compromise between cable sizes, losses, and cost of cable. The proper cable size is dependent on combined factors of voltage drop, amperage and available space between tubing collars and casing. Figure 18-6 shows voltage drop in various sizes of cable.

At the selected motor amperage and given downhole temperature, the selection of a cable size that will give a voltage drop of less than 30 volts per 1,000 ft is usually recommended for current carrying capability of cable. For deep wells, the selection of a cable size that will give a cable voltage drop of less than 15% of motor nameplate voltage is usually recommended. If the voltage drop is between 15% and 19%, a variable speed drive may be required. Above 19%, contact the submersible pump manufacturer for special considerations. If the voltage drop is too low, the starting torque may result in shaft breakage. As a rule of thumb, consider using a variable speed drive (VSD) if the cable voltage drop is less than 5%.

Selection of cable type is primarily based on fluid conditions and operating temperature. The operating temperature can be determined using Figure 20-6 (IEEE – RP 1019). Using Figure 20-7, the motor current (35 amps) and the bottomhole temperature (180° F or 82° C), the cable operating temperature is 193° F or 89° C. Select the cable based on this operating temperature.

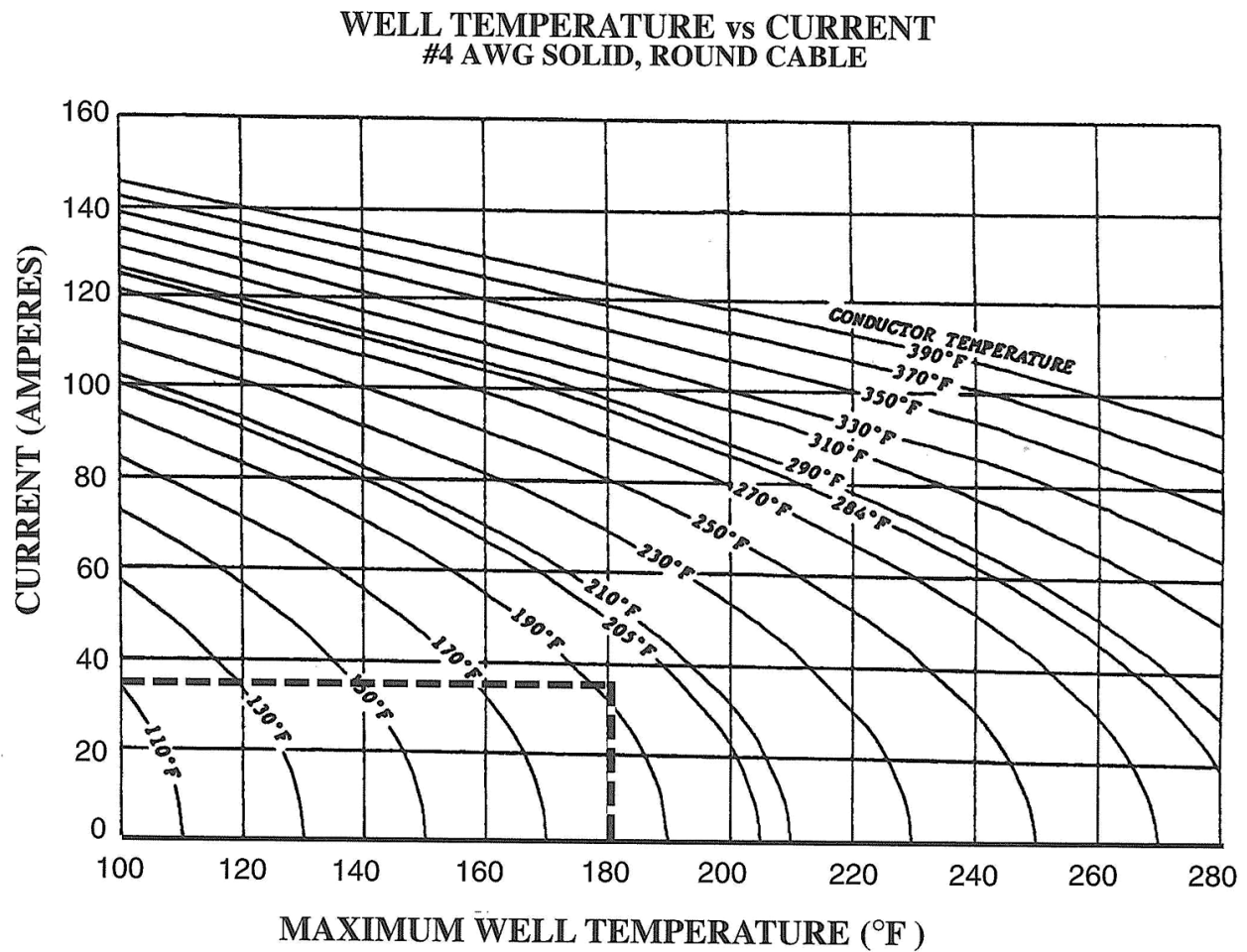
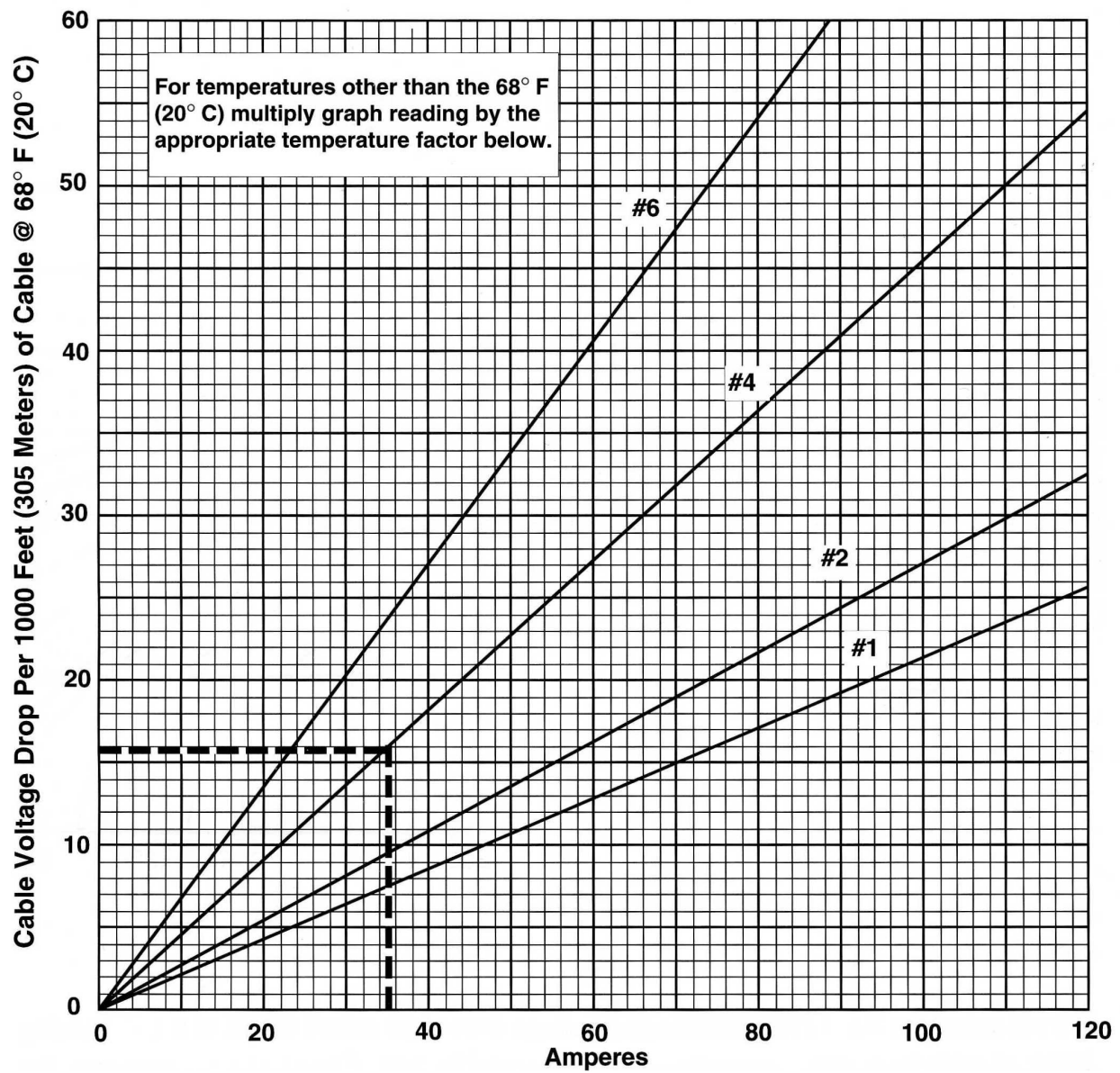


Figure 20-6: Well temperature vs current graph



Temp °F (°C)	Multiplying factor	Temp °F (°C)	Multiplying factor	Temp °F (°C)	Multiplying factor
100 (38)	1.070	170 (77)	1.223	240 (116)	1.376
110 (43)	1.092	180 (82)	1.245	250 (121)	1.398
120 (49)	1.114	190 (88)	1.267	260 (127)	1.420
130 (54)	1.136	200 (93)	1.288	270 (132)	1.441
140 (60)	1.157	210 (99)	1.310	280 (138)	1.463
150 (66)	1.179	220 (104)	1.332	290 (143)	1.485
160 (71)	1.209	230 (110)	1.354	300 (159)	1.507

Figure 20-7: Cable voltage drop chart

We will select the No. 4 cable, which has a voltage drop of 16 volts/1,000 ft at 68° F or 20° C. Adding 200 ft of cable for surface connections and correcting for 193° F or 89°C conductor temperature, the total voltage drop would be:

$$\text{Voltage Drop} = \frac{16 \text{ volts} \times 5,400 \text{ ft.} \times 1.267}{1,000 \text{ ft.}} = 110 \text{ volts}$$

The above voltage drop is 5% of the nameplate voltage, therefore it's safe to say the unit will start using a standard switchboard.

Next, we can determine the required surface voltage, which is equal to motor nameplate.

Voltage + Voltage Drop:

Surface Voltage = 2,205 Volts + 110 Volts = 2,315 Volts

Now the total system kVA can be calculated with this equation:

$$\text{kVA} = \frac{\text{Surface Voltage} \times \text{Motor Amps} \times 1.73}{1,000}$$

$$\text{kVA} = \frac{2,315 \text{ Volts} \times 37 \text{ Amps} \times 1.73}{1,000} = 148 \text{ KVA}$$

Accessory and optional equipment

The type of transformer selected depends on the available power supply voltage (7,200/ 12,470), the required surface voltage (2,315 volts) and the kVA rating (140). Either a single three-phase transformer or three single phase transformers with a total kVA of 140 or larger could be used to lower the primary voltage to the required surface voltage.

Motor controller selection is based on surface voltage, motor amps, and the total kVA rating. In this example we will assume the voltage to the switchboard will be the surface voltage. Other miscellaneous equipment may include a 2⁷/₈-in. check and drain valve, wellhead, cable bands, and motor flat cable.

The wellhead selection would be based on casing size, tubing size, pump setting depth, pressure limitations, cable size, and construction (round or flat). High pressure wellheads are also available which use electrical penetrators, instead of packing rubbers, to transmit power downhole.

Notes:

Chapter 21

Variable speed drive (VSD) sizing procedure

Various approaches to sizing ESP equipment have been discussed in detail with the use of several examples. All were designed to operate at a constant speed. Next, we will concentrate on designing systems capable of operating over a much wider operating range, at multiple flow rates and/or head requirements.

- Collect and analyze data.
- Define the stock tank production rates for minimum and maximum flow rates, pump setting depth and the pump intake pressures, or fluid levels, at desired production rates.
- Calculate the volume of oil, free gas and water at the pump intake using test data or the multi-phase correlations that best match your conditions. Calculate the percent of free gas to total volume of fluids as previously discussed. If excessive gas is indicated, use a gas separator and adjust the fluid volumes based on your selected separator efficiency.
- Calculate the total dynamic head required for minimum and maximum flow rates, which is equal to the sum of the net lift, friction loss and wellhead pressure, or if data's available, determine the pump discharge pressure using multi-phase flow correlations and PVT data.
- Based on the VSD pump performance curves, select a pump that will fit within the casing of the well and the flow rate at pump intake falls within the capacity range of the pump at the desired frequency.

From the performance curve, determine the head/stage and brake horsepower/stage at the desired maximum operating frequency. Calculate the number of stages required to provide the maximum total dynamic head, which is equal to the maximum total dynamic head divided by the head produced per stage at the maximum operating frequency.

Next, determine the head/stage developed at the minimum desired flow rate:

$$\text{Minimum Head/Stage} = \frac{\text{Minimum TDH}}{\text{Number Stages}}$$

Using the minimum head/stage and the minimum desired pump intake flow rate, locate the operating frequency on the pump performance curve. Check to make sure the point is within the pumps recommended operating range.

Solve for the maximum brake horsepower requirement as follows:

$$\text{Maximum BHP} = 60 \text{ Hz. BHP/Stage} \times \text{No. Stages} \times \left(\frac{\text{Max. Hz.}}{60 \text{ Hz.}} \right)^3 \times SG.$$

The equivalent 60 Hertz horsepower requirement can now be determined as follows:

$$\text{Equivalent 60 Hz. BHP} = \text{Maximum BHP} \times \frac{60 \text{ Hz}}{\text{Max. Hz.}}$$

- Based on the technical information provided by the supplier, select appropriate size and model of the seal section and determine horsepower requirements for both the pump and seal section. The selected motor should be large enough to withstand the maximum load without overloading it.
- Using the technical data provided by the submersible pump manufacturer determine if any load limitations were exceeded (shaft loading, thrust bearing loading, housing pressure limitations, etc.)
- Select power cable, determine voltage losses as previously described, and calculate the surface voltage as follows:

$$\text{Surface Voltage} = \text{Motor Voltage} \times \left(\frac{\text{Max. Hz.}}{60 \text{ Hz.}} \right) + \text{Cable Voltage Drop}$$

- Calculate kVA and select accessory and other equipment as previous examples.

Example: Variable speed ESP system

To better understand the selection process, the various steps are discussed in greater detail and illustrated by the following example:

Collect and analyze the available data:

Well data

- Casing – 7-in. OD, 32 lb/ft
- Tubing – 3 ½-in. OD external upset 8 round (new)
- Perforations depth (vertical) – 6,500 to 6,700 ft
- Pump setting depth – 5,500 ft (vertical)
- Pump setting depth – 6,000 ft (measured)

Production data

- Wellhead tubing pressure – 125 psi
- Datum depth (vertical) – 6,600 ft
- Static bottomhole pressure – 2950 psi
- Productivity index (PI) – 2.5 bpd/psi
- Bottomhole temperature – 180° F
- Gas to oil ratio – not available
- Water cut – 75%
- Desired stock tank production range – 3,000 bpd to 5,000 bpd

Well fluid conditions

- Specific gravity of water – 1.08
- API gravity of oil – 32° (0.865)
- Specific gravity of gas – not available
- Bubblepoint pressure of gas – not available
- Viscosity of oil – not available

Power sources

- Available primary voltage – 480 volts
- Frequency – 60 Hertz
- Power source capability – stable system

Determine the well productivity

The desired production range was given as 3,000 bpd to 5,000 bpd and pump setting depth was known. The well productivity has been defined by the reservoir engineering staff as having a PI of 2.5 bpd/psi. Therefore, the solution to this exercise will be similar to that of the high water cut example presented in Chapter 18.

Solve for the new well flowing pressures (P_{wfd}) at the desired production rates (Q_d).

$$P_{wfd} = \bar{P}_r - \left(\frac{Q_d}{PI} \right)$$

P_{wfd} @ Minimum Desired Rate=

P_{wfd} @ Maximum Desired Rate=

$$2,950 \text{ psi} - \left(\frac{3,000 \text{ bpd}}{2.5 \text{ bpd} / \text{psi}} \right) = 1,750 \text{ psi}$$

$$2,950 \text{ psi} - \left(\frac{5,000 \text{ bpd}}{2.5 \text{ bpd} / \text{psi}} \right) = 950 \text{ psi}$$

The pump intake pressure can be determined by correcting the flowing bottomhole pressure for the difference in pump setting depth and the datum point and by considering the friction loss in the casing annulus. First, it's necessary to find the composite specific gravity of the produced fluids (SG_L) using the available well data.

$$SG_L = (0.75 \times 1.08) + (0.25 \times 0.865) = 1.03$$

The pressure drop, due to the difference in datum depth and pump setting depth, can be determined (assume no casing friction loss) and the pump intake pressure (PIP) at the minimum and maximum production rates can be calculated as follows:

$$PIP = P_{wfd} - \left[\frac{(\text{Datum} - \text{Pump Depth}) \times SG_L}{2.31 \text{ ft} / \text{psi}} \right]$$

$$\text{Minimum PIP} = 950 \text{ psi} - \left[\frac{(6,600 \text{ ft.} - 5,500 \text{ ft.}) \times 1.03}{2.31 \text{ ft} / \text{psi}} \right] = 460 \text{ psi}$$

$$\text{Minimum PIP} = 1,750 \text{ psi} - \left[\frac{(6,600 \text{ ft.} - 5,500 \text{ ft.}) \times 1.03}{2.31 \text{ ft} / \text{psi}} \right] = 1,260 \text{ psi}$$

Calculate fluid volumes

This third step will not be necessary due to the lack of information pertaining to gas volumes and properties.

Total dynamic head (TDH):

Sufficient data is now available to determine the total dynamic head requirements for the minimum and maximum desired flow rates (3,000 bpd – 5,000 bpd).

Total Dynamic Head = Net Lift + Friction Loss + Wellhead Pressure

$$\text{Net Lift} = \text{Pump Depth} - \left(\frac{PIP \times 2.31 \text{ ft} / \text{psi}}{SG_L} \right)$$

Minimum Rate

$$5,500 \text{ ft.} - \left(\frac{1,260 \text{ psi} \times 2.31 \text{ ft} / \text{psi}}{1.03} \right)$$

Maximum Rate

$$5,500 \text{ ft.} - \left(\frac{460 \text{ psi} \times 2.31 \text{ ft.} / \text{psi}}{1.03} \right)$$

Net Lift=2,674 ft

Net Lift= 4,468 ft.

Tubing friction loss. Refer to Friction Loss Chart Figure 20-1 in the previous Chapter 20.

Friction loss for 3 ½-in. tubing (new) is 30 ft /1,000 ft @ 3,000 bpd and 75 ft /1, 000 ft @ 5,000 bpd.

Using the measured pump setting depth (6,000 ft):

Minimum Rate

$$\text{Friction Loss} = \frac{6,000 \text{ ft.} \times 30 \text{ ft}}{1,000 \text{ ft.}} = 180 \text{ ft.}$$

Maximum rate

$$\text{Friction Loss} = \frac{6,000 \text{ ft.} \times 75 \text{ ft.}}{1,000 \text{ ft}} = 450 \text{ ft.}$$

We will assume the discharge pressure head (desired wellhead pressure) is the same for both flow rates. Converting wellhead pressure into ft:

$$\text{Wellhead Pressure} = \frac{125 \text{ psi} \times 2.31 \text{ ft} / \text{psi}}{1.03} = 280 \text{ ft}$$

TDH Minimum Rate

$$2,674 \text{ ft} + 180 \text{ ft} + 280 \text{ ft} = 3,134 \text{ ft}$$

TDH Maximum Rate

$$4,468 \text{ ft} + 450 \text{ ft} + 280 \text{ ft} = 5,198 \text{ ft}$$

Pump selection

The hydraulic requirements for our variable speed pumping system are:

Minimum Hydraulic Requirement

Flow Rate 3,000 bpd

Total Dynamic Head 3,134 ft

Maximum Hydraulic Requirement

Flow Rate 5,000 bpd

Total Dynamic Head 5,198 ft

As we have many options available, our selection criteria is to select a pump that will fit in the casing, have a maximum flow rate (5,000 BPD) of 70 Hertz and is near the best efficiency point (bep). The 538P47 satisfies these conditions (Figure 21-1).

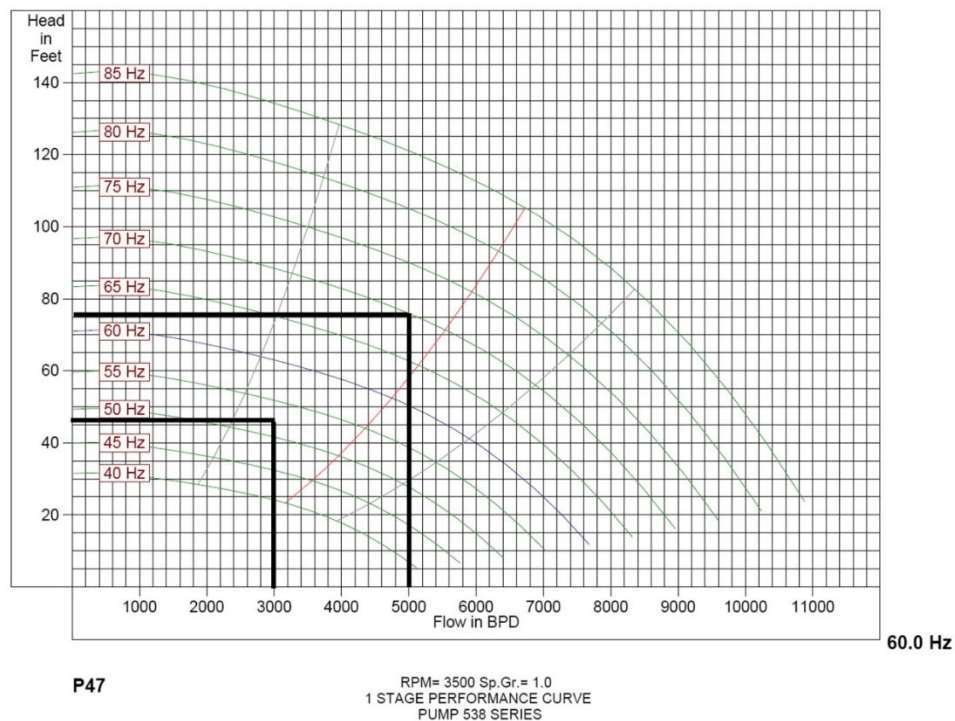


Figure 21-1: Tornado head curve

Next, select the head per stage from the curve at that point, should read 76 ft/stage. With the maximum total dynamic head of 5,198 ft, find the number of pump stages required.

$$\text{No. Stages} = \frac{\text{Maximum Total Dynamic Head}}{\text{Head / Stage}}$$

$$\text{No. Stages} = \frac{5,198 \text{ ft.}}{76 \text{ ft./stg}} = 69 \text{ stages}$$

To check the point of our minimum hydraulic requirement, divide the minimum total dynamic head (3,134 ft) by the number of stages selected.

$$\text{Minimum Head / Stage} = \frac{3,134 \text{ ft.}}{69 \text{ stgs}} = 45.4 \text{ ft./stg.}$$

Plotting the minimum head/stage (45.4 ft) and the minimum flow rate (3,000 bpd) on the 538P47 performance curve indicates a minimum operating frequency of 54 Hz. As can be seen, this point is well within the operating range of the pump selected.

Next, using the VSD Power Curve (Figure 21-2) for the 538P47 find the BHP/stage at 70 hertz (4.2 BHP/Stg). To calculate the BHP at the maximum frequency:

$$\text{BHP @ Max. Hz.} = \text{BHP/Stg. @ 70 Hz.} \times \text{No. Stgs.} \times \text{Sp. Gr}$$

Or

$$\text{BHP @ Max. Hz.} = 4.2 \text{ BHP/Stg.} \times 69 \text{ Stgs.} \times 1.03 = 290 \text{ BHP}$$

To calculate the equivalent 60 Hertz BHP for the pump:

$$60 \text{ Hz. BHP} = \text{BHP @ Max. Hz.} \times 60 \text{ Hz.} \times \frac{60 \text{ Hz.}}{\text{Max. Hz.}}$$

Or

$$60 \text{ Hz. BHP} = 290 \text{ BHP} \times \frac{60 \text{ Hz.}}{70 \text{ Hz.}} = 249 \text{ BHP}$$

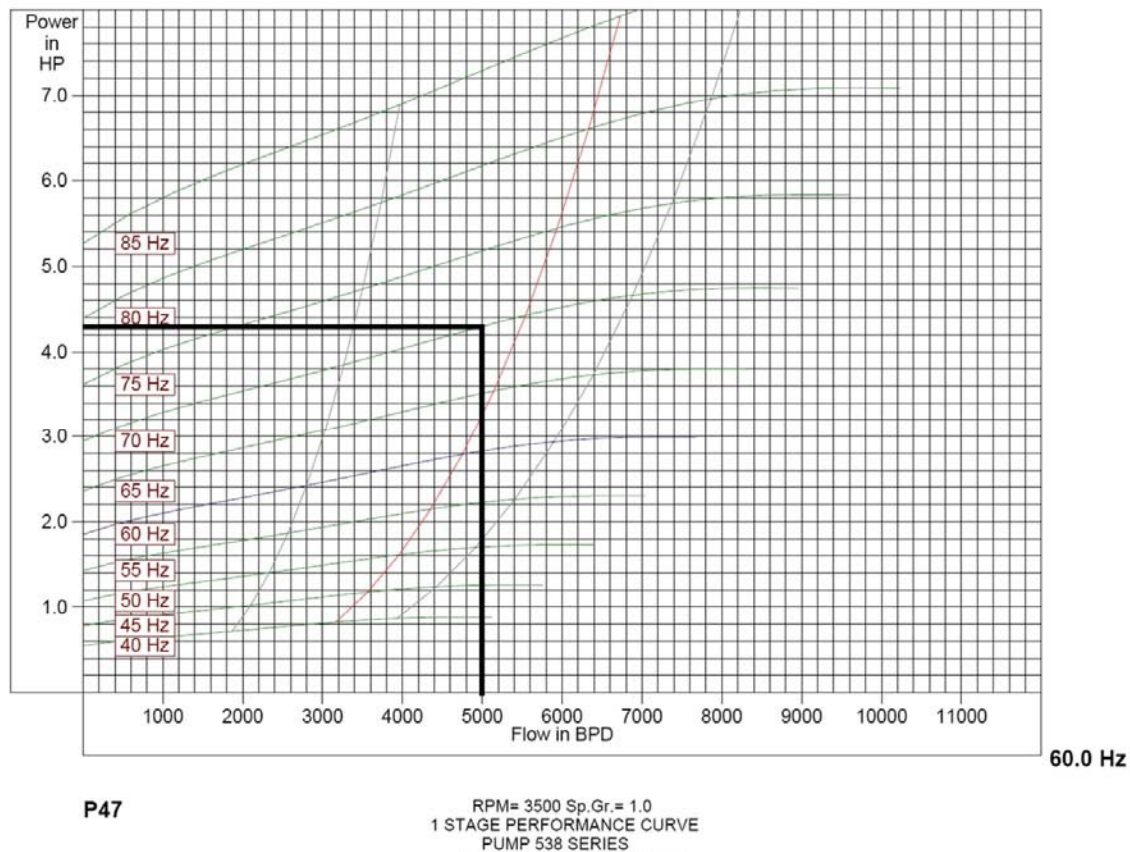


Figure 21-2: Tornado power curve

Select seal and motor

Select the appropriate model seal section and determine the horsepower requirement at the maximum TDH requirement. Select a motor which is capable of supplying total horsepower requirements for pump and seal. We will select the 562 series motor, 266 HP, 2,345 volts and 69 amps.

Check load limitations

Check for load limitations (e.g., shaft loading, thrust bearing loading, housing burst pressure limitations, fluid velocity passing the motor, etc.).

Select power cable

Select cable as in previous examples using motor current and conductor temperature. Based on the motor current (69amps) and the conductor temperature of 206° F (see engineering section - Well Temperature vs. Current), number 2 cable can be used. Adding 200 ft for surface connections, the cable voltage drop is:

$$\text{Cable Drop} = \frac{19 \text{ Volts} \times 1.3 \times 6,200 \text{ ft}}{1,000 \text{ ft.}} = 153 \text{ volts}$$

Solve for the required surface voltage (SV) at the maximum operating frequency as follows:

$$\text{SV} = \text{Motor Volts} \times \left(\frac{\text{Max Hz}}{60 \text{ HZ}} \right) + \text{Voltage Drop}$$

$$\text{SV} = 2,345 \text{ volts} \times \left(\frac{70 \text{ Hz}}{60 \text{ Hz}} \right) + 153 \text{ volts} = 2,889 \text{ volts}$$

Calculate kVA and select accessory equipment

Sufficient data is now available to calculate kVA.

$$\text{kVA} = \frac{\text{SV} \times \text{Motor Amps} \times 1.73}{1,000}$$

$$\text{kVA} = \frac{2,889 \text{ Volts} \times 69 \text{ Amps} \times 1.73}{1,000} = 345 \text{ KVA}$$

All other accessory equipment would be selected as the previous example.

The complexity associated with designing variable speed electrical submersible pumping systems, along with the introduction of numerous multi-phase flow correlations, have made them the ideal candidate for microcomputer applications. Baker Hughes AutographPC sizing software can greatly simplify the ESP sizing process.

AutographPC pumping system application and simulation software

The AutographPC software is the artificial lift industry's most comprehensive and dynamic pumping system application and simulation software. It can be used to design production systems for all of Baker Hughes product lines, including electrical submersible pumping systems, progressing cavity pumping (PCP) systems, and surface pumping systems. Each system installation is unique and all the specific well information, including production characteristics and well conditions, can be entered into Baker Hughes proprietary sizing software, AutographPC, during the initial ESP system design phase to produce a unique performance curve for each sizing.

The AutographPC software can be used for both fixed speed and variable speed applications and makes it practical to produce custom performance curves for each sizing. The AutographPC software is the only ESP application software that provides a sensitivity analysis to quickly evaluate an equipment design in a range of operating conditions. The AutographPC dynamic simulator is the only software of its kind in the industry, allowing the user to "see" how the pumping system behaves in the first crucial minutes or hours of operation after start up, or longer term as the well ages and downhole conditions change. This feature allows the user to change up to 28 operating conditions to simulate how the system will react and get immediate feedback. The simulator can track the resulting changes to flow rates, pressure, current, motor temperature and torque, just to name a few parameters. In addition, the simulator can indicate alarms when the system goes out of its operating range; help diagnose common problems like tubing leaks or pump wear; and assist in a forensic analysis by simulating conditions that lead to a failure.

Notes:



Section 7: Operations

Chapter 22: Installation

Chapter 23: Troubleshooting

Notes:

Chapter 22

Installation

After a pump selection has been finalized, assembled, and shipped to the well location for installation, the service company and customer representative have the responsibility of ensuring that the equipment is installed correctly. It is not recommended to rush the job because this action can be a safety issue and costly mistake. The equipment being installed is an expensive investment. Care and time taken during assembly and operation is a good investment for the future.

Safety and close cooperation between the representatives of both companies are the keys to a successful installation. To deliver long term, efficient, and reliable operation, several precautions should be taken during the installation process and the day to day operation of the ESP system.

Equipment transportation and handling

The safety of company personnel is always a concern whenever heavy equipment is moved and precautions should always be taken to prevent accidents. The following recommendations on transportation and handling of ESP equipment should be followed whenever possible to prevent injury to personnel or costly damage to the ESP components:

Transportation

- The equipment transported to and from the field location should always be placed in the proper shipping container. Some locations not using shipping boxes will require each component to be secured and supported to avoid bouncing and/or bending that could damage internal components during shipment. The use of shock sensors is recommended to maintain control of equipment care during shipment.
- The vehicle transporting the equipment should be long enough that equipment is not hanging over the end of the vehicle bed.
- The controller and transformers should be loaded on the vehicle in a manner that provides the smoothest possible ride so that they are not damaged by load shifting.
- Cable reels should always be chocked (wedge to hold an object steady) and the tie downs should be installed through the center of the reel on top of the hub.
- In addition, travel permits are required to move this type of equipment.

Handling

- To prevent damage to the components inside, shipping containers should not be dropped or handled roughly because the damage cannot always be detected during the normal installation or servicing process. The use of shock sensors is always recommended.
- All input or removal of equipment to and from shipping containers should be under the supervision of a qualified service technician.
- Equipment should always be lifted with the appropriate safety approved and certified lifting clamps and under the supervision of a qualified service technician.
- Equipment removed from shipping containers is even more susceptible to damage and care should be taken not to jar the equipment against cat walks, wellheads, etc.
- Always lift the motor controllers and transformers from the top with a spreader bar and slings using the lifting lugs provided on the units.
- Care must be taken not to puncture the transformer tank or damage the high or low voltage bushings.
- The proper way of lifting the cable reel is to place the adequate part of the lifting equipment through the center of the drum's reel that is long enough to attach a spreader bar with slings to the ends.
- If any of the equipment is dropped, it should not be installed.

Preparation

Representative in coordination with customer representative should make sure that all the necessary equipment is available for the installation. Equipment like couplings, o-rings, penetrators or pigtails, wellhead, service kits, splice materials, and tools to provide a good installation. In addition, ESP equipment serial numbers and descriptions and any special tools or parts (e.g. crossover adapters, pothead protectors, cable guards, check and drain valves, etc.) should be verified against shipping documents and installation program.

Field technician will corroborate as much information as possible about the application (e.g., anticipated production, pump setting depth, casing size, bottomhole temperature, available power supply, etc.) in order to check compatibility with the submersible equipment.

Well preparation

Precautionary steps should always be taken before the ESP system is installed into the well. Well profile should be reviewed to make sure of a smooth transition from surface to pump setting depth. A scraper should be run, especially in small casing, to the pump setting depth to check for tight spots and to remove any sharp edges, scale or paraffin from the casing.



Figure 22-1: ESP Installation

Note: The following information outlines the installation of an ESP system; however, it is an abbreviated version of proper ESP installation procedures. For more detailed information, the “API 11S3 Recommended Practice for ESP Installation” is a good reference.

Safety on the jobsite

Before any assembly work takes place, it is responsibility of field technician to do a pre-job safety audit. The primary goal of safety program is the protection of the employees and people taking part of the operation. To accomplish this, it is necessary that all employees become involved in safety and give it their total cooperation.

Representatives should be familiar with the safety program and its contents. Employees must comply with all the safety program rules, including observation cards and/or stop work program.

All personal protective equipment (PPE) provided to the employees will be utilized. The type of personal protective equipment (PPE) required for a particular job will be determined by the area safety guidelines and/or the area supervisor.

All employees are required to attend all safety meetings and provide input to aid in the safety of the people.

Installation of downhole equipment

The pump, motor, seal, gas separator, and cable must be assembled and handled during installation or removal according to the manufacturer's instructions. The service company representative should be on the job and his experience fully utilized.

Always allow sufficient time to clean out the well prior to installation, as any foreign material left in the well fluids could easily plug or lockup a pump. These precautionary steps should be taken to minimize potential damage to the ESP equipment.

The serviceman's job at installation is a mechanical one with set procedures and one for which he has been trained and qualified. Assembly of the unit must be done as carefully and as cleanly as possible. Care must be taken to keep any moisture or dirt from entering into the ESP components like seals, motors and/or sensors.

Keep in mind that the manufacturer builds this equipment to tolerances of 0.003-in. per foot for straightness and concentricity and that it should remain within these tolerances after it is installed. The following steps are performed during normal ESP installation:

Documentation

Prior to installing the downhole equipment, each component is identified and its description documented on an installation program. The motor and cable electrical properties are checked prior to the installation and the readings recorded on the installation report. A poorly documented installation would make it extremely difficult to troubleshoot the application should operational problems occur in the future.

Motor installation

The service rig must be centered over the wellhead and its mast raised into a vertical position. The motor is the first component to be lifted by the rig and placed over the wellbore using a specially designed lifting clamp. The motor is lowered into the wellbore and filled with oil, utilizing vacuum pump or gear pump. This oil is specially formulated to provide lubrication and dielectric strength. The motor shaft is rotated so that it rotates freely and its extension checked with a go/no-go gauge.

Use of phase rotation equipment is recommended so that the proper direction of rotation is attained at the start. This eliminates the need to stop and change rotation in those cases where the initial operation was in the incorrect rotation.

Seal servicing

The next component to be lifted and coupled to the motor is the seal section. O-rings located on the seal base are used to seal the connection between motor and seal and, if damaged, could allow contamination of the motor oil. The seal is a vital part of the ESP system and correct servicing procedures play a critical role in preventing premature failures.

The seal section is serviced with the same mineral oil that is used in the motor. Pumping oil into the seal is another important step in the installation procedure and should never be hurried. After servicing with oil, all vents, drains, and injection ports are sealed with the proper cap screws and washers, the upper shipping cap is removed and the shaft extension and rotation are checked in preparation for installing the next component.

Pump assembly

The pump is the next component lifted and placed above the seal section for assembly. The intake and discharge are checked for obstructions. The shipping cap is removed from the pump base, the shaft rotation is checked and the pump lowered onto the seal section. Caution is taken during this process to make sure that the proper engagement of coupling to pump and seal shafts is made.



Figure 22-2: ESP Cable Spooling

Cable installation

The cable reel should be placed 75 to 100 ft away from the service rig or, in a small well location, as far as possible from service rig and in visual sight of the rig operator. The cable guide wheel, over which the cable passes, is usually never more than 30 ft from the ground, although during the installation of the motor lead cable, it is lowered to no higher than 15 ft above the rig floor. Flexure of the cable is reduced by running the cable over the largest possible sheave during installation or pulling. A 54 inches diameter sheave is recommended during running into the hole.

Care is taken to keep slack between the cable reel and the cable guide wheel while preventing it from touching the ground and recognizing that tension applied to the cable could cause elongation of the conductor and/or weaken the cable armor that provides protection for the jacket and conductor insulation.

It is very important that the cable be run straight up the tubing. Rotation of the tubing must not be allowed while running the ESP equipment. Once the integrity of the cable insulation is destroyed, well fluids will contact the conductors and result in a short circuit.

Cable bands or cable protectors are used to attach the power cable to the tubing. The number of bands per joint of tubing is calculated based on the cable weight but, it is recommended a minimum of two bands per joint. The cable bands are attached perpendicular to the tubing and care is taken not to over-tighten, causing damage in the armor and insulation. Loose bands must be avoided. **If a band is loose, it is removed and replaced before proceeding.**

The recommended installation speed for the cable is 1,000 ft to 2,000 ft per hour depending on the experience of the service rig crew. Under no circumstances should the operator install the tubing and cable at a speed where he is actually pulling the cable from the reel. A backup is used on every joint where there is any chance of the tongs turning the pipe in the slips.

While running the equipment, the service technician should be allowed to check the cable electrical properties every 1,000 ft. or less. If cable damaged is detected, it can be returned to the surface for repair or splice.

Where crooked holes are encountered, it may be necessary to run centralizers or protectors to provide additional protection for the cable and to keep the motor centered in the casing. This will eliminate any hot spots that could result if the motor is lying against the well casing. The centralizers will also minimize the amount of wear on the cable as it is being run in the hole.

Proper procedures in the care of the cable can and do reduce cable failures. Carelessness with the cable during installation creates difficulties later, which might be misdiagnosed as cable failure or misapplication when it is in fact handling damage caused during installation. Careful handling is imperative if cable life is to be prolonged.

Installation of surface equipment

Power distribution literature establishes that distribution systems are better protected if the system is grounded. Fast-acting relays can be applied to detect grounds on a live conductor, disconnect them and prevent excessive damage to both the system and to human life.

However, in a submersible pump installation, the motor and all of the cable except a few feet, which could be in conduit, is, or should be, underground, and not accessible. In this case, an ungrounded system is better. If the power cable is damaged and it does have maximum exposure to the possibility of physical damage, a single line ground will not prevent successful operation. This case would be the equivalent of operating with one corner of the secondary delta grounded.

Caution: Lethal voltages may be present, only trained and qualified personnel should perform servicing.

Motor controllers

It cannot be overemphasized that careless procedures around the controller, highline cables, and input or output transformers can result in equipment damage, injury or death. Check to see that the controller cabinet has not voltage and it is securely grounded.

The preliminary adjustments to motor controller prior to start-up vary, depending on the type of controller being used. Under normal circumstances, the overload current relay is set no higher than 120% of the motor's nameplate amperage. The recommended setting is provided by the application engineer.

Note: If the overload circuitry shuts the system down, the surface and downhole equipment should be completely checked out before restarting.

The undercurrent relay should be set at a minimum of 80% motor amperage. 90% is recommended if the unit will start and operate normally. This will give maximum protection under pump-off, gas locking, or pump intake plugging conditions. In some instances, if the fluid gradient is very light, the relay may be adjusted lower if there is adequate fluid production to permit reasonable satisfactory pump operations and cooling of the motor.

Restart delay should be set for a minimum of 30 minutes or longer. This is to make sure that the unit will not restart while the downhole system is backspinning or motor is still hot.

Transformers

Transformers can either be pole mounted or located on a pad. For safety's sake, make sure that the transformer case is securely grounded and has not voltage, and if pad mounted, the transformer should be inside a grounded locked fence. Since most of the ESP motors are designed to run using low current (approximately 100 amps or less), the voltage might be any number from 230 volts up to 5,000 volts.

For example: A 975 volt, 92 amp, 150 HP motor at a 100 ft setting would require 1,005 volts, at 5,000 ft it would require 1,125 volts and at 8,000 ft it would require 1,215 volts (depending of cable size and well temperature). The manufacturer offers and can provide delivery on a transformer with taps for this range of voltage requirements.

The most trouble-free installation has one pumping unit per isolation transformer. Multiple units operating from a large substation without individual isolation transformers are sure to be more costly to maintain than single unit installations. Single unit ungrounded installations can be operated with a line to ground cable fault whereas substations with multiple units connected should be a grounded system. In this case, without isolation transformers for each unit, a cable ground means an inoperative unit and rework is necessary at that time.

Vent box

A vent box (junction box) should be used and securely grounded, preferable to the wellhead. The vent box should be located approximately 50 ft from the wellhead and motor controller (see API recommended practice RP11S3 for details).

Operation

After the unit has reached its setting depth (never below or into the perforated interval or above the perforations without a motor jacket) and a complete equipment checkout at the surface has been made, the unit can be started.

Starting

When a submersible unit is started, the load voltage should be no less than 95% of no load voltage. If it is less than 95%, this could mean that there is inadequate electrical capacity available, which may be insufficient transformation and/or insufficient conductor size. The current inrush is 450% or higher in the first cycle and decreases immediately. The average inrush current over the 20 hertz or less at starting time is roughly 250%.

Testing

Installation program should provide a means of gauging the pumping rate on start-up. The unit should be closely monitored for the next couple of days and good initial start-up data obtained. Periodic tests and equipment analysis are required to obtain the most efficient service from any artificial lift system.

We recommend tests on the following schedule:

- Upon initial startup
- Five to seven days after startup
- On new installations, every two weeks until the well stabilizes
- Monthly thereafter

The test data should include a minimum of:

- Running amperage
- Pumping rate (oil, water, and gas)
- Bottomhole pressure (If downhole gauge installed)
- Tubing and casing pressure
- Motor temperature and wellbore temperature (If downhole gauge installed)

A careful study should be undertaken on any pump installation that does not produce as originally designed since the problems may be either with the downhole equipment assembly or may be a wellbore deficiency. To make sure that subsequent installations will be satisfactory, as much information as possible should be collected.

In many wells, it is difficult to obtain accurate fluid level shots because of mechanical problems, or more often because of foamy annulus fluids. A working fluid level should be a direct indication of the pump intake pressure. With poor intake pressure data, pump performance cannot be accurately established. To eliminate this problem, the use of downhole pressure sensor is always recommended.

Notes:

Chapter 23

Troubleshooting

Failure analysis

The purpose of this section is to aid the engineer or technician involved with ESP operations to become more knowledgeable concerning the causes of equipment failures and to provide recommendations for reducing or preventing these equipment failures. This discussion of failure analysis is divided into two sections; 1) possible causes, and 2) recommendations for reducing failures by becoming familiar with these causes and recommendations. Operating personnel can contribute a great deal to an overall improvement in the performance of submersible pumping equipment.

Corrosion

The deterioration of metal due to corrosion will result in holes being eaten through the housings. These holes will allow well fluids to enter and contaminate the motor and seal or cause loss of pressure in the pump. To protect the external housings of the motor, pump, and seal sections, various types of coating are available. For the corrosive environment, a non-metal coating is available that has been used with a wide degree of success for several years. There are also several metal coatings and housings built using metals with corrosion resistant properties that provide a great solution to this problem. Representatives can be helpful in suggesting a proper coating for your application.

Faulty installation

This possible cause of failure pertains to the serviceman's installation of the equipment or to the existence of bad electrical conditions (insufficient voltage, voltage surge, etc.). The serviceman's job at the installation is a mechanical and set procedure type operation. If he is not rushed and can systematically follow proper procedure, the installation should be a good one.

Motor controllers

Even considering mechanical defects, motor controllers do not suffer a great deal of component failures. However, the presence of dirt or moisture can cause electrical devices to malfunction; therefore, the cabinets should have door gaskets installed to prevent this type of failure. Some of the electronic components will not operate if the ambient temperatures fall far below freezing, and

an internal heating device should be utilized in sub-zero environments. Extremely high ambient temperatures will also affect some solid state controllers. Shading or shelters can be installed to prevent direct exposure to the sun or other heat sources.

Faulty equipment

Occasionally a manufacturing defect will go undetected at the plant and in the field; it is probable that such an equipment defect will result in a short run.

Worn-out pump

Since the longitudinal reactions or thrust on centrifugal pump impellers and shaft is transferred to the unit's thrust bearing, generally a sustained pump overload or underload condition will not result in failure of the pump itself, but rather, in the thrust bearing. Pumps will normally fail because of wear or become locked because of scale, sand, or paraffin. The degree of wear may be greatly accelerated by the presence of entrained abrasives such as sand in the pumped fluids.

Transient voltages

Damage to transformers, motor controllers, cable and motor can result from lightning striking at or near the surface equipment or from transient voltages caused by capacitor bank switching or faulting loads.

Electrical system

Low or unbalanced voltage is detrimental to submersible operation and can result in heat buildup, which can cause equipment failures.

Note: Providing adequate voltage is the responsibility of the operator and the power company.

Causes of ESP failures

- Excessive overload for an extended period of time
- Seal section leak
- Well conditions – excessive operating temperature, corrosion, abrasive materials in fluid stream, etc.
- Bad or faulty installation
- Motor controller issues
- Worn pump
- Lightning
- Bad electrical system

Causes of pump failures

A pump failure is usually the result of one of the following reasons:

- Downthrust wear due to producing below peak efficiency
- Upthrust wear due to producing above peak efficiency
- Grinding wear due to producing abrasives
- Plugged or locked stages, due to scale build up
- Longevity wear
- Twisted shaft, due to locked pump, starting during backspin or absence of variable speed drive
- Corrosion

In some cases, on initial start-up, the formation may tend to produce large amounts of sand. This is especially true when the producing zone is an unconsolidated sand formation. This problem can be minimized by maintaining back pressure on the tubing and reducing back pressure slowly over a period of several hours.

Causes of motor failure

Excessive motor overload, resulting from one or more of the following reasons:

- Abnormally high specific gravity of the well fluid
- Bad design (undersized motor) resulting from poor data
- Worn out pump
- High, low, or unbalanced voltage

Seal Section Leak: A leaking seal section allows well fluids to enter the motor and usually results in a failure. Possible reasons for a seal section leak are:

- Worn out pump causing seal damaging vibrations
- Broken mechanical seals from rough handling
- Defective seal section construction
- Bad installation methods and/or procedure

Insufficient Fluid Movement: Causes the internal operating temperature of the motor to exceed the temperature limitation of the insulation, resulting in an electrical failure.

- This occurs when the fluid velocity by the motor is insufficient to cool it
(Recommended velocity is 1 ft/sec).
- Occurs where a unit is set below the perforations in a well and a motor jacket is not installed to direct the fluid by the motor to cool it.

Causes of cable failures

Mechanical damage during running or pulling operations caused by:

- Crushing
- Stretching
- Crimping
- Cutting

Cable deterioration due to:

- High temperatures
- High pressure gas
- Corrosion
- Normal aging

Excessive current creates a high conductor temperature capable of breaking down the insulation.

Ammeter technology

In order that the investment in a submersible pump is protected, all facilities available must be used to avoid premature unit failure. A combination of common oilfield test procedures, including the recording of fluid volumes, pressures, unit voltage and current can provide the desired insurance.

A correctly designed submersible pump will provide a relatively maintenance free, long duration operation. The usual cause of premature failure for a properly designed unit is an unattended correctable mechanical malfunction, which results in downhole failure. It is, therefore, mandatory that each unit be properly and rigorously monitored in order that these malfunctions are corrected before premature failure occurs.

One of the most valuable and least understood tools available is the recording ammeter. The ammeter chart, much like a physician's electrocardiogram, is a recording of the heartbeat of the submersible electrical motor. Proper, timely, and rigorous analysis of amp charts can provide valuable information for the detection and correction of minor operational problems before they become costly major ones. Other well data, such as producing rate, pressures, etc. are important and should be checked periodically in conjunction with the ammeter chart.

The recording ammeter is located on the motor controller's menu. Its function is to record the input amperage of the motor. The amperage is recorded from one power leg and displayed on the screen. This is done by the use of a current transformer coupled to one leg of the cable inside the motor controller.

There are many models of motor controllers and depending of the memory's capacity, the length of amperage information recorded should vary. Usually, the minimum is seven days. As previously mentioned, every well is different and each application will have its own unique pattern.

The ammeter chart is an extremely valuable tool for monitoring the well's operation. If the chart is used correctly, (monitored in real time) it will warn you of changes in the well's operation, such as voltage fluctuation in the power distribution system. The amp chart also can be helpful in determining that the motor current is the expected, whether or not the well is pumping off or gas locking, the possibility of an emulsion problem or other motor loading deviations.

Production plots for a well also assist in preventing failures. The plots will help spot wells where deposition is taking place or where a hole in the tubing has developed (sharp production decline). If a well test indicates low production, another test should be run immediately to verify that it is correct. If the low test is verified, it may be advisable to shut down the unit until corrective action is initiated. If the volume of fluid pumped is not sufficient to cool the submersible motor, a burned motor could result and thus an expensive repair cost.

The production foreman, monitoring engineers and pumpers are most important in gathering data and monitoring the well's operation. If a good line of communications exists between the field and engineering, the job of data gathering and well monitoring is an easy one.

Monitoring the recording ammeter, a number of changes in operating conditions may be defined by proper interpretation of the amp trends. Some of these potentially damaging conditions are:

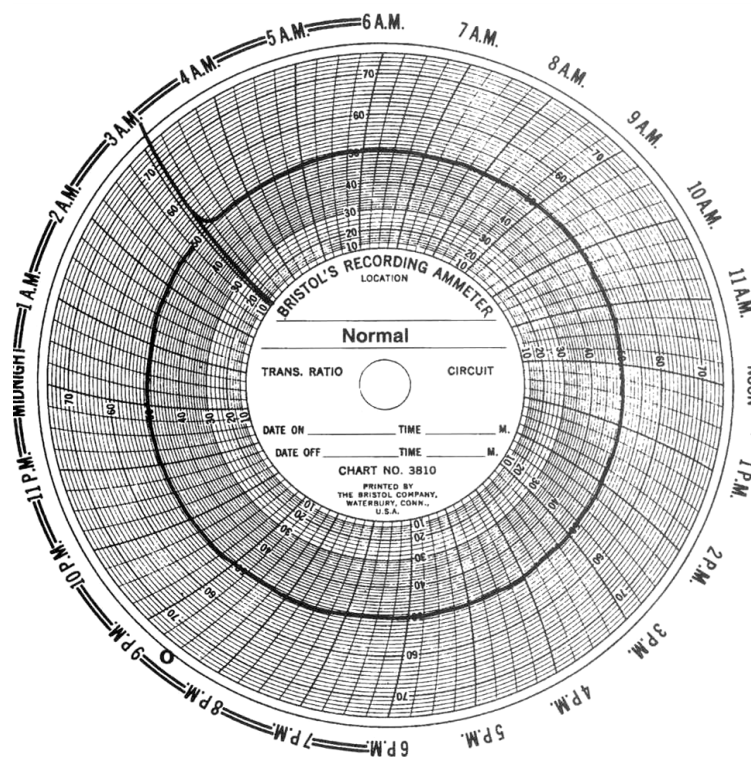
- Primary power line voltage fluctuations
- Low amperage operation
- High amperage operation
- Erratic amperage operation

The following text and examples deal with the proper interpretation of ammeter charts and their interrelationship with other guides in the troubleshooting and preventative maintenance of electrical submersible pumps. The drawn examples of current changes are representations of about every type ammeter chart you could encounter. There will be deviations in these charts, but as you become experienced in analyzing the charts, you will be able to determine to a large degree of accuracy what is occurring and what the possible reasons for the erratic operation could be. Therefore, you have the tools to make a decision for problem solving.

Normal operation: Figure 23-1

Three phase induction motors operating at fixed load draw constant current. An ideal submersible installation is designed such that the actual horsepower to be used is rated nameplate HP or less, and such that the total dynamic head and producing rate match the expected well productivity. Under these conditions, the ammeter should draw a smooth symmetrical curve near nameplate current.

Normal operations may produce a draw above or below nameplate amperage, but it should be smooth and symmetrical. An spike on start-up would be observed and it extends the full swing of the pin. This is a normal occurrence when the submersible unit is controlled by a motor controller and is caused by the starting inrush current. The duration of the inrush current is only a fraction of a second and the actual start-up may be indicated by a small mark or dot.



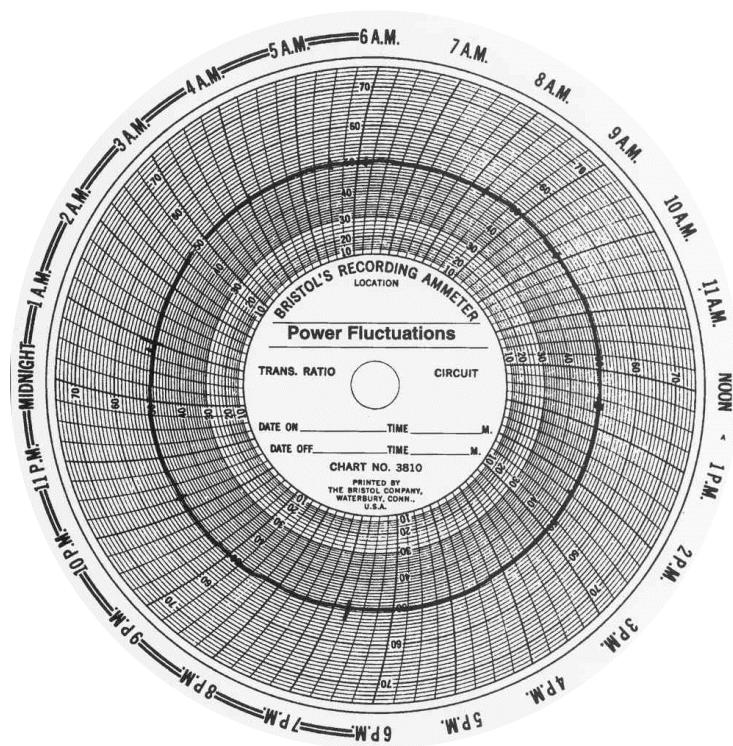
Power fluctuations: Figure 23-2

Under normal operations, motor output is relatively constant. Consequently, if the primary power supply voltage fluctuates, the amperage will fluctuate in an attempt to supply the pump horsepower demanded. The fluctuations will be reflected on the amp chart.

Possible cause

- The most common cause of power fluctuations is periodic heavy loading of the primary power system, e.g., the start-up of a high horsepower injection pump powered by the same power supply.
- Occasionally, it may be a combination of smaller simultaneous loads. If this is the case, some effort must be made to re-space these loads so that their combined impact is small. Investigation of the fluctuations may determine the exact cause.
- Weather related electrical disturbances (lightning).

Generally, if the power fluctuations do not cause a system shutdown, and are short term, they are considered acceptable and have little effect on the operation of the ESP.



Gas locking: Figure 23-3

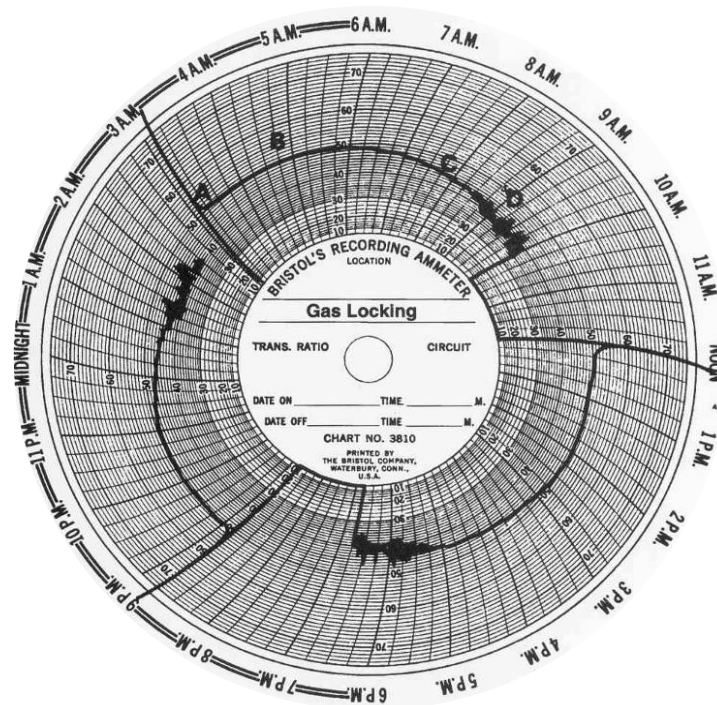
This chart shows events prior to gas locking. Amp chart below shows a decrease in current as the volume falls below design and fluctuation as gas begins to evolve and erratic low amperage as the pump suction pressure decreases and large volumes of gas are ingested into the pump. Cyclic loadings of free gas and liquid eventually cause undercurrent shutdown of the unit.

Possible solution

- A PID (Proportional, Integral and derivative) amperage mode of operation could be recommended to reduce/eliminate the erratic variation of the well parameter.
- It is possible to remedy this situation by lowering the pump, thereby, increasing the pump submergence pressure and compressing some of the gas back into solution.
- Choke production back until a suitable fluid level is established.

Caution: Do not choke back to a point where the fluid production is outside the recommended operating range of the pump installed.

- A system of programmed down time should be designed for the maximum fluid withdrawal, using the fewest number of cycles. The pump should be resized on the next change out or some type of gas separator should be installed.

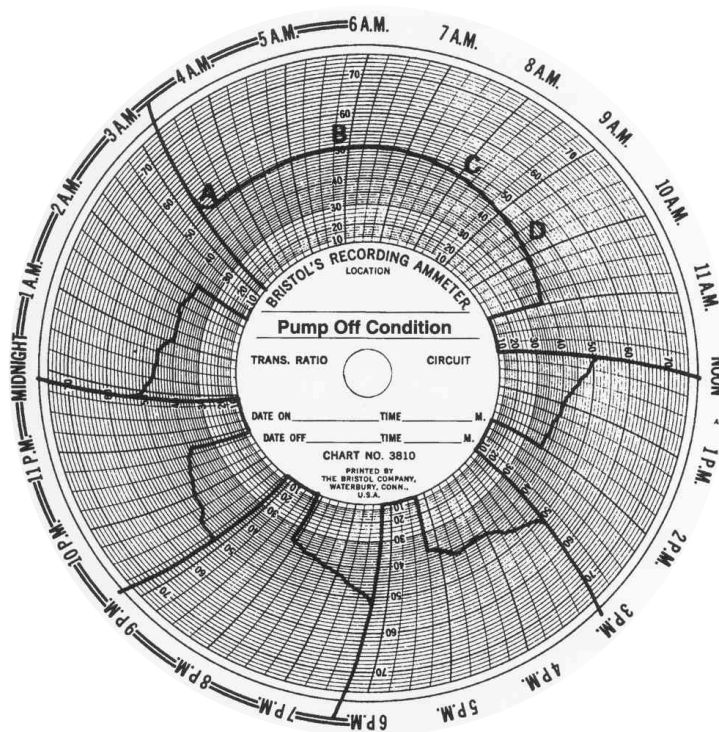


Fluid pump off conditions: Figure 23-4

This chart shows a unit which has several pump offs and shutdown on undercurrent, restarted automatically and shut down again for the same reason. Analysis of all sections are identical to that for gas locking except no free gas breakout fluctuations are evident. Before pump stops, the fluid level approaches the pump intake and current declines as a result of lower fluid production and pump performance characteristics. Finally, the preset undercurrent level is reached and the unit shuts down. After a preset time delay, the unit automatically restarts.

Possible cause and corrective action

- The unit is too large/big for this application. Remedial action is similar than gas locking.
- The well inflow performance has changed, i.e., reservoir conditions have changed (decrease in reservoir pressure, permeability, fluid properties, etc.) Check fluid levels and compare with pump performance.
- The pump may be worn. Check fluid levels and determine pump performance.
- The pump is producing higher volume than well reservoir can provide. A solution is reduce pumped flow, by reducing the frequency delivered to the motor.



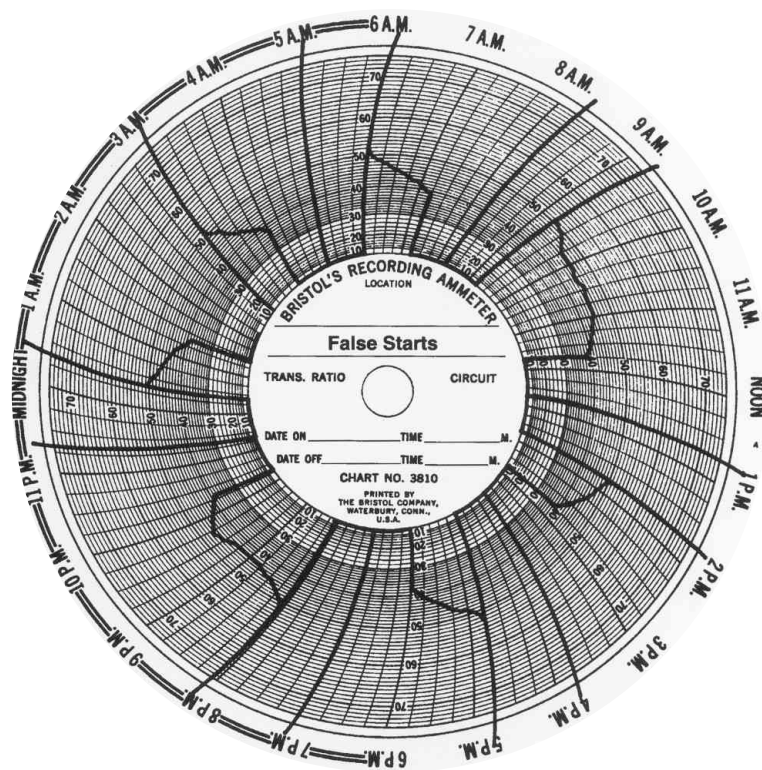
Pump off conditions – False starts: Figure 23-5

Below is a chart from a unit which has shut down on undercurrent (underload), failed in an attempt to restart automatically, timed out and restarted, beginning the cycle again. Analysis of this plot is similar to that for pump off conditions except that the auto-restart delay is not of sufficient length to allow adequate fluid buildup.

Possible cause and corrective action

- Oversized pumping system or higher flow than required. Check well data (fluid levels, pressures, etc.) and equipment design criteria.
- Changing well performance characteristics (reservoir pressures, permeability, fluid properties, etc.).

This type of operation must be corrected before equipment damage occurs.

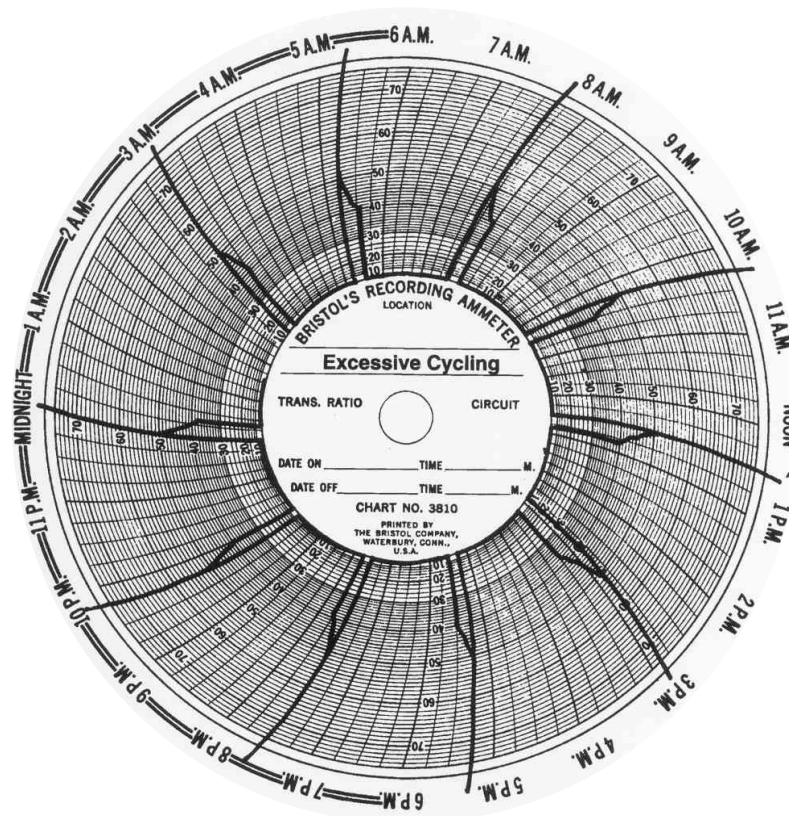


Excessive cycling: Figure 23-6

Below is a chart similar to pump off conditions except that the running times are shorter and the cycles more frequent. This type of operation is extremely detrimental to the ESP components and should be corrected immediately.

Possible cause and corrective action

- The pumping unit is large or flow is too high for the application. Check sizing against well data.
- Tubing leak. If the wellhead pressure is reasonable or low, check for low rate of fluid production and high fluid level immediately after pump up. An abnormally low rate may be caused by a tubing leak. A tubing leak near the surface will result in reduced or no fluid to the surface while the fluid level should remain high.
- Closed valve or plugged flow line. A check for unusually high wellhead tubing pressure should be made. If the discharge line is plugged or a valve is closed against the flow, a reduction in fluid production should occur, accompanied by a drop in amperage, with an increase in surface pressures.

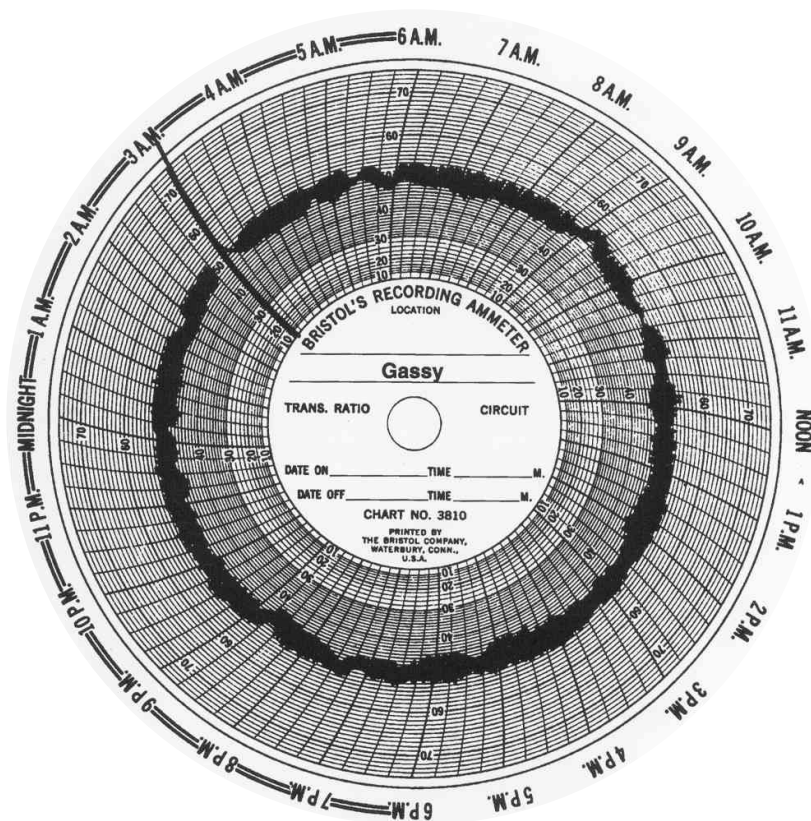


Gassy conditions: Figure 23-7

Below is a chart from a unit which is operating near design levels, but which is handling some gas. The fluctuation is caused by entrained and free gas in the fluid production. This condition is usually accompanied by a reduction in total fluid production (actual stock tank barrels).

A submersible pump will attempt to pump whatever is present at the pump intake. It will attempt to pump the predesigned number of barrels of whatever fluids available, including gas. With this in mind, one barrel of gas represents a very small stock tank contribution, but represents a substantial volume through the pump.

This type of operation is considered normal for many applications around the world. The unit operates continuously without gas locking, therefore, is not considered to be a problem.

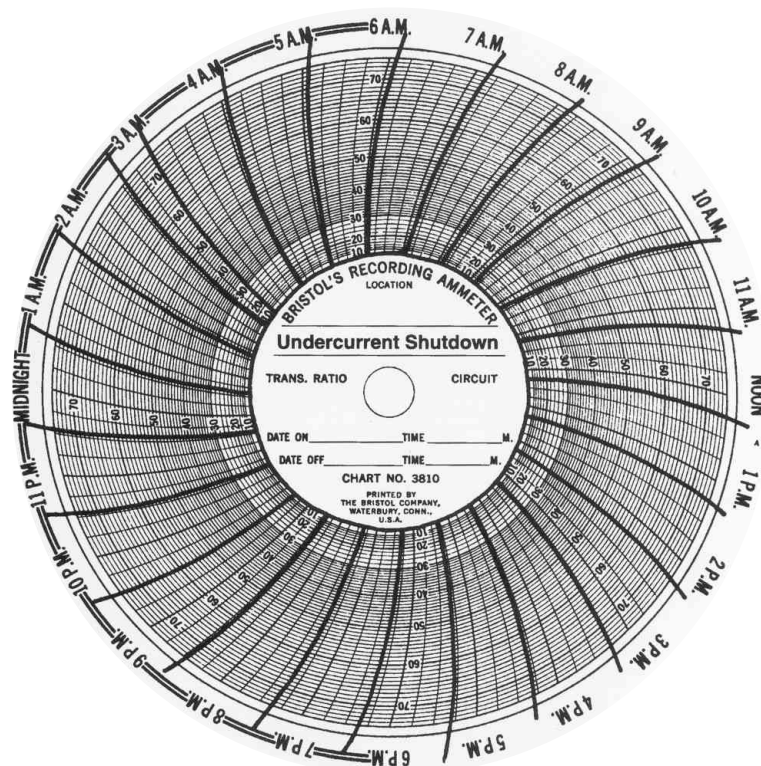


Immediate undercurrent shutdown: Figure 23-8

The following chart is from a unit which is starting, running a few seconds and shutting down on undercurrent. This cycle is repeated by the automatic restart sequence.

Possible cause

- Fluid lacking sufficient density or volume to load the motor above the undercurrent setting. If tests show fluid available at the pump intake, it is possible to rectify this problem by lowering the undercurrent. This job is best left to the pump company representative.
- A broken shaft in the submersible unit causing the motor to draw idle amperage (below undercurrent setting) and shutting down.
- Pumping against a closed valve. Generally, the lowest horsepower (lowest current) demanded by the pump occurs at zero flow through the pump.
- Tubing leak near the pump discharge (e.g., sliding sleeve open, "Y" tool standing valve leaking, etc.) causing re-circulation of fluids.
- Plugging of pump, tubing, or surface equipment.
- Faulty motor controller circuitry or inaccurate alarm setting.

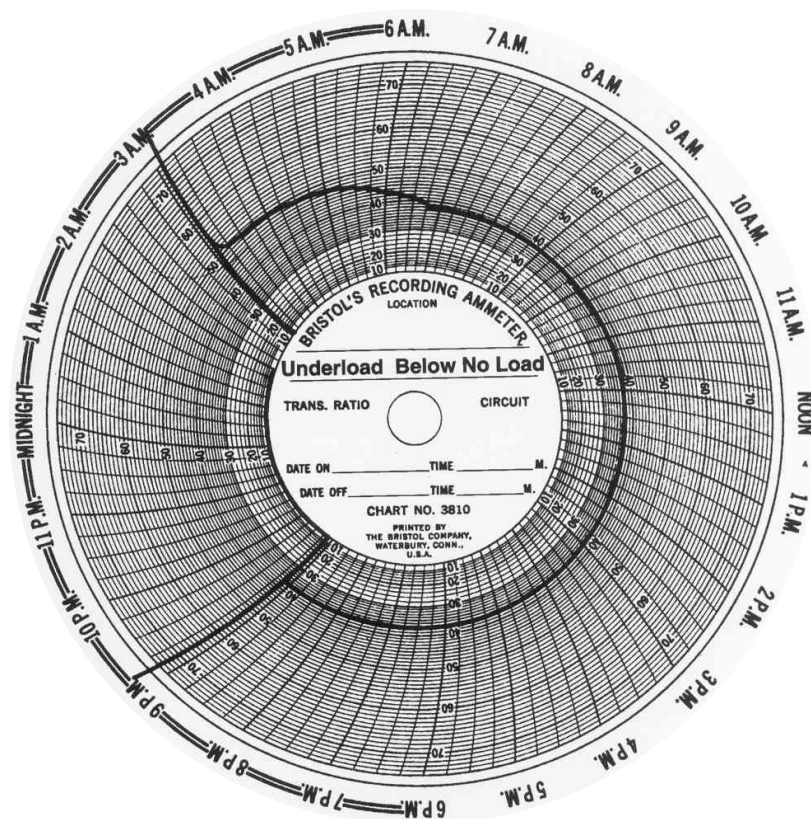


Underload below idle current: Figure 23-9

The following chart shows a normal start followed by a decline to the idle current of the motor. Finally, after a period of time, the unit faults on overcurrent (overload).

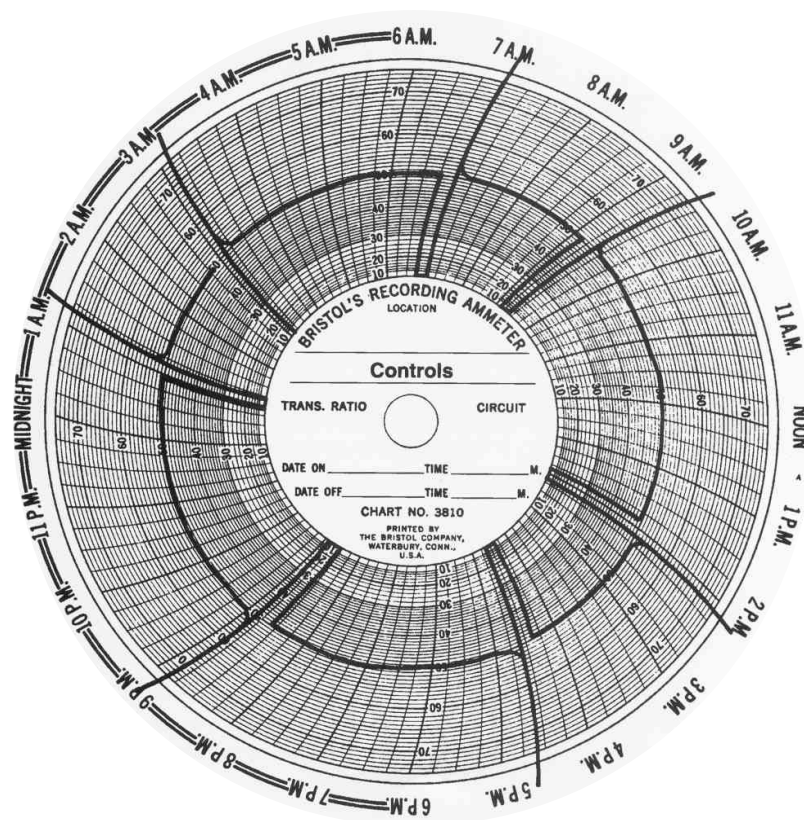
Possible cause

This curve is typical of a unit oversized for the application or pumping higher flow than well can produce. The unit pumps the well down to a point where the undercurrent relay should stop the unit. In this case, however, the undercurrent relay was preset below idle amperage of the ESP system. With low or no fluid flow, the motor ran at idle current until heat build-up caused a motor or cable burn. Fluid passage by the motor is mandatory for submersible motor cooling.



External controls: Figure 23-10

The following chart shows a unit which is being controlled by an external control (may be tied into tank level, Tubing Pressure, flow temp, etc.). The switch stops the unit and starts the automatic restart sequence. This type of operation can be considered normal, but in this case the off time is far too short (15 minutes). In almost all cases when a unit is shutdown, fluid will tend to fall back through the pump, spinning the unit backwards (backspin). Attempting to restart any submersible pump in a backspin mode may result in damaged equipment such as twisted or broken shafts. A minimum of thirty minutes is recommended to avoid against backspin by allowing all fluid levels to stabilize.



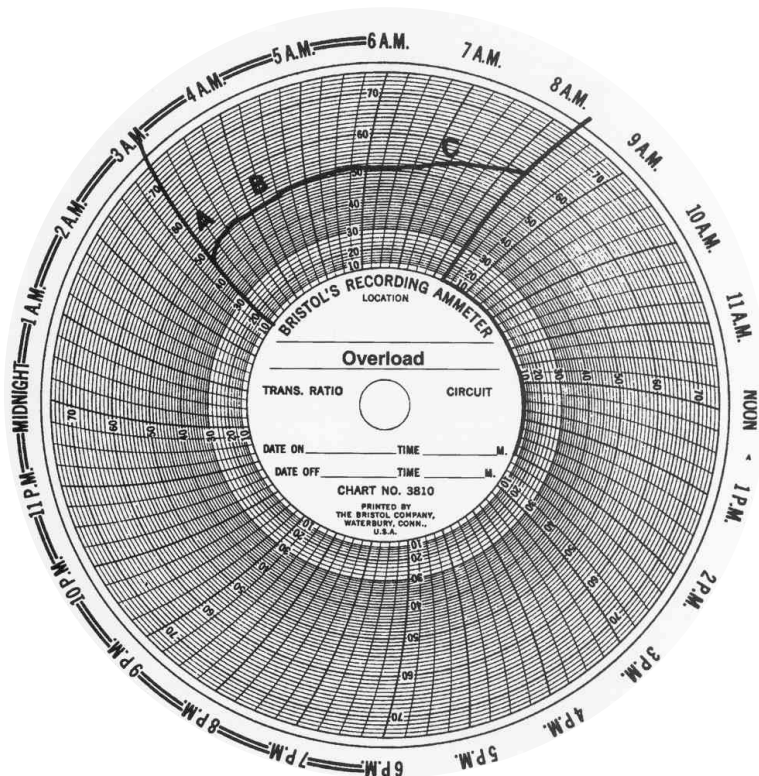
Overload conditions: Figure 23-11

The following chart shows a unit which has shut down due to overcurrent (overload) conditions. Until the cause of this overload has been corrected, restart should not be attempted.

Possible cause

- This type shutdown is typically caused by increases in fluid specific gravity (such as heavy brines), increasing fluid viscosities, emulsions, or sand production. Catch a sample of fluid for analysis.
- Long term power fluctuations (brown outs, etc.).
- Casing leak causing drilling muds or lost circulation material to enter wellbore and eventually the pump.

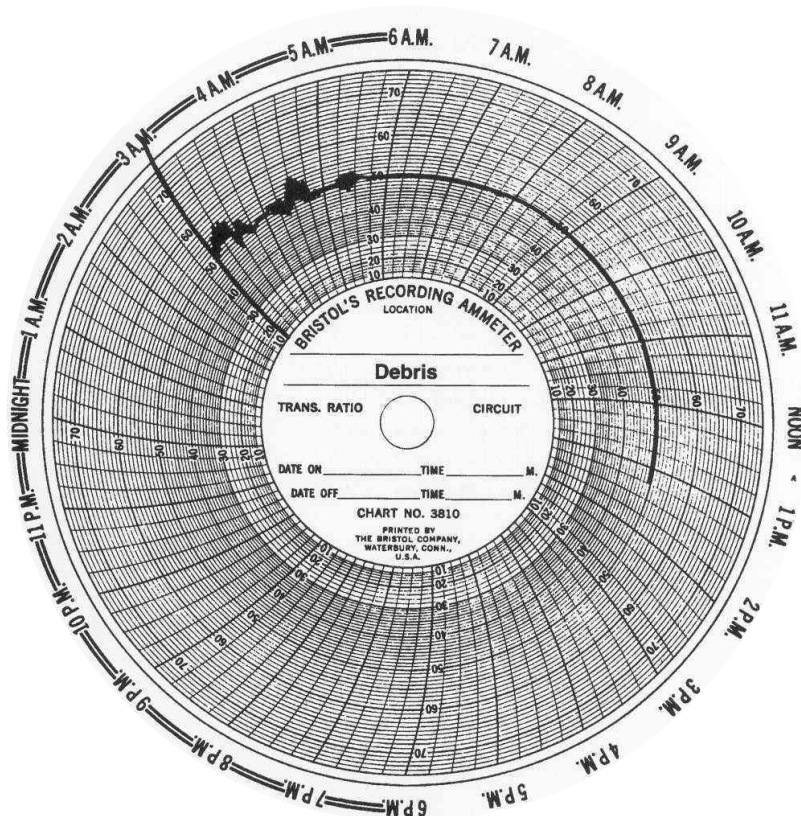
Normally, automatic restart will not occur when an overload occurs due to the possible severity of the condition. Before restart of the unit, it should be thoroughly checked by the pump company representative.



Pumping debris: Figure 23-12

The following chart shows a unit which started, pumped erratically for a short period and then became normal. This is expected when cleaning a well of such debris as scale, loose sand, weighted muds or brines. This type of operation is not unusual, but is not recommended where avoidable. It is quite possible that the pump could plug up or lock up during this cleaning out phase, causing the unit to be pulled for repair.

Keeping in mind that the actual horsepower required is a function of the specific gravity of the fluid, if it becomes necessary to kill a well, use the lightest possible brines and determine the start-up horsepower required. Verify that the motor selected for the application is of sufficient size to "clean up" the kill fluid.

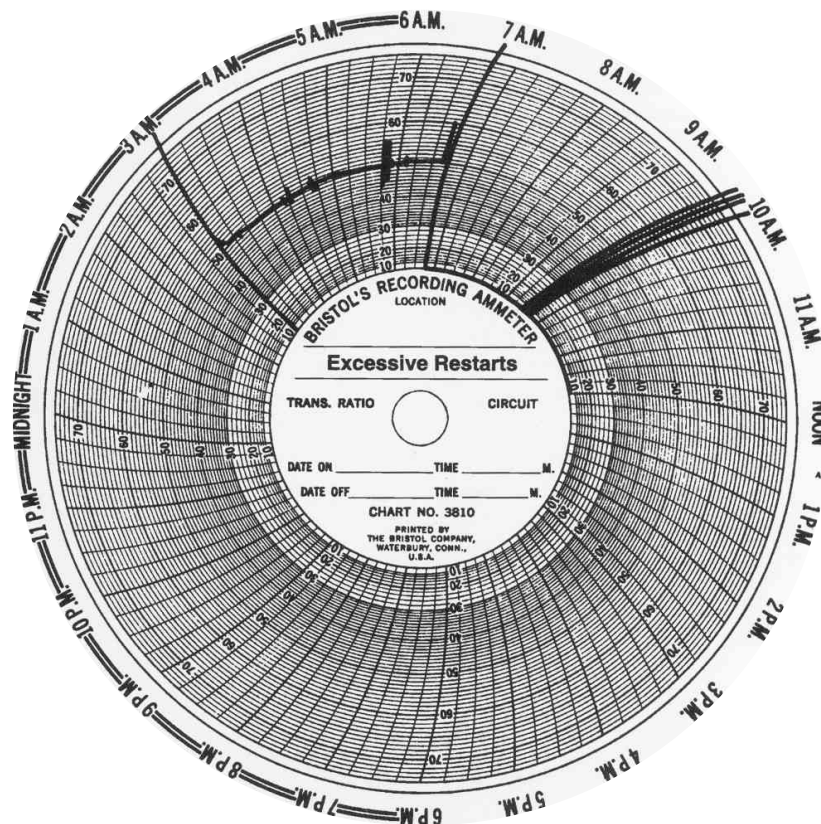


Excessive manual restart attempts: Figure 23-13

The following chart shows a relatively normal chart until the unit stopped. It is also evident that manual restarts were attempted. If a single manual restart attempt fails under these conditions, the unit should be checked by a pump company representative.

Possible cause

- In this case, power fluctuations, such as lightning storms, caused the unit to shut down. When the unit did not start, problems should have been looked for elsewhere. If, for example, a primary line fuse had blown or electronic components are damaged, the unit might attempt to restart under single phase conditions, immediately shutting down. This type of restart attempt will eventually destroy the equipment.
- It is possible that a cable failure caused the unit to shut down. Repeated attempts to restart could easily damage the motor or cause additional damage to the cable.

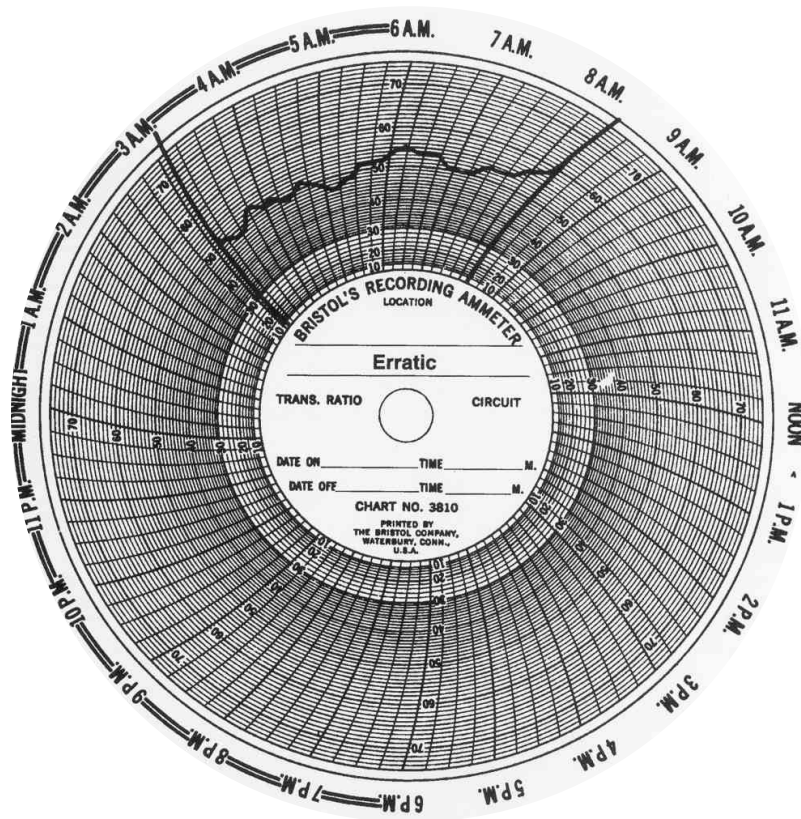


Erratic loading conditions: Figure 23-14

The following chart exhibits an unpredictable varying plot. The unit finally stopped due to overload and will not automatically restart. Manual restart should not be attempted until the unit is thoroughly checked by a service technician and the cause of the problem solved.

Possible cause

- This is usually produced by drastic changes in fluid properties (i.e., changes in density, viscosity, volume, etc.) or large changes in surface or subsurface pressures.
- A severely worn pump could create a similar pattern. Check production, fluid levels and well history.
- Some typical causes for overload failure of this nature are a locked pump, burned motor, burned cable or blown fuses (primary and/or secondary).



Troubleshooting

Field checkout

Many times a pump company's service technician is unnecessarily called out to an installation when the problem could have been solved by the operator or the company electrician. This usually results from a lack of understanding as to what has occurred or is occurring.

Once the operator becomes familiar with the well's normal operation, there are several checks which can be made that could possibly solve some equipment problems or could prevent the unit from being damaged. These checks do not necessarily involve contact with any of the electrical system with which the operator is usually unfamiliar, but will allow the operator to quickly detect changes in the well's normal behavior. This change in behavior could be an indication that operation problems may be on the horizon.

The company electrician should periodically check the primary voltage so that it is balanced between phases and adequate to maintain sufficient secondary voltage to the unit. This will help prevent operating problems and enhance equipment performance.

The electrician should not modify the motor controller circuit without approval of a pump company's engineering department. All external circuits should be connected only as shown in the general circuit schematic, which is on the inside of each motor controller door.

If changes are made inside the motor controller, the electrician should make sure that the fuses are properly sized for the motor being used and that the underload (UL) and overload (OL) settings are properly set (OL: maximum of 120% of motor nameplate current rating; UL minimum of 80% of motor running amps).

The following are troubleshooting guidelines that should prove to be beneficial in the day-to-day operation of the ESP system. They can be used effectively to prevent equipment damage and premature failure.

Trouble shooting chart		
Trouble	Possible cause	Corrective action
Unit will not start (No output current)	Power supply failure or disconnected	Check input power supply on all three phases
	Motor controller circuits faulty	Check that main disconnect switch is fully closed
		Test electric and electronic components
		Check all power and control fuses
		Check auxiliary equipment for proper operation
		Check all control and time delay settings for proper operation/setup
		Check for loose connections
Unit will not start (High current)	Low surface voltage	Check and increase as required
	Low motor voltage	Check cable voltage drop and adjust
		Check conductor size against length and use larger cable if required
		Disconnect from controller and check resistance values
Unit will not start (High current)	Short circuit in cable and/or motor	
	Insulation failure of cable or motor	Disconnect from controller and check resistance values
	Pump, motor or seal locked	Reverse rotation and try to start.
		Acidize or flush pump out to remove foreign material
Pump output is low or zero	Incorrect rotation	Reverse rotation of motor
	Low intake pressure	Check fluid level with pump running and check pump design
	Obstruction in surface or subsurface flow lines	Check pressure regulators and valves, etc.
	Split tubing	Pull and replace
	Low voltage	Increase as required

Trouble shooting chart		
Trouble	Possible cause	Corrective action
	Worn pump	Pull for repair
	Plugged pump	Acidize or flush pump to remove foreign material
Pump output is low or zero	Viscous or gaseous fluids	Check values and contact pump company for recommendation
Unit is shutting down on underload	Well pump off or gas locked	Check pump design and lower unit if possible
		Increase down time for longer continuous operation
	Tubing leak	Pull and replace
	Broken shaft in equipment	Pull unit for repair
	Underload protection set incorrectly or malfunction	Check with pump manufacturer and, set or replace as required
	Surface valve closed or plugged	Open or repair as necessary
	Pump running backwards	Reverse rotation of motor
	External controls connected incorrectly or malfunction	Disconnect controls and restart
		Check wiring schematic
Unit is shutting down on overload	Low or high voltage	Check and adjust as required
	Overload protection not set properly	Check with pump manufacturer and set as required
	Faulty overload protection	Replace faulty component
	Pump back-spinning	Allow fluid in tubing to flow back
	Single phasing	Check power on all three phases
	Electrical failure downhole	Disconnect downhole equipment and check electrically. If required, contact pump manufacturer

Trouble shooting chart		
Trouble	Possible cause	Corrective action
	Equipment overloaded or damaged	Check pump design and contact pump manufacturer
	Foreign material in pump	Catch sample, identify and remove from fluids if possible
Unit running with high amps	Unit setting in bend of crooked hole	Raise or lower the submersible unit a few joints
	Unit either setting on, or caught in a packer	Relieve the compression or tension on the unit
	High or low voltage	Adjust up or down as necessary
Unit running with high amps	Pump running backwards	Reverse the rotation of the motor
	Over staged pump	Check pump curve for loading
	Heavy or viscous fluid	Check values and contact the ESP manufacturer
	Solids, mud or other foreign material	Catch sample, identify and remove material from produced fluids
Erratic current	Drastic changes in surface pressures or fluctuations in fluid density	Check surface equipment and/or fluid gradients
	Fluctuating power supply	Monitor power supply and contact the utility company
	Worn pump	Check fluid levels, production rate and design criteria

Fixed speed (Hz)

Observed condition	Hz	A	PIP	Temp (motor)	Stock tank flow rate	Pressure (tubing)	Pressure (discharge)
Closed valve	c	↓	↑	↑	↓	↑	↑
Plugged tubing	c	↓	↑	↑	↓	↓	↑
Plugged pump	c	↓	↑	↑	↓	↓	↓
Leaking tubing	c	c	↑	↑	↓	↓	c
Open choke	c	↑	↓	↓	↑	↓	↓
Broken shaft	c	↓	↑	↑	↓	↓	↓
Pumped off well	c	↓	↓	↑	↓	↑	↑
Worn out pump	c	↓	↑	↑	↓	↓	↓
Shutdown	d	↓	↑	↑	↓	↓	↓
Overloaded motor	c	↑	c	↑	c	c	c
Gas locking	c	↓	c/↓	↑	↓	↓	↓

Hz = Hertz or Frequency (Speed)

PIP = Pump Intake Pressure

A = Amperage

c = Constant

d = Unit off

Summary

The previous troubleshooting table and observed condition matrix has been developed using examples and certain guidelines for the interpretation of amp charts, operational trends and typical ESP problems based on operational experience. Not all configurations and conditions can be described in detail and related back to component causes as they are well specific and application dependent. However, some configurations may be used with each individual alert to avoid premature failure. Through the proper inspection and maintenance of surface equipment(s), longer and more efficient runs could be accomplished for electrical submersible pumps.

Notes:



Section 8: Appendix

Appendix A: Glossary

Appendix B: Engineering data

Notes:

Appendix A

Glossary

Absolute Pressure - the sum of gauge pressure and atmospheric pressure

Affinity Laws - The laws that govern the performance of the centrifugal pump, as changes in speed occur.

Ampere - a unit of current or rate of flow of electricity

Atmospheric Pressure - the force exerted on a unit area by the weight of the atmosphere

Bottom Intake Booster Pump - With cooling shroud, it is developed for pumping from caverns, mines, sumps or anywhere you need to lower fluid to the lowest possible level.

Brake Horsepower - total power required by a pump to do a specific amount of work.

Cable bands - used to strap the power cable to the tubing.

Capacitance (C) - An influence on an alternating current is caused by the presence in the circuit of alternate plates of conducting material separated by insulation.

Cavitation - When a liquid enters the eye of the pump impeller, an increase in velocity takes place. This increase in velocity is accompanied by a reduction in pressure. If the pressure falls below the vapor pressure corresponding to the temperature of the liquid, the liquid will vaporize, thus the results will be liquid plus pockets of vapor.

Check Valve - a check valve usually located 2 to 3 joints above the pump assembly can be used to maintain a full column of fluid above the pump.

Conductors - a substance which permits electrons to flow freely through them

Current (I) - The flow of electrons when a potential or voltage of sufficient strength is applied to a conductor.

Density - Or specific weight, is the weight per unit volume of substance.

Fixed Impeller Pump Stage - Has its impellers mounted on the shaft in such a way that they are not allowed to slide or move axially on the shaft.

Floating Impeller Pump Stage - Allows its impeller to move axially on the shaft and engage the thrust surfaces on the diffuser.

Gas Locking - There is excessive free gas present and not enough intake pressure to control the amount of free gas handled by the pump.

Gauge Pressure - the differential pressure indicated by a pressure gauge, as opposed to absolute pressure

Gradient - the pressure exerted by a fluid for each foot of fluid height

Head - the amount of energy per pound of fluid

Horsepower - a measure of time-rate of doing work

Hydraulic Fundamentals - the study of the behavior of fluids at rest and in motion

Hydraulic Horsepower (water horsepower) - The energy output of the pump is derived directly from the outlet parameters (flow and head).

Impedance (z) - the vector sum of resistance and reactance in an alternating current circuit

Insulator - a substance through which electrons have great difficulty in traveling, e.g. rubber, glass, certain plastics, fiber, and dry paper

Motor Efficiency - the ratio of the power output to the power input and is usually expressed as a percent

Nameplate Motor HP - the manufacturer's recommended rated HP for the operating conditions allocated to that motor

Nameplate Voltage - the voltage which should appear at the motor terminals to generate the rated HP

Ohm - a unit of electrical resistance

Ohm's Law - The voltage required to make a current flow depends upon the resistance of the circuit. A voltage of one volt will make one ampere flow through a resistance of one ohm.

Power (P) - the rate of doing work. In electrical terms, it represents the energy necessary to maintain current flow.

Power Factor - the ratio of true power (KW) to the apparent power (KVA)

Pressure - the force per unit area of a fluid. It can be considered a compressive stress.

Productivity Index (PI) - The measurement of static bottomhole pressure; and, at one stabilized producing condition, measurement of the flowing bottomhole pressure and the corresponding rate of liquids produced at that pressure.

Pump Intake Pressure (PIP) - The feet of fluid over the pump.

Pump Thrust - Is produced by fluid pressures on the impellers and fluid pressures acting on the end of the pump shaft.

Rated Motor Torque - the value of torque the motor will produce when fully loaded at its rated speed

Rotary Gas Separator - These components, typically with high gas-liquid ratios with low bottomhole pressures use centrifugal force to separate the free gas (gas not in solution) from the well fluid before entry into the pump.

Specific Gravity - the ratio of the density, or specific weight of a given material, to the density of some standard material

Transformer - a device by which the voltage of an alternating-current system may be changed

Vibration – the process of moving or being moved back and forth very rapidly

Viscosity – a measure of a liquid's internal resistance to flow, such resistance being brought about by the internal friction resulting from the combined effects of cohesion and adhesion

Volt – a unit of electromotive force

Volt Amperes – a unit of apparent power

Watt – a unit of true power

Watt-hour – a unit of electrical work. It indicates the expenditure of electrical power amounting to one watt for one hour.

Wellhead – The wellhead is designed to support the weight of the subsurface equipment and is used to maintain surface annular control of the well.

Notes:

Appendix B

Engineering data

Electrical terms and definitions	
Ampere	unit of current or rate of flow of electricity
Volt	unit of electromotive force
Ohm	unit of resistance (Direct and Alternating Current) unit of impedance (Alternating Current)
Impedance	vector sum of resistance and reactance in an alternating current circuit
Ohm's law	$Current = \frac{Electromotive\ Force}{resistance} (Direct\ Current)$ $Current = \frac{Electromotive\ Force}{impedance} (Alternating\ Current)$ $Ohms = \frac{Volts}{Amperes}$
Volt amperes	unit of apparent power = Volts x Amps for Single Phase Power = Volts x Amps x 1.73 for Three Phase Power
Megohm	1,000,000 Ohms
Watt	unit of true power = Volts x Amps x Power Factor
Power factor	ratio of true power to apparent power
Watt-hour	unit of electrical work; Indicates the expenditure of electrical power amounting to one watt for one hour
Horsepower	a measure of time-rate of doing work; Equivalent to raising 33,000 pounds one foot in one minute Equivalent to raising 4,561 Kilograms one meter in one minute
	One Horsepower - 746 Watts

Useful formulas

To Find	English Formula	Metric Formula
Brake HP	$= \frac{GPM \times TDH \text{ (Feet)} \times Sp. Gr.}{3,960 \times Pump \text{ Eff}}$	$= \frac{M^3/D \times TDH \text{ (M)} \times Sp. Gr.}{6,570 \times Pump \text{ Eff}}$
Brake HP	$= \frac{BPD \times TDH \text{ (Feet)} \times Sp. Gr.}{136,000 \times Pump \text{ Eff}}$	$= \frac{M^3/D \times TDH \text{ (Kp)} \times Sp. Gr.}{64,300 \times Pump \text{ Eff}}$
Brake HP	$= \frac{GPM \times TDH \text{ (psi)}}{1,715 \times Pump \text{ Eff}}$	$= \frac{M^3/D \times TDH \text{ (Bar)} \times Sp. Gr.}{643 \times Pump \text{ Eff}}$
Brake HP	$= \frac{BPD \times TDH \text{ (psi)}}{58,900 \times Pump \text{ Eff}}$	
Pump Eff	$= \frac{GPM \times H \text{ (Feet)} Sp. Gr.}{3,960 \times Brake \text{ HP}}$	$= \frac{M^3/D \times H \text{ (M)} \times Sp. Gr.}{6,570 \times Brake \text{ HP}}$
GPM	$= \frac{Pounds \text{ Fluid Per Hour}}{500 \times Sp. Gr.}$	$= \frac{Kilograms \text{ Fluid Per Hour}}{227 \times Sp. Gr.}$
BPD	$= \frac{Pounds \text{ Fluid Per Hour}}{14.6 \times Sp. Gr.}$	
M ³ /D	$= \frac{Pounds \text{ Fluid Per Hour}}{9.18 \times Sp. Gr.}$	$= \frac{Kilograms \text{ Fluid Per Hour}}{41.7 \times Sp. Gr.}$
HP Input (3Phase)	$= \frac{I \times V \times 1.73 \times PF}{746}$	$= \frac{I \times V \times 1.73 \times PF}{746}$
HP Input (3Phase)	$= KW \times 1.34$	$= KW \times 1.34$
KVA (3Phase)	$= \frac{V \times I \times 1.73}{1,000}$	$= \frac{V \times I \times 1.73}{1,000}$
Torque/Ft.Pounds	$= \frac{BHP \times 5,250}{RPM}$	$= \frac{BHP \times 5,250}{RPM}$

WHERE:

BEP = Best Efficiency Point
 BPD = Barrels Per Day
 M³/D = Cubic Meters Per Day
 Eff (Decimal) = Efficiency
 GPM = Gallons Per Minute
 H = Head
 HP = Horsepower

I = Amperes
 Kp = Kilopascal
 KW = Kilowatts
 M = Meters
 PF = Power Factor (Decimal)
 RPM = Revolutions Per Minute
 Sp. Gr. = Specific Gravity
 V = Surface Volts

$$HP \text{ at Meter} = \frac{R \times K \times M}{0.2072 \times t}$$

WHERE:

K = Meter Disc Constant
 R = Revolutions of Meter Disc

M = Multiplier (Product of PT & CT Ratios)
 t = Time Required for "R"

Useful formulas and relationships regarding flow in pipes

To Find	English Formula	Metric Formula
Velocity (Ft/Sec)	$= \frac{GPM}{2.46 \times (Dia.)^2}$	$= \frac{LPM}{4.76 \times (Dia.)^2}$
Velocity (Ft/Sec)	$= \frac{0.321 \times GPM}{Area}$	$= \frac{0.165 \times LPM}{Area}$
Gallons/Min	$= \frac{Area \times Velocity}{0.3}$	$= \frac{Area \times Velocity}{0.165}$
Gallons/Min	$= 2.45 \times V \times (Dia.)^2$	$= 4.76 \times V \times (Dia.)^2$
Pipe Dia. (In.)	$= \sqrt{\frac{GPM}{2.45 \times V}}$	$= \sqrt{\frac{LPM}{4.76 \times V}}$
Gallons/Day	$= 3530 \times V \times (Dia.)^2$	$= 6850 \times V \times (Dia.)^2$

WHERE

A	=	Area in Square Inches	A	=	Area in Square Centimeters
Dia	=	I.D. of Pipe in Inches	Dia	=	I.D. of Pipe in Centimeters
GPM	=	Gallons Per Minute	LPM	=	Liters Per Minute
GPD	=	Gallons Per Day	LPD	=	Liters Per Day
V	=	Velocity in Feet/Second	V	=	Velocity in Meters/Second

RELATIONSHIPS Regarding FLOW AND PRESSURE DROPS IN PIPES

At a constant pipe diameter, the friction loss (head) is proportional to GPM squared.

EXAMPLE: A Flow of 1,000 GPM produces 12 Feet of friction in a pipe.
What friction will result with 2,000 GPM?

$$\text{ANSWER: } \left(\frac{2,000}{1,000} \right)^2 \times 12 = 48 \text{ Feet} \quad h \approx Q^2$$

At a constant pipe diameter, flow is proportional to $\sqrt{h}$

EXAMPLE: In a 10' pipe, the friction (pressure drop) "h" is 16' per 100' length.
What is the flow?

OBSERVATION: From Friction Tables, the nearest figure to 16 is 10' for 3500 GPM.

ANSWER: The flow is greater by the following relationship:

$$\frac{3500 \times \sqrt{16}}{\sqrt{10}} = 4430 \text{ GPM} \quad Q \approx h^{.5}$$

At a constant head, the flow in a pipe is proportional to I.D. (d)

EXAMPLE: A 6' pipe discharges 400 GPM.
How much will a 3' pipe deliver under the same conditions?

$$(6)^{2.5} = 88.18 \quad (3)^{2.5} = 15.59 \quad d^{2.5} = d^2 \times \sqrt{d}$$

$$\text{ANSWER: } \frac{15.59}{88.18} \times 400 = 70.72 \text{ GPM} \quad d^{2.5} \approx Q$$

Temperature rise in pumps

t = Temperature rise of liquid in pump, degrees F

$$t = \frac{5.1 \times \text{BHP Loss}}{\text{Sp. Gr.} \times \text{Sp. Heat} \times \text{GPM}} = \frac{27.8 \times \text{BHP loss}}{\text{Sp. Gr.} \times \text{Sp. Heat} \times (M^3/D)}$$

$$= \frac{\text{BHP} (100 - \text{Pump Eff}) \times 0.707 \times 60}{\text{GPM} \times 8.33 \times \text{Sp. Gr.} \times \text{Sp. Heat}}$$

BHP loss is found by subtracting efficiency at rated capacity (flow) from 100 and multiplying by BHP at that capacity (flow).

Specific Heat for water is 1.0

Limit rise in temperature to 35°F., maximum:

1 HP = 42.21 B.T.U. per minute

Also; $t = \frac{H \left[\frac{100 - \eta}{E} \right]}{780 \times \text{Sp. Heat}}$

WHERE: H = Head in feet
E = Pump Efficiency expressed by whole number

EXAMPLE:

Find the temperature rise in a type FC-925 pump at peak efficiency at 3,000' of head.

	English Formula	Metric Formula
Pump Efficiency	= 64.5%	64.5%
Capacity	= 900 BPD = 26.24 GPM	143.0886 M ³ /D
Assume:		
Specific Heat	= 0.50	0.5
Specific Gravity	= 0.85	0.85
Motor Efficiency	= 0.86	0.86
Feet	= 3,000	Meters = 914.4M
HP Output	$= \frac{\text{GPM} \times \text{Feet} \times \text{Sp. Gr.}}{3,960}$	$= \frac{M^3/D \times \text{Meters} \times \text{Sp. Gr.}}{6,579}$
	$= \frac{26.24 \times 3,000 \times 0.85}{3,960}$	$= \frac{143.0886 \times 914.4 \times 0.85}{6,579}$
	= 16.9 HP	= 16.9 x 1.0139 = 17.13 HP
Brake HP	$= \frac{\text{HP Output}}{\text{Pump Eff.}}$	$= \frac{\text{HP Output}}{\text{Pump Eff.}}$
	$= \frac{16.9}{0.645}$	$= \frac{16.9}{0.645}$
	= 26.2 HP	= 26.2 x 1.0139 = 26.564 HP

Example: (continued)

	English Formula	Metric Formula
HP Input	$= \frac{\text{Brake HP}}{\text{Motor Eff.}}$ $= \frac{26.2}{0.86}$ $= 30.5 \text{ HP}$	$= \frac{\text{Brake HP}}{\text{Motor Eff.}}$ $= \frac{26.2}{0.86}$ $= 30.5 \times 1.0139 = 30.9 \text{ HP}$
Power Lost (HP)	$= \text{HP Input} - \text{HP Output}$ $= 30.5 - 16.9$ $= 13.6 \text{ HP}$	$= \text{HP Input} - \text{HP Output}$ $= 30.5 - 16.9$ $= 13.6 \times 1.0139 = 13.79 \text{ HP}$
Since 1 HP = 42.41 BTU/Minute:		Since 1 HP = 0.746 KW:
Heat Lost	$= \text{Power Lost} \times 42.41$ $= 13.6 \times 42.41$ $= 577 \text{ BTU/Min.}$	$= \text{Power Lost} \times 0.746$ $= 13.6 \times 0.746$ $= 10.15 \text{ KW} = 0.169 \text{ Kw-Hr/Min}$

The heat will be carried away as the fluid is pumped past the motor through the pump.

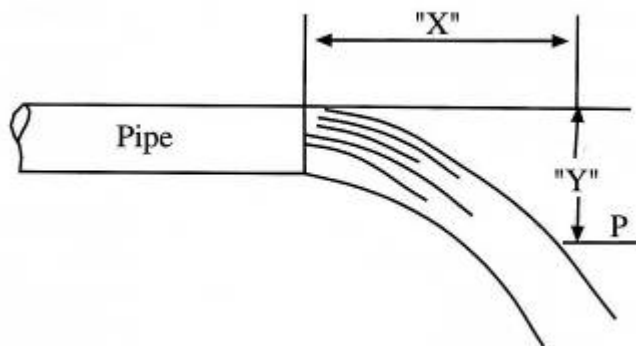
Pounds/Minute	$= \text{GPM} \times \text{Pounds/Gallon} \times \text{Sp. Gr.}$ $= 26.24 \times 8.34 \times 0.85$ $= 186 \text{ Lb/Min}$	$= \frac{M^3/D \times \text{Kg}/M^3 \times \text{Sp. Gr.}}{\text{Minute/Day}}$ $= \frac{143.0886 \times 1000 \times 0.85}{1,440}$ $= 84.46 \text{ Kg./Min.}$
Heat Added/Lb	$= \frac{\text{BTU/Min}}{\text{Lb/Min}}$ $= \frac{577}{186}$ $= 3.1 \text{ BTU/Lb.}$	$= \frac{\text{Kw-Hr/Min}}{\text{Kg/Min}}$ $= \frac{0.169}{84.46}$ $= 0.002 \text{ Kw-Hr/Kg}$

From the previous page:

Temp Rise	$= \frac{5.1 \times \text{BHP Loss}}{\text{Sp. Gr.} \times \text{Sp. Ht.} \times \text{GPM}}$ $= \frac{5.1 \times 13.6}{0.85 \times 0.5 \times 26.24}$ $= 6.2^\circ \text{ F.}$	$= \frac{27.8 \times \text{BHP Loss}}{\text{Sp. Gr.} \times \text{Sp. Ht.} \times M^3/D}$ $= \frac{27.8 \times 13.6}{0.85 \times 0.5 \times 143}$ $= 6.2^\circ \text{ F.}$
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Measurement for water flow

Measure the internal diameter of the pipe in inches, and **square it**. Thus, if the internal diameter is 2 in., you will have $2 \times 2 = 4$. Then multiply the distance x inches.



Thus, if the distance "X" is 20 in., you will have $4 \times 20 = 80$.

Then multiply that by 2.56 which gives us $80 \times 2.56 = 204.8$

Lastly, divide that by the square root of the distance "Y".

Thus, if the distance "Y" is 25 inches, the square root of 25 is 5.

Dividing 204.8 by 5, we get 40.96 GPM, which is the answer.

All measurement is in inches and not in feet and the answer is always in GPM.

SHORT CUT - Choose point "P" such that "Y" is distance 9, 16, 25, or 36 inches because their square roots are very simple; namely, 3, 4, 5, and 6 respectively.

Areas of circles

The following table gives the areas of circles having diameters from 1 to 10. For diameters larger than 10 or smaller than 1, the table may be used by moving decimal points. The decimal point in the area is always moved twice as many places as the decimal point in the diameter.

For instance:	Diameter area	Area
	5.25	21.648
	0.525	0.21 648
	52.5	2164.8

If the diameter is measured in inches, the area will be square inches. If the diameter is in feet, the area will be in square feet.

Based on a Circle = $3.1416 r^2 = 0.7854 d^2$

d = diameter

r = radius

Conversion factors – Miscellaneous hydraulic units											
Dia.	Area	Dia.	Area	Dia.	Area	Dia.	Area	Dia.	Area	Dia.	Area
1.00	.7854	2.50	4.909	4.00	12.566	5.50	23.758	7.00	38.485	8.50	56.745
1.05	.8659	2.55	5.107	4.05	12.824	5.55	24.192	7.05	39.036	8.55	57.415
1.10	.9503	2.60	5.309	4.10	13.202	5.60	24.630	7.10	39.592	8.60	58.088
1.15	1.0387	2.65	5.515	4.15	13.526	5.65	25.072	7.15	40.152	8.65	58.765
1.20	1.1310	2.70	5.726	4.20	13.854	5.70	25.518	7.20	40.715	8.70	59.447
1.25	1.2272	2.75	5.940	4.25	14.186	5.75	25.967	7.25	41.282	8.75	60.132
1.30	1.3273	2.80	6.157	4.30	14.522	5.80	26.421	7.30	41.854	8.80	60.821
1.35	1.4314	2.85	6.379	4.35	14.862	5.85	26.878	7.35	42.429	8.85	61.514
1.40	1.5394	2.90	6.605	4.40	15.205	5.90	27.340	7.40	43.008	8.90	62.211
1.45	1.6513	2.95	6.835	4.45	15.553	5.95	27.805	7.45	43.592	8.95	62.912
1.50	1.7671	3.00	7.069	4.50	15.904	6.00	28.274	7.50	44.179	9.00	63.617
1.55	1.8869	3.05	7.306	4.55	16.260	6.05	28.748	7.55	44.770	9.05	64.326
1.60	2.011	3.10	7.548	4.60	16.619	6.10	29.247	7.60	45.365	9.10	65.039
1.65	2.138	3.15	7.792	4.65	16.982	6.15	29.706	7.65	45.963	9.15	65.756
1.70	2.270	3.20	8.042	4.70	17.349	6.20	30.191	7.70	46.566	9.20	66.476
1.75	2.405	3.25	8.296	4.75	17.721	6.25	30.680	7.75	47.173	9.25	67.201
1.80	2.545	3.30	8.553	4.80	18.096	6.30	31.172	7.80	47.784	9.30	67.929
1.85	2.688	3.35	8.814	4.85	18.475	6.35	31.669	7.85	48.398	9.35	68.661
1.90	2.835	3.40	9.079	4.90	18.857	6.40	32.170	7.90	49.017	9.40	69.398
1.95	2.986	3.45	9.348	4.95	19.422	6.45	32.675	7.95	49.639	9.45	70.138
2.00	3.142	3.50	9.621	5.00	19.635	6.50	33.183	8.00	50.265	9.50	70.882
2.05	3.301	3.55	9.898	5.05	20.030	6.55	33.696	8.05	50.896	9.55	71.630
2.10	3.464	3.60	10.179	5.10	20.428	6.60	34.212	8.10	51.530	9.60	72.382
2.15	3.631	3.65	10.463	5.15	20.831	6.65	34.732	8.15	52.168	9.65	73.138
2.20	3.801	3.70	10.752	5.20	21.237	6.70	35.257	8.20	52.810	9.70	73.898
2.25	3.976	3.75	11.044	5.25	21.648	6.75	35.785	8.25	56.456	9.75	74.662
2.30	4.155	3.80	11.341	5.30	22.062	6.80	36.317	8.30	54.106	9.80	75.430
2.35	4.337	3.85	11.642	5.35	22.480	6.85	36.853	8.35	54.760	9.85	76.201
2.40	4.524	3.90	11.942	5.40	22.902	6.90	37.393	8.40	55.418	9.90	76.977
2.45	4.714	3.95	12.254	5.45	23.328	6.95	37.937	8.45	56.079	9.95	77.756
2.50	4.909	4.00	12.566	5.50	23.758	7.00	38.485	8.50	56.745	10.00	78.540

$$\text{Head (Feet)} = \frac{2.309 \times PSI}{Sp. Gr.}$$

$$\text{BPD} = \text{GPM} \times 34.3$$

$$\text{Specific Gravity} = \frac{1415}{131.5 + \text{degrees API}}$$

CONVERSION FACTORS - Converting From 60 Hertz to 50 Hertz

NOTE: In the formulas below the term "cycle" is used interchangeably with the term "hertz".

50 Cycle Capacity Flow	$= \frac{50}{60} \times 60 \text{ Cycle Flow}$	$= 0.833 \times 60 \text{ Cycle Flow}$
50 Cycle Head	$= \left(\frac{50}{60}\right)^2 \times 60 \text{ Cycle Head}$	$= 0.694 \times 60 \text{ Cycle Head}$
50 Cycle HP Pump Load	$= \left(\frac{50}{60}\right)^3 \times 60 \text{ Cycle HP Load}$	$= 0.579 \times 60 \text{ Cycle HP Pump Load}$
50 Cycle Motor HP Rating	$= \frac{50}{60} \times 60 \text{ Cycle HP Rating}$	$= 0.833 \times 60 \text{ Cycle HP Rating}$
50 Cycle Motor Voltage	$= \frac{50}{60} \times 60 \text{ Cycle Motor V}$	$= 0.833 \times 60 \text{ Cycle Motor Volts}$
50 Cycle Motor Amps	= Same as 60 Cycle Motor Amps	
50 Cycle Pump Efficiency	= Same as 60 Cycle Pump Efficiency	

Heat and energy conversion factors

1 Kilowatt-Hour	=	1.341 Horsepower-Hours 2,655,217 Foot-Pounds 341.3 British Thermal Units
1 Horsepower-Hour	=	0.7457 kilowatt-Hours (745.7 Watt-Hours) 1,980,000 Foot-Pounds (33,000 X 60) 2545 British Thermal Units
1 British thermal Unit	=	777.97 Foot-Pounds 1054.8 Joules or Watt-Seconds 0.000293 Kilowatt-Hours = 0.293 Watt-Hours 0.000393 Horsepower-Hours
1 Kilowatt	=	1.341 Horsepower 44.254 Foot-Pounds Per Minute / 56,883 BTU Per Minute
1 Horsepower	=	0.7457 Kilowatt = 745.7 Watts 33,000 Foot-Pounds Per Minute 42,418 BTU Per Minute 1.0139 Metric Horsepower

Conversion factor

FLOW

34.286	Barrels Per Day	per	Gallon/Min
1.429	Barrels Per Hour	per	Gallon/Min
10.689	Barrels Per Hour	per	Cubic Feet/Min
150.972	Barrels/Day	per	M ³ /Hour
8.0208	Cubic Feet/Hour	per	Gallon/Min
0.0005885	Cubic Feet/Sec	per	Liter/Min
0.002228	Cubic Feet/Sec	per	Gallon/Min
0.02917	Gallon Per Minute	per	Barrel Per Day
0.700	Gallon Per Minute	per	Barrel Per Hour
448.831	Gallons/Minute	per	Cubic Feet/Sec
4.4033	Gallons/Minute	per	M ³ /Hour
0.1247	Gallons/Sec	per	Cubic Feet/Min
0.06309	Liters/Sec	per	Gallon/Min
1.6957	Cubic Meters/Hour	per	Cubic Feet/Min

PRESSURE

0.01316	Atmosphere	per	Cm. of Mercury
0.03342	Atmospheres	per	Inch of Mercury
0.9678	Atmospheres	per	Kilogram/Sq. Cm.
0.06805	Atmospheres	per	Pound/Sq. Inch
1.01325	BAR	per	Atmosphere
100.0	BAR	per	Kilopascal
0.73756	Ft.-Lbs. (Force)	per	Joule
29.92	Inches Mercury	per	Atmosphere
2.036	Inches of Mercury	per	Pound/Sq. Inch
28.96	Inches of Mercury	per	Kilogram/Sq. Cm.
0.07031	Kgs./Sq. Cm.	per	Pound/Sq. Inch
0.03453	Kgs./Sq. Cm.	per	Inch of Mercury
1.0332	Kgs./Sq. Cm.	per	Atmosphere
0.0004882	Kgs.Sq. Cm.	per	Pound/Sq. Foot
135.95	Kgs.Sq. Meter	per	Cm. of Mercury
6.8948	Kilopascal	per	Pound/Sq. Inch
2048.0	Lbs./Sq. Foot	per	Kilogram/Sq. Cm.
14.223	Lbs./Sq. Inch	per	Kilograms/Sq. Cm.
0.1934	Lbs./Sq. Inch	per	Cm. of Mercury
0.4912	Lbs./Sq. In.	per	Inch of Mercury
0.14504	Pounds/Sq. Inch	per	Kilopascal
14.504	PSI	per	BAR

GOR AND PI

0.44217	Barrels/Day	per	M ³ /Day
	/PSI (PI)		Kg/CM ² (PI)
5.6145	Cubic Feet	per	Meters ³
	/Barrel (GOR)		/Meters ³ (GOR)

HEAD

0.02945	Atmospheres	per	Feet of Water
0.002454	Atmospheres	per	Inch of Water
0.8811	Inches of Mercury	per	Feet of Water
1.4882	Kgs./Meter	per	Pound/Foot
0.03042	Kgs./Sq. Cm.	per	Feet of Water
0.6720	Lbs./Ft.	per	Kilogram/Meter
0.4328	Lbs./Sq. In.	per	Feet of Water

VOLUME

0.02381	Barrel (Oil)	per	Gallon (U.S.)
0.1781	Barrels	per	Cubic Feet
6.290	Barrels	per	Cubic Meter
7.454	Barrels (36" API)	per	Ton (Metric)
16.387	Cubic Centimeters	per	Cubic Inch
0.00003531	Cubic Feet	per	Cubic Centimeter
0.03531	Cubic Feet	per	Liter
5.6146	Cubic Feet	per	Barrel
35.315	Cubic Feet	per	Cubic Meter
61.02	Cubic Inches	per	Liter
0.15898	Cubic Meter	per	Barrel
0.7646	Cubic Meters	per	Cubic Yard
0.003785	Cubic Meters	per	Gallon (U.S.)
0.02832	Cubic Meters	per	Cubic Feet
1.308	Cubic Yards	per	Cubic Meter
0.00495	Cubic Yards	per	Gallon (U.S.)
0.2642	Gallons (U.S.)	per	Liter
264.17	Gallons	per	Cubic Meter
7.48052	Gallons	per	Cubic Feet
201.97	Gallons	per	Cubic Yard
42.0	Gallons (U.S.)	per	Barrel (Oil)
0.83267	Gallons (Imperial)	per	Gallon (U.S.)
1.20095	Gallons (U.S.)	per	Gallon (Imperial)
0.946	Liter	per	Quart (Liquid)
28.32	Liters	per	Cubic Foot
0.01639	Liters	per	Cubic Inch
0.1342	Metric Ton	per	Barrel 36" API
0.002113	Pints (Liq.)	per	Cubic Centimeter
8.338	Pounds of Water	per	Gallon Water (U.S.)
1.057	Quarts (Liquid)	per	Liter

CONVERSION FACTORS

LENGTH

30.48	Centimeters	per Foot
2.540	Centimeters	per Inch
3281.0	Feet	per Kilometer
3.281	Feet	per Meter
39.37	Inches	per Meter
0.3937	Inches	per Centimeter
1.609	Kilometers	per Mile
0.3048	Meters	per Foot
0.6214	Miles	per Kilometer
1.094	Yards	per Meter
1094.00	Yards	per Kilometer

AREA

6.4516	Square Centimeters	per Square Inch
10.764	Square Feet	per Square Meter
0.0929	Square Meter	per Square Foot

WEIGHT AND DENSITY

16.0	Drams	per Ounce
27.34375	Grains	per Dram
58.417	Grains/Gallon (U.S.)	per Gram/Liter
0.01602	Grams/Cubic Cm.	per Pound/Cubic Foot
27680.00	Kgs./Cubic Meter	per Pound/Cubic Inch
16.02	Kgs./Cubic Meter	per Pound/Cubic Foot
0.45359	Kilograms	per Pound
907.18486	Kilograms	per Ton (Short)
8.328	Lbs./Million Gal.	per Part/Million
0.0022857	Ounces (Troy)	per Grain (Troy)
12.0	Ounces	per Pound (Troy)
16.0	Ounces	per Pound (U.S.)
17.118	Parts/Million	per Grain/U.S. Gallon
2205.0	Pounds (Avoir.)	per Ton (Metric)
2000.0	Pounds (Avoir.)	per Ton (Short)
2240.0	Pounds (Avoir.)	per Ton (Long)
0.0625	Pounds (Avoir.)	per Ounce
0.0056	Pounds/Inch	per Gram/Cm.
0.0003674	Tons (Long)	per Pound (Troy)
0.0003732	Tons (Metric)	per Pound (Troy)
0.0004114	Tons (Short)	per Pound (Troy)

CONVERSION FACTORS

VELOCITY

0.01472	Radians/Sec.	per Rev./Min. (RPM)
0.5080	Centimeters/Sec.	per Feet/Min.
1.969	Feet/Min.	per Centimeter/Second
3.281	Feet/Min.	per Meter/Min.
3.281	Feet/Sec.	per Meter/Sec.
0.05468	Feet/Sec.	per Meter/Min.
0.01829	Kilometers/Hr.	per Feet/Min.
1.609	Kilometers/Hr.	per Mile/Hr.
16.67	Meters/Min.	per Kilometer/Hr.
0.6	Meters/Min.	per Centimeter/Second
0.3048	Meters/Min.	per Feet/Min.
0.6214	Miles/Hr.	per Kilometer/Hr.

ACCELERATION

30.48	Cms./Sec./Sec.	per Feet/Sec./Sec.
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POWER AND FORCE

33000.00	Ft.-Lbs. (Force)/Min.	per Horsepower
44.254	Ft.-Lbs. (Force)/Min	per Watt
550.00	Ft.-Lbs. (Force)/Sec	per Horsepower
2655.00	Ft.-Lbs. (Force)	per Watt-Hour
1.0139	Horsepower (Metric)	per Horsepower
0.0013410	Horsepower	per Watt
3600.0	Joules	per Watt-Hour
1.0	Joules/Sec.	per Watt
367.10	Kilogram (Force)-M	per Watt-Hour
0.10197	Kilograms (Force)	per Newton
0.2248	Pounds (Force)	per Newton
745.7	Watts	per Horsepower

TEMPERATURE

1.0	Abs. Temp (*K.)	per Temp (°C + 273)
1.0	Abs. Temp (*R.)	per Temp (°F + 460)
0.5555	Temp (°F.)	per (1.8 x °C) + 32
1.0	Temp (°C.)	per 0.5555 x (°F - 32)

Conversion tables

Specific gravity – Specific weight (Gradient in PSI/ft at °F)		Weights of liquids				Weights of some gases	
Sp. Gr.	Sp. Wt.	Liquid	Sp. Gr. at °C	Sp. Wt. lb/US Gal	Lb/Cu. Ft.	Gas	Specific Wt.* lb/cu. Ft.
0.70	0.303	Alcohol (mthyl)	0.810 (0°)	6.75	50.5	Air	.07651 (at 59. 0°F) .08071
0.75	0.325	Bezine	0.899 (0°)	7.5	56.1	Air	.12341
0.80	0.346	Carbon Tetrachloride	1.595 (20°)	13.32	99.6	Carbon Dioxide	.07806
0.85	0.368	Ethylene Glycol	1.12	9.3	69.6	Carbon Monoxide	.01114
0.90	0.390	Gasoline	0.72	5.87	44.9	Helium	.005611
0.95	0.411	JP1	0.80	6.65	49.7	Hydrogen	.07807
1.00	0.433	JP3	0.775	6.45	48.2	Nitrogen	.089272
1.05	0.455	JP4	0.785	6.55	49.0	Oxygen	.07651 (at 59. 0°F) .08071
1.10	0.476	JP5	0.817 (15°)	6.82	51.1		
1.15	0.498	JP6	0.810	6.759	50.5		
1.20	0.520	Kerosene	0.82	6.7	51.2		
1.25	0.541	Mercury	13.546 (20°)	113.0	845.6		
1.30	0.563	Oil	0.89 (15°)	7.4	55.3		
1.35	0.585	Sea Water	1.025 (15°)	8.55	63.99		
1.40	0.606	Synthetic Oil	0.928 (15°)	7.74	57.9		
		Water	1.00 (4°)	8.345	62.43		
		Zip (Ethyl Decaborane)		6.9			

*At atmospheric pressure and 0° C

Example = S.G of 1.05 = Spec. W of .455 PSI/Ft.

Temperature conversion table

$^{\circ}\text{F} = 9/5\ ^{\circ}\text{C} + 32 = 1.8\ (^{\circ}\text{C} + 17.8)$ $^{\circ}\text{C} = 5/9\ (^{\circ}\text{F} - 32)$ For Interpretation $1^{\circ}\text{C} = 1.8^{\circ}\text{F}$

$^{\circ}\text{C} \leftarrow$	$^{\circ}\text{F} \downarrow$	$^{\circ}\text{C} \rightarrow$	$^{\circ}\text{C} \leftarrow$	$^{\circ}\text{F} \downarrow$	$^{\circ}\text{C} \rightarrow$	$^{\circ}\text{C} \leftarrow$	$^{\circ}\text{F} \downarrow$	$^{\circ}\text{C} \rightarrow$
-62.2	-62.2	-112.0	32.2	32.2	194.0	112.8	235	455.0
-56.7	-56.7	-94.0	35.0	35.0	203.0	115.6	240	464.0
-51.1	-51.1	-76.0	37.8	37.8	212.0	118.3	245	473.0
-45.6	-45.6	-58.0	40.6	40.6	221.0	121.1	250	482.0
-40.0	-40.0	-40.0	43.3	43.3	230.0	126.7	260	500.0
-34.4	-34.4	-22.0	46.1	46.1	239.0	132.2	270	518.0
-31.7	-31.7	-13.0	48.9	48.9	248.0	137.8	280	536.0
-28.9	-28.9	-4.0	51.7	51.7	257.0	143.3	290	554.0
-26.1	-26.1	+5.0	54.4	54.4	266.0	148.9	300	572.0
-23.3	-23.3	14.0	57.2	57.2	275.0	154.4	310	590.0
-20.6	-20.6	23.0	60.0	60.0	284.0	160.0	320	608.0
-17.8	-17.8	32.0	62.8	62.8	293.0	165.6	330	626.0
-15.0	-15.0	41.0	65.6	65.6	302.0	171.1	340	644.0
-12.2	-12.2	50.0	68.3	68.3	311.0	176.7	350	622.0
-9.4	-9.4	59.0	71.1	160	320.0	182.2	360	680.0
-6.7	-6.7	68.0	73.9	165	329.0	187.8	370	698.0
-3.9	-3.9	77.0	76.7	170	338.0	193.3	380	716.0
-1.1	-1.1	86.0	79.4	175	347.0	198.9	390	734.0
+1.7	+1.7	95.0	82.2	180	356.0	204.4	400	752.0
4.4	4.4	104.0	85.0	185	365.0	210.0	410	770.0
7.2	7.2	113.0	87.8	190	374.0	215.6	420	788.0
10.0	10.0	122.0	90.6	195	383.0	221.1	430	806.0
12.8	12.8	131.0	93.3	200	392.0	226.7	440	824.0
15.6	15.6	140.0	96.1	205	401.0	232.2	450	842.0
18.3	18.3	149.0	98.9	210	410.0	237.8	460	860.0
21.1	21.1	158.0	101.7	215	419.0	243.3	470	878.0
23.9	23.9	167.0	104.4	220	428.0	248.9	480	896.0
26.7	26.7	176.0	107.2	225	437.0	254.4	490	914.0
29.4	29.4	185.0	110.0	230	446.0	60.0	500	932.0

FUNDAMENTAL UNITS OF LENGTH, AREA, VOLUME AND MASS

Some definitions and legal relations

1 in.*	= (1.03937) cm = 2.54000508 cm	1 I.T. cal ₁	= 4.18674 joules
1 Lb.*	= 453.5924277 g		= 1.000654 Cal ₁₅
1 Gal*	= in.3 = 3.785329 liter	1 BTU ₁	= 251.993 I.T. cal ₁₅

Conversion factors, unit of length

	<u>cm</u>	<u>m</u>	<u>in.</u>	<u>ft.</u>	<u>yd.</u>
1 cm.	= 1	0.01	0.3937	0.032808333	0.010936111
1 m.	= 100	1	39.37	3.2808333	1.0936111
1 in.	= 2.5400051	0.025400051	1	0.083333333	0.027777778
1 ft.	= 10.480061	0.30480061	12	1	0.33333333
1 yd.	= 91.440183	0.91440183	36	3	1

Conversion factors, unit of area

	<u>cm²</u>	<u>m²</u>	<u>in.²</u>	<u>ft.²</u>	<u>yd.²</u>
1 cm. ²	= 1	10 ⁻⁴	0.15499969	1.0763867 X 10 ⁻³	1.1959853 X 10 ⁻⁴
1 m. ²	= 104	1	1549.9969	10.763867	1.1959853
1 in. ²	= 6.4516258	6.4516258 X 10 ⁻⁴	1	6.9444444 x 10 ⁻³	7.7160494 x 10 ⁻⁴
1 ft. ²	= 929.03412	0.092903412	144	1	²
1 yd. ²	= 8361.3070	0.83613070	1296	9	0.11111111

Conversion factors, units of volume

	<u>cm³</u>	<u>in.³</u>	<u>ft.³</u>
1 cm. ³	= 1	0.061023378	3.5314455 x 10 ⁻⁵
1 in. ³	= 16.387162	6.4516258 X 10 ⁻⁴	1
1 ft. ³	= 2.8317017 x 10 ⁴	0.092903412	144
1 ml.	= 1.000028	0.83613070	1296
1 liter	= 1.000028 x 10 ³		
1 gal.	= 3.7854345 x 10 ³		

	<u>ml</u>	<u>liter</u>	<u>gal</u>
1 cm. ³	= 0.9999720	0.9999720 x 10 ⁻³	2.6417047 x 10 ⁻⁴
1 in. ³	= 16.38670	1.63870 x 10 ⁻²	4.3290043 x 10 ⁻³
1 ft. ³	= 2.831622 x 10 ⁴	28.31622	7.4805195
1 ml.	= 1	0.001	2.641779 x 10 ⁻⁴
1 liter	= 10 ³	1	0.2641779
1 gal.	= 3.785329 x 10 ³	.3785329	1

Conversion factors, units of mass

	<u>g</u>	<u>kg</u>	<u>lb</u>	<u>metric ton</u>	<u>ton</u>
1 g	= 1	10 ⁻³	2.2046223 x 10 ⁻³	10 ⁻⁶	1.1023112 X 10 ⁻⁶
1 kg	= 10 ³	1	2.2046223	10 ⁻³	1.1023112 X 10 ⁻³
1 lb	= 4.5359243 x 10 ²	0.45359243	1	4.5359243 x 10 ⁻⁴	0.0005
1 mt ton	= 10 ⁶	10 ⁻³	2204.6223	1	1.1023112
1 ton	= 907.18486	907.18486	2000	0.90718486	1

*Legal Relation As defined by International Steam Table Conference, London, 1929.

CONVERSION FACTORS FOR UNITS OF ENERGY

Units	g mass (energy equiv)	joule	cal	I.T. cal	Btu	kw-hr
1 g mass (energy equiv)	= 1	8.98656 x 10 ¹³	2.14784 x 10 ¹³	2.14664 x 10 ¹³	8.51775 x 10 ¹⁰	2.49627 x 10 ⁷
1 joule	= 1.112772 x 10 ⁻¹⁴	1	0.239006	0.238849	0.947831 x 10 ⁻³	2.77778 x 10 ⁻⁷
1 cal	= 4.65584 x 10 ⁻¹⁴	4.1840 ₁	1	0.999346	3.96573 x 10 ⁻³	1.16222 x 10 ⁻⁶
1 I.T. cal	= 4.65888 x 10 ⁻¹⁴	4.18674	1.000654	1	3.96832 x 10 ⁻³	1.162983 x 10 ⁻⁶
1 BTU	= 1.174019 x 10 ⁻¹¹	1.055040 x 10 ²	2.52161 x 10 ²	2.51996 x 10 ²	1	2.93066 x 10 ⁻⁴
1 kw-hr	= 4.00598 x 10 ⁻⁸	3.6 x 10 ⁶	8.60421 x 10 ⁶	8.59858 x 10 ⁶	3.41220 x 10 ³	1
1 hp-hr	= 2.98727 x 10 ⁻³	2.684525 x 10 ⁶	6.41617 x 10 ⁶	6.41197 x 10 ⁶	2.54448 x 10 ³	0.745701
1 ft-lb (wt)	= 1.50872 x 10 ⁻¹⁴	1.355821	0.324049	0.323837	1.285089 x 10 ⁻³	3.76614 x 10 ⁻⁷
1 ft-lb (wt)/in ²	= 2.17256 x 10 ⁻¹²	1.952382 x 10 ²	46.6630	46.6325	0.1850529	5.42328 x 10 ⁻⁵
1 liter-atm	= 1.127548 x 10 ⁻¹²	1.013278 x 10 ²	24.2179	24.2021	0.0960416	2.81466 x 10 ⁻⁵
1 quantum ($\lambda = .6\mu$)	= 3.6829 x 10 ⁻³³	3.3096 x 10 ⁻¹⁹	7.91021 x 10 ⁻²⁰	7.90504 x 10 ⁻²⁰	3.13676 x 10 ⁻²²	9.19342 x 10 ⁻²⁶
1 Mev	= 1.78270 x 10 ⁻²⁷	1.60203 x 10 ⁻¹³	3.82894 x 10 ⁻¹⁴	3.82644 x 10 ⁻¹⁴	1.51845 x 10 ⁻¹⁶	4.4498 x 10 ⁻²⁰
1 amu ²	= 1.66035 x 10 ⁻²⁴	1.49208 x 10 ⁻¹⁰	3.56616 x 10 ⁻¹¹	3.56379 x 10 ⁻¹¹	1.41411 x 10 ⁻¹³	4.14453 x 10 ⁻¹⁷

Units	hp-hr	ft-lb(wt)	ft ³ -lb(wt)/in ²	liter-am
1 g mass (energy equiv)	= 3.34754 x 10 ⁷	6.62814 x 10 ¹³	4.60287 x 10 ¹¹	8.86880 x 10 ¹¹
1 joule	= 3.72505 x 10 ⁻⁷	0.737561	5.12195 x 10 ⁻³	9.86896 x 10 ⁻³
1 cal	= 1.558562 x 10 ⁻⁶	3.08595	2.14302 x 10 ⁻²	4.12927 x 10 ⁻²
1 I.T. cal	= 1.559582 x 10 ⁻⁶	3.08797	2.14443 x 10 ⁻²	4.13187 x 10 ⁻²
1 BTU	= 3.93008 x 10 ⁻⁴	7.78156 x 10 ²	5.40386	10.411215
1 kw-hr	= 1.341020	2.655218 x 10 ⁴	1.843902 x 10 ⁴	3.55282 x 10 ⁴
1 hp-hr	= 1	1.98000 x 10 ⁶	1.3750 x 10 ⁴	2.64935 x 10 ⁴
1 ft-lb (wt)	= 5.05051 x 10 ⁻⁷	1	6.94444 x 10 ⁻³	1.338054 x 10 ⁻²
1 ft ³ -lb (wt)/in ²	= 7.27273 x 10 ⁻⁵	1.44 x 10 ²	1	1.926797
1 liter-atm	= 3.77452 x 10 ⁻⁵	74.7354	0.518996	1
1 quantum ($\lambda = .6\mu$)	= 1.23286 x 10 ⁻²⁵	2.44116 x 10 ⁻¹⁰	1.69531 x 10 ⁻²¹	3.266520 x 10 ⁻²¹
1 Mev	= 5.96751 x 10 ⁻²⁰	1.18157 x 10 ⁻¹³	8.20535 x 10 ⁻¹⁶	1.58100 x 10 ⁻¹⁵
1 amu ²	= 5.55790 x 10 ⁻¹⁷	1.10046 x 10 ⁻¹⁰	7.64208 x 10 ⁻¹³	1.147247 x 10 ⁻¹²

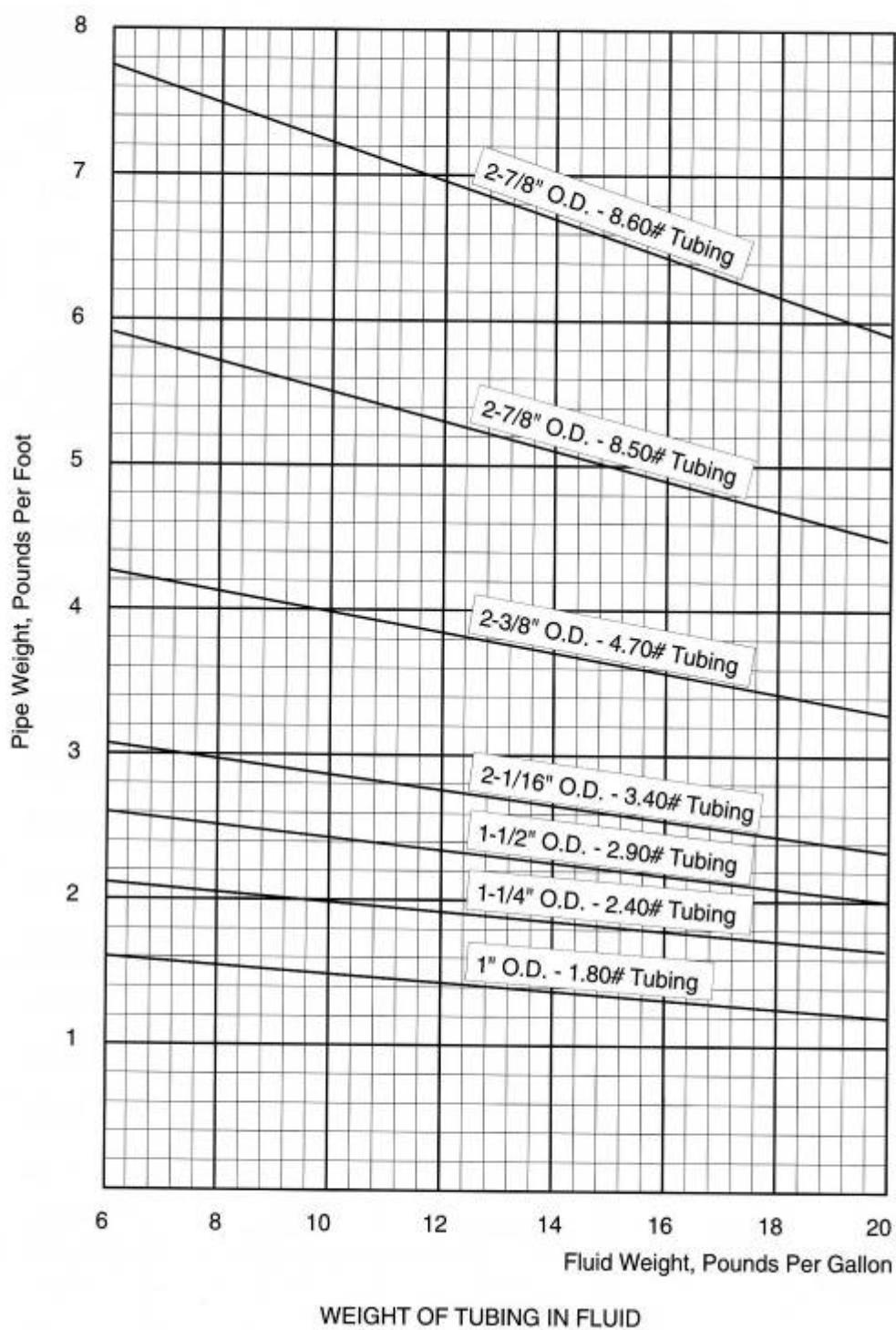
	quantum	Mev	amu
1 g mass (energy equiv)	2.71503 x 10 ³²	5.60961 x 10 ²⁶	6.02308 x 10 ²³
1 joule	3.02125 x 10 ¹⁶	6.24222 x 10 ¹²	6.70232 x 10 ⁹
1 cal	1.26409 x 10 ¹⁰	2.61175 x 10 ¹³	2.80425 x 10 ¹⁰
1 I.T. cal	1.26491 x 10 ¹⁰	2.61346 x 10 ¹³	2.80608 x 10 ¹⁰
1 BTU	3.18754 x 10 ¹⁵	6.58580 x 10 ²	7.07121 x 10 ¹²
1 kw-hr	1.08765 x 10 ²⁵	2.24720 x 10 ¹⁹	2.41283 x 10 ¹⁶
1 hp-hr	8.11062 x 10 ²⁴	1.67574 x 10 ¹⁹	1.79926 x 10 ¹⁸
1 ft-lb (wt)	4.09627 x 10 ¹⁸	8.46334 x 10 ¹²	9.08711 x 10 ⁹
1 ft ³ -lb (wt)/in ²	5.89862 x 10 ²⁰	1.21872 x 10 ¹⁵	1.30855 x 10 ¹²
1 liter-atm	3.06136 x 10 ²⁰	6.32519 x 10 ¹⁴	6.79131 x 10 ¹¹
1 quantum ($\lambda = .6\mu$)	1	2.06593 x 10 ⁻⁸	2.21839 x 10 ⁹
1 Mev	4.84001 x 10 ⁵	1	1.07371 x 10 ⁻³
1 amu ²	4.50776 x 10 ⁸	9.31354 x 10 ²	1

Casing and tubing sizes and capacities					
Normal Size	A.P.I. Size (O.D.)	Weight Per Linear Foot	Inside Diameter	Barrels Per 1000 ft.	Gals. Per 1000 ft.
2	2.375	4.65	1.995	3.869	162.5
2 ½	2.875	6.54	2.441	5.793	243.3
3	3.500	9.25	2.992	8.704	365.5
4	4.500	12.68	3.958	15.23	639.6
5 ½		20.00	4.773	22.2	931.3
6 ⅝		20.00	6.049	35.5	1493
7		23.00	6.366	39.4	1653
7 ⅝		24.00	7.025	48.0	2013
8 ⅝		32.00	7.921	60.9	2560
9 ⅝		36.00	8.921	77.3	3247
10 ¾		40.50	10.050	98.1	4121
11 ¾		47.00	11.000	117.5	4936
13 ⅜		61.00	12.515	152.2	6390
16		65.00	15.250	225.9	9489

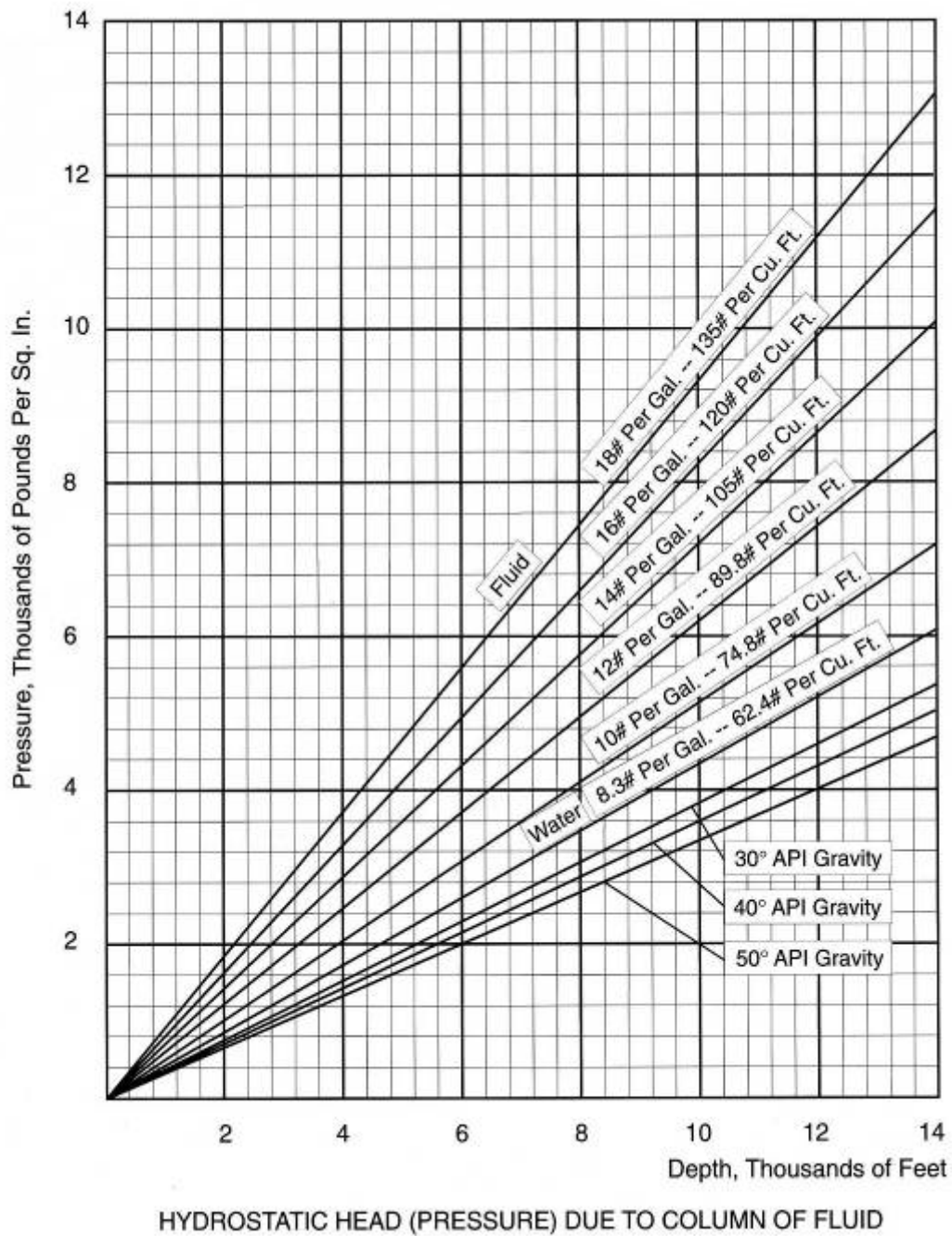
Stretch of suspended casing, tubing or drill pipe

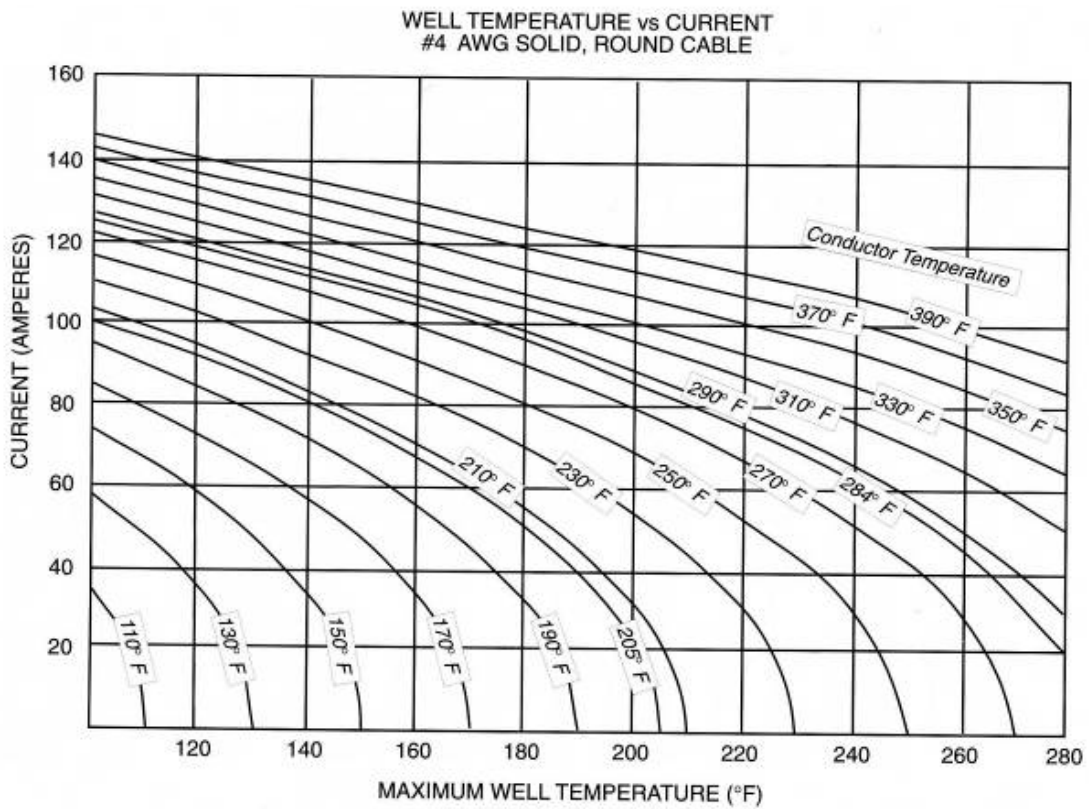
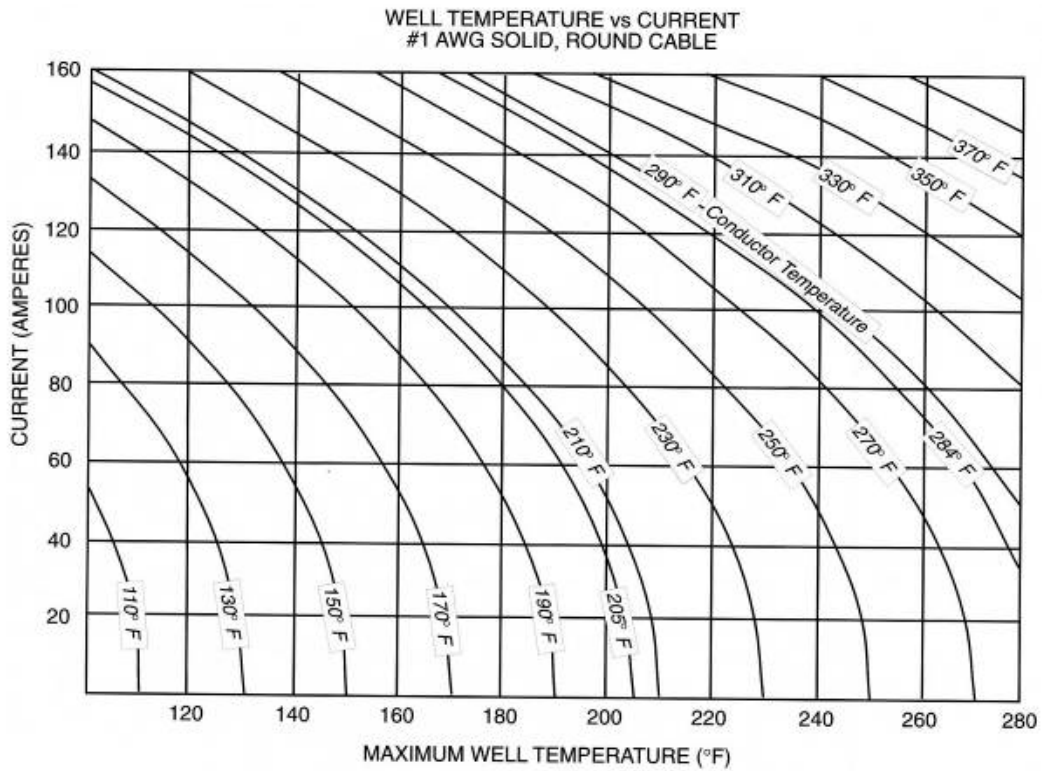
Stretch in air, fresh water, salt water				
Length of Pipe (ft)	Air	8.34	9	9.625
1000	.68	.56	.55	.54
2000	2.72	2.22	2.18	2.14
3000	6.12	5.00	4.91	4.82
4000	10.88	8.88	8.72	8.57
5000	17.00	13.88	13.63	13.40
6000	24.48	19.98	19.62	19.29
7000	33.32	27.20	26.71	26.26
8000	43.51	35.53	34.88	34.30
9000	55.07	44.96	44.15	43.41
10000	67.99	55.51	54.50	53.59
11000	82.27	67.17	65.95	64.85
12000	92.91	79.94	78.49	77.17
13000	114.91	93.82	92.11	90.57
14000	133.26	108.80	106.83	105.04
15000	152.98	124.90	122.63	120.58
16000	174.06	142.11	139.53	137.20
17000	196.50	160.43	157.52	154.88
18000	220.29	179.86	176.59	173.64
19000	245.45	200.40	196.76	193.47
20000	271.97	222.05	218.02	214.27
Pounds Per Cubic Foot		62.4	67.3	72.0
Specific Gravity		1.00	1.08	1.154

TUBING WEIGHT IN FLUID

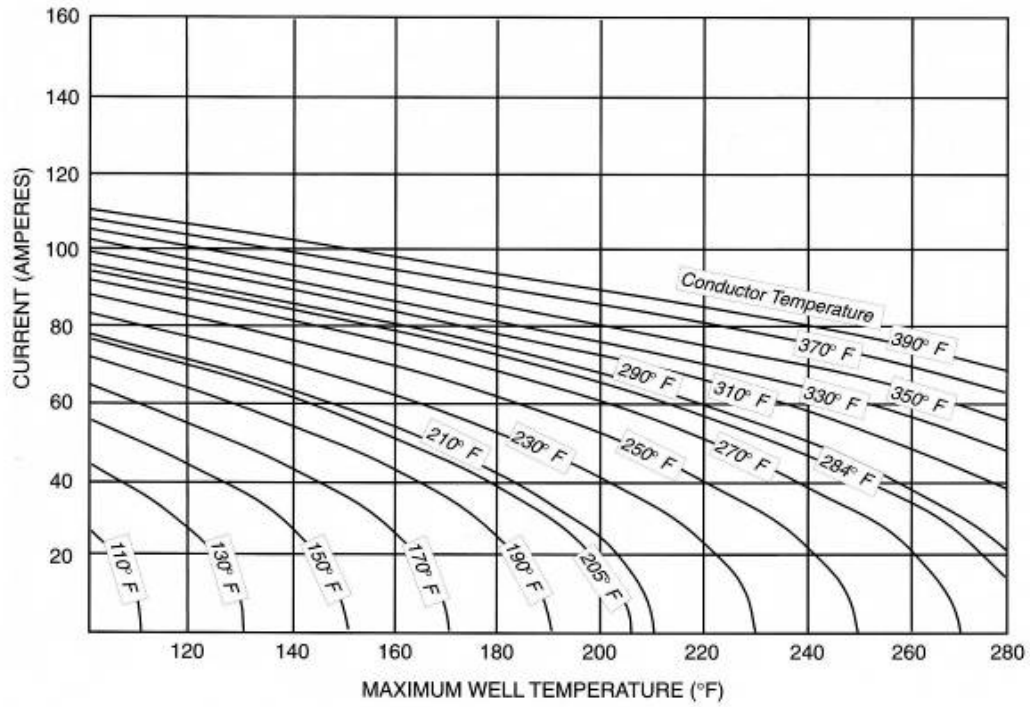


Hydrostatic head

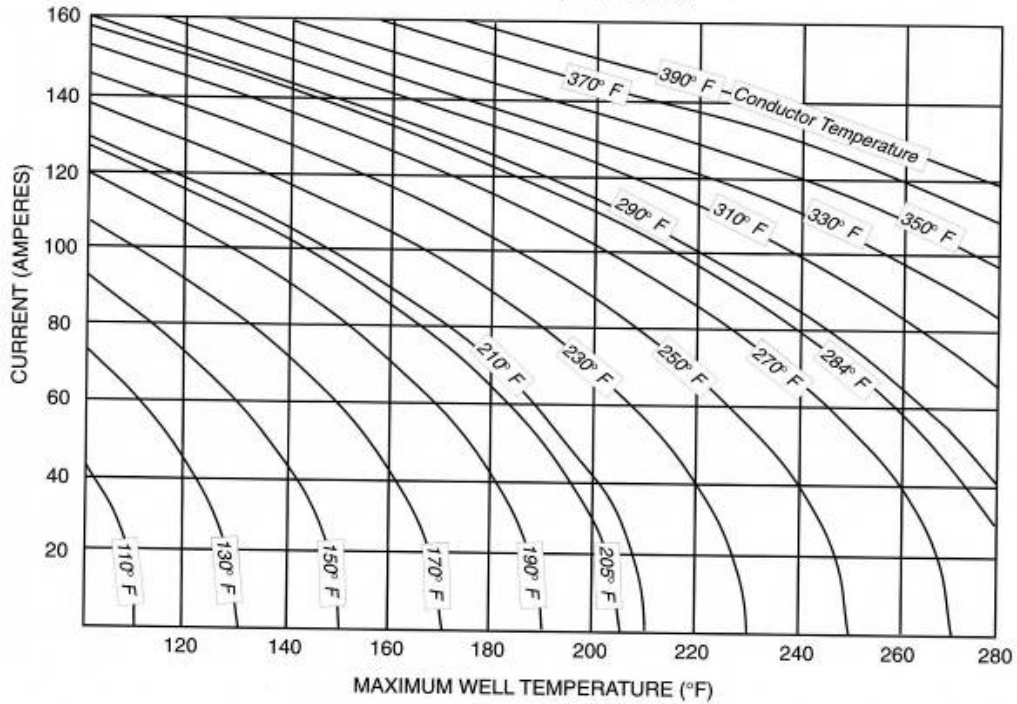


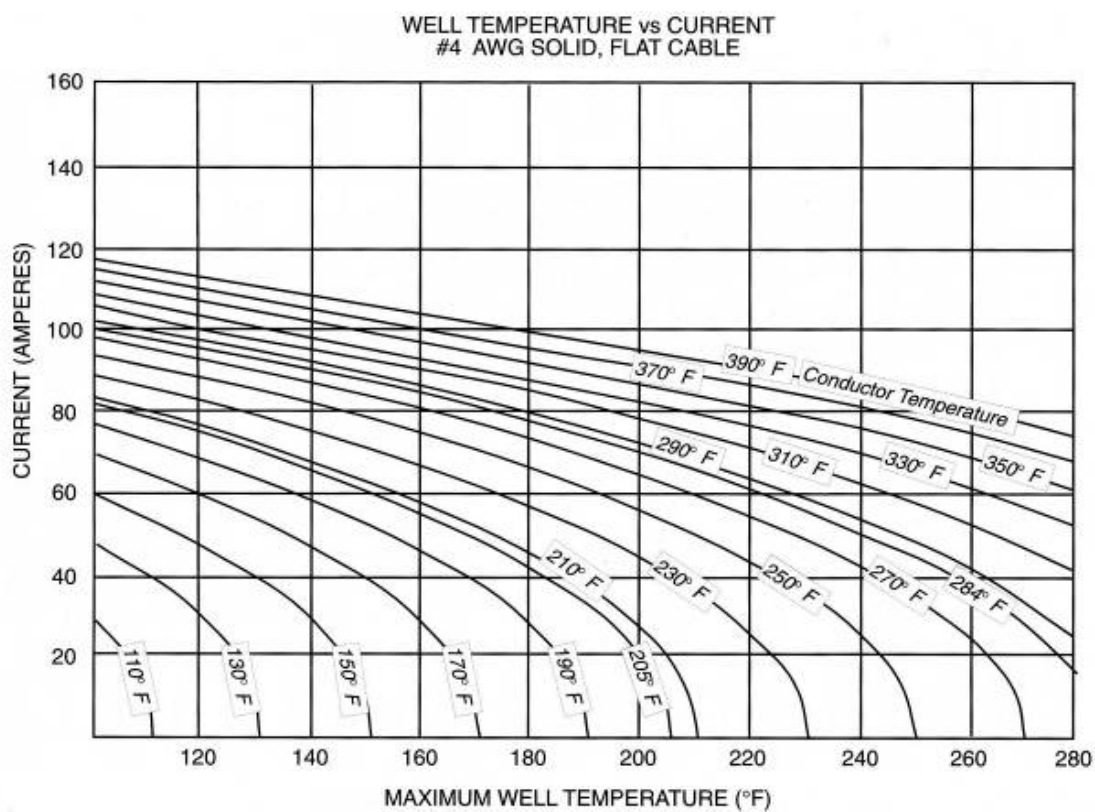
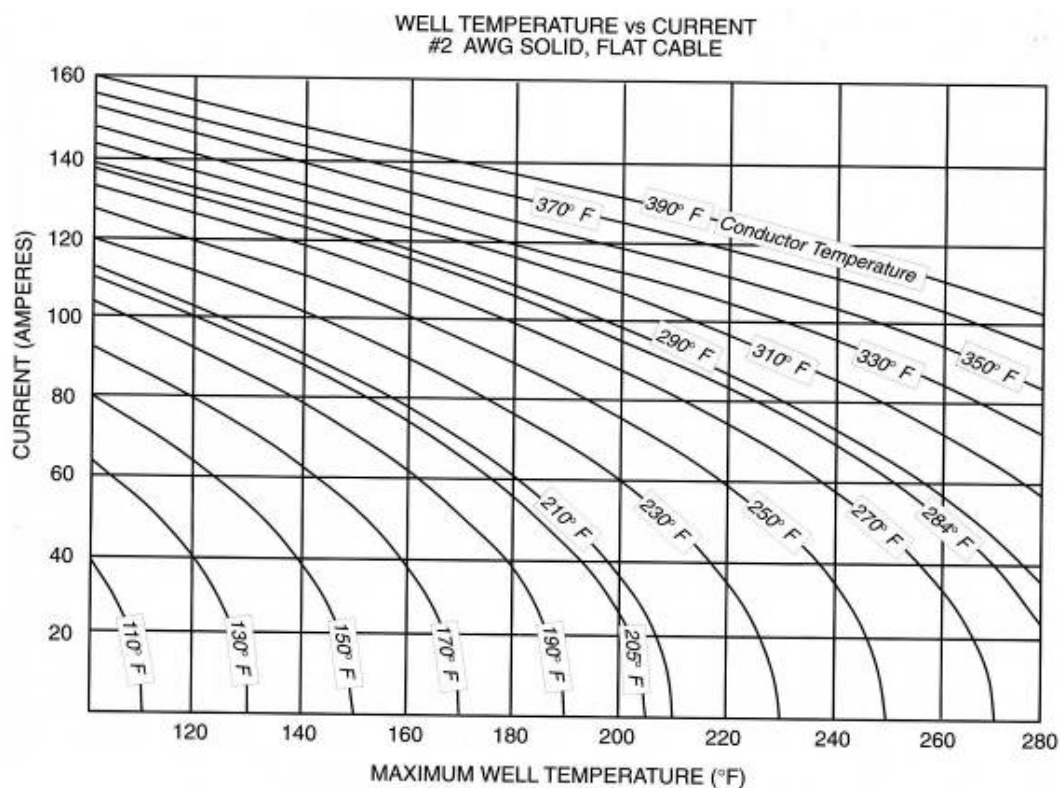


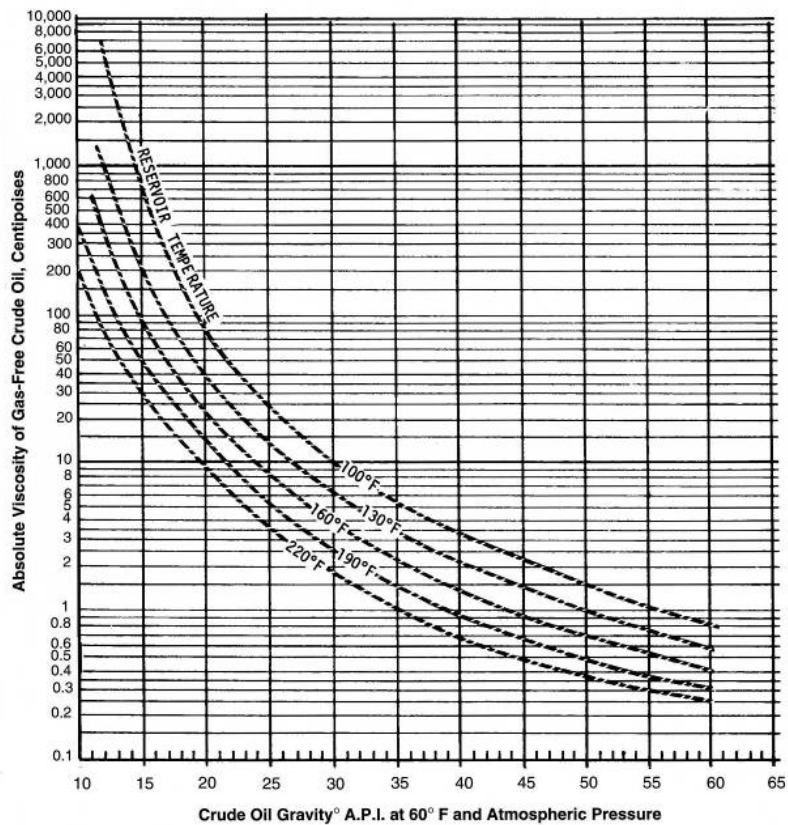
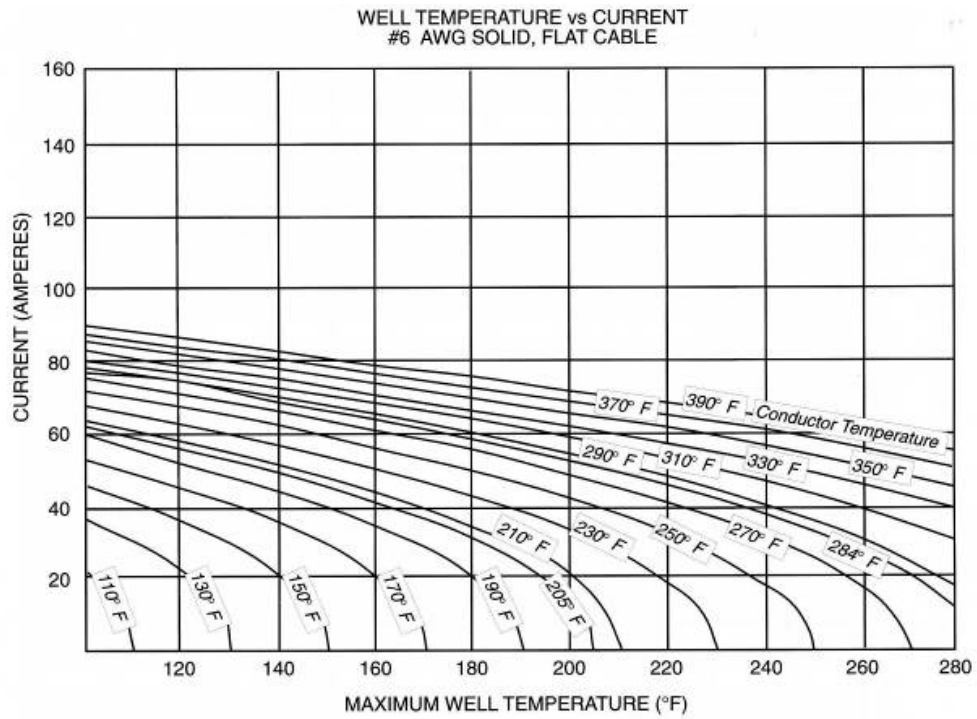
WELL TEMPERATURE vs CURRENT
#6 AWG SOLID, ROUND CABLE



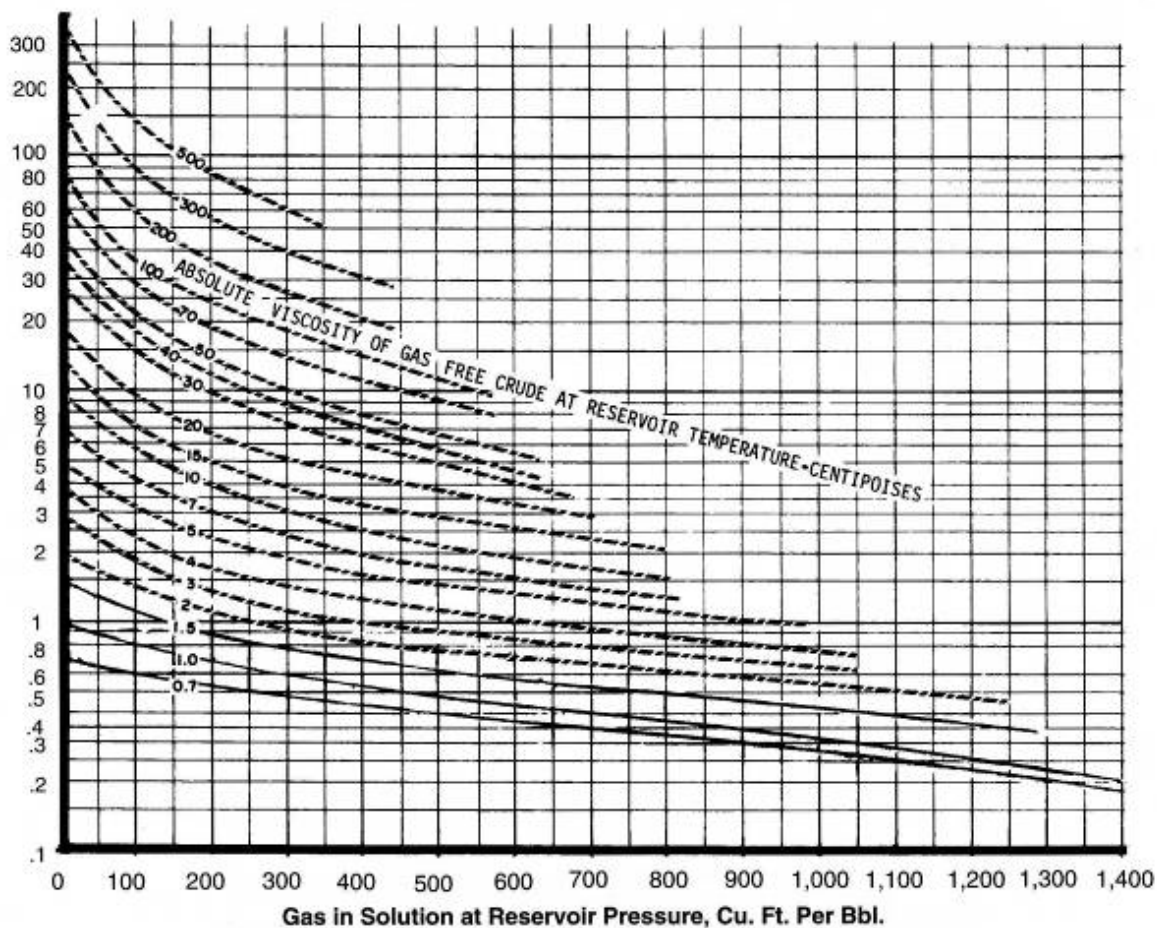
WELL TEMPERATURE vs CURRENT
#1 AWG SOLID, FLAT CABLE



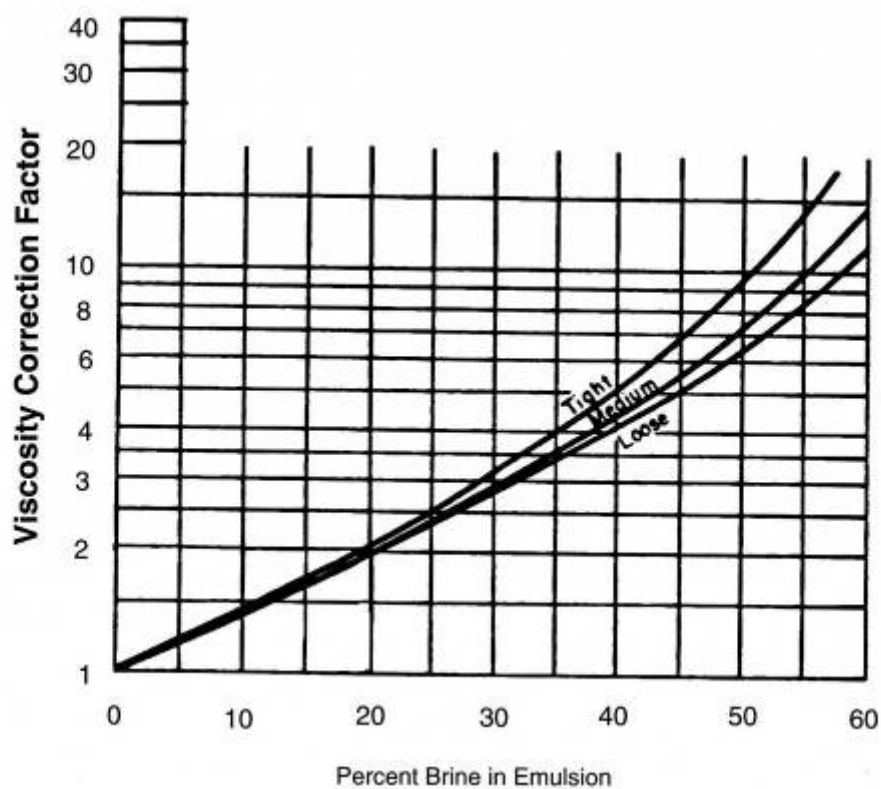
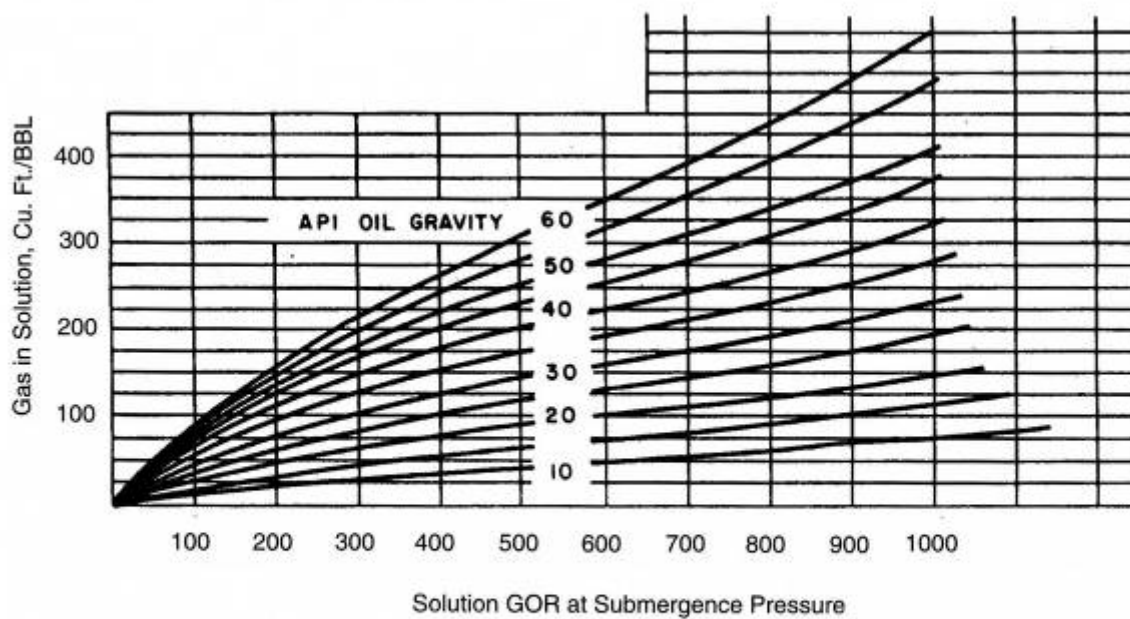


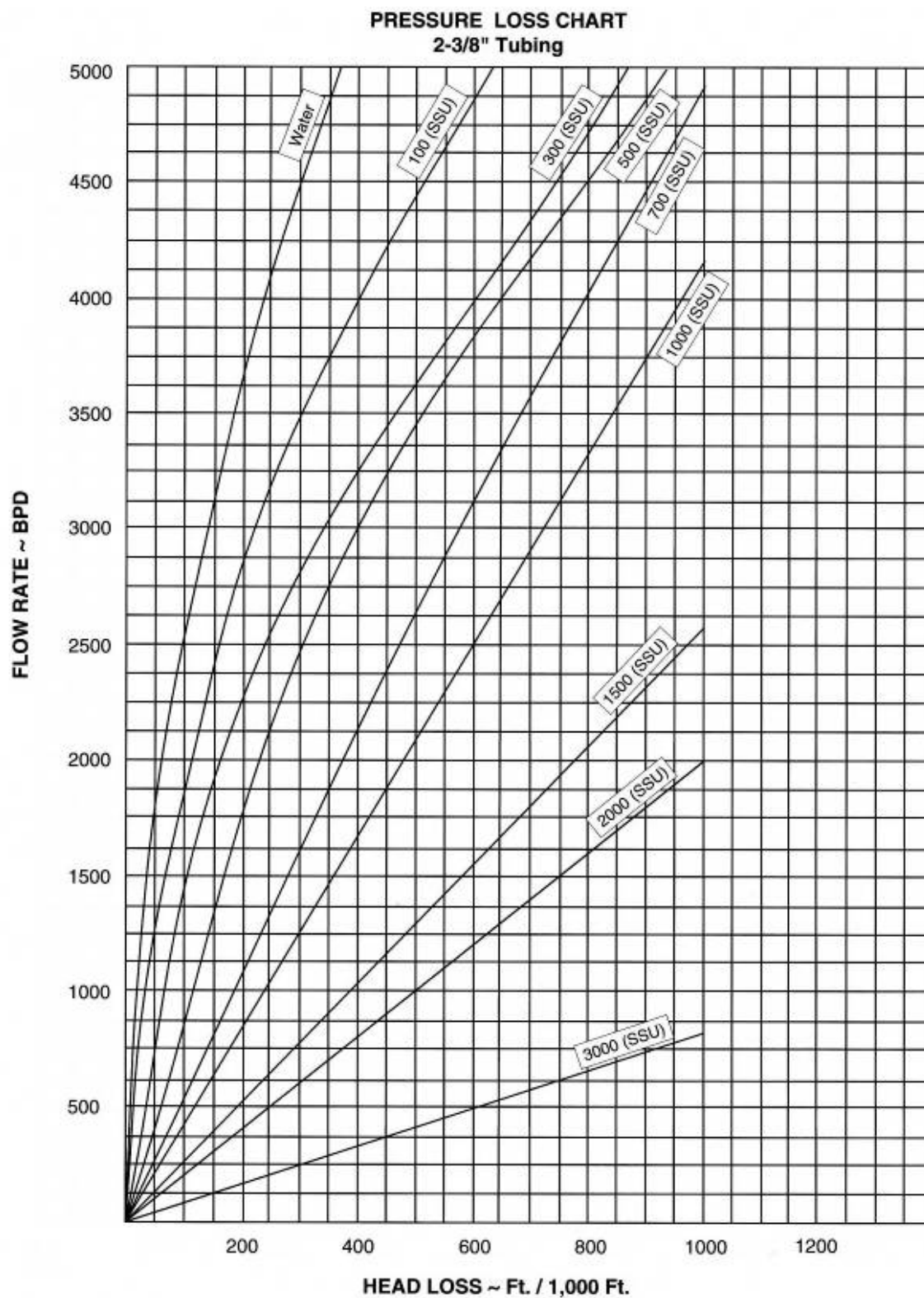


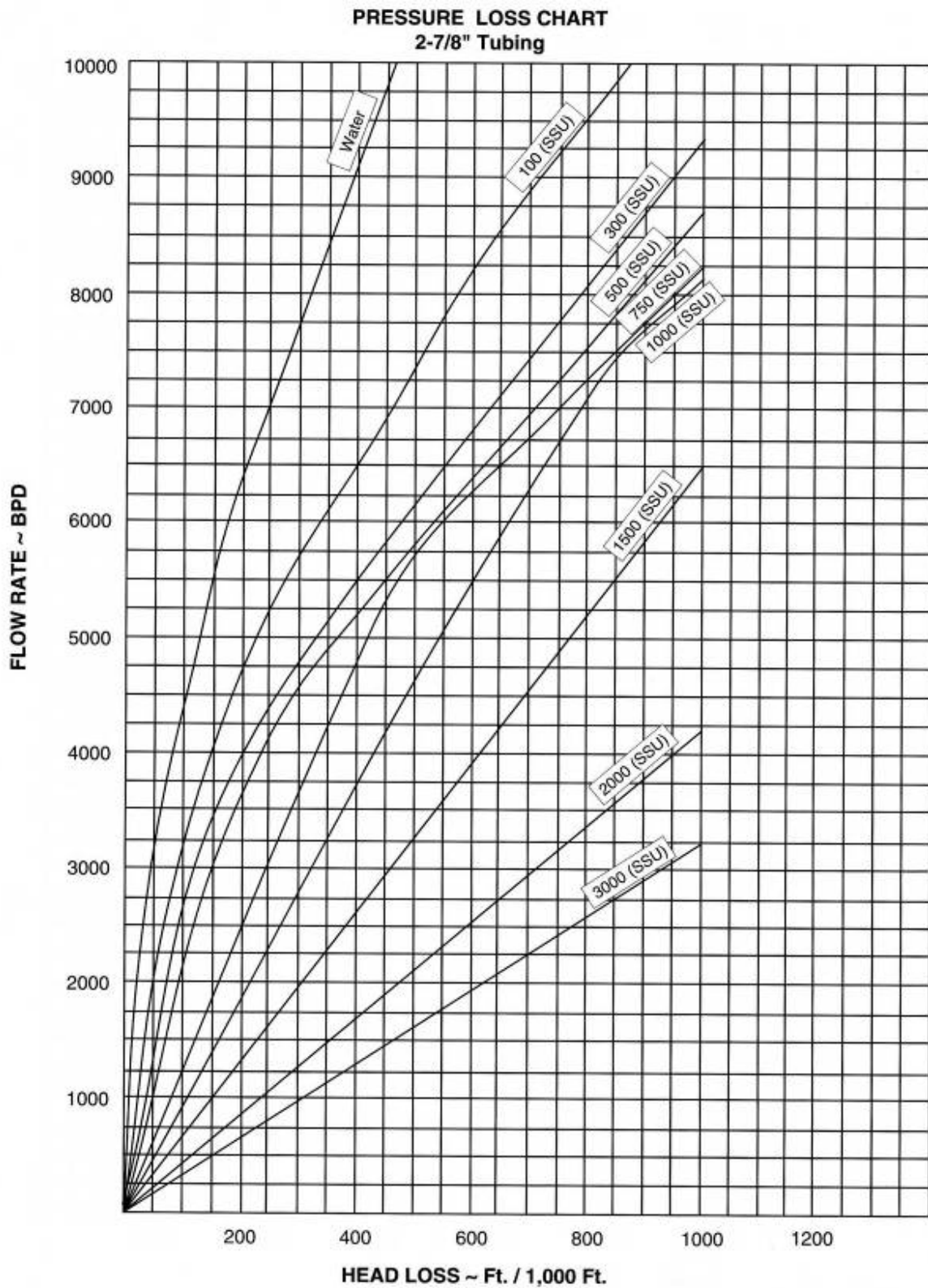
Absolute Viscosity of Gas Saturated (Bubble Point) Crude Oil at Reservoir Temperature and Pressure Centipoises

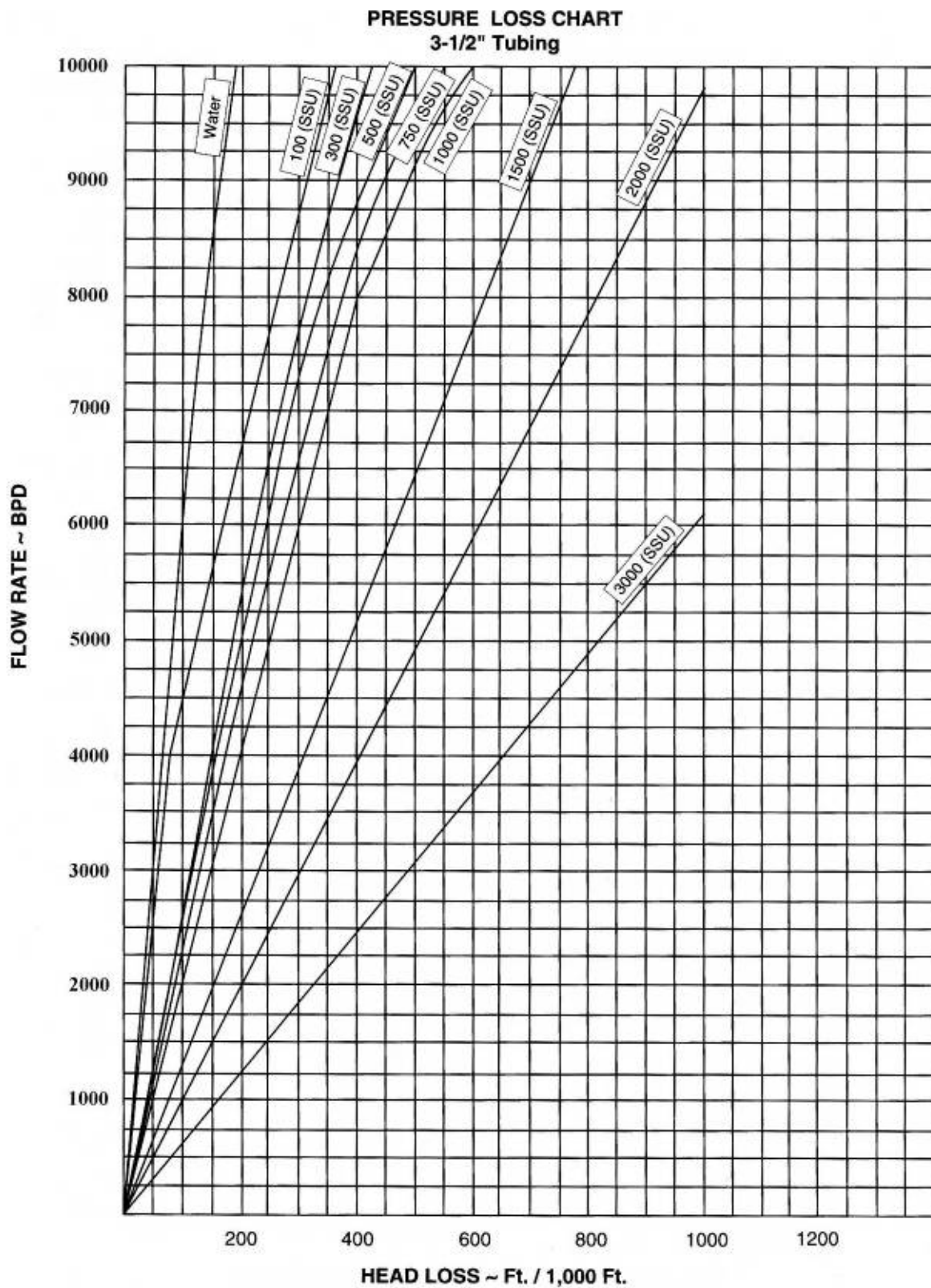


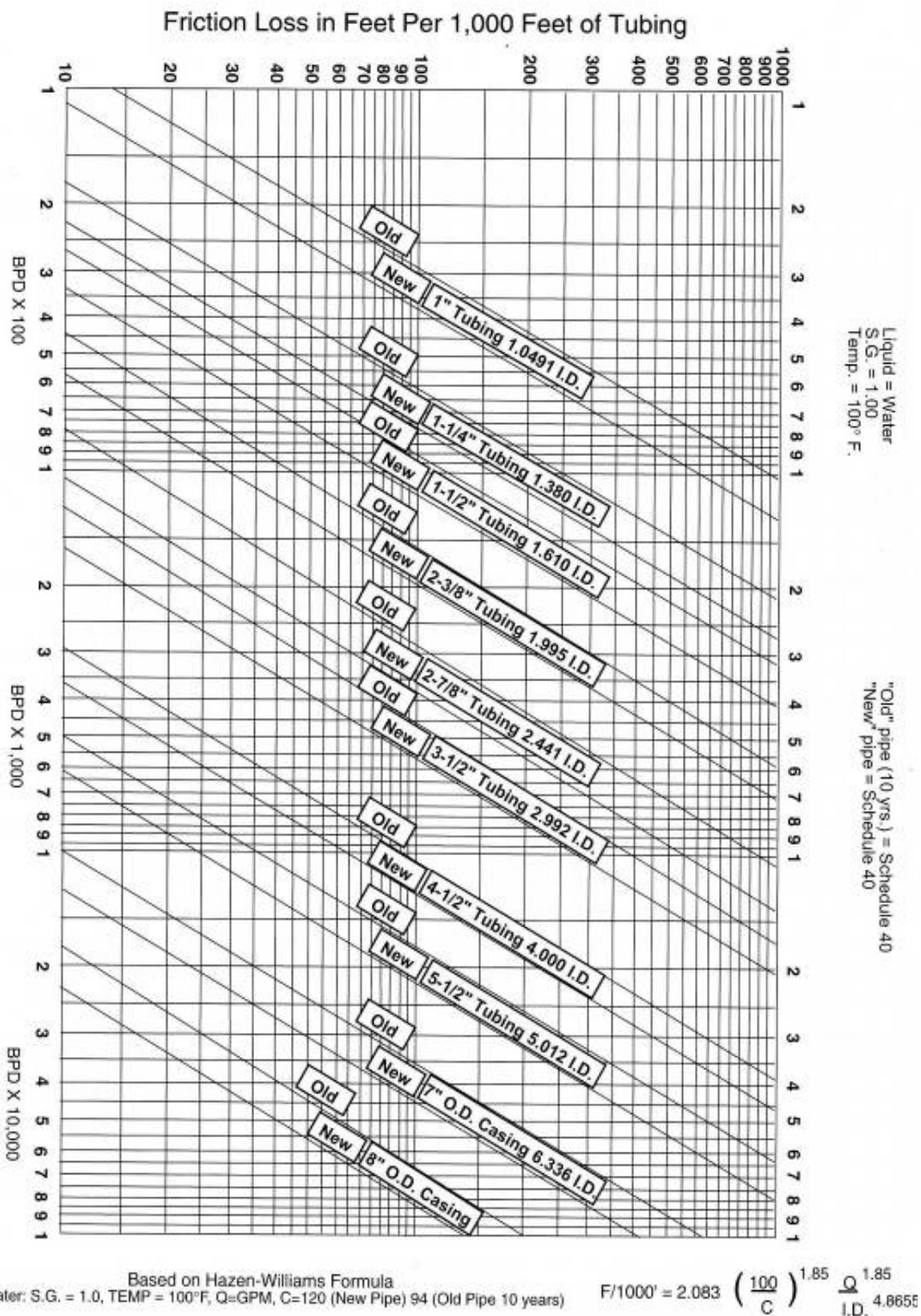
Absolute Viscosity of Gas Saturated Crude Oil at Reservoir Temperature and Pressure











INFLOW PERFORMANCE RELATIONSHIP EQUATIONS

Productivity Index (PI) Method

$$PI = \frac{Q}{\bar{P}_r - P_{wf}}$$

$$P_{wfd} = \bar{P}_r - \left(\frac{Q_d}{PI} \right)$$

$$Q_d = PI (\bar{P}_r - P_{wfd})$$

"Vogel's" (IPR) Method

$$Q_{o \max} = \frac{Q_o}{1 - 0.2 \left(\frac{P_{wf}}{\bar{P}_r} \right) - 0.8 \left(\frac{P_{wf}}{\bar{P}_r} \right)^2}$$

$$Q_d = Q_{o \max} \left\{ 1 - 0.2 \left(\frac{P_{wfd}}{\bar{P}_r} \right) - 0.8 \left(\frac{P_{wfd}}{\bar{P}_r} \right)^2 \right\}$$

$$P_{wfd} = 0.125 \left\{ \bar{P}_r \left[-1 + \sqrt{81 - 80 \left(\frac{Q_d}{Q_{o \max}} \right)} \right] \right\}$$

WHERE:

- Q = Stock Tank Test Rate (PI)
- $\bar{P}_r$ = Static Reservoir Pressure
- P_{wf} = Well Flowing Pressure @ Rate Q
- Q_d = Desired Stock Tank Flow Rate
- P_{wfd} = Well Flowing Pressure @ Q_d
- Q_o = Oil Stock Tank Test Rate (IPR)
- $Q_{o \max}$ = Oil Stock Tank Flow Rate When $P_{wf} = 0$ (IPR)

METRIC UNITS

Solution Gas/Oil Ratio:

$$R_s = 0.1342 Y_g \left(P_b \times \frac{10^{0.0125 \times \text{°API}}}{10^{0.00091 \times (1.8T(^{\circ}\text{C}) + 32)}} \right)^{1.2048}$$

Where: Y_g = Specific Gravity Gas
 P_b = Bubble Point Pressure, kg/cm²
 T = Bottomhole temperature, °C

Formation Volume Factor:

The formation volume factor B_o , represents the increased volume a barrel of oil occupies in the formation compared to a stock barrel.

$$B_o = 0.972 + 0.000147 \times \left\{ 5.61 R_s \left(\frac{Y_g}{Y_o} \right)^{0.5} + 1.25 (1.8t + 32) \right\}^{1.175}$$

Where:
 Y_g = Specific Gravity of Gas
 Y_o = Specific Gravity of Oil
 t = Bottom-hole temperature, °C

Gas Volume Factor:

The gas volume factor B_g , is expressed in reservoir barrels/st'd mcf gas (m³/m³).

$$B_g = 0.00377 \frac{ZT}{P}$$

Where: Z = Gas compressibility factor
 (0.81 to 0.91)
 T = Bottom-hole temperature degrees Kelvin (273 + °C)
 P = Submergence pressure kg/cm²

Notes:

