CEC – EPRI MEMBERSHIP TAILORED COLLABORATION PROJECT:

Optimization of Electric Energy Consumption in Marginal California Oilfields

CONSULTANT REPORT

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
Electric Power Research Institute

January 2003
500-03-062C

Prepared By:
Electric Power Research Institute (EPRI)
3412 Hillview Avenue
Palo Alto, California 94304
Contract No. 100-98-001

Prepared For:
California Energy Commission

Gary Klein
Contract Manager

Terry Surles
Program Manager
Public Interest Energy Research Program

Marwan Masri
Deputy Director
Technology Systems Division

Robert L. Therkelsen
Executive Director

Optimization of Electric Energy Consumption in Marginal California Oilfields

1006210

Final Report, January 2003

Cosponsors:
Public Interest Energy Research Program (PIER)
California Energy Commission
1516 Ninth Street
Sacramento, California 95814

EPRI
3412 Hillview Avenue
Palo Alto, California 94304

EPRI Project Manager
B. Banerjee

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

EPRI PEAC Corporation

WEST COAST PTTC

CALIFORNIA ENERGY COMMISSION LEGAL NOTICE

ORDERING INFORMATION

Requests for copies of this report should be directed to the EPRI Orders and Conferences, 1355 Willow Way, Suite 278, Concord, CA 94520, (800) 313-3774, press 2 or internally x5379, (925) 609-9169, (925) 609-1310 (fax). Copies of this report may also be downloaded from the California Energy Commission's website: http://www.energy.ca.gov/research

CITATIONS

This report was prepared by

EPRI PEAC Corporation
942 Corridor Park Boulevard
Knoxville, Tennessee 37932

Principal Investigator
C. Miller

PTTC West Coast Resource Center
Petroleum Engineering Program
925 Bloom Walk - HED305
University of Southern California
Los Angeles, CA 90089-1211

Principal Investigator
Dr. Iraj Ershaghi

This report was prepared for

EPRI
3412 Hillview Avenue
Palo Alto, California 94304

and

Public Interest Energy Research Program (PIER)
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

This report describes research jointly sponsored by EPRI and the California Energy Commission.

The report is a corporate document that should be cited in the literature in the following manner:

Optimization of Electric Energy Consumption in Marginal California Oilfields, EPRI, Palo Alto, CA, California Energy Commission, Sacramento, CA: 2003. 1006210.

REPORT SUMMARY

This report documents a pilot study of electricity consumption in California oilfields that found significant potential for reducing costs through energy efficiency improvements. It offers suggestions for reducing electricity consumption that, if implemented, could result in a system-wide demand reduction and reduce the need for additional generation and power infrastructure capacity. Moreover, reducing oilfield energy costs would reduce the overall cost of oil production, helping marginal wells remain active longer.

Background

High electricity cost has always been a major expense item in the operation of oilfields. Such high costs are particularly critical to small oil and gas operators. It takes energy to lift oil and water from subterranean reservoirs and bring them to pipeline quality. Additionally, for disposal and pressure maintenance operations, oilfield surface pumps depend on electric power. Opportunities exist for substantially reducing electricity costs by improving the energy usage efficiency of oilfield equipment, including drilling, production, and injection facilities. For small operators, this could mean a difference between premature abandonment and continued recovery. Energy efficiency in oil production supports the need for energy efficiency across all industries brought on by recent power shortages in California.

Objectives

The objective of the project is to develop a methodology for finding where capital improvements or changes in operations will result in improved energy efficiency and reliability while reducing long-term operational costs. The objective of this report is to present the methodology and results of a yearlong study discussing approaches that may be used to reduce energy costs associated with oil production in California oilfields.

Approach

The study collected statistical data on selected oilfields with primary emphasis on the efficiency of their artificial lift operations. Fields selected represent geographical areas from Southern to Central California. A team of troubleshooters was mobilized to visit some of the operators showing interest in study participation. Oilfield surveys were performed from September 2000 through May 2001 resulting in data being collected from 19 fields. From these fields data was obtained on 939 producing wells.

Results

From the database population, 454 wells or 48% should be considered for energy efficiency improvements. Improvement of these wells could result in a potential power consumption reduction of 3.2 GWh/M and a demand reduction of 5.09 MW. Extrapolation of these results to

all wells in California could result in a total benefit that could exceed 139 GWh/M in reduced power consumption and a demand reduction exceeding 221 MW. In light of California's goals to become more energy efficient, savings of this magnitude could curtail the need for addition power plant construction. Similar extrapolation may be applied on a national scale resulting in a national benefit that could exceed 2085 GWh/M in reduced power consumption and a demand reduction exceeding 3300 MW.

EPRI Perspective

This report provides the CEC and California oil producers and energy suppliers with insights on how to reduce electric demand in oil production. If the suggestions are implemented, a reliable system-wide demand reduction may be realized, reducing the need for additional generation and power infrastructure capacity. Oil producers could spend less for energy or achieve a higher production rate per unit of energy consumed, thereby reducing the overall cost of oil production. Reduced production costs will allow marginal wells to remain active longer.

Keywords

Energy Efficiency
Oil Production
Beam Pumps
Rod Pumps
Electric Submersible Pumps
Pump-off Controllers
Progressive Cavity Pumps
Steam Injection
Water Injection
Reservoir
Written Pole Motor
Adjustable Speed Drive
Throttling

EXECUTIVE SUMMARY

High electrical cost has always constituted a major expense item in the operation of oilfields. Such high costs are particularly of a critical nature to small oil and gas operators. There are opportunities that can substantially reduce electric cost and improve energy usage efficiency. For the small operators, this could mean a difference between premature abandonment and continued recovery. Energy reduction in oil production supports the need for energy reduction across all industries brought on by recent electrical energy shortages in California.

There are two areas of concern that need to be addressed to the satisfaction of the operators. First is the development of an accurate energy audit system that can scrutinize energy efficiency according to some acceptable norm and recommendations. Capital investments for upgrades or replacement of electrical consuming devices can be a discouragement to implementation of a major overhaul. The second concern is the side effects of sporadic shut down of electric equipment or downsizing of equipment on the productivity characteristics of oil wells.

A systematic approach to address the above issues must embody three phases. In the first phase, a database needs to be developed to include energy efficiency data for a selected number of operators. Such information can be used to generate a status report with a system labeling a particular operation with an efficiency index. The second phase, a study of productivity of oil wells as a function of interruptible services, re-designed equipment or smaller size artificial lift need to be investigated incorporating geological and reservoir productivity data. The third phase of the study must include recommendations to the operators with suggestions of existing mechanisms to implement energy efficiency management systems with potential cost share from the utilities or US DOE and/or US DOD. This report predominantly addresses the first phase and begins work toward the second phase described above.

Objectives

The objective of this report is to present the methodology and results of a yearlong study discussing approaches that may be used to reduce energy costs associated with oil production in California oilfields. These fields vary in well depth, oil gravity, and reservoir capacity. Careful and deliberate consideration should be given to how to systematically make changes to the production system that will result in savings without driving the producer out of business due to high capital expenses.

Approach

The project team developed a methodology to efficiently survey oilfields to obtain information necessary for determining individual well and overall field performance. Consultants were trained to use the survey methodology. The surveys were performed and a database of the survey data was created. Summary reports from all the oilfield surveys were developed for comparison with individual field and wells. The survey data were analyzed to determine candidate sites for further evaluation. Concurrently, existing technologies were reviewed along with new technologies to improve oilfield electrical efficiency and power quality. This report condenses the results of the surveys, discusses possible solutions to reduce energy costs in California oilfields and suggests the next phase of the project to implement detail trouble shooting and pilot testing of the concepts.

Results

Oilfield surveys were performed from September 2000 through May 2001 resulting in data being collected from 19 fields. From these fields data was obtained on 939 producing wells of which 91% were rod pumped wells. Other lift methods used were electric submersible and hydraulic or progressive cavity pumps. Total gross production from all the fields visited averaged 415,020 BFPD during the study period. This data represents 2.3% of all California onshore producing wells and 0.29% of all onshore fluid production. Fluid lift in oil production accounted for 55.3% of the electrical energy consumed by the fields visited. Therefore, the data analysis focused primarily on power usage for artificial lift.

The term lifting consumption resulting from the data analysis provides operators with the means to compare individual wells in their operations with the norms of the entire population studied. A value of greater than 0.5 kWh/BF/1000' of well depth is considered a threshold for determining wells needing improvement evaluation. Any wells having greater lifting consumption values are considered candidates for further energy reducing actions. From the database population, 454 wells or 48% of the wells are operating above 0.5 kWh/BF/1000'. These wells should be considered for energy efficiency improvements. Improvement of these wells to the threshold level could result in a potential power consumption reduction of 3.2 GWh/M and a demand reduction of 5.09 MW.

Extrapolation of these results to all wells in California could result in a total benefit that could exceed 139 GWh/M in reduced power consumption and a demand reduction exceeding 221 MW. In light of California's goals to become more energy efficient, savings of this magnitude could curtail the need for addition power plant construction. Similar extrapolation may be applied on a national scale resulting in a national benefit that could exceed 2085 GWh/M in reduced power consumption and a demand reduction exceeding 3300 MW.

ABSTRACT

This report documents a pilot study of oilfield consumption of electricity in California. It takes energy to lift oil and water from subterranean reservoirs and bring them to pipeline quality. Additionally, for disposal and pressure maintenance operations, oilfield surface pumps depend on electric power. The study collected statistical data on selected oilfields with primary emphasis on the efficiency of their artificial lift operations. Fields selected represent geographical areas from Southern to Central California. A team of troubleshooters was mobilized to visit some of the operators showing interest in study participation. Data collected includes detail information about 1174 wells from 19 fields.

From the analysis of field consumption data and pumping units, summary statistics were generated and normalized to incorporate variations in well depths and individual well productivity. Applying theoretical energy requirements to lift a barrel of gross fluid and by incorporating various efficiency considerations, more than 400 wells out of a population of 938 wells were found to be candidates for potential power consumption reduction. The demand reduction resulting from corrective actions on this sample of California producing wells is estimated to be about 5 MW and by extrapolation to the entire number of existing producing wells in California, the impact exceeds 230 MW. Subsequent phases to the study have been proposed for further research into corrective measures to identify causes of inefficiency and to take corrective measures to demonstrate cost savings from solution implementation.

ACKNOWLEDGEMENTS

The participation of oilfield operators to provide raw data made this study possible.

The efforts of Dr. Hossein Rassamdana and Che-Yuan Sun from PTTC and the assistance of PTTC troubleshooters Dr. Stan Sawabini, Jeevan Anand, Richard Finken, Herm Schaller and John Yu in bringing this phase of the study to a successful completion is acknowledged. Initial volunteer assistance from Bob Fickes and Casper Zublin from COPE is also appreciated.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1
INTRODUCTION

High electrical cost has always constituted a major expense item in the operation of oilfields. Such high costs are particularly of a critical nature to small oil and gas operators. There are opportunities that can substantially reduce electric cost and improve energy usage efficiency. For the small operators, this could mean a difference between pre-mature abandonment and continued recovery. Energy reduction in oil production supports the need for energy reduction across all industries brought on by recent electrical energy shortages in California.

There has been a need for the development of an accurate energy audit system that can scrutinize energy efficiency according to an acceptable norm. The audit system should lead investigators to oilfield systems and wells that have the greatest potential for energy cost savings resulting from system or equipment improvements. Once targeted these systems may be investigated further to establish design changes or improvement recommendations. Once recommendations are defined capital investments for upgrades or replacement of electrical consuming devices can be more easily justified from an economic perspective.

A systematic approach to address the above issues must embody three phases. The first phase involves developing a database that includes energy efficiency data for a selected number of operators. From this database reports may be generated on each field and well labeling a particular operation with an efficiency index. This index may be compared with other wells or fields to prioritize an area requiring additional studies. The next phase of a process to improve oilfield operations and reduce electrical power consumption is to use the results of phase 1 to focus attention on oilfields and wells to perform detailed studies. These studies should consider reservoir status, interruptible services and production goals to determine equipment re-design, retrofits, or capacity changes. These studies should result in recommendation for capital or operational changes to operators. The third phase of the study must include recommendations to the operators with suggestions of existing mechanisms to implement energy efficiency management systems with potential cost share from the utilities or other public funds such as the CPUC, US DOE and/or US DOD. This report predominantly addresses the first phase and begins work toward the second phase described above.

This report presents the methodology and results of a yearlong study examining approaches that may be used to reduce energy costs associated with oil production in California oilfields. These fields vary in well depth, oil quality, and reservoir capacity. Careful and deliberate consideration should be given to how to systematically make changes to the production system that will result in savings without driving the producer out of business due to high capital expenses. This report addresses these issues.

2
STUDY METHODOLOGY

The methodology for this study was carefully planned in advance to assure a cost-effective process and to maintain close correspondence with the project goals. This section discusses each step of the study plan and summarizes the results of these steps.

Announcement

This study required the support of the general oil producer community in California to be a success. Therefore, at the very beginning of the project, a joint project announcement from the West Coast Petroleum Technology Transfer Counsel (PTTC) and EPRI was prepared to present the project approach and goals. The PTTC led the development of the announcement that was posted on the PTTC web site. The announcement is included in Appendix A.

Assessment of Current Oilfield Operations

With the goal to identify areas of research and development to the benefit of small oilfield operations, staff members of the PTTC and EPRI visited several oilfields run by independent oilfield operators in California. These tours provided PTTC and EPRI staff with an opportunity to assess current operations to determine issues relating to energy management, power quality and efficiency. The results of these tours are discussed as follows.

August 7, 2000 PTTC Meeting at USC

On August 7th EPRI investigators participated in a meeting with PTTC staff and parties interested in project participation. This meeting provided an overview of the project and the agenda for the oilfield visits taking place over the next two days. For the benefit of all in attendance, the purpose of the project was explained with the ultimate goal of the week's activities to develop a template of questions to assist oilfield troubleshooters in surveying the oilfields to determine the usage of electric energy.

As was explained, the CEC (California Energy Commission) is sponsoring a TC (Tailored Collaboration) project with EPRI to identify methods of reducing electric energy consumption in small independent oilfields. EPRI hired EPRI-PEAC to manage the project and provide ideas for reducing energy using technologies, and strategies, which have been successful in other industries. It was suggested that the advent of utility deregulation occurring with electric utility generation capacity being less than demand influences utilities to be more interested in reducing energy consumption on the demand side.

The primary utilities supplying power to the oil producers in this study are Los Angeles Department of Water and Power (LADWP), Southern California Edison (SCE), and Pacific Gas and Electric (PG&E). Electric energy accounts for approximately 40-60% of costs for the oil production industry, therefore; energy efficiency improvements can have a large effect on operating costs. Consequently, there is significant interest within the industry to investing in energy efficiency improvements, with an appropriate payback timeframe.

As explained in the meeting, the goal of this project is to document predominant uses of electric energy in California oilfields to suggest energy use improvements. To meet this goal, a survey template is being developed for use by oilfield troubleshooters who will be retained, to gather energy use information from oil producers. Survey data will be interpreted to suggest energy savings strategies and screening methodologies. A final report will be prepared summarizing the results of the survey along with suggestions for pilot projects and energy saving opportunities, which demand further study. Once the final report has been issued, workshops will be held to disseminate the results of this study.

The field study should include two facets of oilfield production. These facets involve field equipment and reservoir issues. The field equipment issues look at improvements to handling the oil as it is brought to the surface, dehydrated, and shipped to the market. The reservoir issues involve the geological status of the underground oil reserves where the oil is being produced. The reservoir issues should be considered for what future enhanced oil production methods might affect well productivity and the lifting capacity.

A well pump vendor provided a presentation explaining the issues and operation of Electric Submersible Pumps (ESPs) in oil production. ESP hardware and design issues were explained, as were the fluid issues unique to oil pumping, including water oil ratios, sediment and other solids in the fluid that can cause clogging in the pump and tubing. Additionally, the application of Adjustable Speed Drives (ASDs) to ESPs was discussed. ASDs provide additional control and increased efficiency to the fluid lifting process. Utilization of ASDs with ESPs allows fluids to be moved at a minimal rate taking advantage of peak power rate restrictions while preventing possible build up of sludge and sediment in the pump and lift tubing. This build up can seize the pump resulting in pump or motor failure on startup. During off-peak times the VFD can control the lift of fluid at an automated rate for most efficient energy consumption or to support other system considerations such as the rate of water or steam injection.

Many of the submersible pumping ideas presented may be applied to fluid lift utilizing rod pumping. A general discussion ensued regarding rod-pumping utilizing beam-pumps. Reference material from a rod-pumping vendor was provided, in order to help EPRI PEAC representatives understand the special issues involved with rod pumping. The slow rise and fast fall of the Mark II pump appears to provide the most efficient rod-pump design. The meeting was concluded after a brief overview of the oilfields to be visited over the next two days.

August 8, 2000 Oilfield Tours

THUMS Long Beach

The Long Beach Department of Oil Properties provided a tour of the THUMS (formerly Texaco, Humble, Union, Mobil, and Shell and currently owned by OXY) site. The THUMS operation draws oil from the Eastern half of the Wilmington oilfield, and is operated by the City of Long Beach. THUMS operation consists of five sites, of which four are man-made offshore islands and visible from Long Beach. These four island names are Grissom, White, Chaffee, and Freeman. The fifth site is at Long Beach Pier J. Staff from PTTC and EPRI PEAC toured Island White.

THUMS is a high volume facility that produces approximately 16 million barrels of oil per year (~43,800 BPD). To achieve this production level, THUMS consumes over 400 million kWh of electrical energy per year with an approximate demand of 50 MW. Southern California Edison (SCE) supplies the energy from a substation in Long Beach located at Pier 5. Of the 984 active wells at THUMS, 625 are oil-producing wells, with the remaining 359 wells are used for water injection. The average well depth is 5000 feet, and wells are typically highly deviated from the drilling islands. Production wells utilize ESPs powered by 75-100 HP motors. The man made islands and dense exclusive use of ESP's for oil production is unique from all the other sites visited.

In order to prevent the shoreline from subsidence (sinking), THUMS is required to inject a volume of water equal to 105% of total fluid removed. The water used for injection is made up of water separated from the extracted oil and filtered water from the city's wastewater treatment facility. There are about two production wells for each injection well. The water is injected under high pressure, with two systems; one operated at 1,500 psi, the other operated at 2,500 psi, providing the water to the injection wells. Five 1750 HP, 4160V, 3580 RPM motors driving split case centrifugal pumps power high-pressure water systems at Island White. Injection pressure is valve controlled at each well.

THUMS produces and sells approximately 3.5 billion cubic feet of natural gas per year. Depending on the market price for natural gas and electric demand reduction incentives, THUMS should consider the possibility of utilizing this natural gas to generate their own electricity. A 5MW generating turbine could be installed at pier 5 to reduce overall power consumption and demand.

The THUMS production process involves lifting fluid, a mixture of approximately 10-20% oil and 80-90% water, from production wells. The fluid is then processed to separate the water from the oil and natural gas. The water is re-injected back into the formation and the crude oil and natural gas are piped ashore for refinement and shipment, respectfully. When visitors asked THUMS personnel what percentage of energy usage goes to the various processes the "best guess" response was as listed in Table 2-1.

Table 2-1
Approximate energy use by process at THUMS

Production Wells	40%
Injection Wells	42%
Drilling Rig	5%
Dehydration	10%
Other	3%

Tideland Oil Production Co

Adjacent to THUMS, Tideland Oil Production Co. (TOPCo) produces from the western half of the Wilmington Oil field. The tour of TOPCo's facilities provided the greatest variety of production technologies for production, injection and surface handling.

The lift technologies used in production at TOPCo included 46.4% ESPs, 36.4% Hydraulic Submersible Pumps (HSPs) and 17.2 % rod pumps. Submersible pump technologies are utilized because of their ability to be installed in deviated wells. At TOPCo many deviated production wells must be drilled to recover the oil because of the constrained nature of the drilling facilities in the City of Long Beach. HSPs are used in steam flood areas, because the down-hole temperatures are too great for reliable electric motor operation. The HSP also has a low surface profile and assists fluid lifting simply by reversing the flow of working fluid. Hydraulic pumps are, however, subject to the inefficiency losses typically associated with hydraulic systems. Twelve hydraulic pumps on the surface are used to maintain 2 systems of different pressures to drive the down-hole pumps. The hydraulic system utilizes ASDs on two pumps (one in each system) that are used for flow control.

The TOPCo facility uses both high-pressure water flood and steam flood to replace produced fluids and to improve oil production. Water flood is a high-pressure system consisting of 6 water pumps making up 1250-2000HP of which only 3 are in operation. Two of the units in operation use natural gas fired piston engines to operate reciprocating pumps. Engine maintenance is labor intensive, expensive, and offsets the energy savings realized by using produced gas. There are plans to replace the natural gas fired engines with electric motors as the piston engines are retired.

TOPCo produces it's own injection steam using a recovered natural gas fired boiler. The unique part of the boiler system is the utilization of a submersible pump with a design B, 250 HP motor as the boiler feed pump. The submersible pump is used on the surface, and mounted horizontally. This system is advantageous to TOPCo because it is readily available in the local supply system, and is covered in their exclusive provider contract with a local pump vendor.

The remaining surface handling of the fluid from the wells involve the production of oil, which utilizes a variety of electric motors in skimmers, pumps, fin-fan coolers and other process equipment. There appears to be opportunities for efficiency improvement through the use of ASDs, and the adoption of other energy saving strategies associated with the surface equipment.

August 9, 2000 Oilfield Tours

On August 9, 2000, four oil field operations in the Bakersfield area were toured. Bakersfield area production facilities are more spread out than those in the Wilmington field, not being constrained by any major city. As a result, well deviation is not as common allowing the primary use of rod pumps. The fields are referred here as 1 through 4.

Field 1

For production, Field 1 uses a variety of ESP's and rod-pumps. The facility utilizes 3-4 MW of electrical energy plus steam from cogeneration. Field 1 uses steam flood to increase the productivity of the reservoir, and injects produced water back into the subterranean formation.

The steam flood utilizes an 80/20% steam/water mixture to aid in the extraction of the heavy oil in the reservoir. Five natural gas fired boilers are used to produce the injection steam. The blowers for these boilers are to be retrofitted with ASDs and high efficiency motors to better match airflow to combustion needs.

Water injection is used to dispose of produced water. The water injection pump uses a 450 HP, 2300 V, NEMA C motor. The system moves water from a holding tank to the injection well under approximately 100psi. Flow is controlled through two butterfly valves, one automatic and one manual, and a re-circulating system. On the day of the tour, air noise could be heard near the functioning pump, the manual butterfly valve was set in a very restrictive position, and significant re-circulation was occurring. This process may be made more efficient utilizing properly sized high efficiency motors and ASDs. The soft starting capability of the ASD should also improve power quality. Currently the starting of the existing 450 HP motor, sags the system voltage, affecting other processes in the field.

Field 2

Field 2 is a 4 by 12 mile area served with primary metered 12 kV power from PG&E. There are two cogeneration plants operated by an energy supplier that purchases gas and water from the fields' oil producer, and then provides steam and power to support field operations. The energy supplier also operates a third cogeneration plant that provides only steam to the field. In the field there are about 400 active production wells utilizing beam pumps, with an average of 30 HP per well.

Produced water from the dehydration activities is stored in a tank and three 100 HP pumps are used to pressurize the water for transport and injection. Fifty percent of the produced water is transported three to four miles in a 10-inch pipe and injected into two wells, while the remaining water is allowed to flow into surface drainage. The system design is such that the primary control variable is a tank level, which is maintained by re-circulating water from the active pumps. System pressure is controlled by a valve located almost a mile from the pumps. These pumps have experienced premature wear from being operated significantly below pressure capacity (100psi controlled pressure for a 300psi capable pump). A retrofit is planned which will reduce the pressure capabilities of the pumps, and move the control valve closer to the pump and tanks. This should reduce energy consumption somewhat, and dramatically extend the life of the pumps. Additional savings opportunities may exist through the use of ASDs.

Field 3

A brief stop was made at Field 3 to observe the application of a 100HP PumpTrac ASD applied to a 75 HP Rotoflex rod pump. The unconventional Rotoflex rod pump stands very high and uses a vertical belt with the rod connected to one end and a counterweight connected to the other. This type of machine is used when a very long lift stroke is needed.

The ASD controls the speed of the pump, slowing the motor on the upstroke in order to lift the oil very slowly, and driving the motor on the down stroke. The primary control variable in this system is consumed power. The ASD uses internal and external sensors to ensure that power consumption is maintained at the same level throughout operation, resulting in a slower upstroke, and a faster down stroke. Claims indicate that this system reduces energy usage by over 30%. However, it was noted that the pump was balanced at the same time. This application looks like a promising method of saving energy, and has been demonstrated on beam pumps as well. Additional opportunities exist to use advanced energy storage technologies in a similar system to allow the motor to overhaul, and store that energy for use on the lift stroke. Additional testing should be performed to prove the claims and the reliability of the technology.

Field 4

Field 4 was the last site visited, and was a typical example of a very small independent oil producer. The site consists of 3 wells served by one 480 V revenue meter. The fluid from these wells is pumped to holding tanks where the water and oil are separated by gravity, and natural gas is scrubbed. The amount of natural gas obtained from the field is too little to be of practical use and is burned by a unique flair system. Produced water is injected back into the reservoir. The remaining oil in the tank is then periodically emptied into a tanker truck for transport to a local collection point.

Research and Development Issues

Energy Efficiency

While electric energy is a major cost contributor in the production of oil, energy efficiency is of secondary concern to robust, reliable equipment and consistent operation. However, with the advent of deregulation and the threat of rising prices throughout California, energy is of growing concern to oil producers. It is also the case that most oilfields operate on an interruptible rate, which has not been a concern until recently. During the visit, several producers indicated that their power had been interrupted within the previous weeks, often resulting in large operational losses. The energy question therefore is two-part. Producers seek to reduce energy costs while, being struck with the realization of their dependence on an interruptible commodity. Consequently, producers seek to increase the reliability of their energy supply.

In reducing energy consumption and costs, primary expenses for larger independents are artificial lift, high-pressure steam and water for flood operations, transport of water to and from wells, transport and re-injection of produced water. Often these systems are controlled very inefficiently, but with an eye to consistent operation, resulting in the use of many re-circulating systems, and significant throttling losses. In many of these applications, the use of ASDs, on/off controllers with soft starters, and other energy efficiency strategies could go a long way to controlling energy costs. The bulk of production energy in smaller fields and a large fraction of energy in larger ones involves artificial lift in secondary and tertiary production (where most California fields are operating). Technologies based on ASDs, have been developed to reduce power by reducing speed on the upstroke, and increasing it on the down stroke. With the increasing reliability and decreasing cost of ASD equipment, this becomes a real option for oil producers of all sizes. Proper maintenance of the ubiquitous beam pump, including balancing, lubrication, and proper adjustment of the stuffing box, can also go a long way to reducing pumping costs. Application of ASDs fitted with super-capacitors may allow the energy associated with the rod down stroke to be recovered, thereby increasing the electrical efficiency of rod-pumping process. ASDs may also allow the use of high efficiency NEMA design B motors where design D motors are presently being utilized.

Written-pole motors are available that operate at least as efficient as design B and more efficiently then the design D motors commonly used with rod-pumps. Since Written-pole motors have low starting currents, (approximately 2 times full load current), they should match or exceed the starting requirements allowed by the design D motor. Written-pole motors also run at unity power factor providing an additional benefit over traditional motors.

The Pump-off controller and timers that are used in some oil fields also provide opportunities for energy efficiency. By utilizing the energy to pump only when the pump is sufficiently covered in oil, pump-off controllers and timers allow oil producers to utilize electrical energy as efficiently as possible, for relatively low cost.

In the realm of increasing reliability, many oil fields produce a significant amount of natural gas as a byproduct of oil production. In some cases the gas is sold, some cases it is burned on site in boilers and engines, and in others the gas is burned simply to dispose of it. If efforts to reduce oilfield demand from the electric supply become important, the byproduct natural gas may be used as a fuel for cogeneration, microturbines, or fuel cells to make electrical energy, which can then be used to support production.

The survey data should help determine where these technologies may be applicable. Each of these technologies has it's own special considerations and costs, which must be thoroughly reviewed for each site to determine the best application for the most economical payback. The producer's primary goal is to produce as much oil as cheaply as possible. Therefore, energy efficiency improvements must be quantified on a per barrel basis.

Reservoir Issues

There may also be issues involving the reservoir itself, which can reduce or increase the electrical efficiency of an oil field. If the field is producing more oil per barrel of total fluid, electrical costs per barrel of produced oil are reduced, resulting in more efficient use of energy dollars. PTTC and its troubleshooters will be of great assistance in determining what methods, if any, could help small producers to operate more efficiently, while minimizing cash expenditures.

Power Infrastructure and Power Quality

While touring the oilfields it was noted that the majority of motors supporting beam pumps are operated from a 480 Volt three phase system. Typically, the 480-volt secondary system is owned and maintained by the oilfield operator. The secondary system is served by a utility revenue meter, which receives power from the secondary side of transformers used to convert high voltage to the 480 volt operating level of the field. In other larger fields the revenue meter, meters the primary high voltage system. The high voltage is then routed through-out the field where transformers are used to reduce the voltage to the 480 volt secondary level required by the motors for rod pumping operation. This infrastructure used to distribute the power from the utility to the end-use points (motor terminals) is often overlooked or assumed to perform satisfactory as long as the end-use has power to run the equipment.

One oil producer has discovered motor life can be significantly extended if the power infrastructure is reviewed for performance upgrades. ~~The~~ Producers realize that the same power service provider that supplies our oilfields also serves our homes. Our homes don't typically have problems with equipment and motor failures as experienced in oilfields. So what is different in our homes than in the oilfield? First of all the power system in our homes and providing power to our residential communities is well grounded. In most oilfields the system operates from a 3 wire three-phase system that may or may not be grounded. Next the type of loads in our homes is different from the oilfields. In our homes there is a diversity of resistive, inductive and electronic loads. In the oilfields the loads are primarily inductive (motor) loads. These differences should be examined to determine causes of motor failures and what can be done to reduce these failures.

Distribution System Grounding

As previously stated in our homes the electrical system is grounded at the transformer and then again at the service entrance as required by the national electric code (NEC). Although line-to-line (L-L) voltage is 240 volts the line-to-neutral (L-N) and line-to-ground (L-G) voltage is around 120 volts. In the oilfield the motors typically require 480 L-L voltage. The motor will operate this way as long as the L-G voltage is kept low enough to prevent insulation failure of a motor winding to ground. For a 480-volt motor this typically occurs around 1500 volts. Under normal operating conditions 1500-volt values are rare. However, in the event of a fault on the utility's high voltage power system or a lighting strike, L-G voltages of an ungrounded 480 volt system can far exceed 1500 volts that may over time lead to premature motor failure or shortened motor life.

Often 480-volt systems are operated ungrounded so a motor may continue to operate should a single-phase fault occur. By deliberately grounding one phase of a 480 volt system we not only make the system safer to personnel we also limit the amount of voltage that might be experienced between one phase and ground. There are three common types of grounded 480 volt systems, corner grounded Delta, split-phase Delta and Wye. The corner grounded Delta system operates with one phase deliberately bonded to ground through a grounding electrode. A corner grounded delta system will measure 480 volts between all three phases and two of the phases to ground. The remaining grounded phase should measure 0 volts to ground. The split-phase delta system has one transformer grounded midway between windings, similar to how 120/240-volt power is supplied to residences. However instead of measuring 120 volts to ground the unloaded split-phase delta measures 240 volts to L-G on two of the phases while the remaining (wild) phase should measure around 415 volts L-G. At the same time, L-L voltages should all measure 480 volts? The third type of system is the grounded Wye system. A 480-volt Wye system is grounded in such a way that all three phase measure 277 volts L-G while 480 volts are measured L-L. The Wye system is safer to operate than the other two delta systems since L-G voltage is a predictable 277 volts instead of 480 volts or 415 volts possible from the other two system types.

If we accept the premise that high voltage transients reduce motor life, then it makes sense to reduce these as much as possible. The grounded Wye system has the best performance for preventing high voltage transients then the other two systems. This is one of the reasons why the 480-volt Wye system is the most common system used in industrial manufacturing facilities in the United States.

So what should be done in the oil fields to assure the best 480-volt infrastructure to support the end-use load? First of all assure that the systems are grounded by any of the methods described above. A corner grounded system is the easiest to implement. On new installations the additional costs associated with a 4-wire grounded Wye system should pay off in the long run due to increased motor and equipment life.

Once system grounding has been addressed then lightning and surge protection devices may be applied. The application of these devices may depend on the expected lighting activity based on isochronic or ground flash density levels expected in the field. It should be noted even in areas where lightning is rare the use of lightning or surge protection devices can still be beneficial by suppressing transients not caused by lighting such as arcing contactors or arcing faults on the system.

Affects of Oilfield Load Type

As previously mentioned the typical oilfield load is almost all motor-load. Motor loads are inductive in nature and typically require power factor correction capacitors not only to reduce penalties applied to electric bill but primarily to support system voltage when all the motors are on line. Often these capacitors are placed continuously on-line regardless of load condition. In residential communities the loads are diversified enough that problems rarely occur when a power interruption occurs. However, in oilfields, when power interruption occurs the entire motor load drop off-line. When power is restored the power factor correction capacitors are still on-line with no load because the motors have not yet restarted. This may result in elevated system voltages due to capacitor overcompensation until all the motors are brought back on line.

What's the best way to prevent elevated voltage conditions due to overcompensation from occurring? If power factor correction capacitors were connected at the motor terminals, then there would be no need for bulk power factor correction. If the motor drops off line due to a power interruption so does the power factor correction capacitors associated with that motor. Implementing power factor correction in this manner also reduces losses on the distribution infrastructure to the motor conceivably reducing energy costs. Another alternative is to switch bulk power factor correction capacitors on and off depending on voltage level or power factor. There are special controls to control these switched bank capacitors based on voltage or power factor.

Voltage Unbalance

Operation of motor above nameplate temperature can significantly reduce motor life. "When the line voltages applied to a polyphase induction motor are not equal, unbalanced currents in the stator windings will result. A small percentage voltage unbalance will result in a much larger percentage current unbalance. Consequently, the temperature rise of the motor operating at a particular load percentage voltage unbalance will be greater than for a motor operation under the same conditions with balanced voltages."[1] Voltage unbalance is calculated as indicated by Equation 2-1.

Equation 2-1
NEMA Voltage Unbalance

$$Voltage\_unbalance = 100\% \times \left(\frac{\max\_deviation\_from\_average\_voltage}{average\_voltage} \right)$$

Example: With terminal phase-to-phase voltages of 480, 467, 460, the average is 469, the maximum deviation from average is 11, and the percent unbalance = 100% x 11/469 = 2.35%.

NEMA MG-1 does not recommend operation of a motor above 5 % voltage unbalance. A motor operated between 1% and 5% unbalance should be appropriately derated by application of the derating factor in Figure 2-1.

[1] NEM Standards Publication No. MG 1-1998, Motors and Generators, Section II, Application Data – AC Small and Medium Motors, part 14.36.

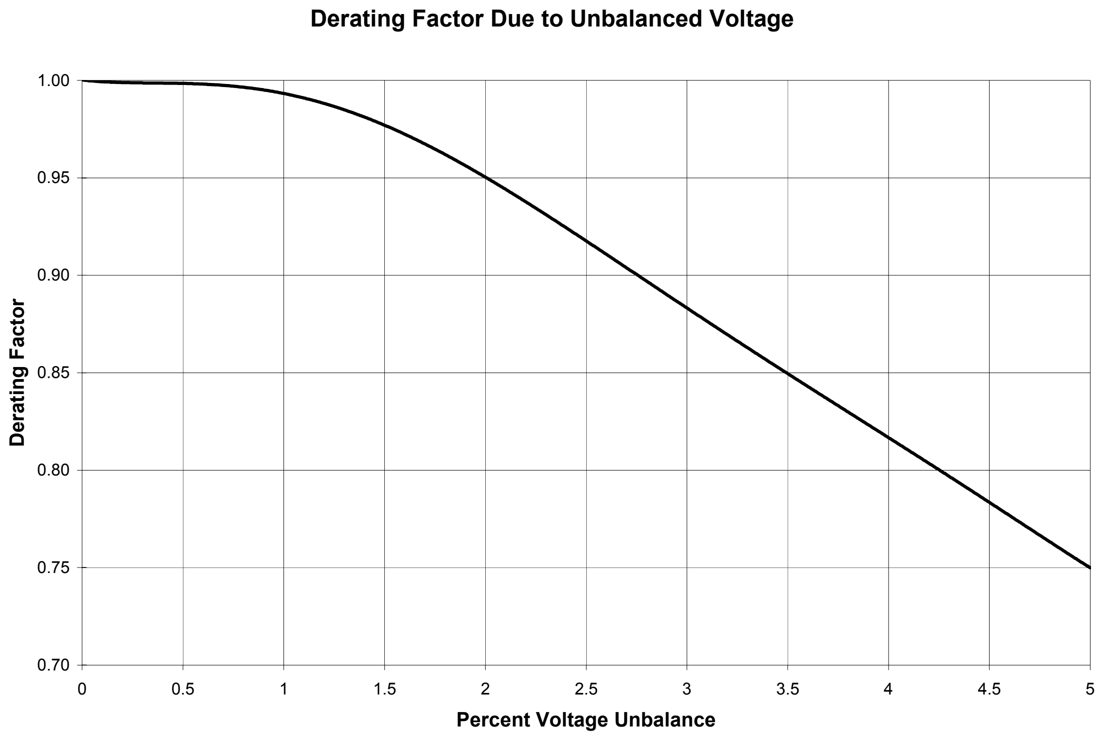


Figure 2-1
Motor Derating Factor Due to Unbalanced Voltage

"Electric supply systems should be designed and operated to limit the maximum voltage unbalance to 3 percent when measured at the electric–utility revenue meter under no-load conditions."[2] Most utilities in the US Utilities conform to this operating practice or closer to 2.5% unbalance.

If the utility is providing voltage at 3% unbalance then only 2% unbalance can be caused by the secondary distribution system before the critical level of 5% unbalance is reached. Motors operating in the oilfield are already operating in a hot and sunny environment so every measure should be taken to reduce motor heating to prolong motor life. If several motors are served by one meter, the chances are high that if one motor is experiencing voltage imbalance then the other motors are also experiencing unbalance. Imbalance motor load currents may cause voltage unbalance if one motor winding is partially failed or shorted. Loose connections or dirty contactors can also be a source for voltage unbalance. Another cause of voltage unbalance might be a blown fuse on a power factor correction capacitor bank. Voltage unbalance on the primary high voltage system might be mitigated with single-phase line voltage regulators installed in each phase of a 3-phase primary distribution line.

[2] American National Standard ANSI C84.1-1989 Appendix D2.

Other Power Quality Issues

Initial discussion with oilfield operators where Electric Submersible Motors (ESP) are used in deep wells, suggested these wells were vulnerable to voltage sags and interruptions. When a sag or interruption occurs the pumps drop off line. If not immediately restarted, fluid pressures cause the pumps to see forces opposite the direction of the motor. Starting a motor under these conditions is either impossible or extremely life shortening to the motor. The option is to let the fluid pressures neutralize before restating the motor that may take minutes to hours depending on well depth. By the time pressures neutralize, sediment collecting in the impellers can cause the pump to seize, further degrading the situation that can lead to motor failure. The time it takes for the fluid pressures to neutralize and the time it takes to re-establish the head before production oil flow is achieved represents lost production time while driving up the overall cost per barrel of oil produced.

Adjustable Speed Drives (ASDs) are available today that can automatically sense the back pressure condition at the motor and control the motor restart without damaging the motor or pump while maintaining production. Where ASDs are not used, motor controls and contactors may be sensitive to voltage sags. There are sag mitigation procedures and technologies available that when appropriately applied can prevent motors from tripping off line due to most common voltage sags. Utilization of ASDs and sag mitigation devices should reduce production down time resulting from voltage sags and interruption while extending pump motor life.

Survey Template Development

In order to guide collection of oilfield operational data for a database it is necessary to develop a survey template personnel may use to guide the survey process. Utilization of the template assures uniformity of data.

Draft Survey Document

EPRI PEAC consulted with the PTTC to analyze the results of the preliminary oilfield tours to identify the most significant areas of potential improvement. Information achieved from oilfield tours and discussions with independent operators were incorporated. This information was used to develop a draft plant/oilfield survey presented in the format of an EPRI “Roadmap” or “Multiple Questions” document. The resulting multiple questions document is attached as Appendix B. Once the draft survey was completed it was posted on the PTTC website.

Survey Template

The objective of the survey was to gather data associated with both the reservoir and the site. The reservoir data includes injection levels, well depths, types of layering, oil gravity and current production levels. The PTTC staff gathered this information from public sources mostly available from the Internet. This information was provided to oil field troubleshooters or consultants performing field surveys to support their understanding of the field being surveyed.

Two survey templates were developed for the gathering of the site data. The first template was developed to gather information about the field. As shown in Figure 2-2, the Field Data Template gathers information on the number of wells by process, number of wells by pump type, production rates, power consumption and potential power quality issues.

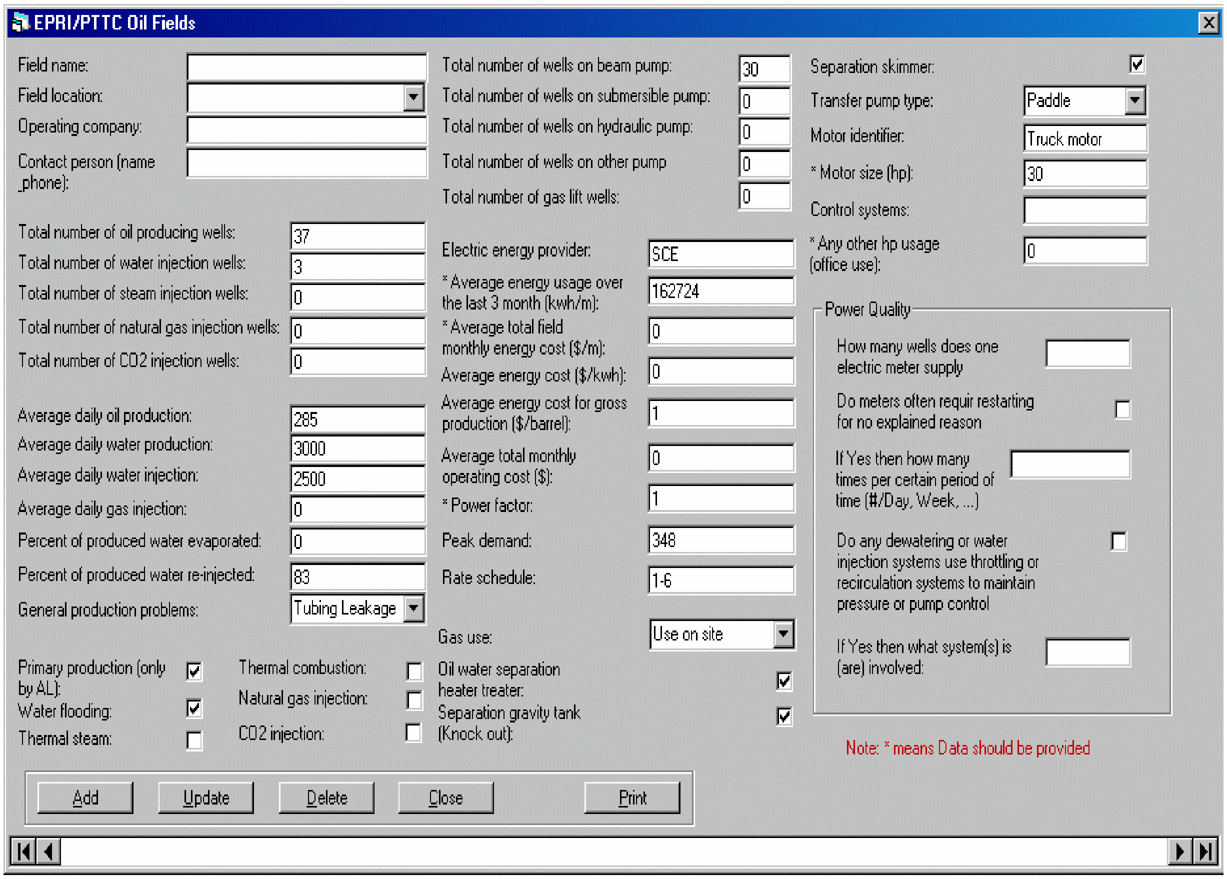


Figure 2-2
Field Data Template

The second template was developed to gather information on individual wells. An example of the Well template is provided in Figure 2-3. After survey completion, data from Well Data Template may be used to consider the use of lower power lift systems and the potential impacts on individual well productivity.

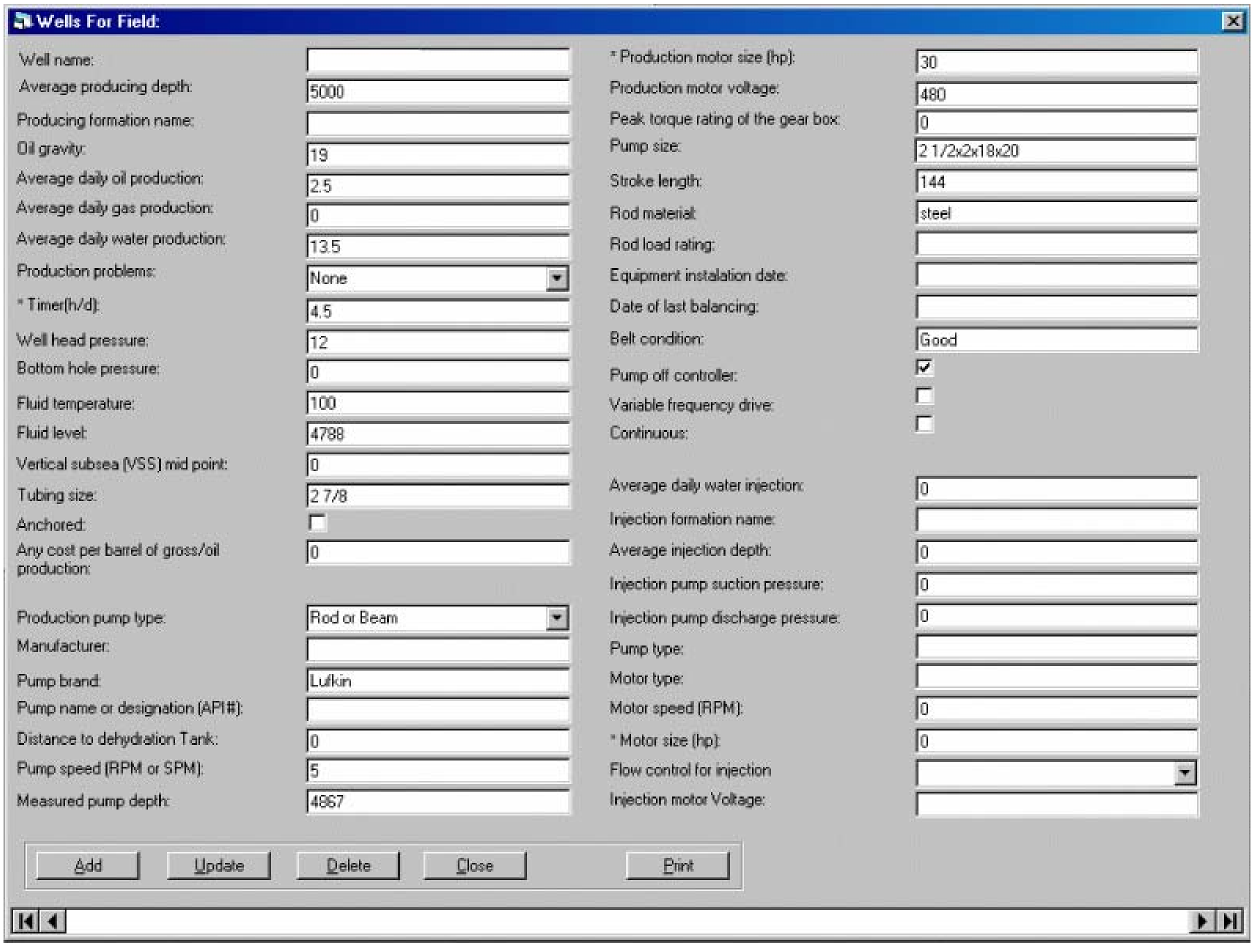


Figure 2-3
Well Data Template

Troubleshooter Training

In order to establish a team of oilfield troubleshooters, which can effectively perform oilfield surveys, the original plan suggested a troubleshooter-training workshop to be conducted by PTTC and EPRI PEAC staff.

The goal was achieved without holding a formal workshop. By fall 2000 the PTTC had 5 candidates for troubleshooter training and contracting. Two of the candidates dropped out because they felt they could not honor the contract requirements. Another dropped out do to other commitments. With only 2 troubleshooters contracted to do the work and the need to start the Pilot Survey it was decided that a full one-day workshop was not feasible. Instead the PTTC staff provided training and an hour-long conference call between the Troubleshooters, PTTC, and EPRI PEAC was held to discuss the issues as outline below:

Since only two troubleshooters were available for the initial pilot study no workshop was presented. At EPRI's direction EPRI PEAC will continue to develop PowerPoint presentations for future training workshops based on the following outline:

- Program Overview
  - Discuss purpose of program and parties involved
  - Discuss individual Tasks of the project.
  - Discuss expected outcome
    - Training workshops after completion of final report
    - Possible demonstration sites for future work
- Detailed Discussion of Site Visits associated with Task 6.
- Discuss Survey Forms
  - Reasons for questions be asked
  - What will be done with the Forms
  - Discuss data to be obtained separate from the forms
    - Monthly power bills
    - Power Quality Questions
- Discuss Roles
  - Troubleshooters
    - Complete Surveys under PTTC Supervision
    - Provide survey data to PTTC
    - Provide invoices for work completed to EPRI PEAC Corp
  - PTTC
    - Contact Producers interested in participating in study
    - Determine sites to visit
    - Manage Troubleshooters
    - Obtain Completed Survey Forms
    - Compile Survey Data
    - Verify data accuracy and communicate recommendation to Troubleshoots
    - Notify EPRI PEAC when survey data is complete
    - Provide Compiled data to EPRI PEAC
  - EPRI PEAC
    - Review Compiled Survey Data
    - Verify data accuracy and communicate recommendations to PTTC
    - Pay troubleshooter invoices

Within two weeks after the telephone training conference the troubleshooters accompanied PTTC staff during the Pilot field surveys involving two fields.

Consequently, 3 additional troubleshooters were trained in a similar manner; meeting with PTTC staff and accompanying the previously trained troubleshooters on one oilfield survey. All troubleshooters were provided the report documenting "A PTTC Oilfield Trouble Shooting Program: Template for Performing Oilfield Surveys." This report basically explains the survey methodology presented in the following paragraphs.

Survey Methodology

This section documents the methodology of how oilfield surveys were performed and how the results were placed in a database. A flow chart is provided in Appendix C illustrating the methodology used. Once data based, the data will be analyzed to provide participating producers a measure of how electrically efficient their oilfields are operating with respect to other participants.

Participant Solicitation

To perform the survey of oilfields in southern California it was first necessary to establish producers interested in participating on a voluntary basis. The flowchart in Figure 2-4 illustrates how volunteer producers to participate in the surveys were recruited.

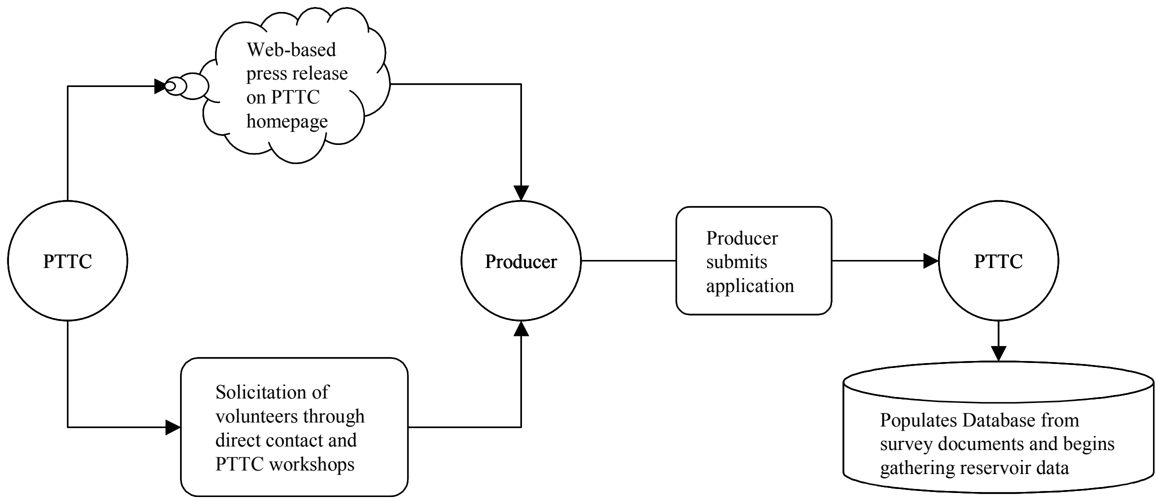


Figure 2-4
Methodology for Establishing Volunteer Producers

A solicitation for volunteers was performed through a PTTC press release and through direct contacts between the PTTC and potential producers. The PTTC press release that was posted on the PTTC homepage July 26, 2000 is attached as Appendix A. Producers interested in participating in the study were required to complete and submit an application similar to Appendix D. Those responding to the web-based PTTC press release were provided a means to submit applications online.

As the applications from the producers were received, the PTTC established a database with the application information. This application information was then used by the PTTC staff to conduct detailed studies on the past and present production characteristics of the particular field. Using the production database of the California Division of Oil and Gas and Geothermal Resources (CALOGGR), the PTTC retrieved production history for individual wells and then generated the field or lease cumulative performance charts. These charts plot oil rate versus time, water oil ratio versus time and gas oil ratio versus time. From these diagnostic plots, the PTTC staff realized a sense of daily productivity levels, seriousness of water cut (cut is water as a fraction of total production), and gas oil ratio increases (a measure of reservoir pressure). The PTTC staff also used other summaries published by the Division of Oil and Gas to ascertain the levels of water injection (if any) into the reservoir under study. This information together with summaries on geologic characteristics of the reservoir were then shared with the consultants selected for the field visits.

The reservoir data was extracted from summaries PTTC has compiled from CALOGGR publications. The purpose of reservoir data and production diagnostic plots are twofold. First, the consultants need to understand the field performance and geology before collecting data. Geological information includes depth, type of layering, oil gravity, and current productivity levels. Second, upon completion of the survey, the PTTC intends to consider the use of lower power lift systems and the potential impacts on individual well productivity. Fields that are currently producing at lower production levels may experience higher production rates with application of stimulation techniques. Redesigned low power lift systems should have the capacity to handle increased production resulting from stimulation techniques.

Consultant Selection

Consultants were needed to complete the oilfield surveys and provide the survey data to PTTC staff. Figure 2-5 illustrates how consultants were solicited and contracted. Potential consultants were solicited through PTTC contacts and PTTC workshops. Interested consultants provided resumes and contact information to EPRI PEAC for consultant selection and contracting. Some of the qualifications for consultant work were:

1. Must be an established consultant in the Oil and Gas industry.
2. Must be a registered professional engineer or have at least 10 years of experience in the Oil and Gas industry.
3. Must have a working knowledge of oilfield production operations.
4. Must agree to the terms of the contract.

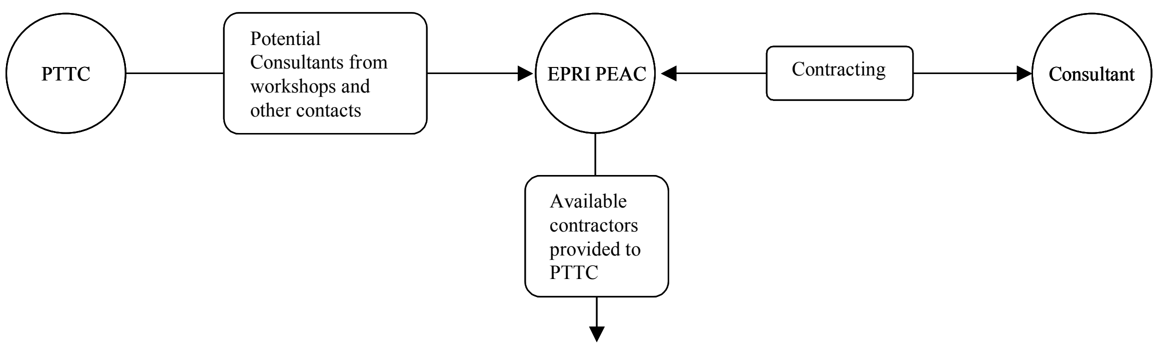


Figure 2-5
Solicitation and Contracting with Consultants

After reviewing each consultant’s qualifications, EPRI PEAC sent contract documents to the consultants for review. If the consultant agreed to the terms of the contract, a general contract was initiated between the consultant and EPRI PEAC. The contract stipulated individual Task Orders (TO’s) to be issued to individual consultants on a field-by-field basis so that costs associated with the consultant fees could be closely controlled.

Once a contract was established between EPRI PEAC and the consultant, the consultants’ name was provided to PTTC staff to be included in a list of available consultants. The PTTC staff selected consultants from the list for assignment to a producer and defined field.

Survey

Oilfield surveys are currently being performed under PTTC staff management. Figure 2-6 illustrates the workflow associated with the oilfield surveys. After determining reservoir specifics for a particular field and associated producer, the PTTC contacts the producer to determine the best time and date to perform the study. Additionally, sample survey forms are faxed to the producers' contact person at the field office scheduled for visitation to provide a preliminary familiarity about the questions that the consultants will be asking. Based on consultant availability and proximity to the field to be surveyed, the consultant is assigned the field and provided the necessary survey forms (Figure 2-2 and Figure 2-3). Once the assignment is made, the PTTC provides EPRI PEAC with the name of the assigned consultant, the producer's name, producer contact information, name of nearest town to the field to be surveyed, approximate number of wells and expected number of days to complete the survey. With this information EPRI PEAC issues Task Orders (TO's) authorizing the consultant to begin work on the field.

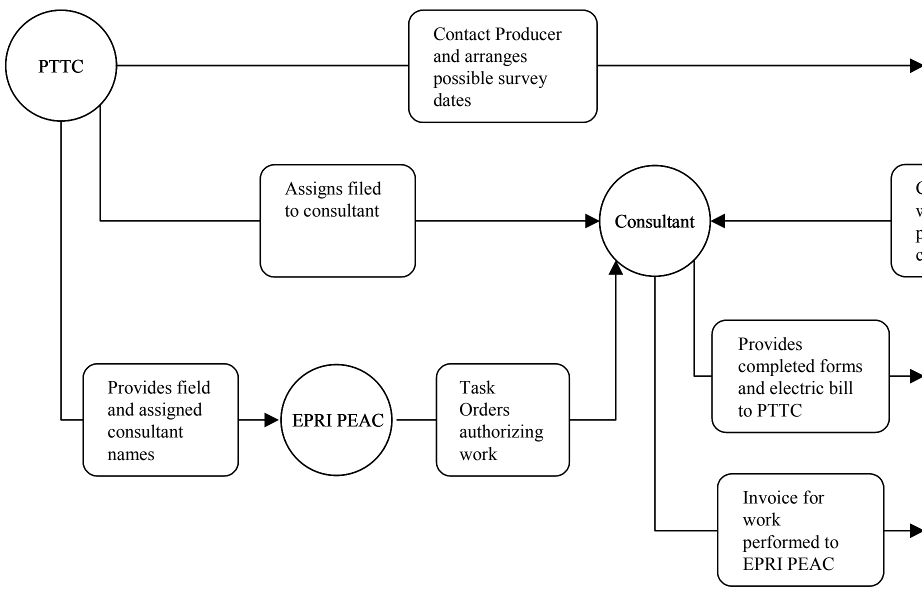


Figure 2-6
Workflow Associated with the Oilfield Surveys

Once the consultant receives a signed TO, the consultant contacts the producer agreeing on a time to begin work on the survey. The consultant works with the producer to obtain the necessary information to complete the survey forms. Additionally, the consultant is provided with copies of the electric bill for the field. After completing the survey forms, the consultant provides the forms and electric bill to the PTTC and invoices EPRI PEAC for the work performed.

Consultant Payment

After the PTTC receives the survey forms from the consultant, the PTTC reviews the forms to assure completion. If there are any deficiencies, the PTTC contacts the consultant to correct the discrepancy. After EPRI PEAC receives verification from the PTTC that the work is satisfactorily completed, the consultants invoice is paid. Figure 2-7 illustrates workflow associated with consultant invoice payment.

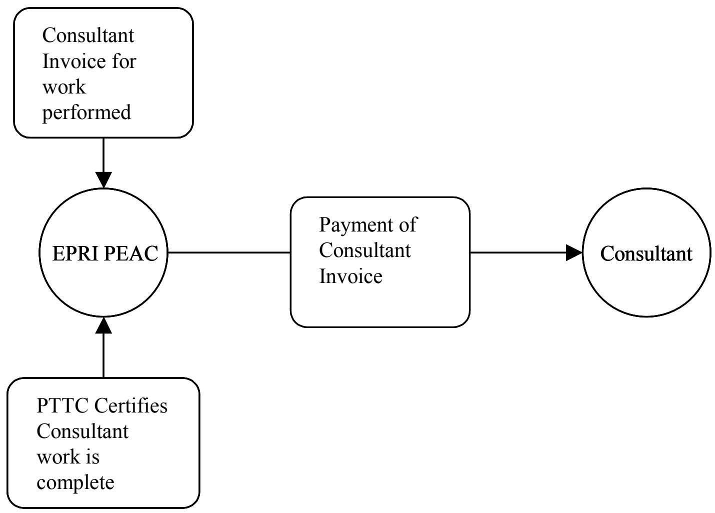


Figure 2-7
Workflow Associated with Consultant Invoice Payment

Database Population and Reporting

The PTTC manually enters data from the completed survey forms to populate a database. A copy of the populated database is provided to EPRI PEAC. The PTTC and EPRI PEAC collaborate to determine reports to be generated from the database. These reports will be used to provide information back to the producer that will give the producer an indication of how energy is being consumed in relationship to the other fields surveyed. The data will also be used to support the overall project final report.

Figure 2-8 illustrates workflow associated with database population and reporting.

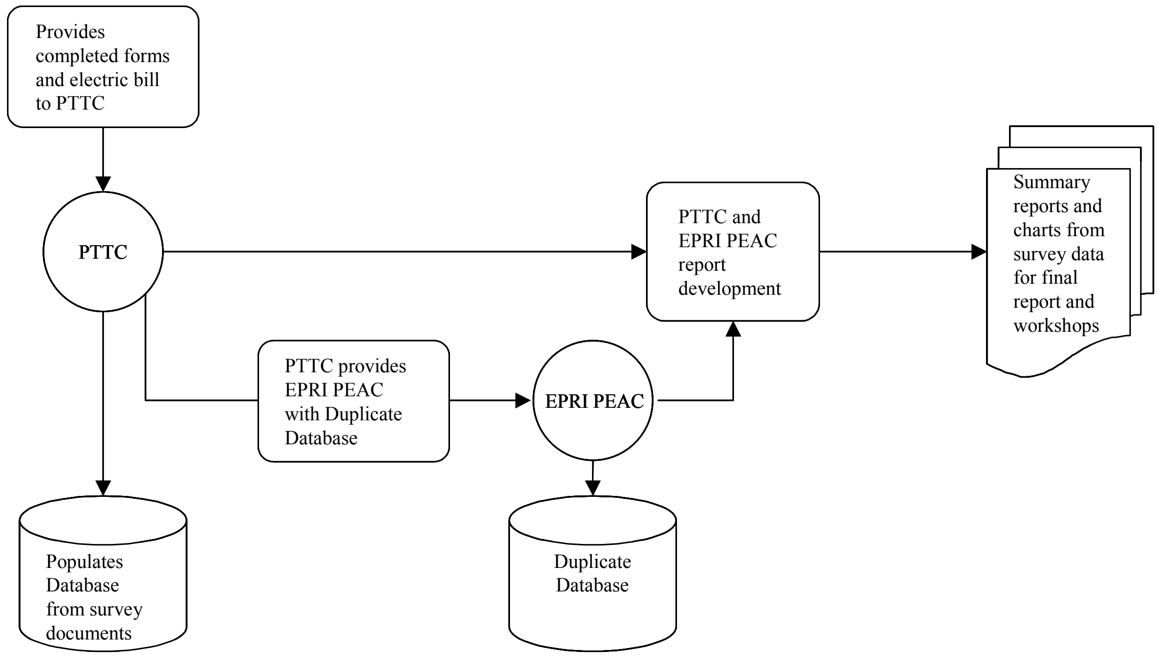


Figure 2-8
Workflow Associated with Database Population and Reporting

Survey Implementation

Pilot Study

In November 2000, a pilot study of two oilfields was performed utilizing the methodology discussed above. The pilot study familiarized participating consultants with the survey requirements, allowed evaluation of the survey tools, and provided data to quantify how long it takes to survey an oilfield.

The pilot study was performed in three parts. The first part of the study involved a conference call, on November 8, 2000, between the PTTC, two Consultants, and EPRI PEAC. The conference orientated the consultants with the project and oilfield surveying. The meeting included discussing:

- The program and survey overview
- Consultant responsibilities
- PTTC responsibilities
- EPRI PEAC responsibilities
- Oilfield assignments to each consultant

One consultant was assigned a field in the Los Angeles area with 43 active wells. The other consultant was assigned a field in the Long Beach area with 91 active wells. The PTTC worked closely during these pilot surveys by providing a staff person to accompany the consultants during the surveys. The pilot oilfield surveys were both completed by the end of November 2000.

The pilot study performed on the two fields represented 134 active wells utilizing two consultants and a PTTC staff member. The oilfield work was completed and all survey data submitted by November 27, 2000. Resulting from the study, minor changes to the survey forms were made from consultant recommendations. Based on the pilot study it was determined only 20 wells could be surveyed per day at a cost of $400 per day plus incidentals. With budgeted funding it was expected that up to 1500 wells could be surveyed for database completion. Initial site selection criteria were established to provide the greatest variety of geographical locations in California.

Survey Completion

By the January 2001 five subcontractors were available and actively performing the oilfield surveys. The surveys were performed using the survey templates and methodology proven in the pilot studies. Surveys continued until the budget was consumed after 19 fields had been visited by March 2001. These 19 fields represented 958 producing well. Of these wells, 92% were rod-pumps, 5% were ESP's and 3% were hydraulic or progressive gravity pumps. A detailed discussion of the data and analysis is provided in Section 4 of this report.

Conduct Workshop

The PTTC and EPRI PEAC conducted a workshop jointly on July 19, 2001. The workshop presented the results of the oilfield survey and additional activities required to implement cost and energy savings solutions in the oilfields. The agenda for the workshop is attached as Appendix E.

Final Report

The last task of the study methodology required a comprehensive report be prepared. This document fulfills the final report requirement.

3 OILFIELD SYSTEMS

Summary

As a part of an electric power consumption study sponsored by California Energy Commission and EPRI, this brief describes oilfields and various components of producing equipment with explanation of their power requirement. Equipment described includes subsurface pumps for production such as rod pumps, ESP (Electric Submersible Pump) as well as surface facilities for fluid injection, separation and treatment.

Petroleum reservoirs consist of subsurface geologic structures that contain hydrocarbons mixed with water in pores or cracks of sedimentary rocks. Some form of energy is required to get the hydrocarbons to the surface. At early stage, most fields produce under the natural forces of solution gas and/or water drive. With the gradual depletion of natural energy, artificial lift equipment is installed to maintain productivity.

Petroleum industry is one of the major consumers of electric power. Power uses, besides the routine applications such as lighting, transportation and heating, include power for subsurface and surface equipment for lifting fluids, fluid injection and processing of hydrocarbon and associated fluids. Depending on the size of the operation and self-sufficiency of a producing area in terms of produced natural gas as a fuel, electric power may be generated on site or purchased from a service provider.

The purpose of an electric power consumption audit of a typical field operation is to examine the inefficiency of existing artificial lift equipment at selected sites and potential unnecessary electric power use. As a routine task, the operators seldom monitor and compare different methods for artificial lift. Electric bills are not split out for various units of a typical oilfield operation. As such, the operators in general are not clear on electric power usage per individual wells. Thus if a well is equipped with an oversized pump, a change in the design may reduce power bills with beneficial effects on operational cost to the field operator and lesser demands to the service providers. Also, in some cases, application of pump-off controllers can substantially reduce power consumption without the loss of productivity.

Introduction

Before describing the lift equipment and other surface facilities in a typical oilfield, a brief explanation is offered on the nature of petroleum reservoirs.

Petroleum Reservoirs

Hydrocarbons - crude oil and natural gas - are found in certain layers of rock that are usually buried deep beneath the surface of the earth. A reservoir is a formation that contains hydrocarbons. For a rock layer to qualify as a good source of hydrocarbons, it must meet several criteria. For one thing, good reservoir rocks have porosity. Porosity is a measure of the openings in a rock where petroleum can exist. Another characteristic of reservoir rock is that it must be permeable. That is, the pores of the rock must be connected together so that hydrocarbons can move from one pore to another. Unless hydrocarbons can move and flow from pore to pore, the hydrocarbons remain locked in place and cannot flow into a well.

Types of Petroleum Traps

Geologists have classified petroleum traps into two basic types: structural traps and stratigraphic traps. Structural traps are traps that are formed because of a deformation in the rock layer that contains the hydrocarbons as shown in Figure 3-1. Two common examples of structural traps are fault traps and anticlines. A fault trap occurs when the formations on either side of the fault have been moved into a position that prevents further migration of petroleum. For example, an impermeable formation on one side of the fault may have moved opposite the petroleum-bearing formation on the other side of the fault. The impermeable layer prevents further migration of petroleum.

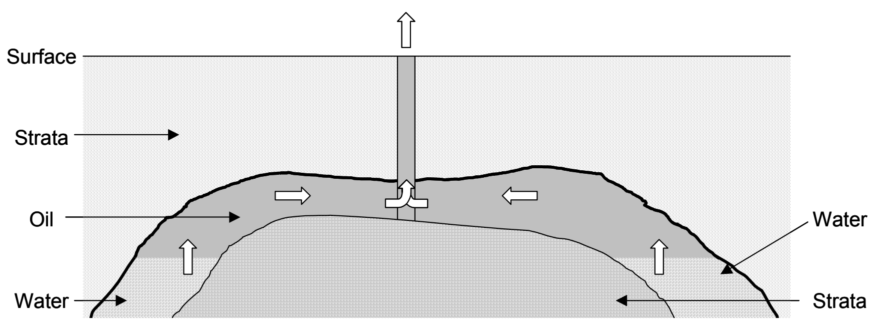


Figure 3-1
Typical Petroleum Structure

An anticline is an upward fold in the layers of rock, much like an arch in a building. Petroleum migrates into the highest part of the fold, and an overlying bed of impermeable rock prevents its escape.

Stratigraphic traps are traps that result when the reservoir bed is sealed by other beds or by a change in porosity or permeability within the reservoir bed itself. There are many different kinds of stratigraphic traps.

Structural setting of an oilfield is a major factor in the placement of the wells and well completion strategy. As shown in Figure 3-2 in modern completion practice, oil wells may be drilled vertical, directional or horizontal to get maximum exposure of the producing intervals to the well bore.

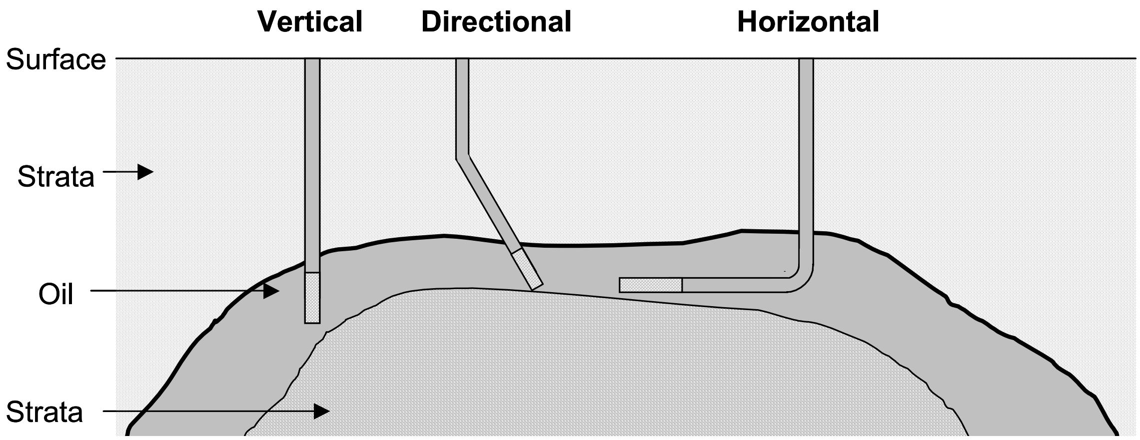


Figure 3-2
Drilling Techniques

Reservoir Fluid and Pressure Properties

Oilfield operations consist of a collection of facilities that allows lifting of substantial amounts of fluids (oil, gas and water) from subsurface reservoirs at depths ranging from one to three miles beneath the surface. In the early life of a newly discovered oilfield, the natural forces such as dissolved gas are often sufficient to cause flowing conditions without the need for subsurface lift equipment. With the decline of natural energy, the use of some type of lift equipment becomes necessary if the recovery of remaining oil is economically viable.

The type and quality of crude oil dictates the method of the lift equipment. At times, such as the case for heavy crude's from many California fields, heat may have to be introduced into a reservoir before the crude oil is fluid enough for lifting purposes. A measure of crude oil quality is its American Petroleum Institute (API) gravity defined in Equation 3-1 as:

Equation 3-1
API Gravity

API gravity= 141.5/Specific gravity-131.5

API gravity is inversely related to the oil specific gravity. Since water has a specific gravity of 1 in this definition, water has an API gravity of 10. Heavier crude oils having specific gravities greater than water will have API gravities less than 10. For example, for light crudes with API gravities above 20, one may use gas lift. For lower gravities rod pumping is the suitable lifting system.

What causes the flow of subsurface fluids to the surface can best be described by Equation 3-2.

Equation 3-2
Production Rate

Production rate = (Productivity index) X (Pressure draw down)

Productivity index is a measure of reservoir and fluid properties. Except for cases where the introduction of heat may be necessary to reduce the oil viscosity and improve the productivity index, this characteristic of in-situ condition is unchangeable. The part of Equation 3-2 under control is the pressure draw down. As illustrated in Figure 3-3, this term is defined as the difference between formation pressure and bottomhole flowing pressure.

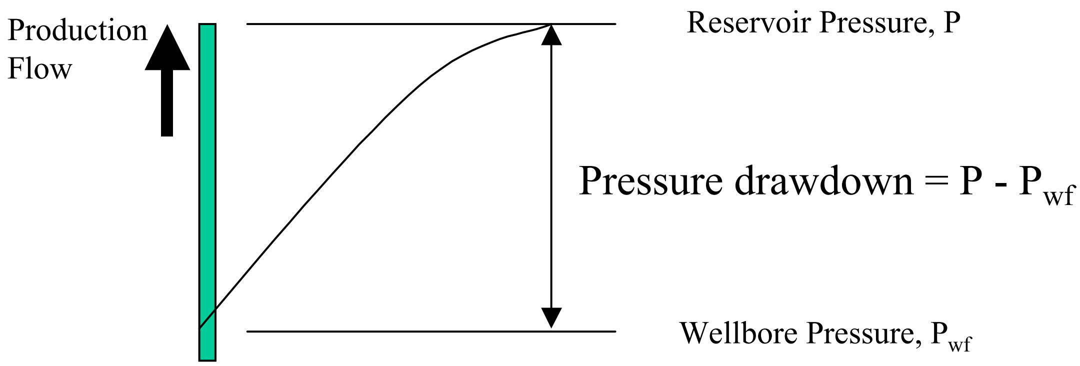


Figure 3-3
Representation of Pressure Draw Down

Pumping equipment is intended to reduce the bottomhole pressure and thus increase the pressure draw down. Besides the lowering of bottomhole pressure, any attempts, such as water flooding, to supplement or increase reservoir pressure can also help in maintaining a high reservoir pressure and a high-pressure draw down.

Depending on the geology of an oilfield and the hydrological conditions, natural forces may keep the reservoir pressure up for a substantial portion of the economic life of an oilfield. Examples include, fields under active water drive, gas cap expansion compaction drive and gravity drainage.

The purpose of this tutorial is to focus on the lift equipment and surface processing. Under the lift equipment, fundamental aspects of lift equipment such as rod pumps, ESP, and gas lift are discussed.

Oilfield Production

Underground reservoirs containing hydrocarbons have been found in different geographical locations from onshore to offshore locations. These reservoirs are in sizes containing from hundreds of thousands barrels of oil to tens of billions of oil or several trillion cubic feet of natural gas. Under applied pressure gradient, the fluids can be released from these tight rocks and brought to the surface for processing. Processing includes separation of oil water and gas and quality improvement (removal of sediments and harmful components such as hydrogen sulfide) before shipment to the market.Table 3-1 shows a summary of different types of reservoirs classified based on the hydrocarbon composition.

Table 3-1
Classification of Hydrocarbon Reservoirs

Reservoir Type	Range of Gas Oil Ratio	API Gravity
Dry Gas	∞	No liquid
Wet Gas	1 Barrel Liquid for 100 MSCF Gas	50-70
Condensate	5000 to 100000 SCF/BBL	50-70
Volatile	3000 SCF/BBL	40-50
Black Oil	100-2500 SCF/BBL	30-40
Heavy Oil	<100 SCF/BBL	12-25
Tar	0	10

Oil Production

Once an accumulation of oil has been found in a porous and permeable reservoir, a series of wells are drilled in a predetermined pattern to effectively drain this “oil pool”. Wells may be drilled as close as one to each 10 acres (660 ft. between wells) or as far apart as one to each 640 acres (1 mile between wells) depending on the type of reservoir and the depth to the “pay” horizon. For economic reasons, spacing is usually determined by the distance reservoir energy will move commercial quantities of oil to individual wells.

The rate of production is highest at the start when all of the energy from the dissolved gas or water drive is still available. As this energy is used up, production rates drop until it becomes uneconomical to operate although significant amounts of oil still remain in the reservoir. Experience has shown that usually only about 12 to 15 percent of the oil in a reservoir can be produced by the expansion of the dissolved gas or existing water. When the well does not produce by natural flow, artificial-lift equipment is usually installed to supplement the formation pressure.

Well Completion

After a well has been drilled, it is usually cased with steel pipes (casing) and perforated at a designated location to tap the producing intervals. Sometimes, certain treatments such as acidizing or fracturing are applied to enhance formation productivity. At times, the completion may require sand control measures to protect the integrity of the producing interval and to avoid abrasion damage to the production equipment. There are also cases that a well may have multiple completions to tap several geologic layers from the same borehole.

Injection Wells

In the ordinary producing operation only a portion of the oil in place is recoverable by primary production methods. Such methods include free-flowing wells and production maintained by pumps. As oil is extracted from a reservoir, the pressure that brings the oil to the well is reduced.

Secondary recovery methods are intended to increase the recoverable percentage of the oil in place by injecting a substance such as gas or water into the producing formation. The injected substance is intended to increase the pressure on the oil in the formation and drive it toward the well-bore. A well, called an injection well or water injection well, is usually drilled in order to inject the substance. Sometimes a previously drilled, abandoned well can be reworked as an injection well. When water is used as the injectant it is often produced on the property itself. Excess water produced by operating wells may be diverted to the injection well and used as the injectant. This method of water disposal usually alleviates the need for a separate water disposal well. If the water from the producing wells does not provide enough injectant to provide proper pressure for secondary recovery, a water supply will be required to provide the balance.

Secondary Recovery

Water flooding is one of the most common and efficient secondary recovery processes. Water is injected into the oil reservoir in certain wells in order to renew a part of the original reservoir energy. As this water is forced into the oil reservoir, it spreads out from the injection wells and pushes some of the remaining oil toward the producing wells. Eventually the waterfront will reach these producers and increasingly larger quantities of water will be produced with a corresponding decrease in the amount of oil. When it is no longer economical to produce these high water-ratio wells, the flood may be discontinued.

As mentioned previously, average primary recoveries may be only 15% of the oil in the reservoir. Properly operated water floods should recover an additional 15% to 20% of the original oil in place. This leaves a substantial amount of oil in the reservoir, but there are tertiary recovery techniques that can technically recover some of the residual oil.

In most cases, oil reservoirs suitable for secondary recovery projects have been produced for several years. It takes time to inject sufficient water to fill enough of the void spaces to begin to move the oil. It takes several months from the start of a water flood before significant production increases take place and the flood will probably have maximum recoveries during the second, third, fourth, and fifth years after injection of water has commenced. The average flood usually lasts at least 6 to 10 years.

Forces to Lift Fluids from Subsurface Reservoirs

Some petroleum reservoirs, at the discovery time, are under hydrostatic pressure conditions. That means the reservoir pressure is equivalent to about 430 psi for every 1000 feet of depth. This pressure is sufficient to lift hydrocarbons to the surface because of lower specific gravity of these substances. With continued production, the depletion of original fluid in place causes a rapid drop in reservoir pressure. Under certain conditions, the drop in original pressure may be delayed because of expansion forces of compressible reservoir rocks, influx of water from massive aquifers or expansion of a gas cap. If the reservoir pressure drops below a critical value, the natural forces are no longer able to maintain flow and some type of artificial lift system must be employed. The typical components of a producing well without artificial lift are displayed in Figure 3-4.

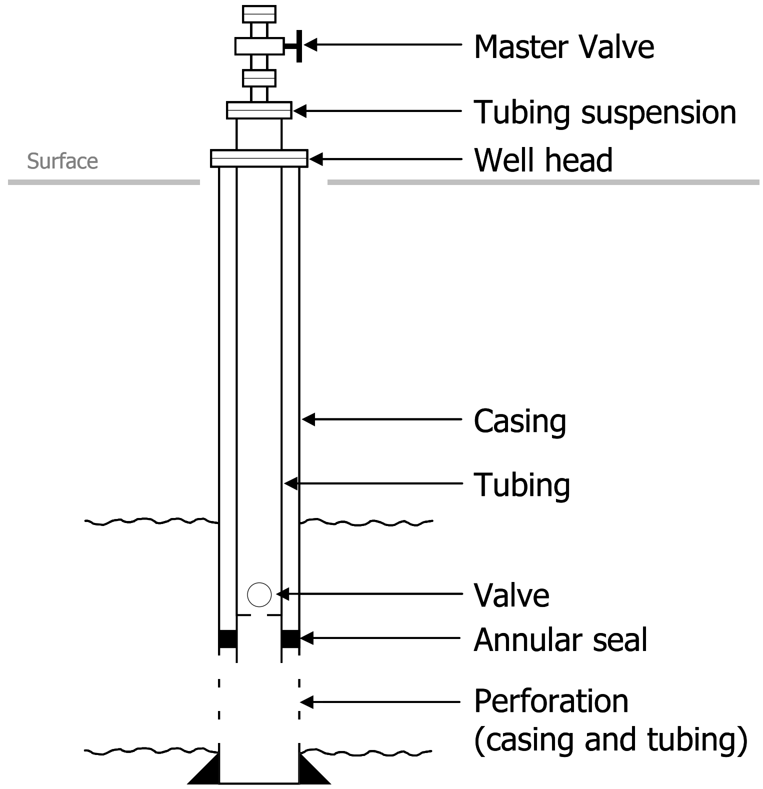


Figure 3-4
Components of a Producing Well

As previously mentioned, after a drop in production rate, oftentimes if the economics of operation is justifiable, some form of enhanced oil recovery (EOR) technique may be employed. These techniques tend to reduce the oil saturation in reservoir rock and increase the recovery efficiency. EOR processes include surfactant polymer, thermal processes and miscible recovery techniques. In general with the injection of water or water with additives, the gross production increases.

A typical oilfield operation may include from several to multitude of hundreds of producing wells drilled to tap every corner of a subsurface field. After the primary phase where the wells may be in flowing conditions, the drop in reservoir energy requires the installation of artificial lift to increase pressure draw down. A number of factors are taken into consideration before a lift mechanism is installed on a producing well. For producing wells, consideration are given to the depth of the formation, predicted producing volumes, expected gas oil ratio, hole angle, bottomhole conditions and availability of electric power or natural gas and at times diesel fuel for operating the prime movers or lifting the fluid. If the field is under water injection or gas injection for pressure maintenance, injection wells need to be equipped with connections to surface injection pumps and compressors.

Water to be injected for pressure maintenance undergoes treatment for quality improvement including removal of particulates and oxygen scavenging. Produced fluid, a mixture of oil, water and gas is first sent to one or a number of separators before the oil is ready for the stock tank and for shipping purposes. Between the separators and stock tank, other processing units such as heater treater may be installed for breakdown of oil-water emulsion.

Production Staff

Pumpers and their helpers operate and maintain motors, pumps, and other surface equipment that force oil from wells and regulate the flow, according to a schedule set up by petroleum engineers and production supervisors. In fields where oil flows under natural pressure and does not require pumping, personnel referred to as “Switchers,” open and close valves to regulate the flow. “Gaugers,” are people who measure and record the flow, taking samples to check quality. “Treaters,” are people who test the oil for water and sediment then remove these impurities by opening a drain or using special equipment. In most fields, pumping, switching, gauging, and treating operations are automatic, not normally requiring human interaction.

Artificial Lift Methods

Artificial lift methods use three basic processes to lift fluids to the surface:

- Lightening of the fluid column by gas injection
- Subsurface pumping
- Piston like displacement

In general, these systems are either of a mechanical pumping system type or are operated by gas injection. Table 3-2 shows a list of artificial lift methods.

Table 3-2
Artificial Lift Methods

1. Mechanical Pumping Systems (creating tubing in-take pressure)

   —Rod

   —Hydraulic

   —Submersible

   —Progressive Cavity

2. Gas Lift
3. Plunger Lift

According to published data, rod pumps are the most frequently used type in the worldwide pumping operation. As shown in Figure 3-5, more than 90 percent of producing wells in the US are on artificial lift. Internationally, the percentage is lower as many fields are still under flowing conditions.

Selection of a particular type of pump depends on many parameters among which are the expected producing rates, fluid properties, hole angle and formation depth. Table 3-3 shows some general guidelines for selection of artificial lift methods.

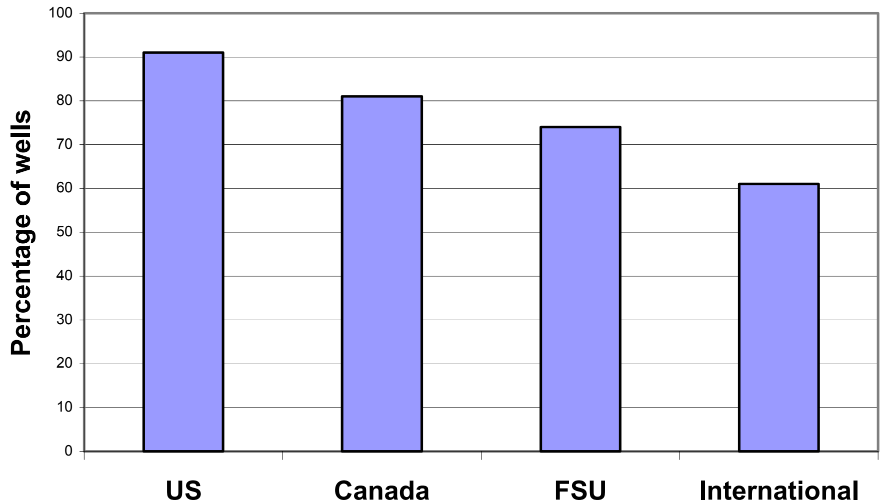


Figure 3-5
Worldwide Distribution of Artificial Lift (Adapted from a supplement to Petroleum Engineering International)

Table 3-3
General Characteristics of the Main Methods of Artificial Lift Systems (Courtesy: a supplement to Petroleum Engineering International)

Characteristics	Rod Lift	Progressing Cavity Pumps	Gas Lift	Hydraulic Lift (Piston)	Hydraulic Lift (Jet)	Elec. Sub. Pumping (ESP)
Operating Depth, ft	500-11000	2000-4000	5000-8000	10000	10000	1000-10000
Operating Volume, b/d	20-1500	50-2200	200-10000	500	1000	200-20000
Operating Temp. F	100-250	75-110	100-250	100-250	100-250	100-275
Corrosion Handling	Good to Excellent	Fair	Good to Excellent	Good	Excellent	Excellent
Gas Handling	Fair to Good	Good	Excellent	Fair	Good	Poor to Fair
Solids Handling	Fair to Good	Excellent	Good	Poor	Good	Poor
Fluid Gravity, API	>8	<35	>15	>8	>8	>10
Servicing	Workover or Pulling Rig	Workover or Pulling Rig	Wireline or Workover Rig	Hyd. or Wireline	Hyd. or Wireline	Workover or Pulling Rig
Hole Angle	0-20	N/A	30	0-20	0-20	N/A
Prime Mover	Gas or Electric	Gas or Electric	Compressor	Multi-cylinder or Electric	Multi-cylinder or Electric	Electric Motor

As mentioned earlier, artificial lift is used in oil wells that either do not have sufficient bottom hole pressure to produce any fluid to the surface without assistance, or in wells that show a better return on investment when supplemental lift is put in place to deplete reserves more quickly. The various methods of artificial lift pumping are described in the following sections.

Rod Pumps

Rod Pumps are often referred to as “Sucker-Rod Pumps,” “Balanced Beam Pumps,” or “Pump Jacks” in the petroleum industry. To avoid confusion, the term “Rod Pump” will be used. As shown in Figure 3-6 rod pumping systems consist of the following four subsystems:

- The surface unit which transfers rotating motion to a linear oscillation of the rod string.
- The gear reducer reduces prime mover speed to the slower crank or counterweight speed.
- The rod string, which transmits power to the pump from surface.

- The subsurface pump which displaces the fluid at the bottom of the well and reduces the bottomhole pressure.

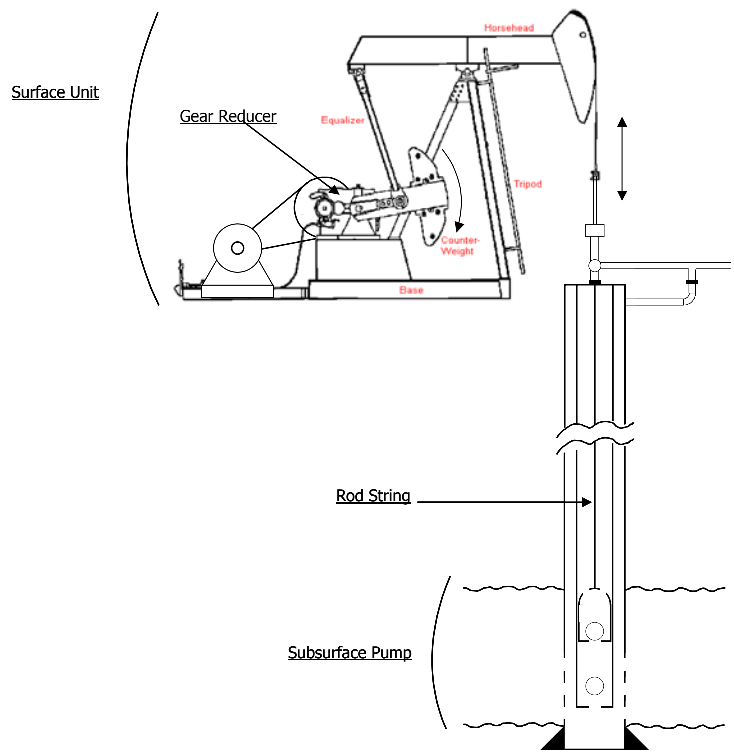


Figure 3-6
Typical Rod Pumping System Components

In rod pumping systems, the pumping motion is transmitted from the surface to the pump by means of a string of narrow jointed rods placed within the tubing. As shown in Figure 3-6, surface equipment used in this method imparts an up-and-down motion to a rod string that is attached to a piston or plunger pump submerged in the fluid of a well. Most rod-pumping units have the same general operating principles. While the surface unit shown in Figure 3-7 represents a Conventional Crank Balanced unit, there are a wide variety of surface units available.

Figure 3-7
A Typical Rod Pump in Bakersfield, California

Surface units vary in design and size. Torque rating, peak load, and stroke length designate unit sizes. Typical designs are Conventional (Class I), Mark II, and air-balanced units. Conventional Units as shown in Figure 3-7, utilize a balanced crank and are considered the "Work Horse" of the industry. The units depicted at web site http://www.lufkin.com/oilfield/pumps.htm are listed as follows:

- **Mark II Unitorque Units**
  Have a unique geometry resulting in lower peak loads and longer rod life.
- **Air Balanced Units**
  Use compressed air instead of heavy iron counter weights resulting in lowering transportation and installation costs.
- **Beam Balanced Units**
  Economically producing many of the shallow wells.
- **Reverse Mark Units**
  Modified conventional type geometry, resulting lower torque and power requirements.
- **Conventional Portable Units**
  Trailer mounted, self-contained conventional that can be erected and pumping in a few minutes at the well site.

The surface unit is connected to the subsurface pump by a rod string. A rod string is made up of individual rods. These rods are typically about 25 feet long and are connected with a threaded coupling manufactured into the rod. Conventional rods are made of steel while lighter materials such as aluminum alloys are also available. Rod string length is dependent upon the depth of the subsurface pump.

The subsurface pump is the device, which forces the fluid from reservoir to the surface. Figure 3-8 provides a breakdown of the subsurface pump used in rod systems with descriptions of basic pump components.

- **Hold-down**
  - an anchoring device at the top or bottom of the pump to retain the rod pump in its worling (pumping) position
- **Valve Rod**
  - connects the lower end of the sucker rod string to the pump plunger.
- **Plunger**
  - a closely fitted tubular piston with a check valve for displacing well fluid from the pump barrel.
- **Traveling Valve**
  - the discharge valve that moves with the plunger.
- **Barrel**
  - the cylinder into which the well fluid is admitted and displaced by a closely fitted plunger.
- **Standing Valve**
  - **the intake** valve of the pump, which, is generally a ball-and-seat-type check valve.

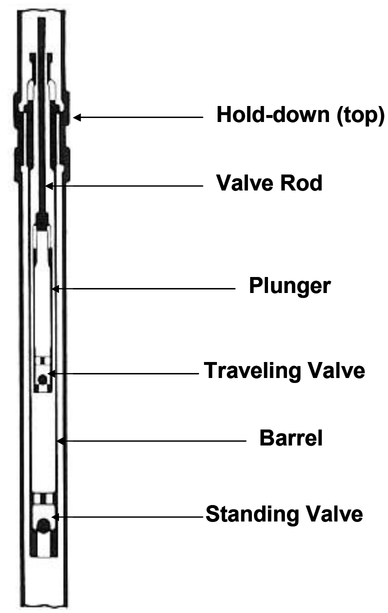


Figure 3-8
Basic Rod Subsurface Pump Components

The subsurface pump is a plunger and valve arrangement within a tube or barrel. When the close-fitting plunger is lifted within the barrel, it creates a low-pressure region below the plunger. This causes the barrel to be filled with fluids from the formation. The valves are designed to open and close so that they allow fluids to enter the pump on the upstroke and be displaced above the traveling valve on down stroke. The fluid above the traveling valve moves one full stroke upward during each upstroke.

There is a wide variety of pump designs. As indicated in Table 3-4, the API (American Petroleum Institute) has designed a classification system using the criteria shown below:

Tubing size	Pump bore size
Rod or tubing pump	Barrel type
Plunger type	Pump seating assembly location
Traveling or stationary barrel	Type of Seating assembly
Barrel length	Plunger length
Extensions	

Table 3-4
API Pump Designation System

Pump Designation

The basic types of pumps and letter designations covered by this specification are as follows:

Type of Pump	Letter Designation			
	Metal Plunger Pumps		Soft-Packed Plunger Pumps	
	Heavy-Wall Barrel	Thin-Wall Barrel	Heavy-Wall Barrel	Thin-Wall Barrel
Rod Pumps				
Stationary Barrel, Top Anchor	RHA	RWA	......	RSA
Stationary Barrel, Bottom Anchor	RHB	RWB	......	RSB
Traveling Barrel, Bottom Anchor	RHT	RWT	......	RST
Tubing Pumps	TH	......	TH	......

Complete pump designations include (1) nominal tubing size, (2) basic bore diameter, (3) type of pump, including type of barrel and location and type of seating assembly, (4) barrel length, (5) plunger length, and (6) total length of extensions when used, as follows:

XX - XXX X X X X X - X - X

- X-X-**X** — Total length of extensions, whole feet
- X-**X**-X — Nominal plunger length, feet
- **X**-X-X — Barrel length, feet
- Type seating assembly: C – Cup-type; M– Mechanical
- Location of seating assembly: A – Top; B – Bottom; T – Bottom, traveling barrel
- Type of barrel; H – Heavy-wall, W – Thin-wall } For metal plunger pumps; S – Thin-wall, P – Heavy-wall } For soft-packed plunger pumps
- Type pump; R – Rod; T – Tubing
- Pump bore (basic): 125 – 1 ¼ in.; 150 – 1 ½ in.; 175 – 1 ¾ in.; 178 – 1 25/32 in.; 200 – 2 in.; 225 – 2 ¼ in.; 250 – 2 ½ in.; 275 – 2 ¾ in.
- Tubing size; 15 – 1900-in. OD; 20 – 2 3/8-in. OD; 25 – 2 7/8-in. OD; 30 – 3 1/2-in. OD

Example: A 1 1/4-in. bore-rod pump with a 10-ft heavy-wall barrel and a 2-ft extension, a 4-ft plunger, and a bottom cup-type seating assembly for operation 2 3/8-in. tubing, would be designated as follows:

20-125 RHBC 10-4-2

In addition to the pump designation described in Par. 2.2, the purchaser must provide the following additional information:

a. Barrel material
b. Plunger material
c. Plunger clearance (ft)
d. Valve material
e. Length of each extension

Pump designator furnished by American Petroleum Institute

Advantages and Limitations of Rod Pumping Systems

Prime movers are either internal combustion engines or electric motors. Changing the pump rate or stroke length may change the production rate of any pumping unit within a limited range. The following is a summary advantages and limitations of the rod pumps:

Advantages:

- High efficiency
- Economic repair and services
- Corrosion resistant materials
- Ability to be repaired while the well is in service
- High salvage value & flexibility to adjust production rate

Limitations:

- Strength of the rod string
- Difficulty in handling high Gas Oil Ratio (GOR)
- Tubing and rod wear

Improvements in Design and Operations

Service companies have over the years offered design improvements in the construction and operation of beam pumps. Recent developments include a folding pump unit, a hydraulic rod-length control cylinder, new fiberglass rods and well analyzing / optimizing systems.

Rod-Pump Controller for Marginal Wells

Because reservoirs are dynamic, time clocks cannot accurately and consistently account for these changing conditions. A low-cost rod-pump controller for marginal wells http://www.worldoil.com/magazine/magazine_link.asp?ART_LINK=99-03_what-lea_fig3.html has been developed that detects pump-off by monitoring motor power derived from motor speed. When motor power declines below a predetermined limit, or reference power, the controller turns the pumping unit off. The unit will remain off for the preset downtime. When the unit restarts, calculated motor power is compared to reference power and a run / stop decision is made. Thus, the controller ensures that each well is producing only when the pump is filling, resulting in the elimination of fluid pound and reduction in electricity usage.

This controller requires no traditional position transducer or expensive load cell, and it defaults to a predefined percentage timer in the unlikely event of sensor malfunction. Recorded data includes SPM and last-72-hr run history. Affordable and simple to operate, the controller provides an economical means to monitor changes in mechanical efficiencies and reservoir conditions.

Rodless Pumping

Rodless pumping involves the use of subsurface pumps that may be categorized as:

- Hydraulic
- Electric
- Progressive Cavity
- Gas Lift
- Plunger Lift

Hydraulic Pumps

These pumps are fluid power operated and include both liquid and gas as power transmitting means. But in most cases it is the liquid operated pumps that are used in oilfield operations. The liquid is crude oil from the operations cleaned and free of water, gas and sediments. See Figure 3-9.

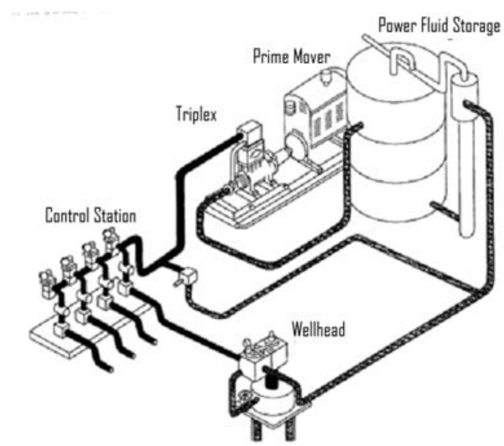


Figure 3-9
Hydraulic Lift System, Which Can Be Open (Jet) or Closed (Piston)

Oil under moderately high pressure is pumped to the bottom of the well as a continuous unidirectional flow. The fluid operates an engine in the bottom of the well, which is mechanically connected with a pump. The engine in turn drives a piston to pump formation fluid and spent power fluid to the surface. The power fluid can be open (OPF) or closed (CPF) depending if the power fluid is commingled with the produced fluid or returned in a closed conduit. This type of pumping requires a surface power fluid pump and a power fluid reservoir. The power fluid is normally oil or water.

Jet and piston are two different types of hydraulic pumps. Jet pumps, made with high alloy and abrasion resistant materials, are used for sandy or corrosive wells and can produce high rate of fluid and handle free gas. Piston hydraulic pumps can lift from great depths, but they do not handle gas or abrasive wells. Hydraulic lift systems can be used for deep and deviated wells with the following typical characteristics:

- Maximum operating depth: 20,000 ft
- Operating volume range: 135 – 15,000 b/d
- Operating temperature range: 100 – 500 ° F

Two basic systems have been applied to hydraulic pumping, the oscillating column system and a continuous system. The difference relates to the length of the passage between the control point and the pump. The bottom hole pump may be: single-acting, differential double acting, or full double acting type.

Electric Submersible Pumps (ESP)

ESPs are typically used in wells that produce from 500 to 20,000 barrels of fluid per day at depths up to 12,000 feet. They are routinely found in reservoirs under water flood and also have wide spread use in offshore applications. They are generally considered the best choice where high production volumes are required and where gas, for gas lift systems, is not available.

As shown in Figure 3-10, the ESP electrical power is supplied via a bank of transformers that convert primary line voltage to system voltage. A switchboard provides instrumentation for control and overload protection. A junction box acts as a vent to prevent gas, which may have migrated up the power cable from reaching the electrical switchboard. The electric motor at the bottom of tubing string is isolated from well fluids. Above the motor there is a separator and motor driven pump, which is normally a multistage centrifugal pump. ESP’s require very little space and can be installed in highly deviated wells, making them ideal for offshore operations.

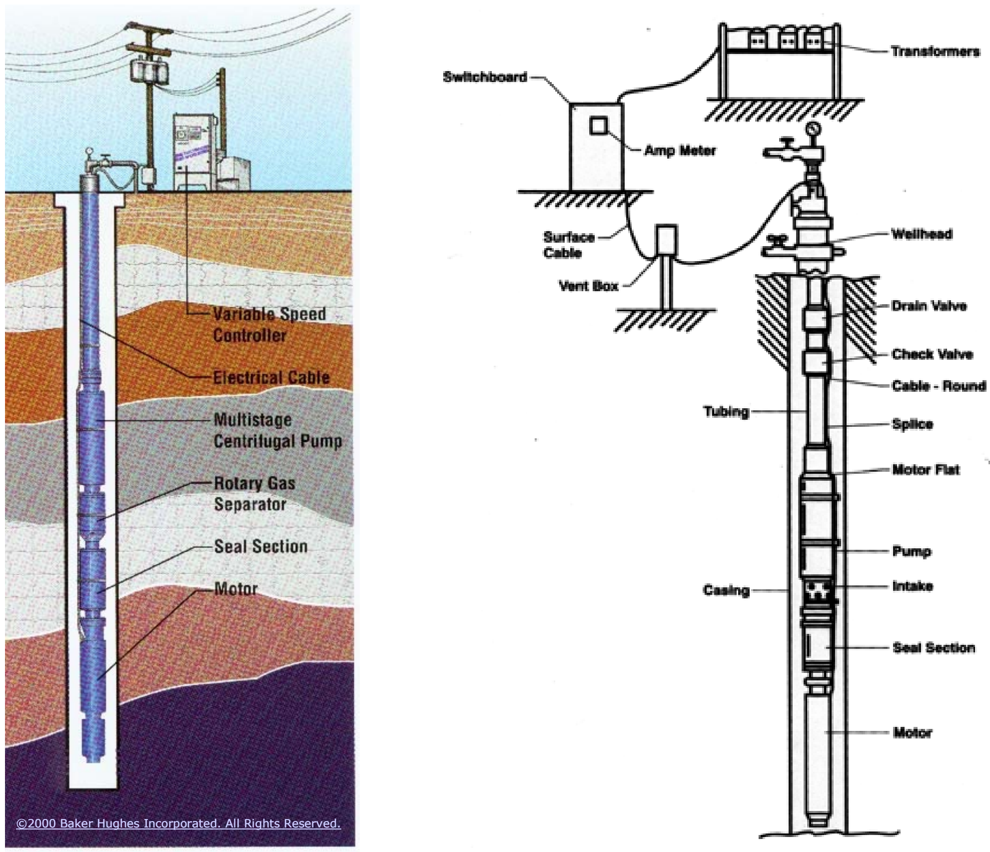


Figure 3-10
Diagrams of Electrical Submersible Pumping Systems[3]

Advantages of ESP include high depths and volume capability and adaptability to a variety of well bore configurations. However, EPS's do not perform well with free gas above 15% at the intake. Pumps are limited in viscosity ranges and cannot be readily repaired in the field. ESP systems are used for:

- Deviated wells and all wells with 4 in. casing and larger
- Handling high volume in deep wells
- Operating depths from 1,000 to 12,000 ft
- Temperatures from 100 to 400 ° F

These pumps can handle a wide range of rate from 200 to 20,000 bbl/d. Typical ESP lives have ranged from weeks up to 10 years. The average worldwide run life is 8 – 15 months. On the right side of Figure 3-11 a line of ESP's are used for water injection.

[3] http://www.bakerhughes.com/bakerhughes/products/ESP Systems

Figure 3-11
Typical Electrical Submersible Pumps, Long Beach, California

Progressive Cavity Pumps

Long used in surface industrial applications, progressive cavity pumps (PCPs) are relatively new to the oil field and were first used there in the 1980's. They are an excellent choice for heavy crude applications and quite competitive with both ESP's and rod pumps in some segments of the market. Cost is lower than ESP's, but higher than rod pump systems.

The market for PCP's is still developing. The pump concept has been in use in other industries for at least fifty years, but has only been used in oil applications to any great extent in the last ten years.

The primary oil application for PCPs today is heavy oil production, but recent developments show promise in a much wider market, including surface multiphase applications and down hole use with an ESP motor drive. For cases of high viscosity oil and sand production, PCP's-have shown promise to maximize production volume, while minimizing costs. PCP systems can have typical efficiencies of 70-98%. Comparable beam pumping efficiencies are 50-60%, and electrical submersible pumping efficiencies are 40-50%. Where PCPs are used or considered for use there are concerns about gas lock, foul up or gum up.

In addition to lower power consumption resulting from PCPs, the operator will achieve longer pump life and experience fewer rod and tubing problems, because of relatively slow operating speed of the pump. The PCP Pump should be run at an optimum speed to maximize efficiency, while minimizing wear on the pump, rod and tubing string. It is better to oversize the PCP pump and allow for an increase on the production at a later date. As such, rotor and rod string speed should be 100-400 RPM.

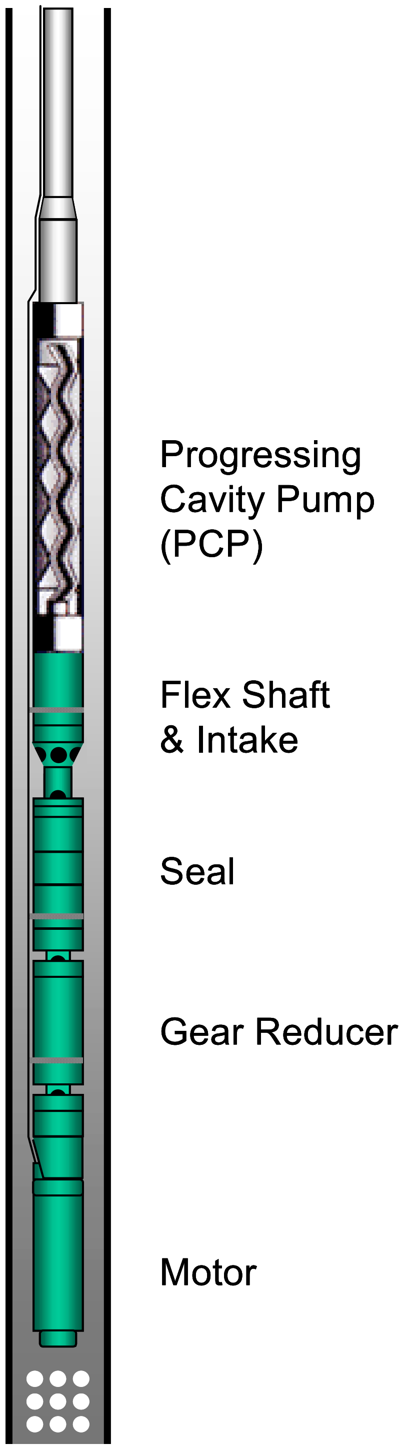


Figure 3-12
Progressing Cavity Pumping System[4]

[4] Rendering based on figure from http://www.bakerhughes.com/centrilift/ESP/pcpsystem.htm

Each PCP Pump has a maximum differential pressure based upon the number of seal lines between the rotor and stator. This maximum differential pressure is determined by the rated lift for a specific pump.

The PCP Pump is very resistant to damage caused by abrasive sand in the production fluid. The natural pumping action of the PCP Pump will result in the production fluid with sand to be displaced by the rotor, although, sand particles may become caught between the rotor and stator. However, this sand will be pressed into the soft resilient elastomer until the next cavity of fluid passes by to carry the sand on through the pump. A PCP system is represented in Figure 3-12.

Multiphase Pumps

Multiphase surface pumps used for pumping well effluents consisting of gas, liquid and solids face unique technological challenges in terms of efficiency, and longevity due to the harshness of the pumped media, each phase requiring different pump characteristics. Used to move the produced fluid in its natural, unsupported state, these pumps can substantially reduce on site separation cost, pipeline cost, as well as reduce well backpressure, enhancing either natural flow, or artificial lift flow.

Multi phase pump designs based on a special design progressing cavity pump offer superior efficiencies and seal longevity over axial flow or twin-screw designs.

Gas Lift

Gas lift is the best choice for very high volume and deep wells, providing that a supply of natural gas is available. The down hole design is simple and easily maintained from the surface using conventional slickline. Gas lift systems are widely used in offshore applications and in new fields where abundant amounts of natural gas is produced with the oil. Gas lifting of oil is accomplished by continuous injection of gas into the tubing string or casing annulus at some predetermined depth or by intermittent injection of gas. Selection of the approach depends on the well productivity index.

Equipment includes main operating valves, wire-line adaptations; check valves, mandrels, surface controlled equipment and compressors. Design aspect of gas lift requires matters related to valve spacing, continuous flow system, intermittent flow systems and chamber design, etc.

There are advantages in using gas lift valves as listed below:

- For wells with fixed surface injection pressure, deeper injection depth can be achieved. Also by selective gas injection at a higher or lower valve, variations in well productivity can be controlled. Furthermore gas lift valves allow controlled gas volumes to be metered into the well. Also for intermittent type operation, valves help in building up a fluid head between the injections.
- Gas injection is accomplished with a packaged compressor unit including compressor, prime mover steel skid gas and water manifolds radiator gas cooling section and scrubber.

Plunger Lift

As illustrated in Figure 3-13, a Plunger lift is an artificial lift method that can be effectively used in maintaining production levels and in stabilizing the rate of decline in production.

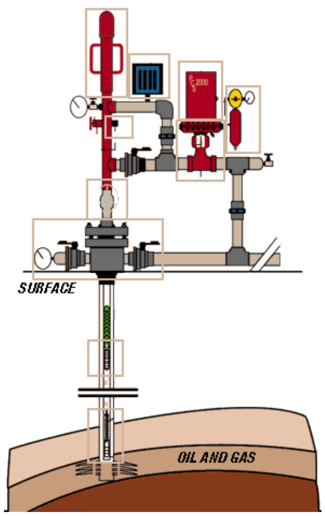


Figure 3-13
Plunger Lift

For plunger lift to be functional there must be sufficient gas present to drive the system. Oil wells making no gas are not plunger lift candidates. However, there is an industry misconception regarding how much gas and pressure is required to successfully operate a plunger lift system. Because many engineers and field personnel have operated under this misconception, large numbers of wells have been placed on more costly forms of artificial lift, such as pumping units, than was necessary. As a result, optimum results have not been achieved and capital expenditures much larger than necessary have been made.

As the flow rate and pressures decline in a well, lifting efficiency declines geometrically. Before long the well begins to ‘load up’ and ‘log off. This is a condition whereby the gas being produced by the formation can no longer carry the liquid being produced to the surface. There are two reasons this occurs. First, as liquid comes in contact with the wall of the production string of tubing, friction occurs. The velocity of the liquid is slowed and some of the liquid adheres to the tubing wall, creating a film of liquid on the tubing wall. This liquid does not reach the surface.

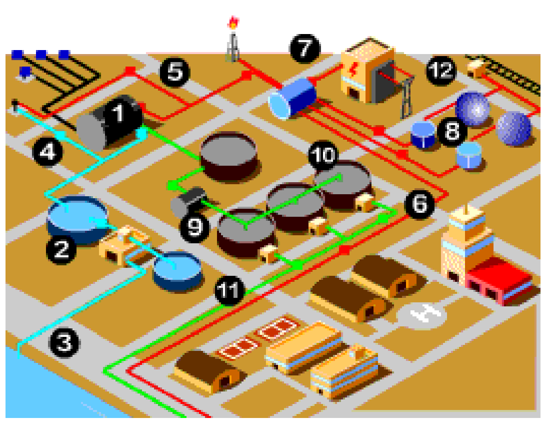
Secondly, as the flow velocity continues to slow, the gas phase can no longer support liquid in either slug form or droplet form. This liquid along with the liquid film on the sides of the tubing begin to fall back to the bottom of the well. In a very aggravated situation there will be liquid in the bottom of the well with only a small amount of gas being produced at the surface. The produced gas must bubble through the liquid at the bottom of the well and then flow to the surface. Because of the low velocity very little liquid, if any, is carried to the surface by the gas a back pressure against the producing formation in a value equal to its weight effectively terminating the well's ability to produce. Properly applied plunger lift systems have been able to bring such wells back to life and to make them extremely profitable once again.

Once a well begins to load with liquid, the least expensive way to keep it flowing is to use an intermitter. An intermitter is simply a controller at the surface, which is used to open and close the well, usually on a time signal. In using this technique the well is stop cocked by shutting it in for a period of time to allow it to build pressure. After sufficient pressure has been achieved, the intermitter opens the valve at the surface, allowing the well to flow into the flow line. Because of the extra pressure in the well from the shut-in period, the velocity in the production string of tubing is higher and some of the liquid can be brought to the surface. There are a number of variations on this theme. One such variation is where the well is continuously flowed to the sales line with an intermitter and valve on a line to a pit or tank. Occasionally the intermitter will open this line, bypassing the backpressure of the sales line and production vessel, and vent to the pit or tank. Again the velocity is increased as the backpressure at the surface is eliminated. Even in using this technique to unload wells there is fluid fall back. The amount of fall back depends upon the depth of the well, size of the tubing, and velocity of the fluid achieved in the tubing string. Generally, there will be between a 5% and 8% fallback rate per thousand feet. Consequently in a 5,500 foot well there can easily be a 50% fall back rate. Keep in mind that any fluid that is not produced at the surface exerts backpressure on the producing formation in the amount of its weight, thus hindering the well's ability to produce.

Plunger lift uses this same intermitting technique, along with a free traveling plunger in the tubing string used as an interface between the liquid phase and the gas phase. Because of the action of the plunger in the tubing, there is less than a 5% fluid fallback rate over the entire length of the tubing string irrespective of well depth. As a result, the well can be operated at a lower flowing bottom hole pressure, as all liquid is removed from the well bore, thus enhancing production.

Surface Facilities

Fluid produced from a well is a mixture of oil, water and gas plus some sediment. As represented in Figure 3-14, surface facilities are intended to turn this mixture into separate streams of clean dehydrated oil and gas and safely disposable water.



1. Separator
2. Casing
3. Waste water
4. Re-injected water
5. Re-injected gas
6. Conveyance of natural gas by gas pipeline
7 Gas burned to produce energy
8 Liquefied petroleum gas (LPG)
9. Pumping crude
10. Crude oil tanks
11. Shipment of crude by oil pipeline
12. Loading facility

Figure 3-14
Typical Surface Facilities (Courtesy Elf5)

The hydrocarbon liquid and gas are then ready for metering and shipment. The main component of surface facilities, depending on the type of the oil, includes one or more stages of separators, free water knockout, heater treater, electrostatic treater and crude stabilizer. Oil metering is either automatic or manual. Automatic devices are positive volume, positive displacement, and turbine and mass flow meters. Manual gauging involves a hand measurement of oil level in a stock or storage tank before and after oil is removed from the sales line. Table 3-5 shows a listing of typical equipment and instruments used in Oilfield operations.

Table 3-5
Typical Equipment and Instruments used in Oilfield Operations

Dehydrators
Separators
Indirect Heaters
Treaters
Meter Runs
Safety Valves
Hi/Lo Pilots
Control Valves
Instrument Controllers
Relief Valves

Oil and Gas Separators

Most crude oils are saturated with natural gas at reservoir pressure and temperature. The physical and chemical characteristic of the oil and its condition of pressure and temperature determines the amount of gas it will contain in solution. Oil and gas separators provide the function of providing space in which oil and gas are separated after they expand into the tubing. The difference in density may accomplish the separation. In most cases, mechanical devices “mist-extractors” are used to remove liquid from gas before it is discharged from the separator.

If water is also produced with oil, free water may be removed by the use of 3 phase separators. At times, emulsion breakers may have to be used to separate oil and water. Heater-treaters may also be used in oilfield to break emulsion further helping to separate water from the produced oil.

Water Injection

Positive displacement pumps are used in systems where the required discharge pressure is below 500 psi. A Triplex plunger type pump is used where the required pressure is above 500 psi. Electric motors and gas engines are widely used in oilfield operation. These systems vary from direct drive, belt drive and direct drive with gear type speed reducer.

[5] http://www.elf.fr/odyssee/us/dev/index.htm

As shown in Figure 3-15, injection pump systems are typically triplexed (operated in groups of 3) from 1-100 hp. Triplexing allows for staging of pumps depending on load requirements, pumps may be driven by gas engines or by motors in areas with limited availability of gas.

Figure 3-15
The Main Water Injection Pumps in Bakersfield area, California

Drilling Wells for Artificial Lift Service

Many wells using new drilling technology are deviated horizontal or multilateral wells. These wells can be producing viscous oil, gas with some liquids, or other types of production. They may require artificial lift to begin sooner or later in the well's life. If a lift system, such as a rod pump, is set in a curved horizontal well profile, failure rate can be high. It would be more desirable to set such a lift system in a vertical section of a larger-diameter casing and have the pay intersected by laterals off the main vertical portion. In other words the vertical well casing would be sized for several wells with horizontal laterals run to adjacent location s of the formation. The pump would be located in the main vertical shaft collecting fluid from all the laterals.

Electric Power Usages

Electric power in typical oil field operations is used for artificial lift systems, fluid injection systems, and fluid transfer on the surface, heating equipment, gas turbines and steam generators. Figure 3-16 and Figure 3-17 indicate how electrical power is used based on motor horsepower.

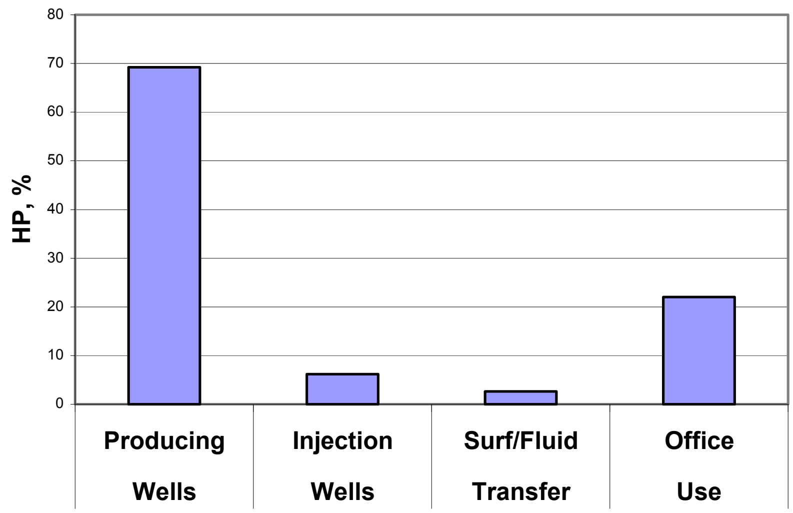


Figure 3-16
Typical Distribution of Electric Power Consumption in a Middle Size Oilfield in California

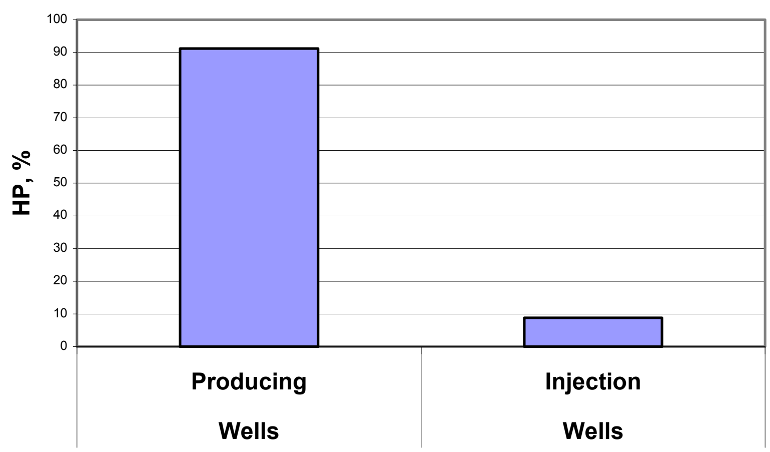


Figure 3-17
Typical Distribution of Electric Power Consumption in a Small Size Oilfield in California

Generally, the power consumed by production pumping is considerably more then other components of the oil recovery system. Depending on the surface conditions, EOR methods, distances between the pumps, tanks, and wells in the oilfields, producers may have different distributions of electric power consumption.

Operational Optimization Steps

The best practices program can be described as one that is continually improving with greater knowledge and awareness gained from further reductions in tubing leaks, rod parts and pump repairs. The program consists of the following five steps:

1. Complete initial pumping well diagnostic analysis on existing wells.
2. Complete predictive analysis on wells not yet on production.
3. Optimize wells to match existing or future lift operations with existing or future equipment. These optimization steps include modification of the following:
   - Pump diameters
   - Strokes per minute
   - Stroke length
   - Tubing anchor catcher
   - Down hole gas separation
   - Re-evaluate rod string designs and installation of sinker bars to manage down hole rod string buckling
4. Install pump-off controllers to manage the following:
   - Production rates
   - Optimize run times
   - Monitor equipment performance
5. Review the well site diagnostic analysis after several months by re-evaluating the initial analysis and original well work, and then implement further modifications.

Prime Movers for Pumping Units

An internal combustion engine or an electric motor is normally used as prime movers for pumping units. Some slow speed single cylinder engines burn diesel or fuel oil.

Selection of the type of prime movers depends on many factors such as horsepower requirements, availability of fuel such as natural gas and local regulations. Today, A-C polyphase induction motors power most modern pumping installations. These usually operate at 200/440 volts, 3-phase from secondary transformers where the primaries are supplied from high voltage distribution lines. At times there may be a lease generating facility supplying the power. Table 3-6 provides horsepower calculations for typical oil production applications.

Table 3-6
Horsepower Calculations

Horsepower Requirements
Rod pumping units
Brake horsepower for slow-speed engines and high-slip NEMA (Natl. Electrical Manufacturers Assoc.) D motors is:
$P_b = (q \times d)/56{,}000$
where:
P_b = brake power, hp
q = fluid flow rate, b/d
d = depth (lift), ft
Selection criteria required for an ESP's are:
Well data
Production data
Well fluid properties
Electric power supply, including:
Available primary voltage
Frequency
Power source capabilities
Submersible Units:
$P_{hm} = P_{hs} \times N_s \times S_g$
where:
P_{hm} = motor horsepower
P_{hs} = horsepower per stage
N_s = number of design stages
S_g = fluid specific gravity
Hydraulic pumping systems (Piston and Jet)
Hydraulic power transmission is:
$P_h = 0.000017 \times Q \times P$
where
P_h = horsepower, hp
Q = flow rate, b/d
P = pressure, psi

Oilfield System Conclusion

The level of future crude petroleum and natural gas exploration and development, remain contingent upon a number of uncertainties—most importantly, the future price of oil and gas and operational cost. Electric power cost constitutes a major portion of the cost.

Typical oilfields in the U.S. are dependent on some type of artificial lift for maintaining productivity. Majority of the pumping systems are of the beam type design. Together with these are ESP (Electric Submersible Pumps) and hydraulic pumps, which make up the major consumer mechanisms of electricity in lifting operations. There are opportunities for optimization of the lift mechanism that can increase efficiency and lower cost. Each field depending on its crude oil characteristic, well depth, hole angle is a separate case requiring detail studies. It is the goal of this project to develop generic guidelines for California producers and especially small producers to reduce electric consumption by optimizing their lift operation.

4
SURVEY RESULTS AND ANALYSIS OF DATA

Introduction and Background

The troubleshooter program was initiated in July 2000 to assist small California oil and gas producers in their efforts to reduce consumption of electricity in field operations. Operators taking advantage of the program volunteered to give troubleshooters access to specific fields operated by them. The troubleshooters then scheduled visits to fields to collect pertinent data. All participating operator's field data were held confidential.

The field visits started in September 2000. Two data collection templates were used, one for general field data and one for individual well data. These templates were refined as they progressed. By February 2001, six fields had been visited and the data collected had been analyzed on a preliminary basis. These early results were reported at the PTTC Energy Crisis Workshop held on March 15, 2001 in Santa Clarita.

Results

Data collection activities continued through May 2001. In general, field production and electrical power data over a consecutive three-month period were collected and averaged. Production and operating data from individual wells covered the same three-month period. Electrical consumption data from power bills were allocated to production, injection, and surface operation based on nameplate motor horsepower and reported run times. In total, 19 fields were visited and the vast majority of data collected covered the last quarter of 2000.

A tabulation of the data obtained from participated operators and fields is shown in Table 4-1.

Table 4-1
Summary of Data from 19 Fields Surveyed

Field No.	Mean HP	Quantity of Pumps by Type				Average real monthly energy usage, (kwh/m) for:				Average daily prod. & inj., (b/d)			Lifting Consumption KWH/(1000Ft.B)
		Rod-pumps	ESP	Hydraulic	Avg. Enrgy Cost Cents/kWh	Total	Oil Production	Water/Steam Inj.	Surface Op.	Oil prod.	W/S Inj.	Gross prod.	
1	42	37	0	0	12.67	198464	156196	42268	0	285	2500	2955	0.596
2	72	49	14	2	13.15	2587992	1738189	778647	89296	1400	43000	49100	0.447
3	68	0	6	23	10.16	1437480	767629	146572	523279	930	7715	11210	1.171
4	1.3	13	0	0	10.16	8315	8110	0	204	22	0	31	10.277
5	15	3	0	0	11.73	2754	2733	0	21	7	0	11.9	2.044
6	17	37	0	0	13.82	211200	148791	54260	8140	218	3094	5265	1.510
7	43	82	0	0	6.87	2187473	1088409	655391	443672	3700	31650	62350	3.053
8	55	268	30	0	11.07	9177934	4221778	2768994	2187159	6564	238204	201219	0.853
9	34	23	0	0	23	145162	124939	20222	0	155	13000	13155	1.525
10	50	2	0	0	9.15	10060	7929	1982	147	54	160	214	0.126
11	88	22	0	0	11.8	430148	391293	23620	15239	800	1792	2600	0.660
12	27	49	0	2	34.4	1027	947	58	22	453	9151	9604	0.005
13	28	6	0	0	11.4	12913	5617	6997	298	40	12000	476	0.276
14	25	15	0	0	6.4	107060	99279	0	7781	42.3	0	5002.3	0.368
15	52	26	0	0	5.34	26451	24375	0	2076	34.6	0	721	4.644
16	14	66	0	0	5.88	144977	142870	0	2107	215.4	0	3091.4	2.596
17	17	16	0	0	5.36	41575	41312	0	262	57.9	0	1716.4	2.267
18	43	13	0	0	26	35085	35085	0	0	53	0	1468	0.263
19	34	143	0	0	5.65	1231867	958053	256269	17545	471.9	44358.6	44830.5	1.256

Of the 939 producing wells for which data were collected, 91% were rod pumped wells. Other lift methods used were electric submersible and hydraulic pumps. Total gross production from all the fields visited averaged 415,020 BFPD during the study period. Thus, the well and field sample represents 2.3% of all California onshore producing wells and 0.29% of all onshore fluid production (study period compared to February 2001 DOGGR data). The majority of electrical consumption, 55.3%, is for lifting fluids as illustrated in Figure 4-1. Resulting from this data, analysis is focused on power used for fluid lifting.

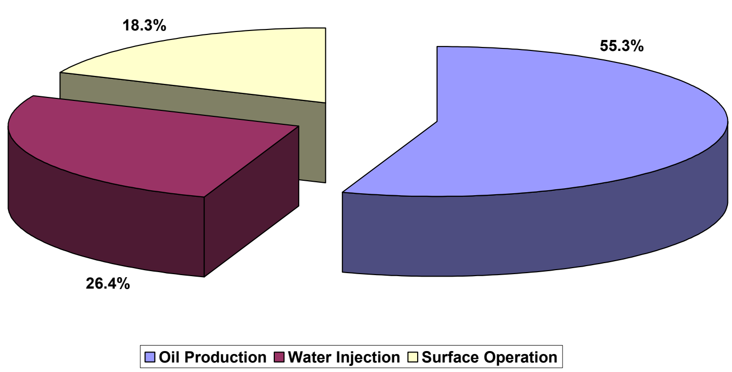


Figure 4-1
Distribution of Electric Power Consumption

A series of charts were prepared to better illustrate and understand the attributes of the data set collected and to provide the basis for analysis of individual field operations.

Figure 4-2 shows the total number of producers and injectors by fields. The operations visited ranged from small (two producing wells) to large (299 producing wells).

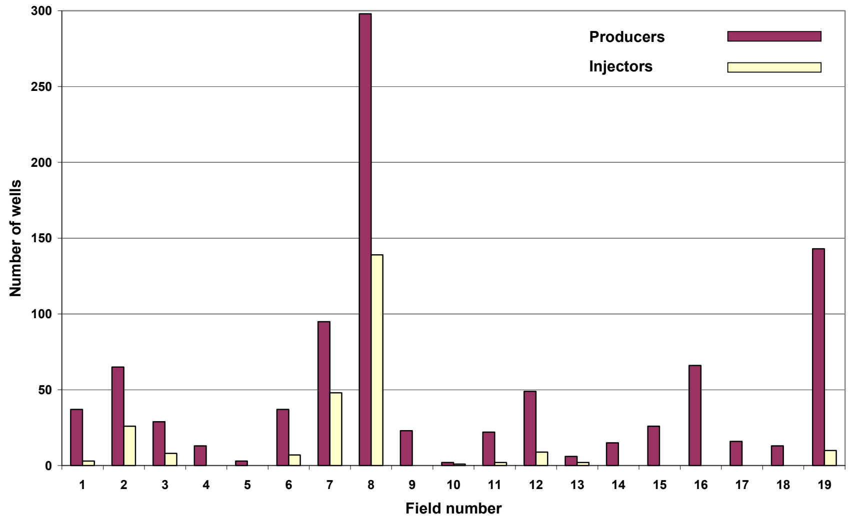


Figure 4-2
Total Number of Producers and Injectors by Field

Figure 4-3 shows the distribution of average producing depth of all the wells in this study. The average depth is around 2,800 feet.

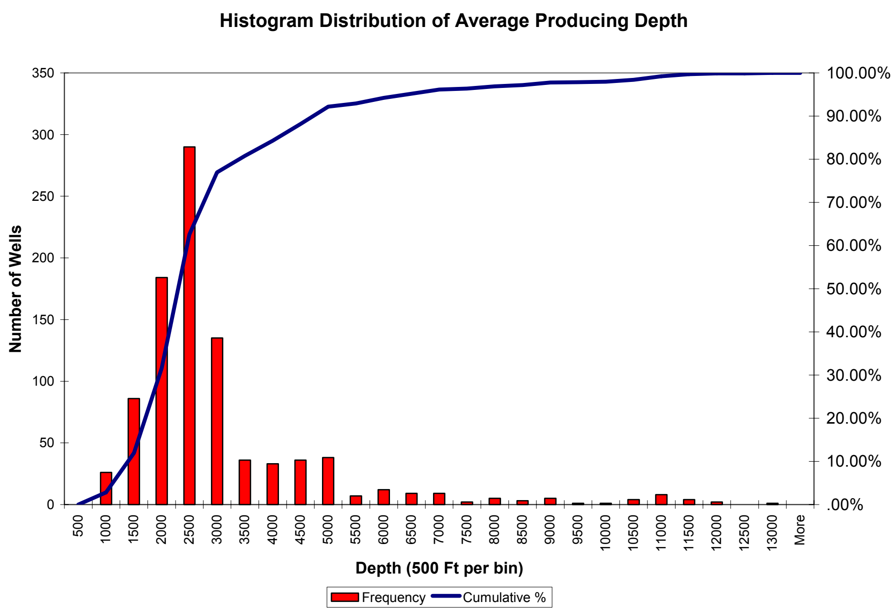


Figure 4-3
Distribution of Average Producing Depth

Figure 4-4 shows the average producing well depth by field. The shallowest well was around 600 feet while the deepest well was over 12,500 feet deep.

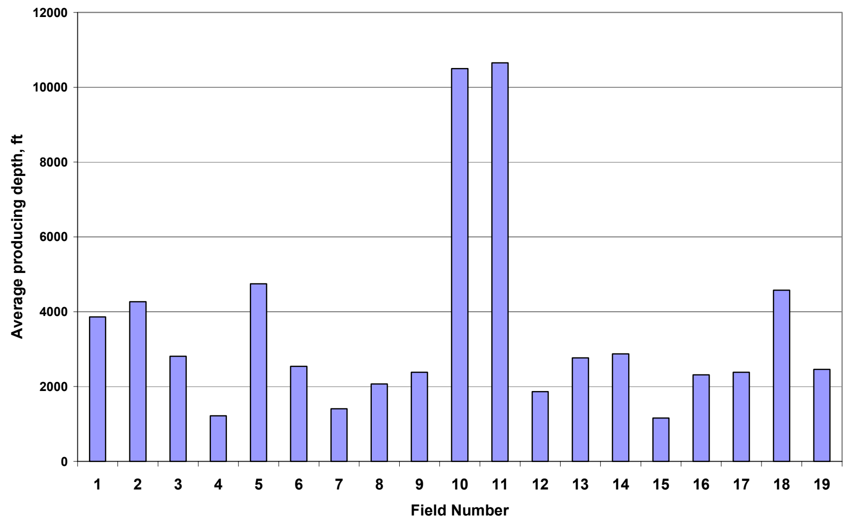


Figure 4-4
Average Producing Depth by Field

Figure 4-5 shows the distribution of average daily gross production for the wells. The range of the gross production was between 0.4 B/D to a maximum of 2672 B/D with a mean of 424 B/D.

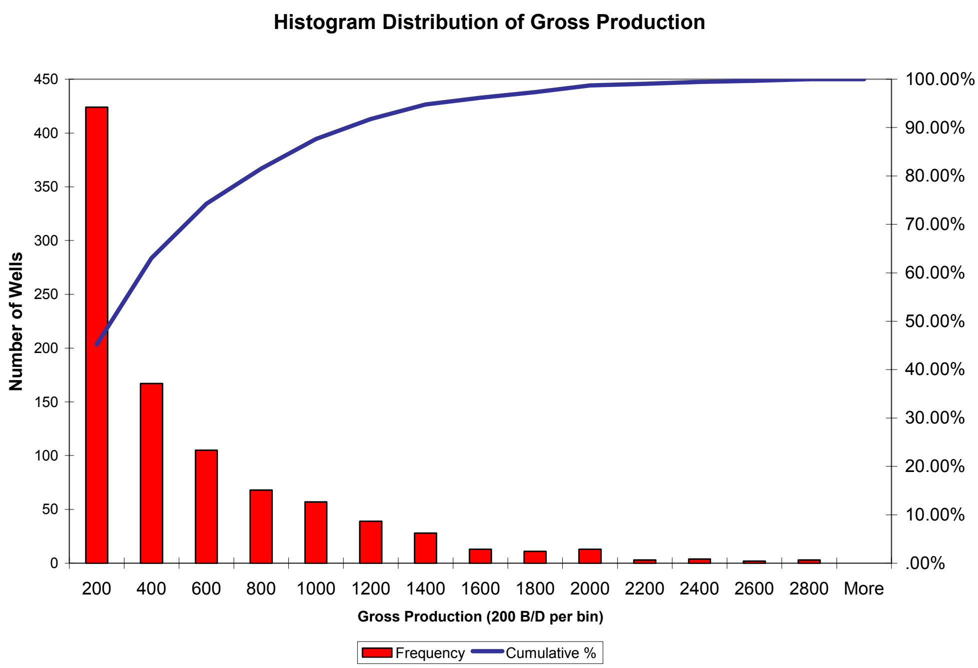


Figure 4-5
Distribution of Average Daily Gross Production

Figure 4-6 shows gross production and injection rates by field for all the visited fields. The total range of operated production varied from 12 to over 200,000 BFPD.

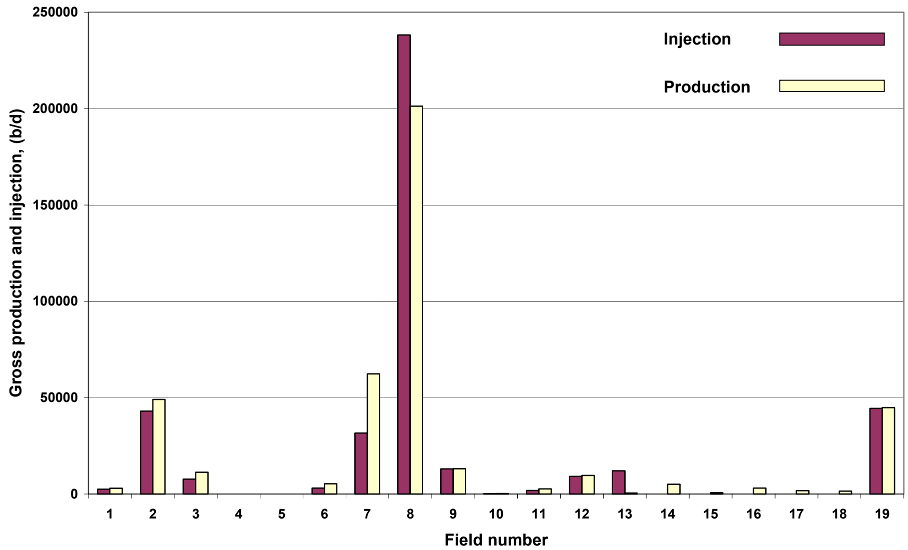


Figure 4-6
Gross Production and Injection Rate by Field

Figure 4-7 shows the distribution of the motor size of the well. Almost all of the motors were less than 100 HP with an average of 43 HP for all the surveyed wells.

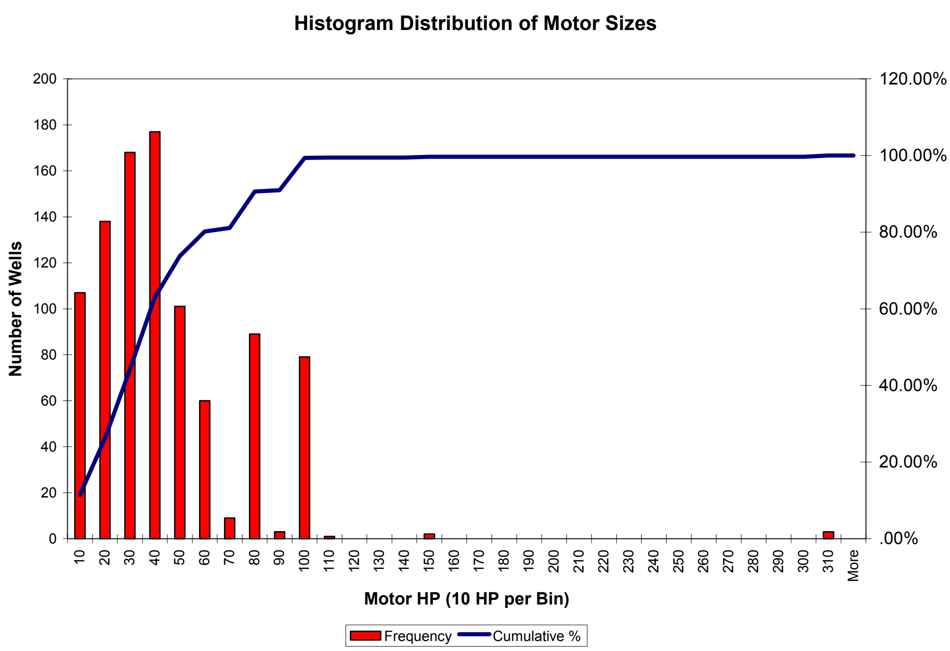


Figure 4-7
Distribution of Motor Sizes (HP)

Figure 4-8 shows the artificial lift methods by field. In all cases except one, rod pump is the predominant lifting method.

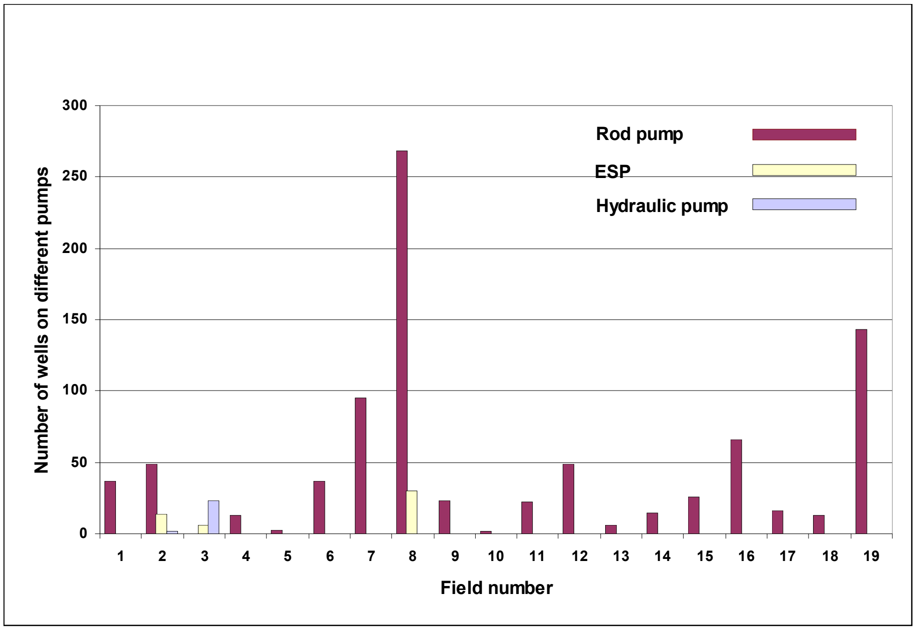


Figure 4-8
Artificial Lift Methods Distribution by Field

Figure 4-9 shows the overall breakdown: 91.1% of all the wells are rod-pump, 5.2% are electrical submersible pump, and 3.7% of wells were producing with hydraulic pump.

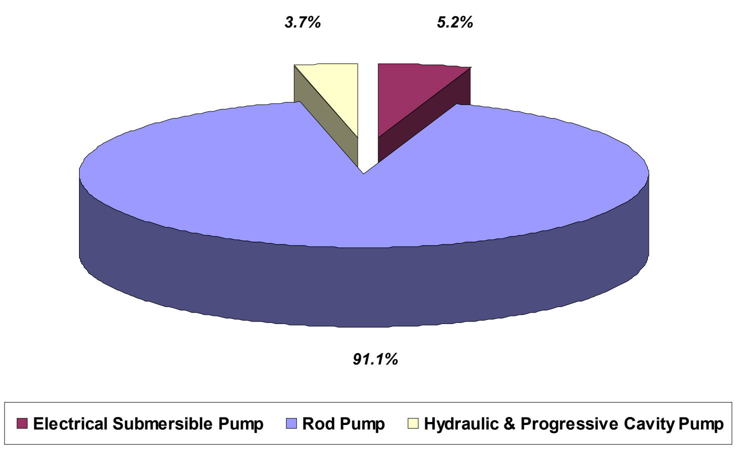


Figure 4-9
Distribution of Artificial Lift Methods Under Study

Figure 4-10, Figure 4-11, and Figure 4-12 show motor size distribution for rod-pumps, electrical submersible pumps, and hydraulic pumps respectively.

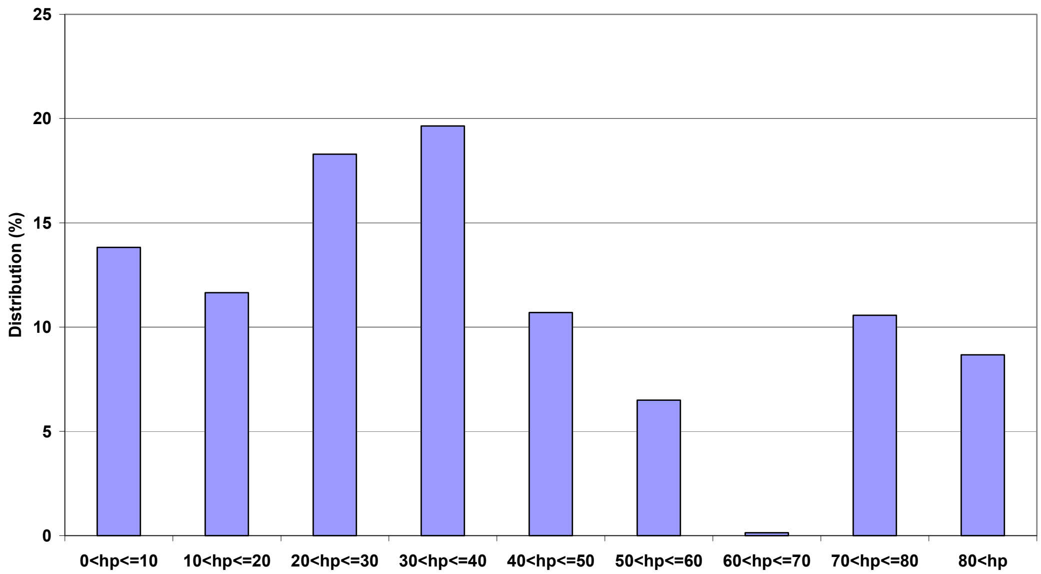


Figure 4-10
Motor Size Distribution for Rod Pumps

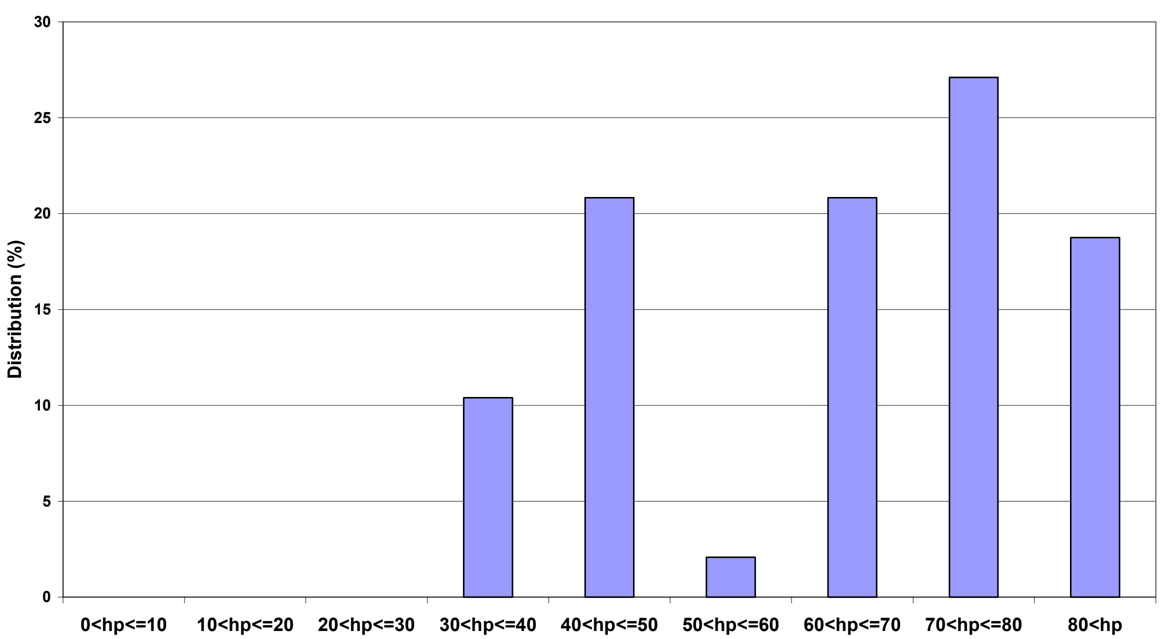


Figure 4-11
Motor Size Distribution for Electric Submersible Pumps

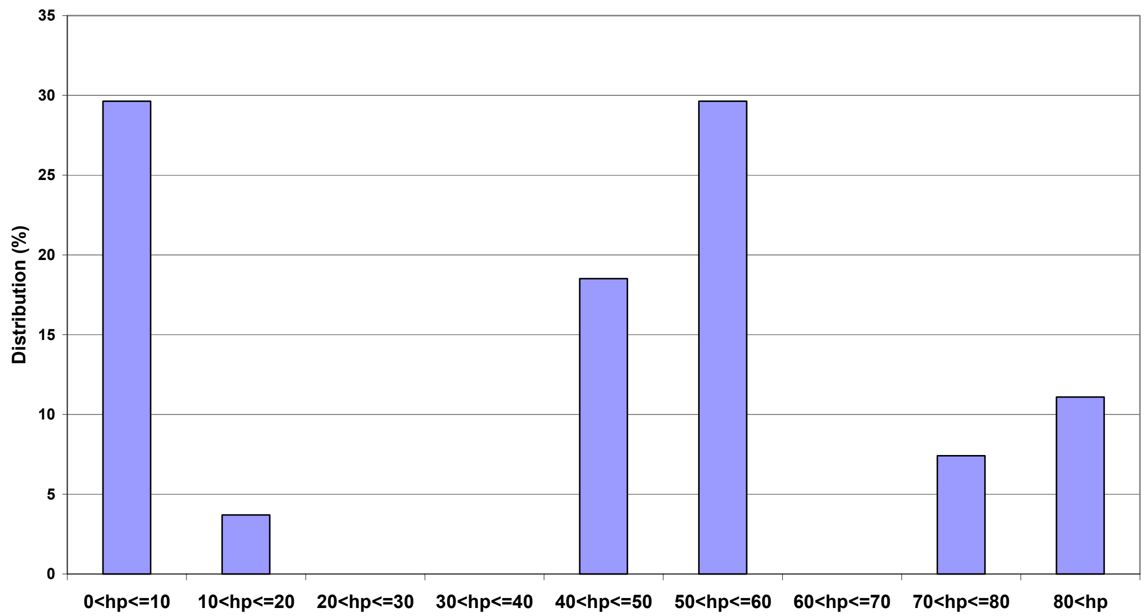


Figure 4-12
Motor Size Distribution for Hydraulic and Progressive Cavity Pumps

Figure 4-13 shows total electric power usage by fields. While Figure 4-14 shows the cost of electric power usage on gross barrel basis, it is realized that cost is also a function of the field specific rates charged by the utilities.

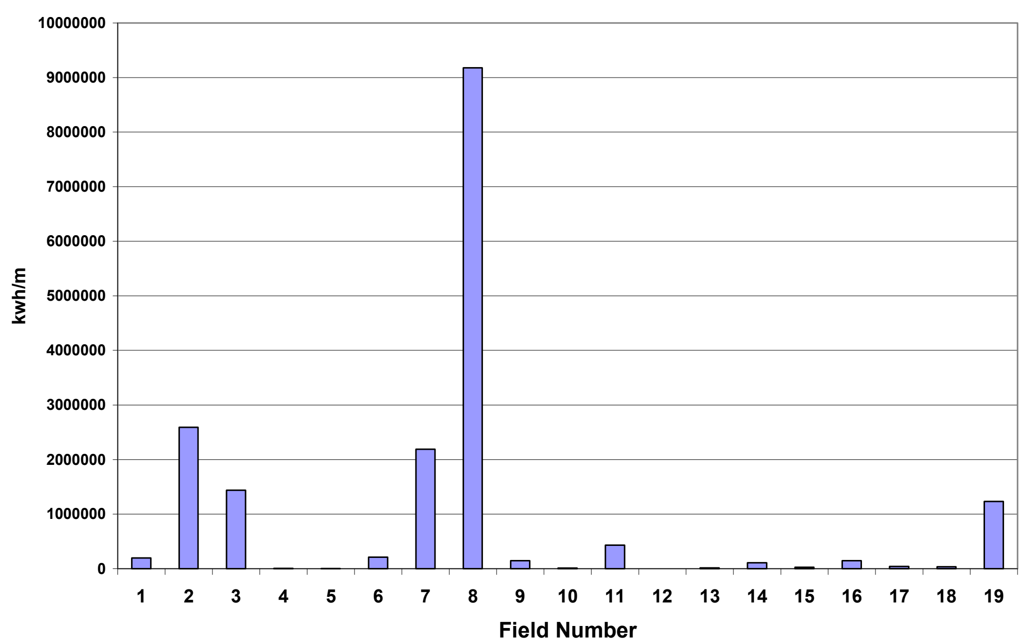


Figure 4-13
Electric Power Usage by Field

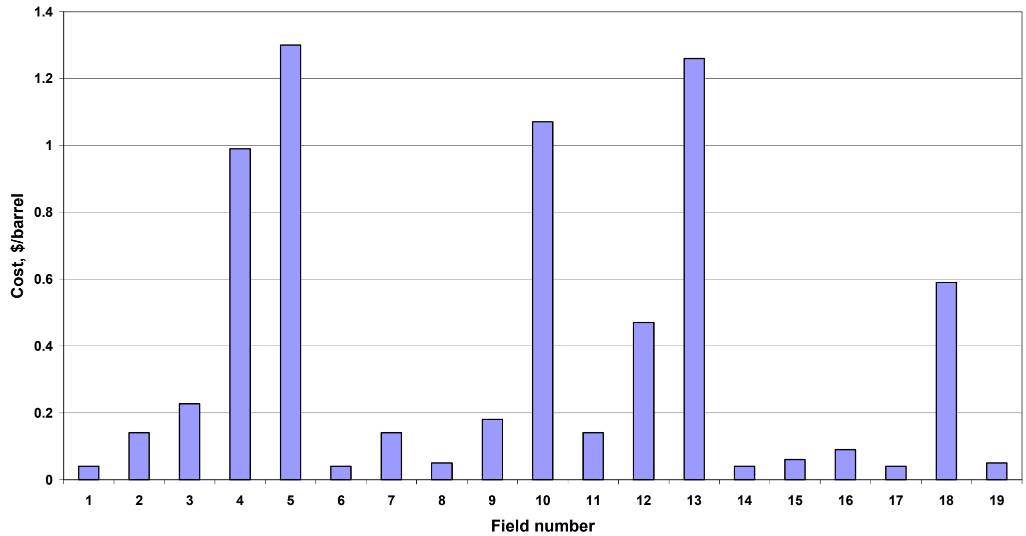


Figure 4-14
Cost of Electric Power Usage Per Gross Barrel by Field (4th quarter, 2000)

Figure 4-15 shows the electric consumption of lifting per bbl of fluids produced by field and method lifting. Note that for two fields, a complete power-use data set was not available.

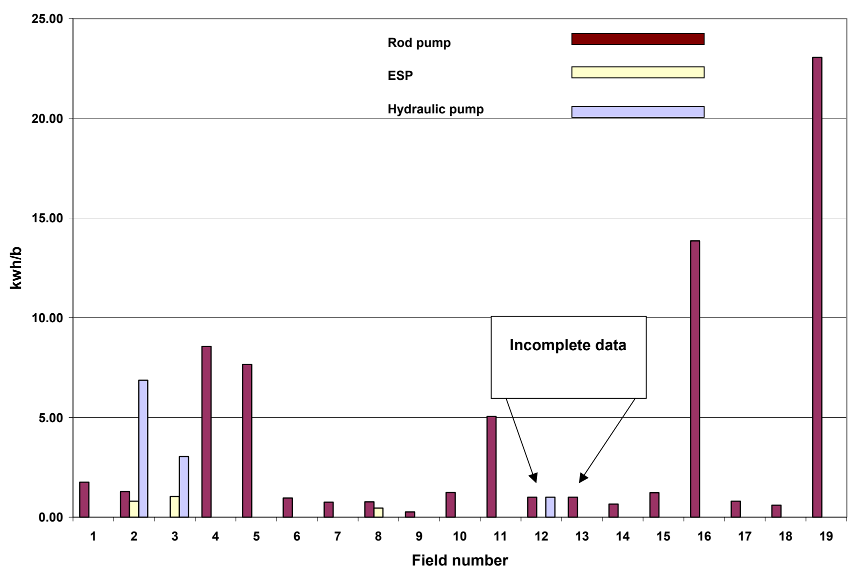


Figure 4-15
Lift Power for Artificial Lift Methods

Figure 4-16 illustrates the portion of the electric usage by field for lifting, injection and surface operations. This chart again shows that the majority of power is consumed for lifting in all cases.

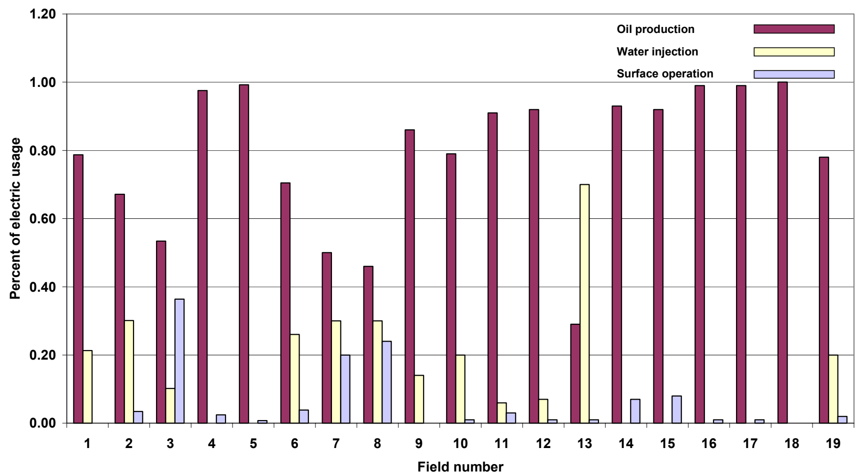


Figure 4-16
Electric Usage Distribution by Oil Field Operation

Figure 4-17 shows the majority of the electric consumption (55.3%) is for production operation, while the water injection operations use 26.4% of electric consumption and the surface operation uses the remaining 18.3%.

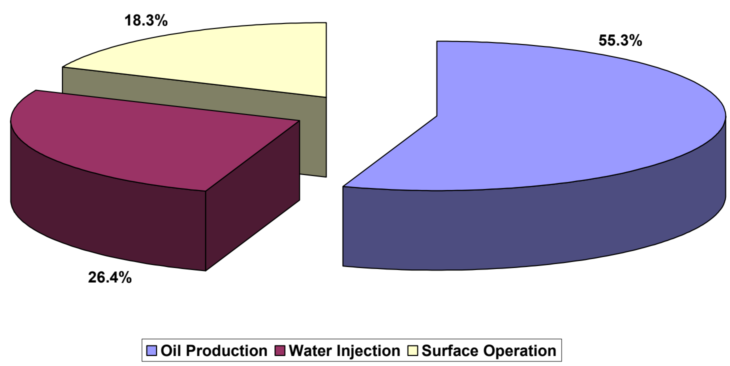


Figure 4-17
Distribution of Electric Power Consumption

Figure 4-18 shows the distribution of lift consumption for all wells. It is a histogram of kWh consumption per 1000 feet of well depth per barrel of gross production. The purpose of this distribution is to identify the total population of wells that may be operating inefficiently. The average well studied requires 0.479 kWH/bbl/l000' to lift fluids. Figure 4-18 indicates that many wells are operating more efficiently than average while many wells are very inefficient. The derivation of lifting consumption is discussed below.

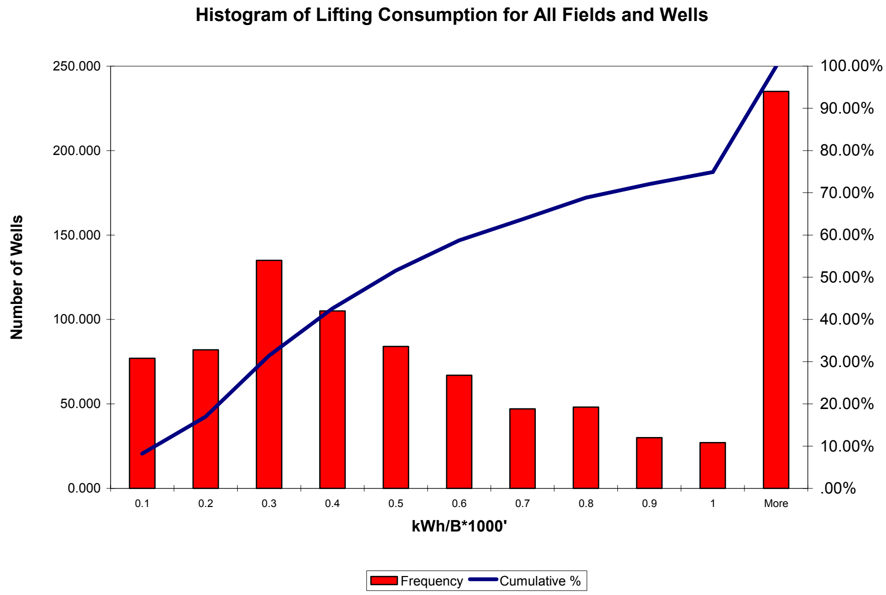


Figure 4-18
Distribution of Lift Consumption

Derivation of Lifting Consumption

Lifting consumption (LC) is a key result of the data analysis as it provides operators with the means to compare individual wells in their operations with the norms of the entire population studied. Therefore it is important to know how lifting consumption is calculated for each well in a field. LC is the energy required to lift 1 barrel of fluid 1000 feet. This should be a strait forward calculation based on energy consumed, well physics and production rates. The oilfields surveyed had more than one well per revenue meter. Additionally, revenue meters recorded power, representing a mixture of producing and non-producing loads. These issues created a challenge to the establishment of energy values for each well needed to calculate of LC values. Table 4-2 represents a sample spreadsheet resulting from data obtained during an oilfield survey.

Table 4-2
Sample Field Spreadsheet

<u>Sample Field</u> 1 (a)

Published Data:

Total energy usage for oil production per month (kwh/m):	83795	(PPa)
Total energy usage for water injection per month (kwh/m):	22676	
Total energy usage for water disposal injection per month (kwh/m):	0	
Total energy usage for oil transfer and surface per month (kwh/m):	0	
Total for field (kwh/m):	106472	(FPa)

Revenue Data:

Avg. monthly electric use (kwh/m):	83500	(RPa)

<u>Producers</u>

(i) Well I.D.	(Bai) Avg. P. D. (ft)	(Cai) Daily O. P. (bbl)	(Dai) Daily W. P. (bbl)	(Eai) Gross P. (bbl)	(Fai) Motor (hp)	(Gai) Timer (h/d)	(Hai) EnergyUs. kWh/M	(Jai) Pi kWh/M	(Kai) Lift Consumpt. kWh/(1000Ft.B)	(Lai) (LCai>0.5) 0.50	(Mai) Savings kWh/M	(Nai) Savings kW
1	5000	4	15	19	30	4.6	3088.44	1620	0.57	0.57	195.31	1.42
2	5100	3	18	21	40	4	3580.80	1879	0.58	0.58	272.12	2.27
3	5100	4	51	55	40	6	5371.20	2818	0.33			
4	4700	4.5	39.5	44	40	4.5	4028.40	2113	0.34			
5	5300	2	19	21	40	4	3580.80	1879	0.56	0.56	209.12	1.74
6	4500	3	33	36	60	6	8056.80	4227	0.87	0.87	1796.89	9.98
7	5000	2.5	13.5	16	30	4.5	3021.30	1585	0.66	0.66	385.08	2.85
8	3600	22	62	84	40	10	8952.00	4697	0.52	0.52	160.54	0.54
9	4000	17	75	92	40	8	7161.60	3757	0.34			
10	3900	14	70	84	40	7	6266.40	3288	0.33			
11	2800	23	69	92	50	15	16785.00	8806	1.14	1.14	4942.01	10.98
12	2800	30	92	122	40	2.25	2014.20	1057	0.10			
13	3300	8	45	53	30	6	4028.40	2113	0.40			
14	4200	9	64	73	40	8	7161.60	3757	0.41			
15	4600	4	25	29	60	2.9	3894.12	2043	0.51	0.51	42.00	0.48
16	4600	6	49	55	40	6	5371.20	2818	0.37			
17	4600	15	210	225	50	15	16785.00	8806	0.28			
18	3300	18	300	318	40	6	5371.20	2818	0.09			
19	4600	8	111	119	40	12	10742.40	5636	0.34			
							125260.86				8003.06	30.26

There are three parts to the Sample Field spreadsheet in Table 4-2. These parts are the Published Data, Revenue data and the Producer well data. The published data provides energy usage for production (*PPa*) and for the entire field (*FPa*). The power consumption from revenue data (*RPa*) results from averaging three months of electric bills for the field. Using the published and revenue data along with individual well motor HP (*Fai*) and well timer (*Gai*) the power consumed for each well was calculated in a two-step process. In the equations that follow the term (*a*) defines a field specific variable and the term (*i*) defines a well specific variable.

The first step required calculating the theoretical power consumed by the motor at each well. This calculation is shown in Equation 4-1.

Equation 4-1
Theoretical Power Consumption for Each Well

$$Hai = (Fai \times 0.746) \times (Gai \times 30) \text{, (kWh/M)}$$

The term "*Fai*" represents motor horsepower and the term "*Gai*" represents timer hours per day that the well operates. Once the theoretical power consumption for each well (*Hai*) calculated, it is necessary to reference the values to published power consumption and field revenue data. Equation 4-2 provides the method used to calculate a field normalized power consumption value for each well.

Equation 4-2
Field Normalized Power Consumption for Each Well

$$Jai = \frac{Hai}{\sum Hai} \times \frac{PPa}{FPa} \times RPa \text{, (kWh/M)}$$

The first term normalizes well consumption based on the ratio of the individual theoretical well consumption to the total theoretical consumption for the field. The second term normalizes well consumption based on the ratio of published energy consumption for production to the total published consumption for the field. Once the normalized power consumption values (*Jai*) for each well are established, the calculation of lifting consumption (*Kai*) may proceed using gross production (*Eai*) and average pump depth (*Bai*) data. Equation 4-3 provides the method used to calculate a lifting consumption value for each well.

Equation 4-3
Lifting Consumption for Each Well

$$Kai = \frac{Jai \times 1000}{Bai \times Eai \times 30} \text{, (kWh/B*1000')}$$

With the development of lifting consumption understood, we may return to the survey results. The lifting consumption values were calculated for each well and averaged for each field to produce the lifting consumption by field chart shown in Figure 4-19. Only about a third of the fields are operating below the 0.479 kWH/bbl/1000' average.

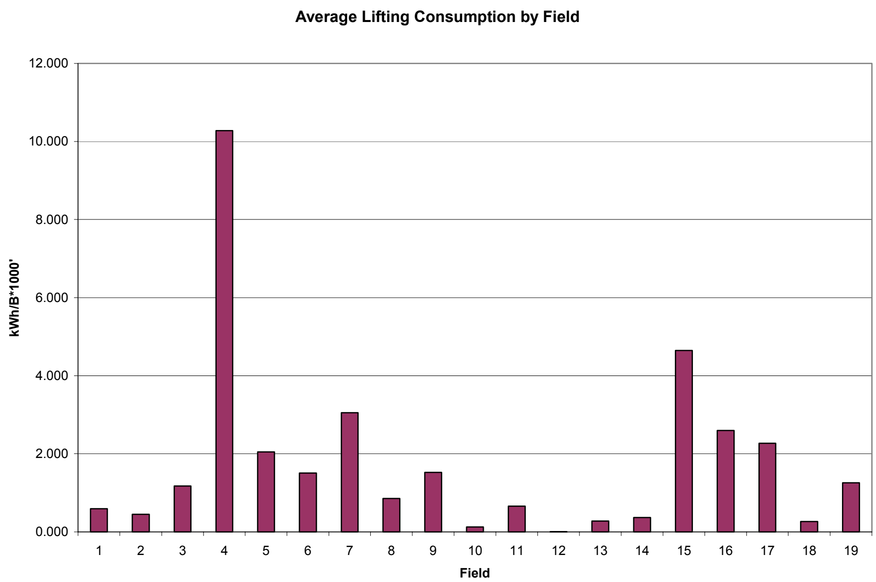


Figure 4-19
Lifting Consumption by Field

Figure 4-20 presents the distribution of the population of all wells operating above a lifting consumption of 0.50 kWh/B*l000'.

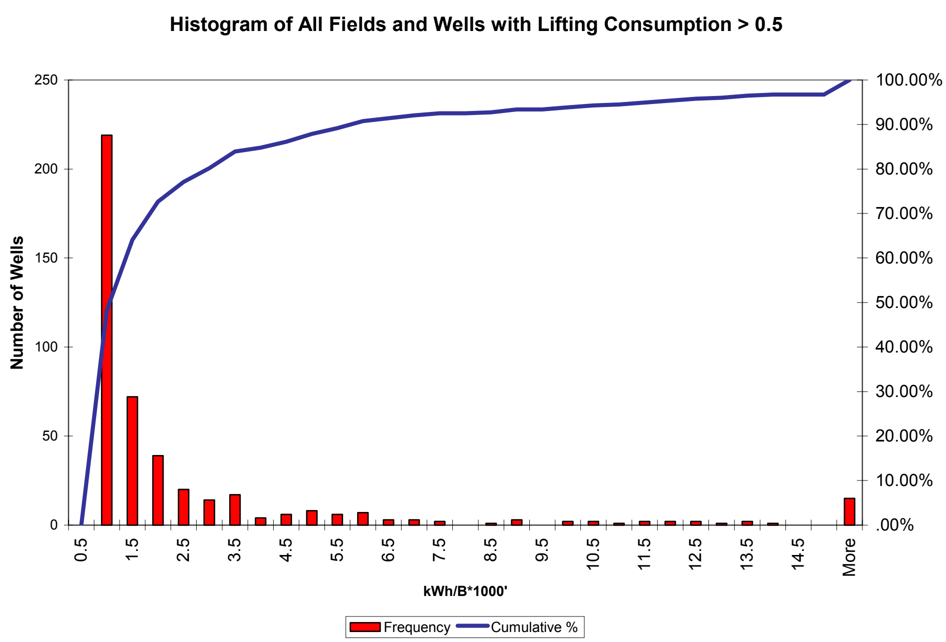


Figure 4-20
Distribution of Lift Consumption for Larger than 0.5 (kWh/B*1000')

Screening Tools

Figure 4-19 and Figure 4-20 present a method of identification of inefficient operations on a per well basis. The distribution of wells shown in Figure 4-20 indicates the wide range of power consumption contributing to fluid lift. There are obviously wells that are candidates for remedial action to improve lifting consumption.

What is a good target value for lifting consumption? Based on the experience of this data set and calculations based on API recommendations for determining prime mover horsepower, a value of 0.5 kWh/BF/1000’ of well depth or less is proposed so that candidates for action can be identified. Of the population studied, only 485 wells or 52% of all the wells studied operate at or below this value. Wells operating at higher levels are candidates for review for possible savings. The population above 0.5 kWh/BF/1000’ consists of 454 wells with a mean value of 2.7 kWh/BF/I000’.

Assuming all wells may be improved to reduce lifting consumption to 0.5 kWh/BF/1000’, Power consumption savings and demand reduction savings were calculated for all wells exceeding 0.5 kWh/BF/1000’lifting consumption. These values were totaled for all fields resulting in a potential power consumption reduction of 3.2 GWh/M and a demand reduction of 5.09 MW.

Since the population studied represents only 2.3% of all wells in California, the total benefit could exceed 139 GWh/M in reduced power consumption and a demand reduction exceeding 221 MW. In light of California goals to become more energy efficient, savings of this magnitude could curtail the need for addition power plant construction.

5
FIELD IMPROVEMENTS AND R&D OBJECTIVES

While electric energy is a major cost contributor in the production of oil, energy efficiency is of secondary concern to robust, reliable equipment and consistent operation. However; with the advent of deregulation and rising prices throughout California, energy is a major concern to oil producers.

In reducing energy consumption and costs, over 18% of energy costs are associated with surface operations. These operations include the movement of fluid, high-pressure steam and water for flood operations, transport of water to and from wells, transport and re-injection of produced water. Often these systems are controlled very inefficiently, but with an eye to consistent operation, resulting in the use of may re-circulation systems, and significant throttling losses. In many of these applications, the use of Adjustable Speed Drives (ASDs), on/off controllers with soft starters, and other energy efficiency strategies could go a long way to controlling energy costs. The survey indicates 55% of energy consumption goes to production involved with artificial lift in secondary and tertiary production (where most California fields are operating). Proper maintenance of the ubiquitous beam pump, including balancing, lubrication, and proper adjustment of the stuffing box, can go a long way to reducing pumping costs. Applications including pump-off controllers, ASDs, and high efficiency Written-pole motors may be used to reduce power consumption. Use of natural gas fired microturbines may reduce power demand. This section discusses these technologies, exploring how they may be applied to reduce energy consumption and what additional research needs to be accomplished.

Pump-off Controllers

The displacement capacity of a rod pumping system for oil production is designed to meet or exceed the fluid inflow from the reservoir. Overtime, changes in reservoir characteristics and equipment wear affect the pumping system's dynamics. Pump off occurs when the fluid level in the well bore is not sufficient to completely fill the pump. Continuing to pump in this state can induce damaging shock loads known as "fluid pound" causing excessive wear and possible damage to the rod string. During pump off pumping efficiency is reduced because the pump barrel does not fill completely for each stroke so less fluid is brought to the surface with each stroke. Pump off controllers have been developed to prevent well pump off while managing the following:

- Production rates
- Optimize run times
- Monitor equipment performance

The simple version of a pump off controller may be a contactor with a timer to allow the pump to only operate a certain number of hours per day. The use of water sprinkler system controls is common where multiple start and run times per day may be programmed. More sophisticated controllers have the ability to detect slow changes in reservoir characteristics and equipment that affect pumping dynamics then automatically make timely adjustments to pump run times so that pumping efficiencies can be maintained and lifting costs reduced. Use of these type devices improves average production while providing savings in electrical energy and maintenance costs. More sophisticated controllers may also control time of day when a pump may operate to take advantage of off-peak electrical power rates. Based on the benefits achieved by utilizing controllers, a well's economical productive life may be extended.

High Efficiency Motors

High efficiency motors should be used wherever possible to reduce power consumption and demand. High efficiency NEMA design B motors typically run with less slip and higher power factor then standard or NEMA design D motors. Consequently, direct replacement of older less efficient motors with design B motors should be considered carefully for the full benefit of the more efficient motor to be realized. For instance if a design B motor is to replace a standard motor on a centrifugal pump the pump will turn faster due to the low slip of the new motor. Consequently, if the pump impeller is not adjusted a higher flow rate will be realized at the cost of higher power demand. Careful planning of retrofit operations can result in significant savings. These savings are compounded if the motor is run continuously easily paying for the retrofit in short a short time frame.

The direct retrofit of the design D motor on rod-pumps with the higher efficiency design B motors has not proved feasible do to high starting currents drawn by the motor and the stress of the starting torque of the new motor on the rod-pump mechanical system. A new motor design called a Written-Pole (WP) motor shows promise. This WP motor starts as an induction motor with only two times full load current. Once running, the motor runs as a synchronous machine, with no-slip and unity power factor. The efficiency of the motor has been show to exceed that of a NEMA design B motor. WP motors have been used successfully at various oil production locations in the United States and Canada. Additional research in the demonstration of the WP motor application to oil field pumping needs to be performed. This research should confirm the advantages and energy saving capabilities of WP motors.

Adjustable Speed Drives

Adjustable speed drive (ASD) applications to support oil production are growing. Generally, speaking an ASD should be able to reduce energy consumption any fluid pumping processes where static head pressure is low and flow is being controlled with a throttling mechanism. Surface handlings of fluids requiring flow control are prime candidates for ASDs. Since fluid injection wells are required in many oil fields, staged induction motors and centrifugal pumps to a common header are used to maintain the required pressure and flow control. Applications such as these are ideal for conventional ASD use.

Some less conventional applications of ASDs apply to artificial lift. These include both ESP applications and rod-pumping applications. For these applications, the use of the ASD and results differ.

ESP motors are susceptible to voltage sags and interruptions. When a sag or interruption occurs the ESP may drop off line. If not immediately restarted, fluid pressures cause the pump to see forces opposite the direction of the motor. Starting a motor under these conditions is either impossible or extremely life shortening to the motor. The option is to let the fluid pressures neutralize before restarting the motor. This option may take minutes to hours depending on well depth. The time it takes for the fluid pressures to neutralized and the time it takes to re-establish the head before production oil flow is achieved represents lost production time while driving up the overall cost per barrel of oil produced.

ASDs are available today that can automatically sense the back pressure condition at the motor and control the motor restart without damaging the motor or pump while maintaining production. Utilization of such drives should reduce production down time resulting from voltage sags and interruption while extending pump motor life.

As previously mentioned ASDs provide a very precise level of control. Using ASDs for production control allows optimization on a well-by-well basis. For example pump-off may be avoided by slowing the motor and the resulting pumping rate. At the same time pumping rate is slowed motor power demand is also reduced. If energy reduction is the goal then the ASD may be used to control demand by reducing production flow rate. Consider an example operation that is provided incentives to reduce power on demand or during peak power hours. If and ESP pump uses 70% of its power to maintain fluid head pressure then the remaining 30% of power may be applied to fluid flow. During power reduction times an ASD may slow down the operation of the motor so only wellhead pressure and a minimum flow rate is maintained. Theoretically, during this operation mode power demand may be reduced up to 30%.

Improved rod-pumping efficiency may also be realized using ASDs. Since ASDs eliminated the need for high slip NEMA design D motors, they may be replaced with high efficiency, low slip NEMA design B motors. Using the NEMA design B motor with an ASD can result in significant increase in efficiency of the conversion of electrical power to mechanical power. These efficiency improvements can result in the overall lower energy cost per barrel of oil produced.

Another energy savings opportunity worth exploring is using the ASD to recover energy from the rod-pump. An ideally balanced rod-pump will drive the motor during a portion of the pump cycle causing the motor to act as a generator supplying power back to the power system. Unfortunately, most revenue meters only measure power consumed by the load. Therefore, for a single pump served by a single revenue meter, the regenerative power is lost; resulting in higher per barrel production cost then is necessary. On the other hand, where the meter serves several pumps the generated energy from one pump may be consumed by another pump.

When drives are used for rod-pumping applications there is a concern of how to handle the regenerative energy associated with the cyclical nature of rod-pump loads. Initial trial applications of ASDs for rod-pumping have met with limited success because the regenerative energy from the motor to the drive's DC bus resulted in DC bus over voltage and failure. To prevent these DC bus failures due to over voltage there are at least three solution alternatives available. These alternatives are:

1. Program the drive to operate from a constant power algorithm that allows the motor to slow during heavy torque then speeds up the motor when the load is forcing the motor to speed up.

2. Allow the regeneration to occur and dissipate the regenerative energy into resistors.

3. Allow the regeneration to occur and absorb the energy for use during the remaining pump cycle.

Operating the ASD with a constant power algorithm as described in the first alternative may be beneficial as it might increase production assuming the reservoir can support the increased production rate. Additionally, this operation should allow the use of higher efficiency motors. If production rate and motor efficiency can be increased then there should be a net energy savings.

Using resistors to dissipate the regenerative energy as suggested in the second alternative provides more control of the pumping system. However, the dissipated energy results in an unrecoverable energy loss resulting in an overall loss in pumping efficiency.

The third alternative provides an opportunity to increase pumping control and efficiency. By absorbing the energy during regeneration mechanical stresses may be minimized. Since the absorbed energy may be used during the energy demand portion of the pumping cycle an overall increase in pumping efficiency is achieved. To understand this concept in greater detail, refer to Figure 5-1 representing power consumed by a motor throughout one pumping cycle. Note power goes negative during a portion of the cycle. This represents the portion of the pumping cycle where the pump is pushing the motor causing the motor to act as a generator. Where one revenue meter serves multiple wells this generated power may be consumed by other operating wells served by the same revenue meter since these pumps rarely have synchronized power cycles. If a revenue meter serves only one well, the generated power from the well flows back onto the power system without benefiting the producer. Revenue meters historically don't record power in the reverse direction. Consequently this represents power that is lost by the producer. The amount of power generated is influenced by rod-pump design and dynamic balance.

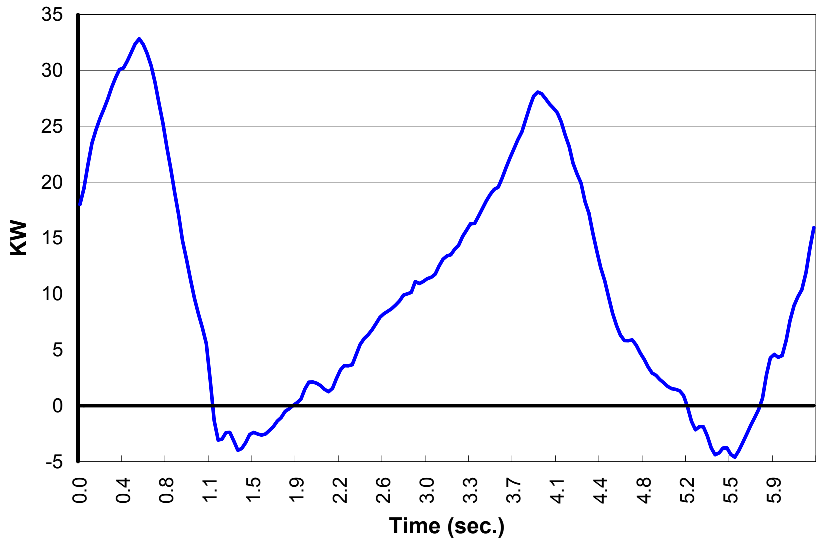


Figure 5-1
A Rod-Pump Motor Power Cycle Operating with a 30 HP NEMA D Motor

In Figure 5-1 two power demands may be calculated. A "With Generation Credit" (WGC) power demand occurs when other wells can use the power generated (negative power). The WGC power demand of 10.3 kW is calculated based on the average of all power samples taken (this includes the negative power samples). If only the revenue meter serves one well then, the meter may not record the negative power samples; therefore only the positive power samples are recorded. This resulting in a "No Generation Credit" (NGC) power demand of 10.8 kW based on the average of only the positive power samples. Theoretically, the energy associated with the 0.5 kW difference between the two demands could be stored and used to support the positive cycle. The resulting power demand seen by the meter would then be only 9.8 kW (10.3 kW - 0.5 kW).

In the past the large capacitors required to implement the third alternative implementation was not cost feasible to implement. However, recent advances in capacitor technology suggest that the third option may now be economically feasible. Additional research needs to be performed to determine the feasibility of this alternative.

Microturbines

Microturbine technology may be useful in some oilfield applications. Microturbines are small gas turbine engines that use the natural gas byproduct of oil production as fuel to produce electricity. Now microturbines are currently available that produce up to 30 kW of energy for onsite use. Using the natural gas produced from the well to provide the energy for artificial lift is not a new idea. Natural gas power internal combustion engines have been used for years to drive rod-pumps. However, environmental restrictions now limit the use of natural gas powered internal combustion engines. The high internal operating temperatures associated with turbine combustion create an environmentally clean method of consuming unprocessed wellhead natural gas that may have up to 7% H_2S content with NO_x emissions below EPA restrictions.

The barriers to microturbine applications are threefold including: cost, fuel availability, and motor starting capability. The initial cost of microturbine equipment is very high. Economic considerations must include equipment purchase versus lease, cost of electric energy from utility and the retail value of the natural gas that will fuel the microturbine. The availability of enough natural gas to support turbine operation is a must, as restricting operation of the gas turbine based on gas availability has a large impact the economic decision to use a microturbine. As presently configured, microturbine sizing to support motor starting is not economically feasible. Therefore, the microturbine must run in parallel with the utility source to provide the large inrush currents associated with motor starting. However, some microturbines may act as a soft start for a motor if the microturbine only supports one motor. Future, research with microturbines and energy storage capacitors may lead to right-sized microturbines with motor starting capabilities. If heat-treating in an oilfield is utilized to break emulsion to aid water separation from the produced oil, microturbine waste heat may be used to support this process, therefore increasing overall system efficiency while supporting the economic decision to use microturbine technology in the oilfield.

6
COST BENEFIT ANALYSIS OF RECOMMENDATIONS

On the previous section several field improvements and R&D objectives were identified and discussed. In this section an economics cost benefit analyses is discussed concerning applications involving electric system changes that may lead to energy savings or demand reduction. These applications should not preclude changes in the mechanical pumping systems such as pump replacement, dynamic tuning, and general good maintenance practices. The following analysis provides a look at the economics of WP motors, microturbines, and prime mover systems involving replacement of the NEMA D motor with and ASD and NEMA B motor.

Written Pole Motor

Analysis

Written pole motors can have a significant impact system power demand. The evaluation provided by Table 6-1 shows how this may be achieved.

Table 6-1
Written Pole Motor Demand Savings Analysis

Type D Motor Efficiency:	80.00%	
Written-Pole Motor Efficiency:	93.00%	
% Energy Savings:	13.98%	
Potential Impact on Power System		
Estimated Number of Production Motors ranging from 10 to 65 HP in California:	1000	Motors
Average Motor HP:	40	Average HP
Estimated kW Power Demand based on average motor HP and above Type D motor efficiency:	37300	KW
Estimated kW Power Demand based on average motor HP and above Written-Pole motor efficiency:	32086	KW
Estimated kW Power Demand Savings:	5214	KW or **5.2**MW

Typical motors used to operate rod pumps are NEMA Type D machines that may have efficiencies of around 93% when running at full speed. However, inherent to the motor design these motors may have a very high slip with compared to the slip of standard low slip motors. If slip is included a NEMA D motor may have an operating efficiency of around 80%. Written pole motors have a nameplate efficiency of over 93% with no slip, due to their synchronous mode of operation. Simply replacing a NEMA D motor with a WP motor could result in a 13% saving in energy consumption.

Based on the database created as part of this report, the average production motor horsepower is approximately 40HP. The estimated power demand of a single NEMA D 40 HP motor is about 37.3 kW. While the estimated power demand of a similarly sized WP motor is around 32.1 kW. If 1000 rod-pumps were retrofitted with WP motors the resulting energy savings would be approximately 5.2 MW. The number of rod-pumps retrofitted with WP motors will impact the overall savings to California. The number of 1000 was chosen to ease analysis. Since there are significantly more rod-pumps the actual energy savings could be even greater.

Further analysis can be performed to determine the economic benefits of a WP motor application as shown in Table 6-2. The table boxed-in values are assumed, while all the remaining values are calculated from the assumptions.

Table 6-2
Economic Analysis of WP Motor Retrofit

Loan Considerations		
40 HP WP motor	$10,000.00	
Installation	$2,000.00	
Total installed	$12,000.00	
Loan Rate	0.09	APR
Loan Duration	10	Years
Salvage Value	$0.00	
Annual Loan Payments	($1,869.84)	
Energy Considerations		
Type D Motor Operating Efficiency:	80.00%	
Written-Pole Motor Operating Efficiency:	93.00%	
Motor HP:	40	HP
Estimated kW Power Demand of Type D motor:	37	KW
Estimated kW Power Demand based of Written-Pole motor:	32	KW
Estimated kW Power Demand Savings:	5	KW
Availability	98%	
Annual Hours of operation	8585	
Annual Power Consumption Savings	44761	kWh

Economic Results	Years 1-10			After 10th year		
Price of Electricity ($/kWh)	$0.05	$0.10	$0.15	$0.05	$0.10	$0.15
Annual Energy Cost Savings	$2,238.05	$4,476.10	$6,714.14	$2,238.05	$4,476.10	$6,714.14
Annual Loan Payments	($1,869.84)	($1,869.84)	($1,869.84)	$0.00	$0.00	$0.00
Annual Net Savings	$368.21	$2,606.26	$4,844.30	$2,238.05	$4,476.10	$6,714.14

Based on the assumptions represented in Table 6-2, it is economically feasible to use WP motor with rod-pumping applications. After the initial loan is paid off considerable savings may be realized.

Recommendation

While accepted in parts of Canada and a few applications in the United States the potential of the written pole (WP) motor for rod pumping applications may be quite large. Previous external designed WP motors were expensive making economic payback slow. The new internal rotor WP motors available today approach the cost of a premium efficiency motors without the high inrush currents associated with the premium efficiency motors. To reduce energy costs while reducing power demand, it is recommended internal rotor WP motors be applied on rod pumping application to demonstrate the compatibility of the motor with the application before widespread application of the motors are recommended.

A WP motor demonstration project should include the following steps:

- Select Demonstration Well Site
    - Determine Power Consumption per barrel of fluid produced
- Dynamically Tune Well
    - Determine Power Consumption per barrel of fluid produced
    - Measure motor efficiency
- Install Written-Pole motor
    - Measure motor efficiency
    - Determine Power Consumption per barrel of fluid produced
- Report Results as Case StudyIf the WP motor proves compatible with rod- pumping applications, wide spread use of these motors may be used to further reduce power demand and electrical energy costs.

Microturbine

Analysis

Where waste or flare gas is available in sufficient quantities, microturbine generators can have a significant impact system power demand. The evaluation provided by Table 6-3 shows how this may be achieved.

Table 6-3
Potential Impact of Microturbine Generator on Power System Demand

Potential Impact on Power System			
Estimated Number wells producing waste gas of sufficient quantity to support Microturbine operation:	1000Sites		
Average unit output with auxiliary gas compressor:	24.5kW		
Estimated kW Power Demand Savings:	24500KW	or	**24.5**MW

As can be seen in Table 6-3 widespread use of on site distributed generation using microturbine generators can have a significant impact on energy demand in California. While energy demand is being reduced the utilization of waste gases avoid environmental issues associated with natural gas flaring or the use of waste gas in internal combustion engines.

Further analysis can be performed to determine the economic benefits of a WP motor application as shown in Table 6-4. The table boxed-in values are assumed, while all the remaining values are calculated from the assumptions.

Table 6-4
Economic Analysis of Microturbine per Well Site

Loan Considerations

Installed cost of 30 kW Microturbine with foil bearing rotary flow compressor	$39,000.00	
Loan Rate	0.09	APR
Loan Duration	10	Years
Salvage Value	$9,750.00	
Annual Loan Payments	($5,435.24)	

Energy Considerations

Average unit output with auxiliary gas compressor:	24.5	KW
Availability	98%	
Annual Hours of operation	8585	
Annual Power Consumption Savings	210328	KWh

Economic Results	Years 1-10			After 10th year		
Price of Electricity ($/kWh)	$0.05	$0.10	$0.15	$0.05	$0.10	$0.15
Annual Energy Cost Savings	$10,516.38	$21,032.76	$31,549.14	$10,516.38	$21,032.76	$31,549.14
Annual Loan Payments	($5,435.24)	($5,435.24)	($5,435.24)	$0.00	$0.00	$0.00
Annual Net Savings	$5,081.14	$15,597.52	$26,113.90	$10,516.38	$21,032.76	$31,549.14

Based on the assumptions represented in Table 6-4, use of a microturbine to generate power from waste gas appears to be economically favorable. Further, analyses indicate a 4-year loan will still result in an annual net savings for an energy cost of $0.05/kW. Therefore if a 4-year loan is made, the savings shown in Table 6-4 after the 10th year would be available after the 4th year making the economics even more favorable.

Recommendation

As shown in the above analysis, gas microturbines can provide an economically viable solution to reduce system power demand by use of the distributed generation resources. Where waste gas in available producers should carefully consider the application of a microturbine to support on site energy requirements while reducing overall production energy costs.

A microturbine demonstration project should include the following steps

- Select Demonstration Well Site
    - Determine availability and quality of produced waste gas
    - Determine Electric Power Consumption per barrel of fluid produced
    - Determine Electric Power Demand and average kWh
    - Perform economic evaluation of microturbine application

- Install microturbine if economically feasible
  - Determine Electric Power Consumption per barrel of fluid produced
  - Determine Electric Power Demand and average kWh
- Report Results as Case StudyIf the microturbine demonstration proves economically feasible, wide spread use of these systems may be used to further reduce system wide power demand and electrical energy costs.

ASD and NEMA B Motor-Drive System

Analysis

ASDs used with high efficiency motors can have a significant impact system power demand while improving pumping control. The evaluation provided by Table 6-5 shows how savings from retrofitting a NEMA D motor with an ASD and NEMA B motor-drive system may be achieved.

Table 6-5
Potential Impact of Combined Motor and Drive Systems on Power System Demand

Type D Motor Efficiency:	80.00%		
Prem. Eff. Motor Efficiency:	93.80%		
Drive Efficiency:	98.00%		
Motor & Drive System Eff:	91.92%		
% Energy Savings of Motor and Drive System compared to Type D Motor:	12.97%		
Potential Impact on Power System			
Estimated Number of Production Motors ranging from 10 to 65 HP in California:	1000	Motors	
Average Motor HP:	40	Average HP	
Estimated kW Power Demand based on average motor HP and above Type D motor efficiency:	37300	KW	
Estimated kW Power Demand based on average motor HP and above Motor & Drive system efficiency:	32462	KW	
Estimated kW Power Demand Savings:	4838	KW or	**4.8** MW

Typical motors used to operate rod pumps are NEMA Type D machines that may have efficiencies of around 93% when running at full speed. However, inherent to the motor design these motors may have a very high slip compared to the slip of standard low slip motors. If slip is included, a NEMA D motor may have an operating efficiency of around 80% or less. High efficiency NEMA B motors are available that operate with less slip and higher efficiency. Unfortunately NEMA B motors have large starting currents and/or fail to start the high torque loads associated with rod-pumps. Application of an ASD provides a soft starting capability to the NEMA B motor allowing it to start without tripping and without excessive starting currents. Utilization of a combination NEMA B motor and an ASD could result in up to 13% savings in energy consumption.

Based on the database created as part of this report, the average production motor horsepower is approximately 40HP. The estimated power demand of a single NEMA D 40 HP motor is about 37.3 kW. While the estimated power demand of a similarly sized NEMA B motor and drive system is around 32.5 kW. If 1000 rod-pumps were retrofitted with NEMA B motor and drive systems, the resulting energy savings would be approximately 4.8 MW. The number of rod-pumps retrofitted with NEMA B motor and drive systems will impact the overall savings to California. The number of 1000 was chosen to ease analysis. Consequently, based on data from the California Department of Conservation – Division of Oil, Gas and Geothermal Resources (DOGGR) 1000 rod-pumps only make up approximately 2.5 percent of wells. Additional savings might be realized from a drive if the motor can be appropriately sized for the load and not for starting requirements. The increased control capability with a drive may also provide operational savings by precisely controlling the pump rate.

Further analysis can be performed to determine the economic benefits of a NEMA B motor and ASD application as shown in Table 6-6. The table boxed-in values are assumed, while all the remaining values are calculated from the assumptions.

Table 6-6
Economic Analysis of NEMA B Motor and ASD Retrofit

Loan Considerations		
40 HP NEMA B Motor	$8,000.00	
ASD	$8,000.00	
Drive Enclosure	$4,000.00	
Installation	$2,000.00	
Total installed	$22,000.00	
Loan Rate	0.09	APR
Loan Duration	10	Years
Salvage Value	$5,000.00	
Annual Loan Payments	($3,098.94)	

Energy Considerations		
Type D Motor Operating Efficiency:	80.00%	
Motor & Drive System Eff:	91.92%	
Motor HP:	40	HP
Estimated kW Power Demand of Type D motor:	37	KW
Estimated kW Power Demand of NEMA B motor and ASD:	32	KW
Estimated kW Power Demand Savings:	5	KW
Availability	98%	
Annual Hours of operation	8585	
Annual Power Consumption Savings	41537	kWh

Economic Results	Years 1-10			After 10th year		
Price of Electricity ($/kWh)	$0.05	$0.10	$0.15	$0.05	$0.10	$0.15
Annual Energy Cost Savings	$2,076.84	$4,153.67	$6,230.51	$2,076.84	$4,153.67	$6,230.51
Annual Loan Payments	($3,098.94)	($3,098.94)	($3,098.94)	$0.00	$0.00	$0.00
Annual Net Savings	-$1,022.11	$1,054.73	$3,131.56	$2,076.84	$4,153.67	$6,230.51

Based on the assumptions represented in Table 6-6, it is not economically feasible to use ASDs with a NEMA B motor on rod-pumping applications if the energy cost is $0.05/kW. Further, analyses indicates an energy cost of $0.075/kW is the break-even point where the annual net savings will be greater than $0.00 based on the assumptions provided. After the initial loan is paid off significant savings may be realized.

Recommendation

To reduce energy costs while reducing power demand, it is recommended NEMA B motor and ASDs be applied on rod pumping application to demonstrate the compatibility of the motor and drive system before widespread application of the motors are recommended.

A motor and drive demonstration project should include the following steps:

- Select Demonstration Well Site
    - Determine Power Consumption per barrel of fluid produced
    - Determine Pumping System Efficiency
- Dynamically Tune Well
    - Determine Power Consumption per barrel of fluid produced
    - Measure motor efficiency
    - Determine Pumping System Efficiency
- Replace existing NEMA D motor with a NEMA B motor and ASD system
    - Measure motor efficiency
    - Determine Power Consumption per barrel of fluid produced
    - Determine Pumping System Efficiency
- Report Results as Case StudyIf the NEMA B motor and ASD system prove to be compatible with rod- pumping applications, use of these systems will only be feasible where energy costs are relatively high and/or additional control of the pumping system is necessary. As ASD costs come down the use of these systems should become more wide spread.

Summary

Of the systems evaluated, the microturbine shows the greatest potential for energy savings. However, the availability of sufficient quantities of waste gases from oil production necessary for microturbine operation may limit the number of sites where microturbines may be economically used. As WP motors are shown to be good retrofits for NEMA D motors, widespread use of the WP motors can be expected. The use of NEMA B motors with ASDs presently requires a high electrical energy cost to be economically feasible. As the cost of ASDs are reduced and packaged for oil field use, ASD may find applications where precise pump control is necessary for production.

The application of the above applications should not preclude proper pump sizing, mechanical tuning and maintenance of the well. These mechanical activities have proven to provide the best form of electrical cost savings in the industry. If pump equipment is being considered for replacement, one of the above applications may be designed into the replacement activities.

7
CONCLUSIONS AND RECOMMENDATIONS

Conclusion

This project resulted in the development of an energy audit system that can scrutinize energy efficiency according to an acceptable norm. The audit system should lead investigators to oilfield systems and wells that have the greatest potential for energy cost savings resulting from system or equipment improvements. Once targeted these systems may be investigated further to establish design changes or improvement recommendations. Once recommendations are defined capital investments for upgrades or replacement of electrical consuming devices can be more easily justified from an economic perspective.

Oilfield surveys were performed from September 2000 through May 2001 resulting in data being collected from 19 fields. From these field data was obtained on 939 producing wells of which 91% were rod pumped wells. Other lift methods used were electric submersible and hydraulic pumps. Total gross production from all the fields visited averaged 415,020 BFPD during the study period. This data represents 2.3% of all California onshore producing wells and 0.29% of all onshore fluid production. Fluid lift in oil production accounted for 55.3% of the electrical energy consumed by the fields visited. Therefore, the data analysis focused on power used for fluid lifting.

The term lifting consumption resulting from the data analysis provides operators with the means to compare individual wells in their operations with the norms of the entire population studied. The mean and median lifting consumption values from the data set is 0.546 and 0.479, respectfully. With these statistics and calculations based on API recommendations for determining prime mover horsepower, a value of greater than 0.5 kWh/BF/1000' of well depth is considered a threshold for determining wells needing improvement evaluation. Any wells having greater lifting consumption values are considered candidates for further energy reducing actions. From the database population 454 wells or 48% of the wells are operating above 0.5 kWh/BF/1000'. These wells should be considered for energy efficiency improvements. If all these wells were improved to the threshold level, a potential power consumption reduction of 3.2 GWh/M and a demand reduction of 5.09 MW may be realized.

Because the population studied represents only 2.3% of all wells in California, the total benefit could exceed 139 MWh/M in reduced power consumption and a demand reduction exceeding 221 MW. In light of California goals to become more energy efficient, savings of this magnitude could curtail the need for addition power plant construction. This same extrapolation could be applied on a national scale resulting in a national benefit that could exceed 2085 GWh/M in reduced power consumption and a demand reduction exceeding 3300 MW.

Recommendations

While proper maintenance of the ubiquitous beam pump, including balancing, lubrication, and proper adjustment of the stuffing box, can go a long way to reducing pumping costs, several technologies were evaluated to support energy reduction opportunities in the oilfield.

Pump-off controllers and rod pump controllers maintain pumping time to prevent pump from attempting to pump more fluid then the well can deliver. The relatively low cost of these devices make them a relatively easy solution to implement it the solution economics prove favorable. Research involved with these devices might include energy and production monitoring before and after installation of these systems to verify system performance.

Written-pole (WP) motors appear to have great potential in oilfield applications. The NEMA design D motors commonly used with rod pumps are typically inefficient motors. Premium efficiency motors may not have the starting torque to start a rod pump or the starting inrush currents are too high for practical use. The relatively new WP motor operated at unity power factor and has been tested to operate as efficient as any premium efficiency motor. WP motor efficiency does not reduce at the same rate as standard motors when operated at less than rated load. The inherent low starting currents associated with the WP motor make it an ideal retrofit for existing motors typically used with rod pumping systems. Because there have been relatively few WP motors applied to rod-pumping where detailed well efficiency studies have been performed, additional research in these applications should verify potential energy savings expectations. Research involved with these devices might include energy and production monitoring before and after installation of these systems to verify system performance. Additionally, research should determine special sizing and design considerations that might be learned as a result of WP retrofits to existing rod-pumping systems.

There may be significant amounts of waste gas resulting from production that is presently being flared. If this gas may be used to fuel a microturbine there may be a potential for significant energy demand reduction by on site generation. With waste gases being a “free” fuel the economics of microturbines prove to be quite favorable. Research needs to be performed to determine how many wells produce enough waste gas to support microturbine operation. Monitoring and reporting results of microturbine applications may support proliferation of these devices. The net affect will be a reduced electrical demand requirement from the California power infrastructure while reducing unaccounted-for emission from incomplete waste gas combustion.

Adjustable speed drives (ASDs) have many uses in oilfields for handling fluid pumping. Where throttling processes are utilized to maintain flow control, ASDs are prime candidates. The oilfield survey database may be used to target oilfields with significant energy use going to water injection systems for additional studies. These studies may determine what throttling processes are being utilized and how ASDs may be applied to reduce energy consumption.

ASDs may also be utilized in fluid lift associated with production. The additional control provided from the use of ASDs may be the prime motivation for ASD utilization. Not until more ASD applications are installed will the overall benefit of this additional control be understood.

ASDs may be used with electric submersible pumps to reduce energy consumption during certain hours of the day without shutting down the well. Additionally, in the case of a voltage sag or fraction of a second interruption, some ASDs are designed with the capability to restart before positive fluid flow is lost. This should have a significant positive impact on ESP pump life and overall production rates. Research in this area might be to evaluate ASD applications to ESP to quantify these issues just discussed. This research would require pre-ASD-installation power quality monitoring of an ESP well to capture events that cause the well to drop off line. The monitoring would follow after the ASD installation to show benefits. With adequate well history the results then could be extrapolated to consider energy reduction and extension of pump life.

Similarly ASDs may be used with rod-pumps for added control that could reduce energy consumption. With an ASD the pump rate may be slowed to avoid pump-off. Operating at a slower pump rate should reduce mechanical stresses while also reducing electric demand. Economic analyses shows that use of an ASD with a premium efficiency motor may also help reduce energy consumption. Research in the use of ASDs on rod-pumps should quantify the issues discussed above including energy and production monitoring before and after installation of ASD systems to verify performance.

New developments in capacitor technology may find applications in fluid lift applications. The inherent design of rod-pumps cause motors to over speed during a portion of the pump stroke resulting in energy being generated by the motor. This energy may be lost if other wells do not utilize this energy. The new capacitor technology may be utilized in ASDs to capture the lost energy to reduce overall electrical demand by the rod-pump. Perhaps, the rod-pump counterweights could be eliminated in new surface equipment designed to use ASD and capacitor technology. In this arrangement the capacitors provide the energy normally delivered by the counterweights. Obviously these ideas are way outside the traditional approach but may be worth addition research to consider the feasibility of this type of application in light of new capacitor and drive technologies.

A
PRESS RELEASE

Press Release

FOR IMMEDIATE RELEASE
July 26, 2000

Program To Reduce Electricity Consumption In Small Oil and Gas Fields

A new troubleshooting program designed to assist small California oil and gas producers reduce consumption of electricity and lower their field operational cost has been developed. The program is a joint venture among the California Energy Commission, Electric Power Research Institute (ER) and the West Coast Petroleum Technology Transfer Council (PTTC).

Starting this September, a team of experts from these agencies will, at no cost, visit up to 60 of the estimated 281 oil and gas fields in California and prepare recommendations for updating equipment and devising alternative approaches to cut electric power consumption. Electricity consumes up to 40 percent of the small producers' operating costs.

The program will present opportunities that can substantially reduce electric cost and improve energy usage efficiency. For small operators, this could mean a difference between premature closure or continued operation.

The Energy Commission's Public Interest Energy Research Program (EPRI) contributed $243,000 to the cost of the joint research on the most effective technologies for California's oil fields.

Operators participating in this troubleshooting program may also qualify for energy efficiency incentives administered by the investor-owned utilities to implement the recommendations made by the PTTC-EPRI team.

A one-page application form for interested oil and gas producers may be obtained from WEST COAST PTTC at their web site, www.westcoastpttc.org or by contacting PTTC at (213) 740-8076.

B
DRAFT SITE SURVEY QUESTIONS[6]

Electrical Cost Savings Associated with Energy Supply

Are you on the best electric utility rate for your operations?

- Changing electric utility rates will not reduce energy consumption but may reduce the cost of energy consumption.
- To assure the best rate possible energy rates should be re-evaluated on a regular annual or semi-annual basis.
    - Electric energy rates may be influence by customer class, energy demand expectations, power factor penalties, time of day use and if power may be interrupted. Since all these issues are subject to change a producer should review energy bills with the electricity provider to assure the best rate.
    - Utility customer classifications based on expected energy is use, may or may not actually reflect how oil production uses energy. Since rates can change without notice a new customer classification could become available that more closely matches the production requirements of an oil field.

Are you paying Power Factor penalties?

- Electric energy rates determine possible power factor penalties.
    - Some electric utility rates do not consider power factor, other rates begin penalizing as soon as the power factor drops below 100%. Many electric energy rates may not begin charging power factor penalties until the drop below 85%.
- Power factor is the ratio of the average power to the average apparent power often calculated by dividing the monthly power consumed in kilowatt-hours (kWh) by the monthly apparent power consumed in kilovolt-amperes (kVA).
    - A good power factor of unity or 100 % indicates the power consumed is the same as the apparent power consumption while; a poor power factor might be 60%.
- Power factor penalties may be avoided by adding power factor correction capacitors to the producers electrical system.
    - Capacitors may be added in bulk at the load side of the meter or at individual motor loads.
    - Electric energy suppliers may be consulted to recommend power factor correction requirements to reduce penalty costs.

How many wells does one electric meter supply?

- Beam pumps consume energy on the upstroke while generating power on the down stroke.
- Utility meters are not designed to record power generated by the load.
- Since beam pumps operate independently at differing speeds during the same time period some beam pumps will be generating power while others are consuming power.
- Operating several beam pumps from one meter allows power sharing to occur
- Since the utility charges for each meter, consolidating beam pumps to one meter reduces accumulated meter charges

---

[6] Adapted from, "Dashboard Guide to Energy Efficiency in the Oil Field," A Publication of the National Association of State Energy Officials, www.naseo.org, developed and published under a contract with the U.S. Department of Energy's Office of Fossil Energy and Office of Industrial Technologies

Do motors often require restarting for no explained reason?

- Voltage sags resulting from faults on the utility distribution system or large motor starts can cause other loads to trip off-line.
- There are relatively low cost solutions available to make motor and control circuits immune to voltage sags

Electrical Cost Savings Associated with Surface Equipment

What maintenance is performed regularly on beam pumps?

- A well maintained beam pump can significantly increase pumping efficiency, These factors should be considered:
    - Bearing inspection, lubrication and replacement as needed
    - Dynamic balancing as required
    - Adjust stroke length if required
    - Assure proper electrical conductor sizing,
    - Correct loose or high resistance connections

Are motors properly sized for the load?

- Operating motors larger than required will cost more per barrel of production then a properly sized motor.
- It is common practice in oil fields to replace failed motors with next larger HP rating motor. While this is operationally a safe practice, after the motor is changed more than once the motor in operation can become much larger then required?
- The smallest HP motor that will start a beam pump is ideally a properly applied motor. On larger pumps sometimes pony motors may be used to support motor starting.
- Motor terminal current measurements may be taken on an operating well to compare with motor nameplate full load current (FLA) to determine motor loading.
- The cost of a new right-sized motor should cost less than a new oversized motor.

Are premium efficiency motors used?

- Studies indicate the additional cost of premium efficiency NEMA design B motor over a standard motor can be paid off through energy savings. The payoff duration is dependent on operation duration and electric energy rates.
- Premium efficiency motors should be seriously considered for all non-beam pump surface applications where motors are operated continuously.
- Premium efficiency design B motors are designed to run with less speed change (then the typical NEMA design D motor) therefore, can exert more torque and mechanical stresses to a beam pump gear box and cause more rod strain.
- A producer should discuss the use of a premium efficiency motor with a beam pump manufacturer when considering the purchase of new pump.
- Older or structurally fragile beam pumps may represent good applications for premium efficiency motors.

Are any wells operated with Pump-Off Controllers?

- "Pumping-off" occurs when the down-hole barrel does not completely fill before the beam pump lifting stroke.
- This can occur when the pump capacity exceeds the production capability of the well.
- Pumping-off wastes energy during the upstroke and can cause mechanical damage to the pump during the down stroke.
- "Pump-off Controllers" automatically cycle the beam unit off and on allowing the wells fluid level to rise during "off" cycles.

- With echo sounding equipment and knowledge of pump depth, analysis can determine if pump-off is occurring warranting the use of a Pump-Off controller.

Are any wells operated with time controls?

- When the Electric Energy Rate dictates time of day usage, time controls may be used to control what time of day the pump operates.
- The resulting rate savings may offset the cost of lost production.

Are adjustable speed or variable frequency drives being used?

- Adjustable speed drives (ASDs) are solid state electronic devices that are used to control the speed of induction motors
- ASDs are used throughout industry to improve fluid pumping system efficiencies by defeating or removing throttling systems. In the oil field ASDs may be used to improve pumping system efficiencies associated with dewatering of crude and pressurized water injection.
- Where it is not feasible to use a Pump-off controller due to down hole conditions, an ASD may provide the same benefit of a Pump-off controller by just slowing down a the beam pump stroke rate.
- Since ASDs have a relatively high cost it may not be economically feasible to apply to beam pumps operating at or below 20 HP.

Do any dewatering or water injection systems use throttling or re-circulation systems to maintain pressure or pump control?

- Pumping applications requiring throttling systems are prime candidates for ASDs and premium efficiency motor systems.
- Significant energy savings may be achievable with properly applied ASD and premium efficiency motor systems.

Can older beam pumps be operated in reverse direction of rotation?

- As beam pump gearboxes age, the teeth on the gears wear down resulting in reduced mechanical efficiency.
- If the gear box and beam system are designed to operate in reverse direction without damaging the system or changing stroke duration, reversing rotation direction allows the less worn sides of the gears to make contact thereby restoring some mechanical efficiency.
- Direction reversal can be achieved by swapping any two leads to the pump motor.

Are High Efficiency belts used with beam pump drive systems?

- Belt slippage resulting from loose or worn belts can reduce pumping efficiency.
- Newer "high efficiency" belts are available that slip less than standard belts.
- The additional cost of "high efficiency" belts may be recovered over the life of the belt.

Are beam pump polished rods too hot to touch?

- An overly tight stuffing box will cause excessive drag and friction on the polished rod reducing pumping efficiency.
- A properly adjusted packing box will allow a small amount of oil to be visible on the polished rod.

Electrical Cost Savings Associated with Down Hole Equipment

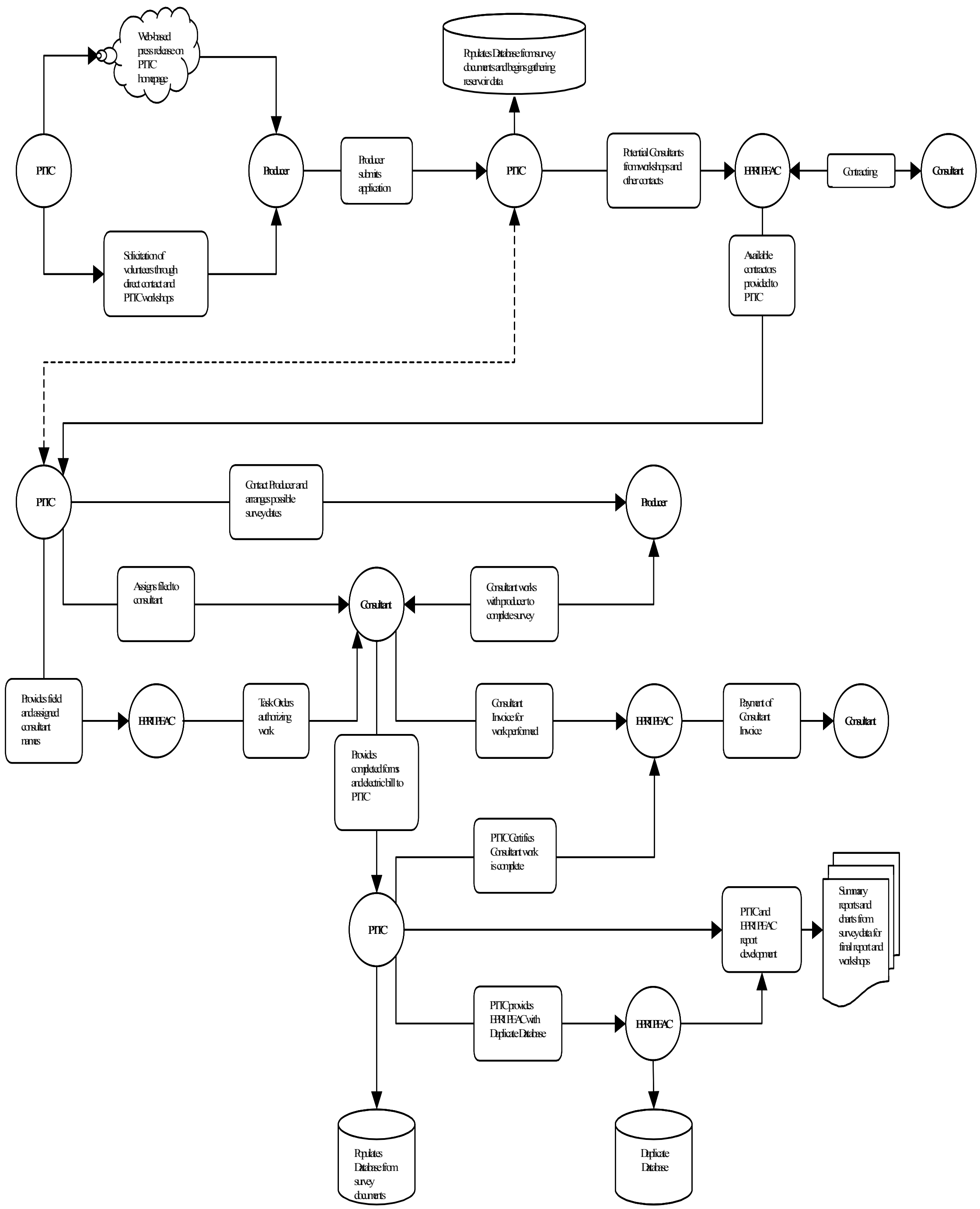
Are pump valves in proper working order?

- Sticking or leaky valves can degrade pumping efficiency.
- Good maintenance practices should assure valves are in proper working order.

Are lightweight materials being utilized for rod strings?

- Lightweight rod strings reduce pump lifting-load providing considerable energy savings over the life of the well.
- Consideration should be given to replacing steel rods with lighter weight rods when a rod is pulled for other maintenance actions.

C
SURVEY METHODOLOGY FLOW CHART



D
PRODUCER PARTICIPATION APPLICATION FORM

PTTC-EPRI Visits of California Oilfield Operations

Application for a No-Cost, No-obligation Field Visit

Our company/organization wishes to be included in the schedule of field visits by PTTC-EPRI trouble shooters for a complimentary review of electric driven motors and receive recommendations for steps that can potentially reduce cost and improve performance.

Please send me an application template

Date: ____

Name: ____

Company: ____

Address: ____

City - ZIP Code: ____

Site Location: ____

Contact Person: ____
(To arrange for a field visit)

Phone Number: ____

Fax Number: ____

E-Mail: ____

Daily Production at the site: ____

Other Comments: ____
____
____
____
____

Applications are accepted on the order received.
A maximum of 60 visits is planned for the period September- November 2000.
Date of visit will be arranged on a mutually convenient day.

E
WORKSHOP ANNOUNCEMENT

West Coast PTTC Workshop

California Energy Commission and EPRI
"California Oilfield Electric Consumption Survey"

This workshop includes a summary of an oilfield survey sponsored by the California Energy Commission and EPRI on electric cost consumption in Selected California Oilfields. Results will be reported for 19 fields and more than 1000 wells. Opportunities to lower consumption for a major fraction of the active wells resulting in improved efficiency and economics will be discussed.

Thursday, July 19, 2001

Marriott Residence Inn, Santa Clarita

Registration starts at 8:30 am

Co-Sponsored by: U.S. Department of Energy (DOE), University of Southern California (USC), California Energy Commission (CEC), California Independent Petroleum Association (CIPA), Western States Petroleum Association (WSPA), Independent Oil Producers' Agency (IOPA), State Lands Commission, Minerals Management Service (MMS), U.S. Department of Interior, Conservation Committee of California Oil & Gas Producers (CCCOGP), State of California, Department of Conservation, Division of Oil and Gas and Geothermal Resources (CADOGGR), Los Angeles Basin Section of SPE, San Joaquin Valley Section of SPE, Lufkin, Theta Enterprises, Precise Power Corporation, EPRI, EPRI-PEAC

8:30 AM	***Registration***	
9:00 AM	***Introduction***	
	Moderator:	***Chris Hall,*** *Drilling & Production Company*
9:10 AM	***California Energy Commission Programs/Incentive for Energy Efficiency Improvement***	***John Sugar & Pramod Kulkarni,*** *CA Energy Comm.*
9:30 AM	***Oilfield Electric Consumption Survey - Objectives and Methodology***	***Carl Miller,*** *EPRI-PEAC*
9:45 AM	***Oilfield Electric Consumption Survey - Results***	***Iraj Ershaghi*** *USC* ***& Carl Miller,*** *EPRI-PEAC*
10:10 AM	***Break***	
10:20 AM	***Predicting Electrical Consumption Saving Using Modern Rod Pumping Software - Technology of Fine-Tuning Rod Pumps***	***John Svinos***, *Theta Enterprises*
11:20 AM	***Pump-Off Controllers and Monitoring Systems***	***Andy Cordova***, *Lufkin*
11:50 AM	***Application of Large Horsepower Single Phase High Efficiency Motors to Rod Pump (Written-Pole Motor Technology)***	***Richard Morash***, *Precise Power Corporation*
12:15 PM	***Lunch Break***	
1:15 PM	***Meeting with Survey Participants: Private Sessions with Trouble Shooters***	
5:00 PM	***Adjourn***	