THE
LEASE PUMPER'S
HANDBOOK

Marginal Well Commission
Lease Pumper's Handbook Disclaimer

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The

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Written by

Leslie V. Langston

Foreword

To Petroleum Operators, Lease Pumpers, and Field Personnel

We take very seriously our obligation to assist you in every way possible to be successful in bringing quality training in your Production Operations. The Commission has been in agreement with me that an important goal was to improve first the quality of training available for the **LEASE PUMPER**. We needed a manual that can make a direct impact in our ability to *understand how to do our best* - in the skills needed in how to produce the *most possible oil and gas from marginally producing wells.* This also includes a higher level of skill in performing *HANDS ON* daily duties.

After many discussions among the commissioners and many of you in the field of how to achieve this goal, we began a search for someone to write the first edition. After much search, we did commit the project, and have met this first objective. You will note that the training outline has been designed with the thought in mind that this publication can be updated easily to permit us to keep abreast of changes in field.

Our future plans include using this publication as a springboard toward the development of the needs for a series of appropriate training programs. When these are grouped together, they will form the basis for a comprehensive Operators handbook of field operations and procedures designed to meet many of other field training needs that have not yet been addressed. This goal includes topics in designing constructing and maintenance of producing facilities. Another might include basic Well Servicing and workover. A final manual in this series may also include topics for Field Supervision and Management. The Common thread that must tie all of these together is the strict goal of all materials must meet definite needs in field activities and solve real problems.

We especially welcome your comments and assistance in these endeavors.

Sincerely,

Rick Chapman
Executive Director (1996-2000)

Commission on Marginally Producing Oil and Gas Wells,
State of Oklahoma
1218-B West Rock Creek Road
Norman, Oklahoma 73069-8590

Dedication

To All Lease Pumpers

We dedicate this training manual to all of the oilfield **LEASE PUMPERS**. It takes a special type of personal drive, dedication, or whatever you choose to call it for a person to choose **Lease Pumping** as a career.

This is an occupation where most of your work is done in all types of weather while working alone, with few thanks, and possibly only a small herd of cattle as company. This takes a high level of self motivation. Everyone is not capable of working alone and efficiently directing their own work efforts and work ethics and be successful.

The purpose of gathering information for this publication is to assist you in understanding your job better and become more professional in the performance of your lease duties. This should result in your extending the producing life of marginally producing oil and gas wells.. If the life of the wells are not extended or it does not make it easier for you to maintain your production to an acceptable level, we have failed in this mission. The writing of this material was done by people who have gauged a lot of tanks and sold a lot of oil and does not necessarily reflect the opinions of the Commission. We do hope, however, that somewhere in this publication, you will receive enough new thoughts, knowledge, or personal motivation to make this effort worthwhile and continuously improve your skill at your chosen occupation.

We wish you every success at your occupation as a Lease Pumper.

Sincerely,

John A. Taylor
Chairman (1992-1998)

Commission on Marginally Producing Oil and Gas Wells
State of Oklahoma
1218-B West Rock Creek Road
Norman, Oklahoma 73069-8590

The Lease Pumper's Handbook

Introduction

The **LEASE PUMPER'S HANDBOOK** has been written to assist you in producing oil and gas from marginally producing wells. This information should be appropriate anywhere that crude oil may be found. Every well that has been drilled where crude oil has been discovered experiences the reality that with each day's production, there is less oil remaining in the reservoir than there was yesterday so production declines. Eventually, production will be so low that all wells will be plugged and abandoned. *You* must have the knowledge and skills necessary to extend or even increase your production and the life of the field with the lowest practical lifting cost. Some fields in the United States have a projected life of more than 100 years, and this is a long time. When your wells are plugged and abandoned, a tremendous amount of oil is always left in the reservoir.

We welcome you to this edition of the **Lease Pumper's Handbook**. We know that this publication will undergo many revisions through the years, and possibly some of these changes may even be a result of your actions. Regardless of how good or poor this handbook may be, it represents a step in the right direction in developing for you a meaningful publication that will help you do a better job and be more successful in your chosen occupation. Different terms and procedures are also in use in different sections of the country, so bear with us if you are not familiar with a few of the ones used here. For instance a new, inexperienced worker might be called a worm, squirrel, weevil, boll weevil, or half a dozen other names.

The information included in this publication is directed at the lease pumper. The roustabout in field maintenance needs to know much more about many subjects that do not apply to your job. What this person needs to know has been deliberately left out. An example of this is in cutting and threading pipe or laying flow lines. Basic information, however, must be included in all manuals.

The daily duties of the **LEASE PUMPER** are extremely varied and complex. Since no two leases are alike, no two lease pumpers will have been assigned identical responsibilities even when working for the same company. This is the way it should be and is everywhere. It is not possible to write a publication that will *exactly* include what just *you* do each day, so you may have to search several publications to answer all of your questions. This publication should, however, include information about most of your normal daily pumping duties. The purpose of this book is to increase your field procedure knowledge and give you more ability to do a good job in the field. Good luck in both your chosen occupation and studies.

Sincerely,

Leslie V. Langston

INTRODUCTION

To Petroleum Operators, Lease Pumpers and Field Personnel

The Commissioners, Advisory Council and Staff of the Commission on Marginally Producing Oil and Gas Wells have dedicated themselves to ensuring the production and completion of the Lease Pumper's Handbook. This project began in 1997 with a team consisting of Les Langston, LaKeta Marty, Rick Chapman, Mike Earls and John A. Taylor. It has since evolved into an effort by many of our present Commissioners, Advisory Council Members and Staff.

Many suggestions and revisions have been made to the original Lease Pumper's Handbook. The Commission has come to realize that this manual is a work in progress and will be continually revised and updated as new processes and procedures are developed and identified. If there is a procedure or suggestion you have that would improve the content of the book, please do not hesitate to contact our office at (800) 390-0460 or in the Oklahoma City area (405) 604-0460.

Our Mission is to serve the Governor, Legislators, oil and gas industry and public by defining, identifying, and evaluating the economic and operational factors of marginally producing oil and gas wells, and to assure that appropriate efforts are made to extend the life of these wells so energy can be economically provided to all citizens of the State of Oklahoma. Our Vision is to train Operators to safely manage marginal properties and to make their operations more efficient and cost effective. The Commission is dedicated to the preservation of oil and gas production in the State of Oklahoma.

We appreciate your input and look forward to serving you.

Respectfully,

COMMISSION ON MARGINALLY
PRODUCING OIL AND GAS WELLS

Liz Fajen

Liz Fajen
Executive Director

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The Lease Pumper's Handbook

CHAPTER 1

RESPONSIBILITIES AND EMPLOYEE-EMPLOYER RELATIONS

The Lease Pumper's Handbook

Chapter 1
Responsibilities and Employee-Employer Relations

Section A

DUTIES AND RESPONSIBILITIES OF THE LEASE PUMPER

This handbook presents information that must be known to the group of field workers who produce so much of the nation's energy. This occupation, like many others today, may be known by a number of different titles within the industry, such as **production technician**. However, this manual will use the long respected and accepted title of **lease pumper**. While the assigned duties of a lease pumper may vary from company to company and even from lease to lease within the same company, some duties are almost always part of the lease pumper's responsibilities, and these duties are the primary focus of this book.

A-1. Job Duties.

The lease pumper's primary job responsibility is to produce, treat, and sell as much crude oil and natural gas as possible with the lowest cost. These costs—often referred to as *operating costs* or *lifting costs*—consist of all lease expenses, costs of tools and equipment, vehicles, supplies such as chemicals, utilities such as electricity, and salaries of personnel who work the lease, including the lease pumper. There are many other not-so-obvious expenses such as paying for the original purchase of the lease, royalties, costs of well services, and supervisory and office expenses. Even less obvious than these are taxes, insurance, employee benefits, lease support, and possibly bank interest and debt repayment. The lease must make a profit above all of these expenses. Most of the oil sold, if not all of it, will be produced from pumping wells or wells with some type of enhanced recovery. As production from a well declines (and most wells are low production or marginally producing wells), the income from the lease also declines, while the time and cost required to coax production increases. Thus, the challenge for the lease pumper to make a profit from the lease becomes more difficult—which means that good skills become even more important.

Another challenge of a career as a lease pumper is to be a good self-starter who can get a job done without a lot of supervision. Some people are capable of working steadily all day by themselves doing necessary and constructive work. Others are not highly motivated and do not do well at pushing themselves, working well only when they have continuous work supervision. When a lease pumper lacks the self-discipline to do the work that is required to maintain the lease, the equipment and site will become run down, and the lack of adequate attention will soon be obvious in the appearance of the lease and the production records.

A-2. Work Hours.

While many lease pumpers are considered to be *full-time* employees working forty hours per week, others work *part-time* accumulating less than forty hours each week, especially lease pumpers that work a variety of leases as a relief worker, filling in for lease pumpers who are sick, on vacation, or on their days off.

Employers differ in how they count a lease pumper's number of hours. Some lease operators consider that the work day begins as soon as the lease pumper begins the trip to the lease and does not end until the return trip is completed. This is called *port-to-port pay*. Other operators mark the start of the workday as the time when the lease pumper actually arrives at the lease. This may be referred to as *lease-time pay*. It is not unusual for a lease operator to pay for travel time one way and not the other. When accepting employment, the lease pumper must clearly understand the terms for calculating pay. Acceptance of these terms is usually a condition of employment.

Lease pumper work schedules. Most lease pumpers get into the habit of going to work early, arriving at the lease once the day is fully light so that everything on the lease can be easily observed. Another advantage of arriving early is that major problems that may have occurred during the night can be identified. In this way, if the problem requires that a service company respond, there is a better chance that they will be able to come the same day.

While starting work after sunrise may benefit the lease pumper, oilfield workers in active districts have probably already been working for several hours, especially in large companies. The early morning tasks for oilfield workers with a major oil company may follow a schedule such as:

4:00 a.m.	Rig tool pushers get morning reports from rig crews.
5:00 a.m.	Rig reports are telephoned to home office.
6:00 a.m.	Superintendents and supervisors meet to plan day.
7:00 a.m.	Field supervisors and pushers meet to outline day and make contract labor arrangements.
8:00 a.m.	Field workers arrive to begin day.

Lunch time. Lease operators differ in how they count the time the lease pumper spends eating lunch in terms of hourly wages. Some employers pay straight through lunch time if the lease pumper remains on the site, but do not count the time if the lease pumper leaves the lease to eat. One reason for this policy is that it is often possible for the lease pumper to eat while monitoring an operation, such as circulating oil. As with other employment policies, the lease pumper must clearly understand the allowances made for lunch.

A-3. Company Policies.

Most companies operate with set policies. Larger companies may maintain documents detailing these policies. These policies may give information about:

- The work day and work week.
- Probationary and permanent employment.
- Overtime policies.
- Sick time.
- Vacation time.
- Insurance plan.
- Holidays and holiday work policies.
- Savings plans.
- Retirement plan.
- Worker's compensation.
- Social security.
- Tax withholdings.
- Education plans.
- Disciplinary actions and termination policies.
- Other important topics.

Many leases are held by small companies. It is not uncommon for an applicant for a position as a lease pumper to meet with the company owner during the hiring process. Often the owner or hiring supervisor may offer the job to a prospective employee during the first interview. Therefore, the person interviewing for the job should be prepared to ask key questions that will help the applicant decide whether or not to take the job. Such questions may include:

- What is the salary being offered?
- What is the company's policy on advancement and pay increases?
- What are duties of the job?
- What hours of the day will be worked?
- Is time driving to and from work considered hours worked?
- Is lunch time considered to be work hours?
- Which days of the week will be worked?
- Is overtime paid and how is it figured?
- What is the company policy on holidays, vacation, sick leave, and other types of absences (jury duty, bereavement, military duty, etc.)?
- Who works the lease on those days when the regular lease pumper is off?
- What happens when the relief pumper gets sick?
- Is the lease pumper allowed to take the vehicle home?
- How are necessary supplies obtained?
- What purchasing authority does the lease pumper have?
- Does the company offer a retirement plan?

Because the duties of a lease pumper can vary greatly from company to company, the experienced lease pumper may want to ask specific about the job duties and responsibilities. For example, the applicant may ask, "Am I expected to bump bottom and lift rod strings by myself? Do I help pull rod and tubing strings?" The prospective employee may want to visit the lease site so that the company representative can explain what the job entails. This also gives the applicant a chance to see how well the lease is maintained, whether the equipment is in good repair, whether the access roads have been kept up, and other indications of how important such things are to the company.

Thus, there can be many differences in working for a small company or working for a large one. The large company may have more structure, with established policies and procedures as well as a large support staff, contracted services, perhaps new tools and equipment, and other features that appeal to some lease pumpers. On the other hand, a smaller company may not offer the support structure and fringe benefits that a large company can afford, but may appeal to some lease pumpers due to their greater flexibility and the work can be very satisfying. Often the lease pumper becomes almost like family with the owners and, in some instances, will eventually own such a company.

Contract pumping services. Many companies now contract construction, maintenance, and pumping services instead of hiring their own personnel. This is the continuation of a trend that started many years ago when production companies began contracting with drilling companies then with well service providers and eventually with workover specialists. Today, many lease operators lease, such as large compressors and engines, and the movement will probably progress to the leasing of pumping units, flow lines, and tank batteries. This movement means that some lease pumpers have little responsibility for maintenance and can focus on production and selling the oil and gas produced. Lease pumpers who prefer the maintenance tasks associated with the job may find employment with equipment leasing companies more to their liking.

Honesty is critical for employer trust. The lease pumper is the only one who knows exactly what happens on the lease each day. The problems that occur may happen downhole, involve the automated or surface equipment, or be caused by an action of the lease pumper or contract personnel. Some people have trouble admitting to the smallest mistake or error in judgment. This can result in false reports being submitted, which may lead to incorrect wrong conclusions being made concerning lease problems.

As an illustration, suppose that a lease pumper inspects a pumping unit. At that particular time of the day, the unit happened to be in an automatic off cycle and was not pumping. As part of the inspection, the lease pumper turns the control switch through the *off* position to *run* and completes the inspection. The switch should then be reset for automatic control. However, if the lease pumper fails to turn the switch far enough to re-engage the automatic control and leaves it in the *off* position, the well will be shut down. It will not produce any oil until the lease pumper returns, meaning that there is likely to be no production for 24 hours. The oil shortage the next day was caused by the lease pumper's carelessness, but no one knows that except the guilty party. What should the lease pumper put in the report? There may be a temptation to list the problem as a control failure. But doing so may mean that a well servicing unit is dispatched when no problem exists

In another example, the lease pumper may accidentally leave a casing valve closed after injecting fluid down the casing during a treatment of a pumping well. In this case, production from the well will decline and, after about three days, will fall almost to zero. The problem can be easily corrected by slowly bleeding off the casing pressure, but the lease pumper may be tempted to hide the mistake.

Such actions are obviously dishonest, but in many cases they are easy for the lease pumper to get away with for on most days no one but the lease pumper visits the site. Yet if an employer cannot trust the lease pumper to be honest about mistakes that anyone can make, how can that employer be assured that the lease pumper is not cheating on oil production, abusing purchasing authority, using the vehicle for personal errands, or even going to the leases as required. The hiring of a lease pumper is a tremendous act of faith on the part of the lease owner. Just as some people may not have the initiative to be their own boss, some do not have the degree of honesty to fulfill their half of this relationship of trust.

A-4. Special Precautions

The use of drugs or alcohol. Clearly lease operators will not tolerate the use of illegal drugs and the consumption of alcohol on the job and while traveling to and from the lease. The lease owner may require periodic unannounced drug tests and is entitled take appropriate actions if problems occur. However, the lease pumper should also be aware that some over-the-counter and prescription medications can impair a worker's ability to operate a vehicle or to perform work around moving equipment. When taking medicine, the lease pumper should check the label or consult a physician or pharmacist about possible side-effects that may prevent the safe performance of required tasks.

Hazards from heat sources. Oil and gas are important because the energy they contain can be released through burning. For this reason, an oil or gas lease naturally presents risks of fire and explosions. Add to this the dangers presented by fuels, stored materials, soiled rags, and other potential fire hazards, and it becomes clear why so many lease operators restrict the use and presence of heat sources on the lease site. For example, smoking may be allowed only in the vehicle and only with the use of the vehicle cigarette lighter. Carrying matches or a lighter may be forbidden (Figure 1). These regulations and policies may seem restrictive but are aimed toward saving life and preventing suffering.

Carrying firearms to work. Lease pumpers should refer to their company's policy on carrying firearms to work

Figure 1. On some leases, the use of open flames may be forbidden.

These are just a few of the policies and practices that a company or lease operator may put into effect with regard to lease operations. The lease pumper should discuss policies with the lease operator to determine what practices are acceptable and which are not allowed.

The Lease Pumper's Handbook

Chapter 1
Responsibilities and Employee-Employer Relations

Section B

FIELD OPERATIONS

In addition to understanding the duties and responsibilities described in the previous section, the lease pumper must be properly outfitted to do the work that is required. This means wearing clothing and other gear that will allow the job to be done efficiently and safely and having and maintaining the tools required to do all assigned tasks.

The cost of lease tools is just one of the expenses required in the operation of a lease. Supplies such as chemicals and utilities such as electricity also contribute to these costs. Often the lease pumper can take actions to reduce operating costs and improve the profitability of the lease.

Another influence on field operations and operating costs is the requirements imposed by regulatory agencies.

This section provides an overview of what it takes for the lease pumper to be properly outfitted and equipped as well as other factors that influence field operations and operating costs.

B-1. Dressed for Work and Weather.

Most of the work performed by a lease pumper is done outdoors and must be done no matter what the weather is. This means that a lease pumper must dress appropriately for the work to be done and the weather conditions. This means that the cloths must allow the lease pumper enough freedom of movement to do the required tasks while providing protection against moving or hot equipment, chemical splatter, falling materials, and other risks. The clothing must also provide protection against the environment, including cold and wet weather or intense sun and heat. The lease pumper must also be aware that weather can change quickly, so that in the course of a day the lease pumper may need protection against cold in the morning and protection against the sun in the afternoon or the day may start out warm and dry but end cold and wet. Clothing can be added or removed, according to changes in the weather. A poor selection of clothing can adversely affect job performance.

Normal lease pumper attire may include:

- Full-length pants.
- Long-sleeved shirt or coveralls.
- Steel-toed shoes.
- Eyeglasses and protective shields.
- Gloves. Rubber gloves for some tasks and cloth gloves for others.
- Hard hat.

Full-length pants and long shirt sleeves. Many of the chemicals and crude oils involved in the job can be a health hazard if not handled properly. Some chemicals are capable of penetrating the skin and entering the body just by coming into physical contact. This is especially true when the oil or chemical is extremely hot. Full-length clothing is the first line of defense against chemicals, oil, sun damage, and insect bites.

Steel-toed shoes. Sturdy shoes with steel toe protectors shield the feet from falling objects. Many serious foot injuries can be avoided by wearing protective shoes.

Eyeglasses and protective shields. Many of the jobs that a lease pumper performs present risks to the eyes. These risks include chemicals that may splash into the eyes, flying objects from moving parts or hammering, intense light from welding or cutting equipment, and other dangers. Because of the number of different types of risks, several styles and types of eye protection are required (Figure 1). For example, shatter-resistant glasses may protect against a flying object approaching the eye directly but offer little protection against chemical splashes from the side or the bright light and spatter from a gas cutting torch.

Figure 1. Some lease activities require the use of eye protection.

Gloves. While there are many types of gloves available, they are not equally suited for all jobs performed by the lease pumper. Cotton gloves are satisfactory for clearing brush or handling some equipment, but leather gloves may wear better when working with pipe and wire rope. Leather gloves as well as rubber gloves offer some protection against electrical shock. Rubber gloves or gloves of other special materials may also afford protection against harmful chemicals, such as some of the chemicals used to test oil prior to sale. The lease pumper should have the different types of gloves required for the tasks to be performed and replacement gloves when those become worn or unusable due to contamination.

Hard hat. A hat offers some protection against the elements and may reduce the chance of injury from falling objects and overhanging obstacles. However, some tasks performed by the lease pumper present greater risks of head injury and require the level of protection offered by a hard hat. Many companies require lease pumpers to wear hard hats whenever they are on the lease and outside the vehicle. In fact, everyone who enters the lease may be required to wear a hard hat.

Lease pumpers should follow their company's policies with regard to wearing hard hats. Hard hats vary in style and fit and features, such as brim width. If more than one style of hat is suitable for the work to be performed, a lease pumper should choose a hard hat that is personally comfortable so that there will be no reluctance to wear it when required.

B-2. Miscellaneous Gear.

There are some items that most lease pumpers consider to be indispensable for day-to-day operations. These may include:

- Rags or wipes.
- Pen, pencils, and paper.
- Pocket knife.
- Measuring tape.
- Pocket calculator.

Rags or wipes. The lease pumper needs a good supply of wipes to clean tools, equipment, hands, vehicles, and most everything else that visits the lease. Some field workers use paper wipes, while others prefer cloth rags. The latter may be shop clothes that have been rented or purchased from an equipment or uniform supplier. Another source of rags is used clothing from an outlet that sells clothing by the pound or bundle. This material can then be cut to a useful size. Many lease pumpers take advantage of bargain sources of rags because the rags quickly become soiled and worn and because there are so many items to keep clean, including the vehicle, tools, tool boxes, gauging and shakeout equipment, the areas around thief hatches, and other places regularly involved in the work. Keeping the site and equipment clean will enhance safety by reducing the chances of slipping on an oil spot, will improve efficiency by making it easier to get around the site, and will reduce the time spent on other maintenance, such as lubrication and corrosion protection.

Pens, pencils, and paper. The lease pumper must maintain the lease record book, record the hours worked by special crews, make notes about equipment and supply needs and work to be done, update equipment readings, and perform a host of other tasks that require a written record. It is important to keep pens, pencils, and paper available, even if the company has electronic equipment to record gauges and field readings.

Other items. The lease pumper may also want to carry a pocket knife, measuring tape, vernier scale, paint marking stick, calculator, and spare site and vehicle keys. Many of these items may prove handy for daily tasks, while others may be most useful in an emergency, such as when the keys have been locked in the vehicle or dropped in a snow drift in the dark.

B-3. Typical Lease Hand Tools.

The tools that are required on the lease will depend on how much of the fieldwork is done by company personnel. As noted in the previous section, there is a trend in the industry to contract with a field service company for much of the service and maintenance. This approach greatly reduces the number and types of tools that the lease pumper must carry, sometimes to the extent that the lease pumper is required to furnish the hand tools.. In some cases, lease pumpers drive their own vehicles and are then reimbursed for the miles driven. This mileage pay must cover the cost of the fuel, maintenance, insurance, and replacement of the vehicle.

The following lists include the basic tools necessary to perform the duties that are generally expected of a lease pumper. However, the exact requirements will vary from company to company. Lease pumpers should ascertain before accepting a job the tools that are required to do the work, those with which they will be provided, and any that they may be expected to provide. The lease pumper should also determine the company policy on replacing tools that are lost, broken, or worn.

This means that an important task of the lease pumper is to learn to take care of those tools. It can be frustrating to need a particular wrench to open a valve only to realize that that wrench was left lying on the pickup fender two wells earlier and is now forever lost somewhere six feet off the road in tall grass. Some lease pumpers who are careless with their tools are quick to make requests for lost tools to replacement supervisors when their regular supervisor is on vacation, neglecting to mention that these tools have already been replaced twice this year. This is why some companies assign tools, and, when the lease pumper leaves the job, each tool must be accounted for or the replacement cost is deducted from the final paycheck. If the lease pumper is not held responsible for issued tools, the lease owner may not be able to afford to keep a lease pumper who is careless with tools.

Vehicle tool and equipment storage. The lease pumper's vehicle generally provides three main areas of storage: the glove compartment, elsewhere in the passenger compartment, and in the rear of the vehicle or bed of the pickup. Rear storage areas generally contain toolboxes or other equipment containers to protect the tools and keep them organized. For safety and security, toolboxes should be lockable and the vehicle should be equipped with a roll bar. Common contents of these areas include:

Glove compartment.

Calculator.	Test gauge.
Pens, paper, pencils.	Measuring tape.
Daily gauge book.	Pocket knife.
Lease record book.	Safety goggles.
Flashlight and batteries.	

Cab storage.

First-aid kit.
H_2S backpack (if required)
Small fire extinguisher.
Hard hat.

Rear compartment.

Water can.	Motor oil.
Oil squirt can.	Gasoline can.
Engine water.	Antifreeze.
Miscellaneous parts as needed.	

The lease pumper's toolbox and storage shed. It would be impossible and impractical for the lease pumper to try to carry every tool and all the supplies that could possibly be needed for the situations that can arise on an oil or gas lease. There are a few tools that are generally essential to being able to pump a lease efficiently, but even so the tools that the lease pumper carries will depend to a great degree on the number of wells on the lease(s), the type of equipment on the lease that must be serviced, the amount of work support that is available, and the depth of maintenance that must be performed. Most of the commonly used tools will be carried in the vehicle. Other tools may be stored on the lease in the lease pumper's office—sometimes called a *doghouse*—or in a storage building. If a tool can conveniently be stored at the lease, this is desirable since tools can become rather shop worn and ragged within a short time when carried around in the vehicle over rough roads.

A minimum set of tools may include:

Digging, moving, and hauling.

Shovel.	Rake.
Hoe.	Moving bar.
Tying rope.	Small chain.
Pick.	Chain boomer.
Weed cutter.	Post hole digger.

Mechanic-style tools.

Screwdriver assortment.	Wire cutters.
Allen hex wrenches.	Pliers.
Fencing pliers.	Socket set(s).
Needle nose pliers.	Punches.
Open-/box-end wrenches.	Chisels.
Adj. smooth jaw wrenches.	Hammers.
Adj. pipe wrenches.	Hack saw.
Assorted files.	Snips.
Locking pliers.	Wire brushes.
36-inch pipe wrench.	Putty knife.

Miscellaneous items.

Safety wire.	Feeler gauges.
Tubing tools.	Packing hook.
Vernier style caliper.	Ease-outs.
Steel wool or sandpaper.	Cleaning fluid.
Small bolt assortment.	Paint brush.
Grease fitting asst.	Small bolts.
Nuts.	Washers.
Cotter pins.	Shim stock.

B-4. Oil Gauging and Test Equipment.

Gauging, test, and other special equipment should be transported in suitable cases. Typically, this equipment may include:

- Gauge line with required tape.
- Oil thief.
- Centrifuge, hand or electric.
- Centrifuge tubes, 12.5 or 100 ml.
- Hydrometer, appropriate range.
- Thermometer (preferably with scoop).
- Kolor Kut paste.
- Wipe rags.
- Tank seals.
- Squirt can with cleaning fluid.

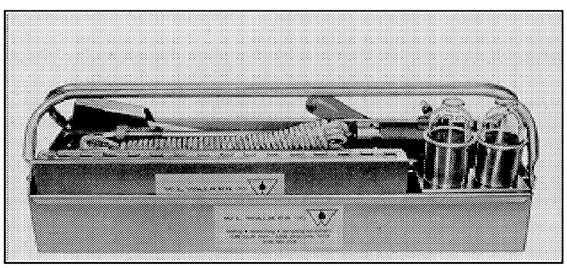


Figure 2. A typical set of gauging and oil analysis tools.
(Courtesy W.L. Walker Company)

B-5. Lease Operating Expenses.

The preceding paragraphs should give some indication of the tremendous investment required to stock a lease with the required tools and equipment. Tools and supplies are just one of the expenses that contribute to the cost of operating an oil or gas lease. The salaries and benefits of the lease pumper and other employees is also an expense that must be paid for from the money made selling petroleum products from the well. Some lease operating expenses are *set*—that is, little that the lease pumper does will affect the amount of the expense. Some of the typical set expenses include:

- Drilling and workover costs.
- Management costs.
- Salaries.
- Vehicle purchase cost.
- Daily supply costs.
- Lease purchase costs.

Obviously the lease pumper does have some influence over some of these costs. For example, if a lease pumper abuses sick leave, the company will have to pay more in salaries to provide relief. If the lease pumper drives the vehicle recklessly and does not care for it, it will have to be replaced more often. Further, there are other costs that are directly affected by how well the lease pumper performs the required tasks. Some of the operating cost that the lease pumper can most directly influence are:

Supply expenses. Supply expenses can be often reduced through the careful use of supplies. This does not mean to avoid buying required supplies, such as not lubricating equipment to save the cost of grease. This is false economy as the damage to the equipment far exceeds the cost of the grease. Suggestions in saving supply costs include:

- **Stuffing box packing.** Stuffing box packing on a shallow well (less than 2,000 feet deep) with stripper production should easily last a year or even two even if the engine runs 24 hours a day. The lease pumper should learn not only how to adjust the packing correctly, but also how to recognize the problems causing high packing consumption and then to solve the problem. Stuffing boxes (Figure 3) often leak because the lease pumper over-tightens them just to be sure that they do not leak.

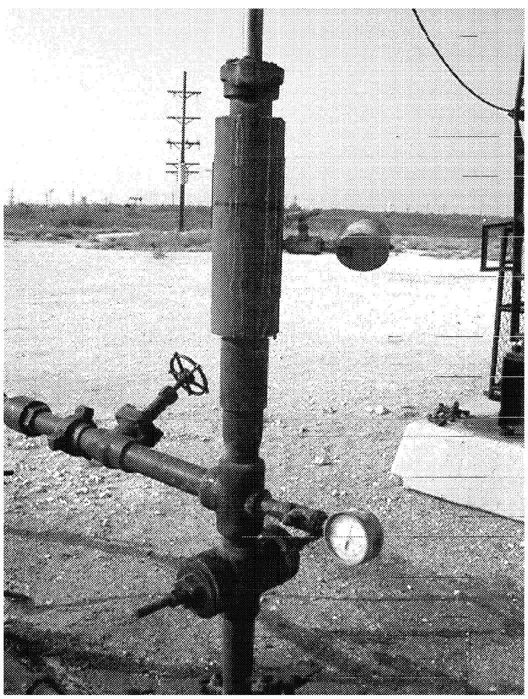


Figure 3. A stuffing box.

- **Lease electricity.** In most areas, electric companies have at least two charge rates for the electricity that they provide. A higher cost is usually charged for electricity used during peak load periods—that is, when electricity consumption is at its highest, such as from 8 a.m. to 5 p.m. If a well must run four hours per day to meet production requirements, the lease pumper should set the well to operate during non-peak periods so that the cost of electricity is less. Another consideration is that pump engines draw a heavy electrical load when they first start to get the idle parts moving. If a well must pump 10 hours per day, it will take less electricity to run it for 10 hours straight rather than to start the engine five times to run two hours each (though other factors may also have to be considered).

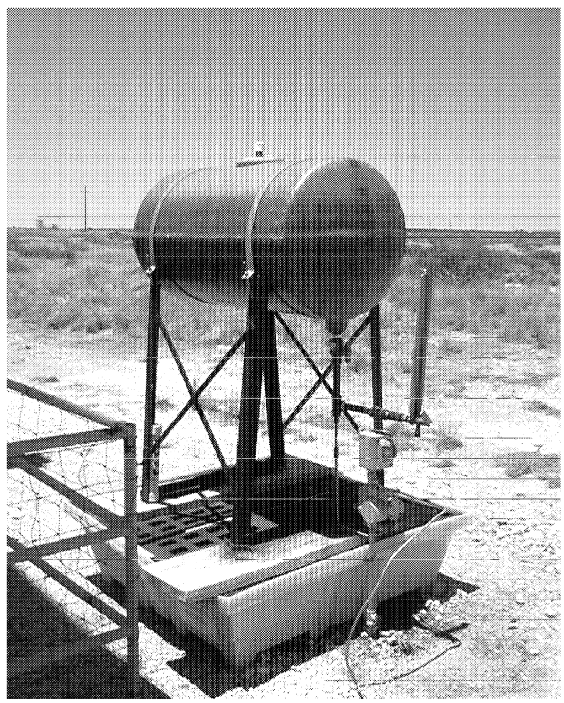


Figure 4. Chemical injection system.

- **Chemical expense.** One of the methods of treating oil is the use of chemicals (Figure 4). Oil treating chemicals can be very expensive. Sometimes a lease pumper may add extra chemicals, thinking that if a little is good, then more is better. Another lease pumper may simply be careless at measuring or may spill chemical. A typical cost for treatment chemicals is $30 per gallon. If a lease pumper has five wells and wastes one gallon of chemical per month at each well, the company pays $150 per month, or $1,800 annually, for wasted chemicals.

B-6. Government Regulating Agencies.

There are several agencies that the lease pumper may have to deal with in the field. The purpose of these agencies is to ensure that lease operations are safe, efficient, do not excessively harm the environment, and are consistent with other concerns of the nation and its people. Some of the more important agencies are:

The Bureau of Land Management (BLM). The federal government owns much of the mineral rights in the United States. The Bureau of Land Management oversees activities on these public lands to protect the citizens' property. BLM inspectors monitor oil and gas lease operations and issue guidelines, such as requiring that the handle on the sales line be sealed in such a manner that the valve cannot be opened unless the seal has been broken. Publications are available that contain guidelines for drilling, production, and pipeline operations.

Occupational Safety and Health Administration (OSHA). Work on the lease site is generally subject to the requirements of the Occupational Safety and Health Act. Under the guidelines of the act, employees must be advised of the dangers they face. This information is usually provided through training or through warning indicators or signs. OSHA regulations may also define protective gear requirements, such as hard hats and safety face shields, and prescribe how the gear is to be used. For example, when performing duties, such as gauging tanks that contain hydrogen sulfide gas, the lease pumper is required to wear a mask that provides a source of breathable air and that prevents the worker from breathing the toxic hydrogen sulfide. Additionally, the worker must wear the mask in such a way that a good seal is obtained, which may mean that beards and facial hair may be forbidden or required to be trimmed in such a way that the mask provides the required seal. Employers are subject to severe fines and penalties if their employees are not in compliance with OSHA regulations, and employees can be punished or fired for failing to comply with government or company safety policies.

Environmental protection and standards. Many laws have been passed to protect the environment. These laws help to protect the air, soil, surface water, and groundwater from contamination. Special guidelines have been issued for various industries, including petroleum production. Special concerns for lease pumpers are oil spills, venting high volumes of gases, or the loss of salt water or oil. Even pipe that is pulled out of a well may be contaminated by radiation and have to be stored in a special manner.

The Lease Pumper's Handbook

CHAPTER 2.

TRANSPORTATION, COMMUNICATIONS, AND LEASE MAINTENANCE

The Lease Pumper's Handbook

Chapter 2
Transportation, Communications, and Lease Maintenance

Section A

GETTING TO THE LEASE

Because many leases are located in remote areas, lease pumpers frequently have to drive long distances to visit all of the wells under their care. Thus, two major concerns of the lease pumper are having a dependable mode of transportation to travel to the lease sites and the ability to find and identify the exact location of the wells to be serviced. This section discusses the means of getting to the lease.

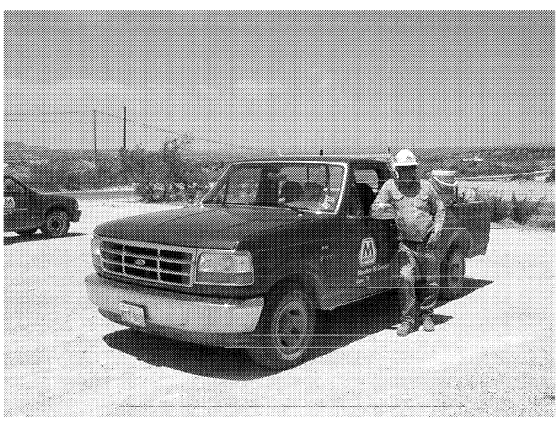


Figure 1. A lease pumper and the lease vehicle.
(courtesy Marathon Oil Co. Safety Dept., Iraan, Texas)

A-1. Vehicle Expense and Maintenance.

As discussed in the previous chapter, lease operating expenses, including vehicle and equipment maintenance, are of constant importance to the lease operator. The lease operator is not only concerned with the cost of the vehicle but also with the expenses of maintaining the vehicle. The lease pumper can help keep these expenses reasonable through the proper use and maintenance of the vehicle.

Taking care of the lease vehicle. The supervisor is well aware of how well the lease pumper takes care of the lease vehicle. Most oil companies maintain monthly and annual records that give costs per mile and total expenses. When a company has several lease pumpers, these records can reflect how the lease pumpers take care of their vehicles and can indicate their driving habits.

Some lease vehicles have a high cost per mile because of long driving distances, often over poor rocky roads with road maintenance. But even the operating costs and maintenance needs of these vehicles can be reduced through good driving habits. High speeds with excessive braking lower fuel economy, wear out the running system or gear train more quickly, and will result in an undependable vehicle. The lease pumper must always observe good driving practices and drive with care. Driving with a heavy foot on the accelerator can seldom be justified.

Driving to and from the lease. If a lease is several miles away from the lease pumper's home, it is easy to fall into the habit of driving too fast. When going to work, the lease pumper is usually thinking about the problems of the day, planning how to achieve the daily work objectives, and thinking about the many things that can go wrong. Distracted in this way, the lease pumper continues to accelerate.

On the way home, the lease pumper is thinking about all of the things to do at home, the little league game tonight, mowing the lawn, getting ready for a fishing trip or vacation, and dozens of other thoughts. There is so much to do that exceeding the speed limit seems justified—after all, it's just for today. But before long, the lease pumper develops the habit of speeding every day and loses good driving judgment. Now the lease pumper is abusing the vehicle not occasionally but every day.

Lease roads. Lease roads are expensive to keep up. There are so many other needs that are required to maintain or enhance production, and money seldom becomes available for road maintenance. Many lease owners are willing to pay higher vehicle expenses rather than spend money on roads.

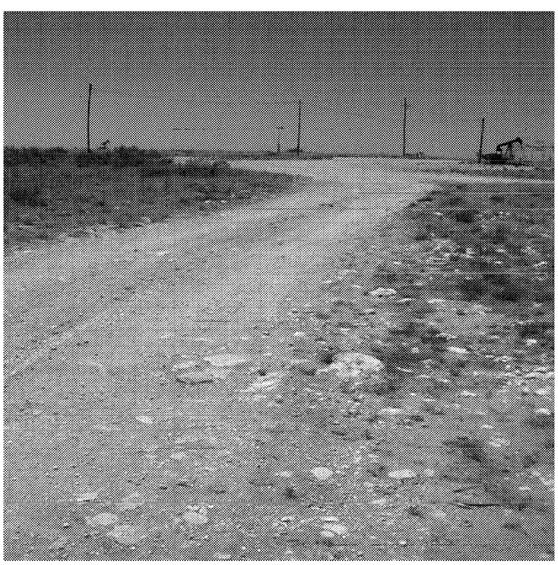


Figure 2. A typical lease road.

The lease pumper must use common sense driving the lease roads. It is important to keep speeds low enough to keep from bruising the tires on rocks. Tire replacement bills will reflect the lease pumper's driving habits. If there is a large rock on the lease road, the lease pumper should stop and move it to the side rather than create a new road from driving around it.

A-2. Company Policies for Vehicle Use.

Personal use of the vehicle. Many lease operators allow their lease pumpers to take the lease vehicle home. That makes it easy to develop bad habits. The lease pumper may occasionally stop at a convenience store because, after all, it is right on the way. The lease pumper may need to buy some stamps, and the post office is only a few blocks away, so the trip gets a little longer.
Soon, the lease pumper has developed the habit of making minor detours away from the direct route to work as a part of the daily routine, so that it becomes a perk, or fringe benefit, to the job. After all, the lease pumper works all business hours from Monday through Friday for the company, and this is the only time many of these businesses are open.

While these side-trips may be acceptable with some companies, lease pumpers should clearly understand the policies of their own companies and use good judgment.

Unauthorized personnel in the vehicle. The lease pumper who picks up hitchhikers or takes someone along on the job can create problems for all involved, including the employer and the passenger. It is difficult when a close friend or relative is visiting from far away, and the lease pumper must drive off to work leaving them behind. After all, the lease pumper is driving a vehicle designed for two or more people and is working alone and may not even see another company employee for the rest of the week.

The first problem is with insurance. What happens if the lease pumper has an accident and the passenger is seriously injured or killed? Who will pay the immediate medical expenses and even long-range medical recovery and rehabilitation expenses? These costs can quickly exceed a hundred thousand dollars and expensive treatments could continue for years. Who will pay the bills? What if the passenger has no insurance? There is a good possibility that the company's insurance will not cover the expenses either. It could fall to the lease pumper's insurance, and that insurer may also refuse to pay because the injury occurred while violating company policies.

This situation could lead to lawsuits, which can result in multimillion-dollar settlements. Even if the lease pumper should win the lawsuit and not be held responsible, lawyer's fees and court costs can prove expensive.

While larger companies are likely to have policies against permitting riders in lease vehicles, many smaller lease operators will not have written policies against the practice and may not verbally object to permitting passengers to ride with the lease pumper for the day. But the lease pumper must always be aware of the position in which the company or lease owner is placed. As a good employee, the lease pumper should at least discuss the matter with the employer. They may also determine the stance of the company's insurance carrier. If the lease owner has no objections, the lease pumper may consider purchasing a permanent or temporary rider policy that can be attached to a personal insurance policy in order to protect the employer, the passenger, and the lease pumper.

A-3. Locating the Lease.

During the last few years, an effort has been made to name roads in rural areas that provide access to a residence. This assists in mail and package delivery and can help workers find a lease.

Location identification signs. Whether or not a road is named, many lease operators will erect a lease identification sign to aid in directing service trucks to their production locations. Some of the information that each sign might include is:

- **The lease operator.**
- **The lease name.** The lease is often named after the owner of the mineral rights.
- **The lease location** based on the Geological Survey system.

The federal system of rectangular surveys. Most globes show the horizontal lines or *latitudes* and vertical lines or *longitudes* that are used to mark the surface of the earth. In the United States, the entire country, except for the original colonies and the state of Texas, is designated with a rectangular survey system. All land in this system is divided into squares that are approximately one mile on each side. These one square-mile blocks are called *sections*. Each group of 36 sections with six sections on a side is called a *township*. The sections within a township are numbered beginning in the northeast corner of the township and going west. The numbering then goes south to the next row of sections and continues east. In this way, the first, third, and fifth rows as numbered from the top or north edge of the township are numbered east to west and the even-numbered rows (2, 4, and 6) are numbered west to east. Thus, section

1 within a township is in the northeast corner and section 36 is in the southeast corner (Figure 3).

6	5	4	3	2	1
7	8	9	10	11	12
18	17	16	15	14	13
19	20	21	22	23	24
30	29	28	27	26	25
31	32	33	34	35	36

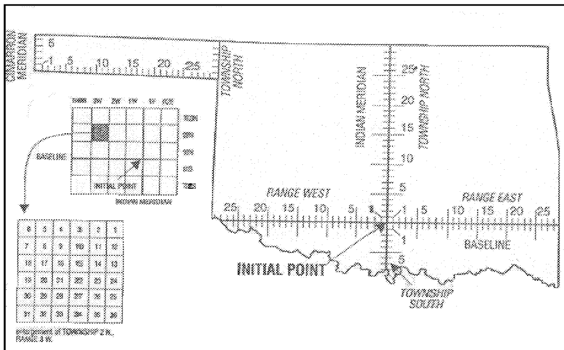
Figure 3. Numbering of the sections in a township.

Townships are also numbered within a survey area. The numbering of townships is based on latitudes and longitudes. Another term for longitude line is *meridian* and one longitude for a particular survey area is called a *principal meridian*. More than twenty principal meridians have been designated in the U.S.

Principal meridians are crossed by latitude lines. One latitude line within a survey area is designated the *baseline*.

An example may clarify this system. Oklahoma has two survey areas: the panhandle is under one survey area and the remainder of the state is under a second survey area. The principal meridian for the major portion of Oklahoma is called the Indian Meridian and lies close along a longitude of 97°14' West. The baseline for this portion of the state lies close to latitude 34°30' North and crosses the principal meridian in south central Oklahoma (Figure 4).

The intersection of the principal meridian and the baseline divides the survey area into quadrants. A column of townships located north and south of each other is referred to as a *range*. A row of townships running east and west of each other is referred to as a *township*. Ranges are numbered beginning at the principal meridian. Thus, all of the townships along the west side of the principal meridian are referred to as Range 1 West or R1W. The next column of townships to the west are designated Range 2 West or R2W and so on until the western edge of the survey area is reached. Similarly, the first column of townships on the east side of the principal meridian are referred to as Range 1 East or R1E. This numbering continues consecutively to the eastern edge of the survey area.



Township and Range Adapted from *The Atlas of Oklahoma*, ed. Tom Wikle (Stillwater: Department of Geography, Oklahoma State University, 1991).

Figure4. Principal meridian and baseline locations in Oklahoma.

The rows of townships are numbered in a similar manner. Thus, the baseline of the survey area forms the southern boundary of Township 1 North or T1N and the northern boundary of Township 1 South or T1S. The numbering of the rows of townships continues north and south to the ends of the survey area.

This system allows the identification of a piece of land within one square mile. For example, if a lease is located on Section 31 of township T7N, R14E, the lease pumper knows that the land is in the seventh row of townships north of the baseline and the fourteenth column of townships east of the principal meridian. Further, the lease is on the section of land located in the southwest corner of that township.

This system of identifying land is used to create a *legal description* of most rural land (though some land, especially within towns and cities, may be identified with a system of *plats*). The legal description locates a section of land by means of its township and numbered section location and then identifies portions of the section. For example, a section of land contains about 640 acres. If a piece of property consists of the 160 acres—that is, one-fourth of the section—in the northwest part of the section within the township described in the previous paragraph, the legal description of that piece of property may be given as T7N, R14E, Sect. 31, NW¼. Often the description is written beginning with the smallest division, thus: NW¼, Sect. 31, T7N, R14E.

Naturally, this system would be impractical if a person had to actually start at the intersection of the principal meridian and the baseline to locate a particular parcel of land. Many land maps identify the townships using this system. Additionally, most leases have signs that identify the well locations within the section. These are generally given as a distance in feet as measured from two boundaries of the section. For example, assume that the well is located 660 feet from the north boundary line of the section and 1,980 feet from the west boundary line, then the location can be indicated as 660' FNL (from north line) and 1,980' FWL. If a line is drawn east to west across the property at 660 feet from the north boundary line, the well should be located along that line at a distance of 1,980 feet from the west boundary line. For this well location, the lease site may display as sign containing the following:

John Doe Oil Company
Federal C Jones No. Y7
660' FNL-1,980' FWL,
Sec 31-T7N- R14E- OK

Reading the sign from the end, shows that the well is located in Oklahoma (OK). States are generally designated by their two-letter postal abbreviations. The state abbreviation may or may not appear on the sign.

Within this survey area, the well is located on section 31 of the township that is 7 north and 14 east of the intersection of the principal meridian and the baseline. This specific well is situated 660 feet from the north line of the section and 1,980 feet from the west line of the section.

Other information given on the sign includes:

John Doe Oil Company. This is the present owner of the oil well. If the owner changes, the sign is changed, and a closing bond must be placed in effect for the life of the well.

Federal C Jones. The federal government owns the mineral rights, and the C indicates that this is the operator's third federal lease. Elsewhere there will be land representing lease Federal A and at some other block of leased land is Federal B lease. These leases may or may not be active, but will not be redesignated once the letter is assigned. If an oil company leases more than 26 (the number of letters in the alphabet) blocks of federal land, the designations would start at the beginning of the alphabet with an A added to each identifier, so that the 27th well would be AA, the 28th would be AB, and so on. This process would be repeated through the alphabet, and started over with BA, BB, BC, etc. if required.

Jones. A lease name may be designated by the operator. Often this will be the name of the surface rights owner.

No. Y7. The well itself will often be designated by a letter and a number. The number generally represents the sequence of the wells drilled on the lease. In the example, the sign refers to the seventh well drilled on this lease. The letter is a code for the status of the well. For example, Y indicates that problems were encountered while drilling the well and the initial well was plugged, the rig repositioned, and the well re-drilled from the surface. A dry hole marker should be located nearby.

Locating the next lease. In addition to providing a legal description of a piece of land, knowing the section location can also help a lease pumper find another lease. For example, assume that a lease pumper is at the lease gate in the northeast corner of the lease described above and now needs to travel to the southeast corner of Section 28, T8N, R13E. Each section is approximately one mile or 5,280 feet along each side. The lease to be visited next is one township to the west and one to the north. The northeast corner of section 31 is one mile east of the R13E column of townships. It is then five miles north to the row T8N townships. Traveling another mile north will take the lease pumper to the south edge of the row of sections in T8N, R13E that includes Section 28. The lease pumper would then have to travel three sections or miles west to reach the southeast corner of Section 28. The total distance traveled would be 1 + 5 + 1 + 3 = 10 miles.

Of course the exact distance may vary for several reasons. First, there may not be roads that allow the lease pumper to follow that exact route. It may be necessary to travel an extra distance and double back to reach the desired destination. The circumference of the earth (the distance around the earth at a latitude) gets progressively smaller as the distance from the equator increases. The earth also has continuous elevation changes to further complicate distance measurements. The driving distance from one side of a township to the other can be considerably more than six miles if there are a lot of hills and valleys to cross.

In those areas of the country where the Federal System of Rectangular Surveys is not used, the lease pumper must be familiar with latitude and longitude designations that use compass directions and a system of 360 degrees in a circle, 60 minutes in a degree, and 60 seconds in a minute.

Survey markers. Before drilling wells on a lease, to locate the exact spot to drill the well, an accurate land survey must be made by a professional survey crew. This survey will begin at some recorded and recognized accurate marker as close to the leased land as possible. The survey crew will then determine the location of the lease relative to the witness point. Because land surveys can be expensive and their costs increase in proportion to the distance from the starting point, lease operators will often ask the survey crew to place a survey marker on the lease or as near to it as possible. This marker (Figure 5) will generally be installed in cement or other permanent structures. Often a sign will be posted nearby to indicate the presence of a survey marker (Figure 6). The survey marker may be centrally located within a lease area so that as more wells are drilled, future surveys can be made from the marker point that the first survey crew has established.

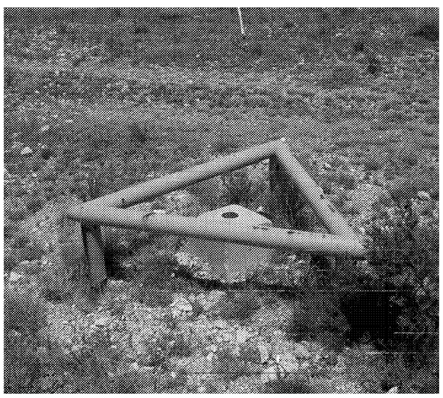


Figure 5. A survey marker.

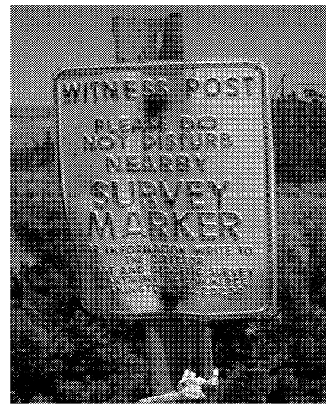


Figure 6. A witness post sign indicating that a survey marker is nearby.

Chapter 2
Transportation, Communications, and Lease Maintenance

Section B

ROUTINE AND EMERGENCY COMMUNICATIONS

One of the interesting aspects of work as a lease pumper is that the job is seldom the same from day to day. Depending on the level of production, the status of the equipment, the requirements of the maintenance schedule, and numerous other factors, different tasks will be required today than were required yesterday. Tasks that are repeated from the previous day may be done in a different way, performed to a different degree, or accomplished on other equipment or at a different site. The lease pumper is also likely to encounter unexpected situations, such as a leaking pipe, an engine that has locked up, livestock in the overflow pit, or other surprise. Often performing routine tasks or dealing with emergencies will require that the lease pumper contact someone by telephone or radio.

Generally, phone books are not available on the lease site and it is unlikely that the lease pumper will be able to memorize the number of every resource who may have to be contacted, as well as one or two backups if the first choice on the list cannot be reached. So the lease pumper must have immediately at hand the information necessary to deal with these situations. Further, if the lease operator or supervisor cannot be reached for directions in dealing with a situation, the lease pumper must have some idea of what to do and what he or she does not have authority to do. This section provides tools and suggestions that will help prepare the lease pumper to deal with emergencies.

B-1. What Is an Emergency?

Basically, an emergency is any situation that is causing an undesired result or has the potential to cause and undesired effect unless immediate corrective action is taken. When an emergency presents itself on the highway driving to or from the leases or in various situations that might arise on the lease, the lease pumper must be prepared. It is too late to ask the boss what to do in an emergency when time does not permit contacting anyone or when the required person cannot be reached. The lease pumper needs to know what to do in advance.

As an illustration, if a large hole has opened on the side of a stock tank and oil is pouring out onto the ground forming a small pond, the lease pumper should immediately begin circulating the oil out of the leaking vessel even before switching the tank. Then the lease pumper should call the office to request a vacuum truck to pick up whatever oil can be salvaged. Time is money and holding the loss to a minimum requires quick action. By planning ahead with the supervisor for this type of situation, the lease pumper will know what to do when the situation arises. By having contact information, such as the name of a vacuum truck operator, the lease pumper will have a course of action if no one at the office can be contacted.

The list of possible lease emergencies is extensive. If electrical power to the lease has been disrupted, most of the time no one will know about the problem until the lease pumper arrives. The electrical service company may not know there is a problem until they are notified. Other emergencies may involve life-threatening situations and require contacting medical personnel. The lease pumper should have all relevant numbers available in advance of the emergency.

If the lease pumper does not have a two-way radio or mobile telephone, then the nearest phone will have to be used. It may be a farm or ranch house, a nearby town, another worker who has mobile communications, etc. This is one reason that the lease pumper should become familiar with the area around each lease and get to know people who live nearby. To be adequately prepared, the lease pumper should plan two or more response options and carry the information required to carry out all planned options.

The remainder of this section provides tools and guidelines that a lease pumper may find useful in planning routine and emergency communications.

B-2. Emergency Telephone Numbers.

Page 2B-5 provides a form that lists some of the persons and agencies that the lease pumper may have to contact while on the job. The form also provides spaces for listing contact information. The lease pumper should complete a form similar to the one shown and keep it in the vehicle. If the lease pumper is working at sites spread over a large area, it may necessary to have a separate form for each of the different leases. For example, it is not unusual for a lease pumper to work leases that are in different law enforcement jurisdictions or different fire districts. Some rural areas and small towns do not have 911 emergency service, so the lease pumper must also know whether 911 can be used at a site or if a specific telephone number must be dialed.

B-3. Company and Personnel Communications.

Another list that is convenient to have is contact information for company personnel and for others who may work on the lease, such as relief personnel. Even if the lease pumper knows this information, the list should be comprehensive because when the lease pumper is off duty, ill, on vacation, or gone on a family emergency, the information may be needed by relief personnel who may not be as familiar with the company, employees, or staffing structure.

A suggested form for this information is shown on pages 2B-7 and 2B-8. However, the specific information required will vary from one operation to another, so the form may include information that is not needed for one lease pumper, while omitting information that is vital to those working a different lease. Each lease pumper should list information that may be of value on the job or to a relief person.

B-4. Field Support Services Telephone Numbers.

As noted earlier in the example concerning a leak in a stock tank, maintenance of lease often requires completing tasks for which the lease pumper is not qualified or equipped. Times also arise when the lease pumper may have to buy supplies, such as engine fan belts or hardware to replace nuts and bolts that have worked loose and become lost. These situations represent other instances in which the lease pumper will benefit from having information about how to contact the suppliers. Sometimes it is also important to know the physical addresses of suppliers so that the required items can be picked up.

A sample form for listing suppliers and support service resources is shown on pages 2B-9 and 2B-10. While the form includes a list of typical types of service providers, the exact needs of a particular lease or company may differ, so the lease pumper should modify the form so that all required resources can be listed.

B-5. Lease Locations.

Because lease sites may be located in remote areas and be hard to find, it is a good idea for the lease pumper to carry information about how to reach a site. Obviously, this would be helpful for relief personnel or service providers who may not be familiar with how to reach the site. But the information can also be helpful to the regular lease pumper in describing alternate routes for reaching the site in the event that the normal route is closed due to road construction, weather conditions, bridges being out, etc. In describing how to reach the lease, the lease pumper should include town names, highway numbers, mile markers, distances, and descriptions of cattle guards, road divisions, highway signs, and other noticeable landmarks that will help to identify the route.

An example of a form that may be used to describe lease site locations is provided on page 2B-11.

COMMUNICATION INFORMATION

Nearest Telephones:

1. Name________________________ Location ____

2. Name________________________ Location ____

Emergency Numbers

The National General Emergency Number 911 or ____________________________

State Highway Patrol. City________________________ _____________________________

City Police. City_________________________ _____________________________

Fire Department. City__________________________ _____________________________

County _______________________ _____________________________

Ambulance and Paramedics

Hospital, City ____________________________ ____________________________________

Hospital, City ____________________________ ____________________________________

Federal Game and Fish Department ____________________________________

State Game and Fish Department ____________________________________

Forest Department ____________________________________

Environmental Department ____________________________________

Other ______________________________ Other ______________________________

COMPANY AND PERSONNEL COMMUNICATIONS

Regular Lease Pumper

Name ______________________________ Address ____
City _______________________________ State ____________________Zip__________________
Home telephone ___________________ Mobile _________________Fax __________________
In case of emergency notify ___________________________ Relationship __________________
If unable to reach this person, call _____________________ Relationship __________________
Vacation Schedule ____
Special Information ____

Relief Pumper Information

Relief Pumper 1

Name ______________________________ Address ____
City _______________________________ State ______________________ Zip ________________
Home telephone ___________________ Mobile ____________________ Fax ________________
In case of emergency notify ___________________________ Relationship ___________________
If unable to reach this person, call _____________________ Relationship ___________________
Vacation Schedule ____
Special Information ____

Relief Pumper 2

Name ______________________________ Address ____
City _______________________________ State ______________________ Zip ________________
Home telephone ___________________ Mobile ____________________Fax ________________
In case of emergency notify ___________________________ Relationship __________________
If unable to reach this person, call _______________________ Relationship __________________
Vacation Schedule ____
Special Information ____

Lease Operator Information

Company name (Lease owner/Company) ____
Business mailing address ____
City ___________________________________ State ______________________ Zip _____________
Telephone _____________________________________ Fax ___________________________________
Owner/Manager ______________________________ Telephone ______________________________
My supervisor ___________________________________ Title _________________________________
Office telephone ________________________________ Mobile ________________________________
Home telephone ____

COMPANY AND PERSONNEL COMMUNICATIONS
(Continued)

Contract Pumper Information

Company name ____
Business mailing address ____
Owner/Manager ______________________________ Telephone __________________________
My supervisor ________________________________ Title ______________________________
Office telephone ____________________ Mobile __________________ Fax __________________
Home telephone _____________________________ Fax __________________________________

Other information

FIELD SERVICES SUPPORT SERVICES TELEPHONE NUMBERS

Pipeline or oil transport company Name ____________________
Telephone ____________________
Weekend or Emergency ____________________

Water transport company Name ____________________
Telephone ____________________
Weekend or Emergency ____________________

Rural electrical company Name ____________________
Telephone ____________________
Weekend or Emergency ____________________

Electrical services and repairs Name ____________________
Telephone ____________________
Weekend or Emergency ____________________

Electrical motor rewinding Name ____________________
Telephone ____________________
Weekend or Emergency ____________________

Hot oiling services Name ____________________
Telephone ____________________
Weekend or Emergency ____________________

Chemical supplier Name ____________________
Telephone ____________________
Weekend or Emergency ____________________

Oilfield supplies (Store 1) Name ____________________
Telephone ____________________
Weekend or Emergency ____________________

Oilfield supplies (Store 2) Name ____________________
Telephone ____________________
Weekend or Emergency ____________________

Maintenance and construction Name ____________________
Telephone ____________________
Weekend or Emergency ____________________

FIELD SERVICES SUPPORT SERVICES TELEPHONE NUMBERS
(Continued)

Well servicing andworkover Name ________________________
Telephone ________________________
Weekend or Emergency ________________________

Downhole pump repairs (1) Name ________________________
Telephone ________________________
Weekend or Emergency ________________________
Address ________________________

Downhole pump repairs (2) Name ________________________
Telephone ________________________
Weekend or Emergency ________________________
Address ________________________

Engine and mechanical (1) Name ________________________
Telephone ________________________
Weekend or Emergency ________________________
Address ________________________

Engine and mechanical (2) Name ________________________
Telephone ________________________
Weekend or Emergency ________________________
Address ________________________

OTHERS

________________ Name ________________________
Telephone ________________________
Weekend or Emergency ________________________
Address________________________

________________ Name ________________________
Telephone ________________________
Weekend or Emergency ________________________
Address ________________________

Comments ____

____

HOW TO REACH EACH LEASE

Lease 1. Name_____________________________________ Location _______________________

____

____

____

Lease 2. Name_____________________________________ Location _______________________

____

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Lease 3. Name_____________________________________ Location _______________________

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The Lease Pumper's Handbook

Chapter 2
Transportation, Communications, and Lease Maintenance

Section C

GENERAL LEASE MAINTENANCE

Previous sections have discussed the relationship between the lease pumper and the lease owner, as well as the influence of regulatory agencies. Another important player in lease operations is the owner of the land on which the wells are situated. This section focuses on maintaining a good relationship with the landowner and the role of good lease maintenance in that relationship.

C-1. Landowner and Lease Operator Rights.

Under United States laws, **surface rights** and **mineral rights** are recognized as separate property and can both be owned by the same individual, owned by different individuals, or owned jointly by many individuals or companies. During the early years of our country's history, mineral rights were generally sold with the land. As minerals of value were discovered, the government began retaining mineral rights and withdrawing them from future sales. Now it is quite common for the surface rights to have one owner while the mineral rights belong to other individuals, state governments, the federal government, foundations, Indian nations, counties, cities, banks, land grant universities, or some other owner. They may even be owned by an entity in another country.

The surface rights may also be owned by the state, the federal government, an Indian nation, others, or a combination of these. The owner of the surface rights or the **landowner** has the right to use the surface of the land. The landowner also has the right to fence the land, control the use of the surface, and control access to the property. In some cases, the persons residing on the land may not own it but may be lease tenants. The surface rights of some government-owned land are leased under long-term agreements. Often families have lived on land under this type of lease agreement for several generations and have much of their wealth invested in land improvements. When the mineral rights are leased, the landowner or lessee will receive payment for any damages caused by exploration for minerals.

The mineral rights owner or lessee has the right to search for minerals under most of the land. Before the first well is drilled, the owner or lessee of the mineral rights must reach an agreement with the surface rights owner, generally involving payment of a sum of money to compensate for the use of a part of the land. This includes not only the areas on which wells and equipment are located but also land for access roads. This agreement is usually in force for as long as the wells are being produced. As additional wells are drilled, additional fees will be paid for damage to the land and for the loss of income from land involved. When the hydrocarbons have been depleted and the last well has been plugged and abandoned, the lease to enter the property and the right to use the existing roads and locations usually expires. The land reverts back to the land surface owner, and the lease operator must withdraw from using these facilities in compliance with the original and subsequent land use agreements.

A landowner who does not own any of the mineral rights and who will not receive any further compensation for the loss of the land may not feel too friendly toward the lease operator. The landowner may prefer to maintain privacy and may feel invaded. For this reason, the lease pumper, as the lease operator's representative, must try to maintain good relations with the landowner.

C-2. Off-Road Travel.

Mineral lease agreements specify the type and location of road construction, the widths of the roads, and locations of wells, tank batteries, and pits. If a mud hole develops in a low area of the access road, the lease pumper may be tempted to drive around it. As this bypass grows muddy, the pumper and other lease visitors drive even farther off the road to avoid the water and mud, making the roadway even wider. Instead of trying to solve the problem by bringing in a load of small rock and fill to repair the road damage, the lease pumper has exceeded the width of the leased road width by many feet and is driving on private property. Other damage that can occur as a result of such right-of-way violations include dead grass, soil erosion, and collisions with equipment or livestock. Often the first indication that the surface rights owner does not approve of the lease pumper's practices is a bill to the lease operator for damages.

The landowner may go directly to the lease operator or hire a lawyer to seek compensation for damages. Some landowners take direct action by changing the lock on the gate or forbidding the lease pumper entry to the property. In some cases, the damage may have been caused by a third party, such as a well service crew, but the landowner will still generally consider the problem to be the lease operator's fault.

Regardless of the property damage, real or imaginary, caused or not caused by the pumper, serious problems can begin when the lease pumper or anyone working for the oil operator drives off the leased roads or locations. The lease pumper is a representative of the lease operator, and the landowner will hold the lease operator accountable for damages. The pumper should always try to get along with the landowner, take pride in maintaining the vista of the land adjacent to the leased roads, and not drive off the agreed-to routes. When it is necessary to get off the roadway to examine nearby installations, the lease pumper should use common sense and walk if damage or problems may result from driving, or if the landowner might object. Any trash or other objects that have blown off lease-related vehicles should be picked up the first time that it is noticed and not allowed to accumulate. Trash barrels should be available at convenient locations and emptied on a regular schedule.

When possible, the landowner should be cultivated as a friend. Some landowners and lease pumpers become such close friends that the operator is allowed a lot of latitude. Then if a situation arises that the landowner considers to be a problem, the chances are greater that the landowner will talk to the lease pumper rather than get angry.

C-3. Livestock Injuries.

Many leases are located in ranching and farming country where livestock roams freely across the leases and access roads. As the lease pumpers drive around performing their daily duties, livestock is encountered regularly. Livestock may develop the habit of seeking shade close to lease equipment if the area is not fenced (Figure 1). The lease operator must install adequate fencing to keep these animals from accidentally damaging delicate and automatic equipment. Calves, goats, or sheep may lie down in the shade cast by the counterweights of a pumping unit next to the counterweight guards. While lying down, the animals are only a few inches high and low enough to work themselves under some fences. Then, when they stand up, they are inside the fence next to the counterweights. If the pumping unit starts automatically, the young animal may panic and injure itself on the fence or equipment. This is a problem for the animal, the lease pumper, and the rancher that could have been avoided with proper fencing.

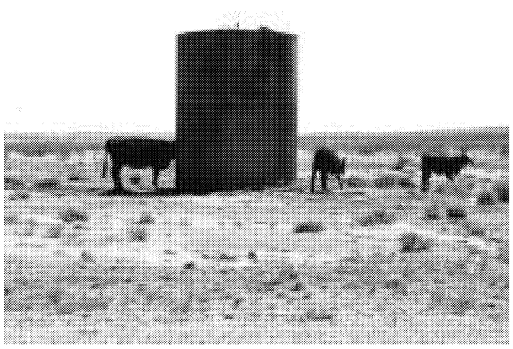

Figure 1. Cattle like to stand in the shade of oil field equipment.

Guards are added to equipment to protect against injury to people, not animals. A 1200-pound bull may decide to scratch his itching hide against a small valve sticking out on a header. Doing so, the bull can turn valves on or off, break delicate lines and valves, disconnect electrical grounding lines, turn a pumping unit on or off, change a variable choke setting, and create a host of other odd and unexpected surprises. The lease pumper may need to add close meshed wire around some units to protect animals and to protect the equipment (Figure 2).

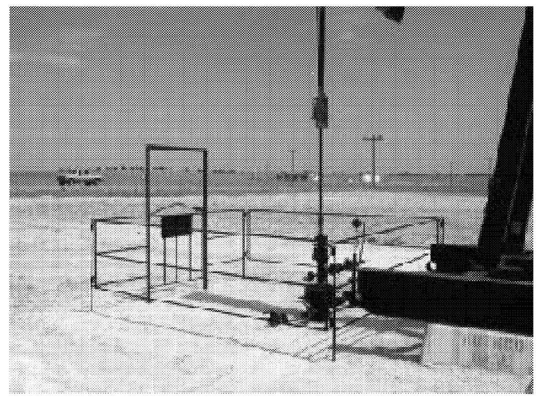

Figure 2. Fences may have to be installed around equipment to keep livestock out.

The lease pumper must recognize the landowner's right to run livestock on the property and willingly accept responsibility for protecting them from being injured by the actions of oilfield equipment or fluids that they may eat, lick, or drink.

Care must be taken when driving through livestock herds. When a herd of cattle who are used to being fed supplement feed are first placed on the lease, they may pursue the lease pumper diligently for a few days expecting food. At every stop that first day, the lease pumper will be surrounded by cattle that expect to be fed.

The responsibility of the lease operator for injuring cattle will vary depending upon the type of other vehicle traffic on the lease. If the road is an unfenced public roadway, the lease operator cannot be held accountable for animals injured by other drivers. If, however, the lease is on private land behind locked gates with an absence of traffic, the killing of a domestic animal by the lease pumper or a servicing company vehicle is more obvious. Landowners usually recognize that animals are sometimes injured or die from other causes, but the operator needs to acknowledge and pay damages when the accident occurs as a result of the lease pumper's activities or equipment movement. At the same time, when the lease pumper notices a sick or injured animal, the owner will usually appreciate being notified. This will help to promote good relations with the landowner.

C-4. Plants and Animals.

The lease pumper will come into contact almost daily with plants, birds, and animals that are on the lease. The plants may be native or planted by the landowner as a cash crop or to improve the vista and appearance of the land. Wild birds and animals are regulated and protected by the state fish and game department and, in some cases, by federal regulation. The landowner may also consider wildlife to be part of the property and exercise some degree of care for them.

It is not possible to pump a lease without coming into contact with wildlife. Birds are going to nest on the oilfield equipment, and wild animals will seek shelter under the equipment. The lease pumper and the lease operator do not have the absolute right to try to control wild animals on the lease. Some truckers have a policy that if a threatened or endangered species of wild bird is nesting on the equipment, they will wait until the young birds have hatched and left the nest before the equipment will be hauled.

The lease pumper should talk to the landowner when experiencing problems that are caused by plants or domestic or wild animals and, if necessary, to the fish and game department before taking actions that may compound the problems.

C-5. Lease Maintenance.

General lease maintenance is the least liked part of the job for many lease pumpers, who may feel that they were hired to produce oil wells. But a lease can occupy a lot of country. While some steam recovery wells in tar sand areas may be drilled with one-per-acre spacing and shallow wells may, with permits, be drilled on each 10 acres of land, the more common spacing for shallow wells is one per 20 acres and for medium depth wells one per 40 acres. This means that 16 wells can be drilled on each square mile, placing wells about 1,320 feet or a quarter of a mile apart and about 660 feet from the nearest property line for their closest spacing. Most fields do not exhibit this density. Thus, most wells are going to be more than a quarter of a mile apart. So a lease pumper who takes care of several wells is likely to be working a large area of land.

The lease pumper and the lease company will generally have responsibility for maintaining several aspects of the large area covered by the lease, including:

- Roads.
- Cattle guards and gates.
- Fences.
- Vista of the lease.
- Weed control.
- Trash removal
- Open pits and vents.
- Lease offices and stored equipment.
- Soil contamination caused by spills.

Road maintenance. Roads are expensive to build and maintain. As a result, unless the wells are high producers, little money is available for road repairs. Pot holes develop, rainy seasons may cause water and mud on the roadway, and rocks seem to grow larger daily and work to the surface.

A good lease pumper will spend a small amount of time periodically performing miscellaneous road services, such as moving larger rocks to the edge of the roadway. An occasional small load of gravel in mud holes will usually help to keep them from growing larger. Sections of road where these types of problems develop are generally short, so effort is required to prevent small problems from becoming big ones.

Cattle guards and gates. Once a producing well has been established on a site, the need for daily access by the lease pumper begins. To allow vehicles to pass through the fences that are likely to surround the lease, the company will probably install a fence or a cattle guard and will be responsible for maintaining them. Sometimes a cattle guard is preferable so that the lease pumper will not have to stop and get out of the vehicle twice just to open and close gates.

When the cattle guard or gate is installed, the first safety consideration is the distance from the highway to the cattle guard. This distance must be great enough to permit a well servicing unit or the longest truck and trailer transport to stop completely off the public road or highway before crossing the cattle guard or opening a gate. If the truck cannot get completely off the road before the driver gets out to open a gate or security bar, an accident may be caused by the truck blocking the road.

Access roads are often built at the lease operator's expense and maintained by the lease operator, unless a joint responsibility agreement has been reached. Although the landowner may find it convenient to occasionally use the road, it may be the lease operator's complete responsibility to maintain the cattle guard or gate. Cattle guards must periodically be cleaned out and sometimes re-leveled if they become hazards to drive across. If the well is closed and abandoned, the lease operator will usually remove the cattle guard and replace the section of fence, or install a gate if the roads are to remain.

Figure 3 illustrates a poor cattle guard installation. Note that the guard has become filled with dirt, allowing animals to walk across it, and that the ends do not have expanded wire across them from the center post to the outside. Small animals and calves can enter at the ends.

Figure 3. A poorly maintained cattle guard.

Fences. The perimeter fences on a lease are usually owned by the landowner and are of little or no concern to the lease operator. As the lease operator drills wells and produces oil, there will be many occasions where fences need to be constructed. The maintenance of these fences is usually the responsibility of the lease pumper.

Some of these fences are to protect oilfield workers, plants, domestic animals, and wildlife. In populated or heavily traveled areas, these fences are to protect children and to keep people away from automatic equipment and other facilities. Gates into the protective enclosures should be padlocked.

The quality of the fence that is built will depend greatly on what type of service it is supposed to provide, and if it is to remain for only a few days or for a long term. The types and sizes of animals to be excluded will govern the fence design, including the type of fencing material (such as square mesh wire, chicken fencing, or barbed wire), the height of the fence or number of strands of wire fencing, the spacing of the fence from the ground, and the type and placement of fence posts.

Some fences are only temporary and may be in use for just a few weeks. The fence in Figure 4 fits this category. The posts are not set very deep, the wire is stretched loosely, and it was probably built by one person. As the three strands were attached (starting with the lower strand and working upward), each strand wrapped around the post as the strand was completed so that the remainder of that coil of wire was not cut but just hung over the post.

Figure 4. Temporary fence.

When the wire is removed, each coil is returned to its original loop, and the roll remains in one piece. Since this wire is reserved for temporary fences, the company does not end up with a bundle of many short sections of wire. This is an excellent procedure to follow in temporary situations. If the fence must keep out sheep, goats, or calves, more strands can be added to the lower section of the fence.

When wells, tank batteries, or other facilities must be installed in towns or along well-traveled highways, the fencing must be much more secure, and cyclone fencing is generally used. The height of the fence and the trim or barbed wire requirements are adjusted according to need. In the photograph in Figure 5, the fence would be too low for in-town installations where children may be playing and no barbed wire would be installed on the top.

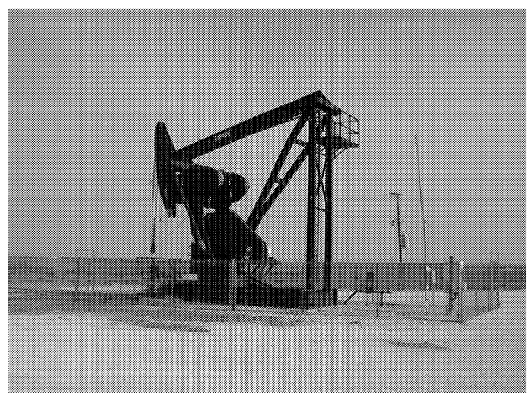

Figure 5. A security fence has been installed around this pumping unit because the well is near a busy highway.

Vista of lease. The vista of the lease refers to the general appearance of the equipment and everything on the lease including pipe racks, idle equipment, junk, and scrap materials. As a regular habit, everything should be arranged neatly. Pipe racks should be arranged in order. Every joint of pipe should be aligned straight on the rack with similar amounts of overhang on each end and be collared and racked neatly. Available stripping materials to separate layers of pipe should be in neat stacks aligned with the racks. Stored equipment should be in aligned rows and chemical barrels organized in rows. Permanent lines should be in 90-degree grid line arrangements when entering the tank battery and should look neat.

Operating along organized patterns becomes a way of life and should always be followed in every instance possible. Materials are moved on a regular basis on the lease, and every contractor performing specialized services on the lease will follow company procedures. If the lease pumper keeps everything neat and aligned, other workers will keep materials neat and aligned. If the site becomes unorganized and jumbled, that is the way other will place supplies and equipment from the time they unload it. Well organized stored equipment is never an unexpected benefit. It is the result of operating with well organized policies and procedures.

Weeds. Weeds and vegetation should be kept clear of equipment and stored materials. Excessive vegetation is not only unsightly, but it can be a fire hazard, accumulate trash, increase rust and corrosion of metal, provide a haven for snakes and other animals, and cover up holes and other hazards. The lease pumper should ensure that excessive vegetation is cleared or trimmed back.

Trash removal. Trash should not accumulate on the lease. No lease agreement with a landowner gives the lease pumper or anyone entering the lease to service the wells the right to scatter trash, bottles, and cans along the right-of-way. With private lease roads, the lease operator's responsibility is to remove trash immediately and keep the roadway clean. The best procedure is to stop and pick up any trash instantly, every time that it is seen. In this way, trash never begins to accumulate. The lease pumper should be able to drive over the lease and never see a can, piece of plastic, or other trash lying on or beside the roads.

Open pits and vents. Open pits are commonly used in the oil fields. Open pits invite local and migratory birds to land on or beside the ponds and get a drink. Because of dams and the lowering of water tables by pumps, water is no longer as widely available across the bird migratory flyways. The number of deaths of animals and birds due to oil and non-potable water is staggering.

Similarly, open vents present attractive nesting and roosting spots for birds, bats, squirrels, and other animals.

The petroleum industry and the lease pumper must comply with open pit and vent regulations. The petroleum industry is doing an outstanding job in meeting these necessary regulations and has done much to protect wildlife.

Pits at the well must be fenced to protect against the possibility of people or animals falling into them. If the pit contains any fluids, the lease pumper may also be required to put protective netting over the top.

Pits at the tank battery are considered permanent installations. The fences are put in with more care. The pit lining is of high quality; the cover netting is carefully planned.

The number of species that have been thoughtlessly wiped out of existence since the industrial revolution is startling. Within our children's lifetime hundreds of major animals and birds will be lost forever. Careful maintenance practices can help stem the tide of this tragedy.

Lease Offices. Lease offices are generally referred to as *dog houses*. Lease offices are usually small—such as 8 feet wide and 12 feet long—one-room buildings that provide a little room for desk work and storage. For some large leases, the building may be much larger or smaller and house several daytime pumpers, each with individual desks. These facilities may have an attached materials storage room with a truck unloading door at the back. The office may even stock a few often-used fittings.

A common practice is to run a gas line from the battery to heat the building. Natural gas in pure form is colorless and odorless. Thus, a leak in the gas line can present a danger, as can carbon monoxide If the heater is not properly vented.

Thus, lease buildings must be maintained for good appearance and safety.

Soil contamination. The chemicals, petroleum production, salt water, and other substances that the lease pumper handles on the site can cause damage to the environment. Spills of these materials may present hazards to people, livestock, and wildlife and, as runoff from rain, to fish. Such substances can kill grass and other vegetation and may keep anything from growing in the spot for many years.

If the lease pumper spills such materials or finds a leak involving such materials, every effort must be made to clean it up. Sometimes this can be accomplished by the lease pumper by following product label instructions, which may indicate that soil should be mixed with the spill, that water should be used to dilute it, that a chemical neutralizer should be applied, or that other action should be taken. In some instances, a special cleanup crew will have to be called in.

Further, depending on the substance and the amount involved as well as what becomes contaminated (such as soil versus a waterway), the spill may have to be reported to a regulatory agency.

Obviously, there are many areas of responsibility in maintaining a lease. Of extreme importance is building a good relationship with the landowner and others who may be affected by lease operations. In this way, the work of maintaining the lease is more likely to be a shared responsibility and any problems that develop may be worked out agreeably.

The Lease Pumper's Handbook

CHAPTER 3

SAFETY

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   - WARNING.
   - CAUTION.
   - NOTICE.
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   - Barriers.
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   - Goggles.
   - Hearing protection.
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B. Hydrogen Sulfide and Natural Gas Safety.

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The Lease Pumper's Handbook

Chapter 3
Safety

Section A

PERSONAL SAFETY

Much of the work that the lease pumper does is done alone. While following proper safety practices is always important, safety is even more important when a person is performing potentially dangerous tasks and no one else is around to assist if an injury occurs or the person loses consciousness. For these reasons, it is especially important for the lease pumper to be careful and not to take any unnecessary chances. To assist the lease pumper, companies put into place safety procedures, provide safety equipment, and post signs that warn of dangers on the job site. This section discusses these important elements of job safety.

A-1. Good Judgment and Common Sense.

Working alone is not the same as working with a group. The lease pumper working alone needs to remember at all times that any problems that occur must be small enough that lease pumper can work out of them alone. The lease pumper never takes dangerous chances unless the event is already in motion, and this action is a last resort to avoid death or to prevent exceptional injury. As an illustration, a good lease pumper would never walk under a load on a winch line rather than walk around it. If the engine should stall or the line break, the lease pumper is risking injury and possibly death to save a few minutes. The savings in time is not worth a fraction of the risk.

Being prepared. In being prepared to work alone, the lease pumper must be ready for many contingencies. This means planning ahead for problems that may occur and taking steps to prevent those problems or to lessen their impact if they do occur. For example, a problem with the vehicle can leave the lease pumper stranded, and usually on the most remote part of the lease. What does the lease pumper do if the vehicle has a flat tire and the spare is also flat? What if this occurs on a warm summer night in an area full of rattlesnakes? Is there a flashlight available? Have the flashlight batteries been checked lately? Should the spare tire have been checked for air occasionally? This is the kind of planning that is required to avoid dangerous situations.

The lease pumper should make it a habit to check the spare regularly. Just a thump will usually do. If lease engines must be started with jumper cables off the vehicle battery, the lease pumper should have two batteries mounted under the hood. It is easy to connect them so that both charge, and one can be used as the field battery. If the vehicle battery fails, the lease pumper can jump-start the pickup off the engine starter battery. For a few dollars, the lease pumper can buy a small compressor that will run off the vehicle battery or a device that uses vehicle engine compression to pump up a low tire or flat spare. An extra set of keys will be helpful if the lease pumper accidentally locks the keys in the vehicle.

Communications are important when the lease pumper needs help from someone else because of an accident, a problem with the vehicle, an urgent problem with the lease equipment, or other emergency. A radio or portable telephone can be invaluable in such situations. Knowing the location of the nearest public telephone or house with a phone can also be important if the radio has been damaged or loses power because of a battery problem or if cell phones are out of range. Many companies, knowing the importance of communicating with their lease pumpers, provide phones or radios.

The lease pumper must think about what to do in various types of emergencies because such problems occur regularly.

A-2. Taking Unnecessary Chances.

Many of the problems that people encounter while working alone develop because the worker took an unnecessary chance. For example, assume that a leak develops at a coupling and that a small amount of gas is escaping. The lease pumper can install a collar leak clamp in less than 15 minutes. Surely nothing will happen in so short a time so it is not necessary to shut in wells or isolate and bleed the pressure off the line before the installation. Invariably, a complication arises. The lease pumper has trouble finding a suitable clamp and the wrench to install it, so 15 minutes become 30. The wrench slips while installing the clamp and the coupling breaks. The lease pumper drops the wrench, causing a spark that ignites the gas. Many incidents are on record where oilfield workers have died repairing small leaks. In cost cases, the leaks looked too small to be risky, so chances were taken and the field worker was killed because of carelessness. No one was around to give first-aid. If the wind had been blowing or if the leak had not occurred in a low area, perhaps the gas would not have accumulated. Every accident is the sum of a series of unfortunate circumstances and poor decisions.

This does not mean that the lease pumper must fear death constantly in order to do the work. But the lease pumper must evaluate every action in each specific situation and anticipate the potential outcomes. When it appears that the action is risky, the lease pumper should consider other actions or obtain the help necessary to reduce the risks involved to a safe level.

A-3. Making Safety a Part of the Job.

Many people feel that safety is like a coat. When the weather is cold they put it on, and when it is warm they take it off. When a situation comes up that may be dangerous, they become concerned about safety, and when the crisis is gone thoughts of safety disappear. A safety attitude has everything to do with work, but it also has everything to do with driving, fishing, or taking a walk. Safety is a way of life.

How the lease pumper drives to work reflects an attitude toward safety. Speed limits are set as a safety reminder to motorists concerning a speed that can expected to be safe for an alert driver in a vehicle in good condition with fair weather, dry roads, and normal traffic. When these conditions are met, most drivers begin to feel that a few miles per hour over the speed limit would be just as safe. In truth, they are probably right, as long as conditions remain ideal. But when the lease pumper is cruising along at that speed, thinking about all of the tasks that are waiting at the lease, the situation has changed: there is no longer an alert driver. A light rain begins to fall, and now the pavement is no longer dry, but the driver is no longer thinking about driving conditions or about slowing down. Then, just as the lease pumper meets an oncoming car—without warning—an emergency occurs: a tire blows, something falls off a truck, or a hundred other possibilities. One of the vehicles invades the opposite lane by several feet. It occurs in the blink of an eye, and the lease pumper is driving too fast for proper defensive action.

At this instant, it does not matter who caused the accident or why it happened. The wound is just as severe and the crash is just as fatal.

People have been severely injured while driving across the lease and hitting the end of the cattle guard, because they were reading a newspaper while driving, or talking on a radio or telephone. In each case, something had become more important to that person than safety. It takes a lot of thought and effort to make safety a routine part of a person's life, but it takes little thought or effort for a lack of safety to be part of a person's death.

A-4. Industry Standard Notices, Warning Signs, and Markers.

In the same way that highway signs—such as stop signs, yield signs, and railroad crossing signs—have shapes and colors related to their meaning, signs used by industry to warn of danger and provide other information often use standard shapes and colors and even messages. The appearance and meaning of signs have been refined and standardized over the years until the size, shape, and colors indicate something from a distance, even before they are within reading distance. Generally these signs provide information about potential dangers or information about equipment and supplies, such as the location of fire extinguishers and first-aid kits. Many of these signs are used by the petroleum industry and can be found on oil and gas leases.

Additionally, lease sites are generally marked with a sign that is unique to the industry. These signs describe well locations in such a way that they can be precisely located on the lease site.

Both types of signs provide information that is useful to the lease pumper and others who may visit a lease site. This section presents information about the use of these signs and how to interpret them.

Industry standard signs are made from a wide range of materials, including wood, aluminum, fiberglass, various plastics, and metal. They may be painted and lettered with enamel, acrylic, reflective compositions, or any of various other methods. Examples of some of these signs are shown in Figure 1.

Figure 1. Some of the signs that may be seen on a lease site.
(Courtesy Marathon Safety Department, Iraan, Texas.)

There are some basic information signs that are generally black lettering on a white background, such as KEEP OUT. Other signs identify the location of general safety devices, such as first-aid kits, or the location of fire safety equipment, such as fire extinguishers. Many of the industry standard signs consist of two halves: an upper header that describes the type of information and the lower half which contains the information.

The header and the information section generally have set color combinations for the lettering and the background to provide further clues about the purpose of the sign. The following paragraphs describe signs that may be found in the oil field or in other related industries. The signs are identified by their headers.

- **DANGER.**

White lettering on red background. The background may be oval with black corners. The information area has a white background with black lettering. Danger signs are used to indicate a condition that could lead to death or serious injury. Typical advisories that may be included are:

High Voltage.
Flammable Materials.
Equipment Starts Automatically.
No Smoking.
Hard Hat Area.
High Pressure Gas Line.

- **WARNING.**

Black lettering on an orange background for both the header and information areas. Warning signs indicate a condition that could lead to permanent injury but generally not to death. Typical examples include:

Ear Protection Required in this Area.
Hard Hat Area.
Eye Protection Required.
Do Not Use Two-Way Radios.

- **CAUTION.**

White lettering on yellow background on the header. The information area contains black lettering on a yellow background. Caution signs are installed where the danger is not likely to lead to death or serious injury or where the risk is not always present. Typical caution signs include:

Step Down.
Low Head Room.
Use Hand Rails.
Trucks Turning.

- **SAFETY.**

White lettering on a green background. Lettering in the information area is black on white. Safety signs are generally reminders of good safety practices, such as:

Keep This Area Clean.
Wash Your Hands.
Safety Begins With You.

- **NOTICE.**

White letters on a blue background. The information area has a white background with black lettering. Notices generally provide advisory information, such as:

Keep Doors Closed.
Authorized Personnel Only.
Tornado Shelter.

- **RADIATION.**

Purple lettering on yellow background. The heading may say *radiation*, *danger*, or *warning*, often based on the risk presented. Typical conditions described in the information area include:

Radiation Hazard.
X-Ray Equipment in Use.
Radioactive Waste.

While safety signs have been standardized to a large degree, the lease pumper is likely to see many variations from what has been described. For example, the use of colors for particular headers may vary. Depending on the risk presented by a condition, the header may be different for signs that have the same information.

The location of safety and fire safety equipment. The general safety notices are generally green lettering on a white background or white lettering on a green background. These signs are generally posted near the location of first-aid kits, safety showers, eye washes, or other areas that may be sought in the event of an accident.

Fire safety notices are red lettering on a white background. They are used to mark the locations of fire exits, fire extinguishers, fire blankets, fire hoses, and other items that may be useful in escaping or fighting a fire.

Barriers. Barriers are used to prevent entry into an area or route personnel and vehicles along desired paths of travel. The most common types of barriers used in the oilfield are:

- Pylons or cones. There are generally red or orange.
- Barrels.
- A-Frames with 4-inch diagonal alternating white/red reflective stripes.
- Barricade tape.

Typical lease signs. Some of the most common industry standard signs that may be found at the well site or tank battery include:

- Hard Hat Required.
- Authorized Personnel Only.
- Do Not Enter.
- Equipment Starts Automatically.
- High Voltage.
- No Smoking.
- H_2S Poisonous Gas.
- Air Pack Required.

Most of these signs are intended to reduce safety risks to personnel who are authorized to be on the lease site. Additional signs may also be provided to warn workers of dangers they may encounter when approaching the lease. Other signs that may be found on the lease are intended for persons who do not have a valid reason for entering the site. Some examples of these signs include:

- Private Road.
- Private Property.
- No Trespassing.
- Travel at Your Own Risk.
- Speed Limit.
- Keep Gate Closed.
- Livestock on Road.
- No Hunting or Fishing.

A-5. Safety Equipment.

Because there are dangers on the lease, companies generally provide safety equipment for their employees and visitors to the lease. Sometimes safety equipment is required by state or federal regulations. The following paragraphs discuss some of the more important pieces of safety equipment likely to be found on a lease.

Breathing apparatus. There are several styles of fresh air packs commonly available for field use, and these are reviewed in Section B. The lease pumper always carries a personal air mask on the job. Some leases store air packs on the lease for other personnel in a protective cabinet.

Goggles. Wearing goggles (Figure 2) is recommended when gauging atmospheric vessels that produce hydrogen sulfide or when using a vapor recovery unit where the tank has several ounces of pressure inside. Wearing goggles is mandatory in any situation where there may be flying objects.

Hearing protection. Earmuffs (Figure 2) must be worn in situations where a loud noise may be experienced. Such noises may damage hearing or interfere with the sense of balance.

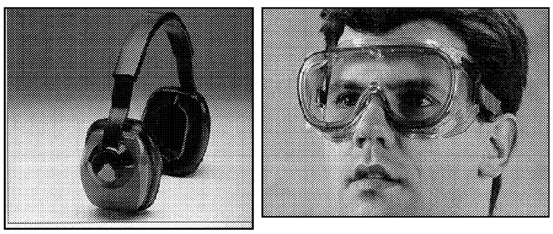

Figure 2. Examples of ear and eye protection. *(Courtesy MSA)*

Eye wash stations. Eye wash stations (Figure 3) are available for installation where there is a high risk of eye injuries from particles or chemicals. When gauging a tank, the lease pumper's eyes are exposed to hot gases rushing up out of the tank, and severe eye injuries can occur in seconds with the worker hardly being aware of it. The hot, poisonous gas open the pores in the surface of the eyes and penetrate them. As soon as the person looks away, the cooler ambient air will close these pores, trapping the gas in the eyes and causing a reaction that is similar to burning the eyes from exposure to the light of an arc welder. This extremely painful experience will last for at least 24 hours until the gas escapes or diffuses into the body. Eye wash solution and lubricant are available at any drug store and should be carried in the lease pumper's first-aid kit.

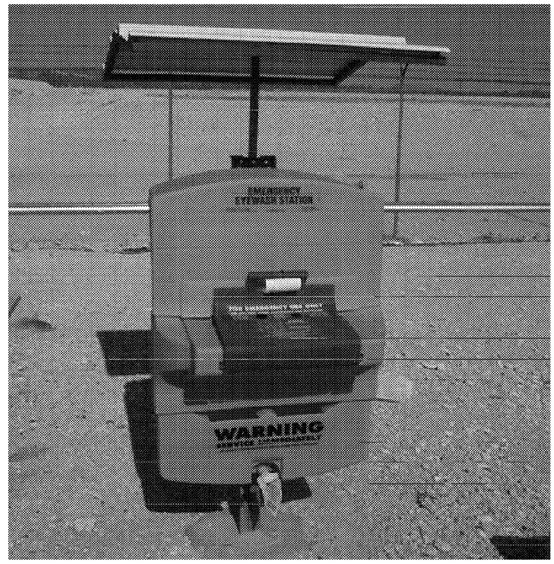

Figure 3. An eye-wash station.

Spark-proof tools. Spark-proof tools (Figure 4) are used to reduce the chances of creating a spark that might create a fire or ignite an explosive atmosphere.

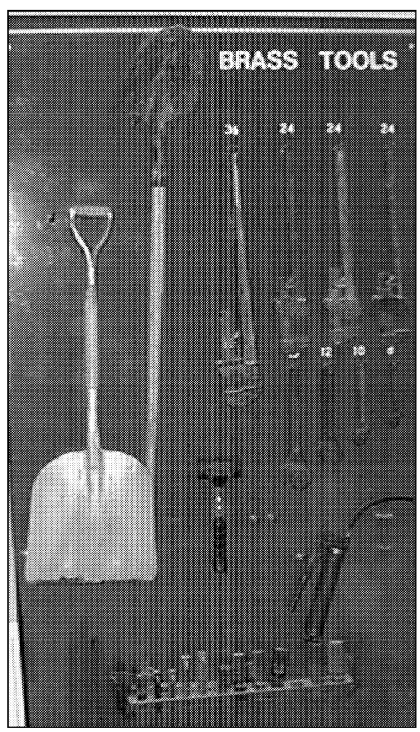

Figure 4. Examples of spark-proof tools.
(Courtesy Marathon Safety Department)

Spark-proof tools are usually made of brass and are expensive. Most lease pumpers do not carry many spark-proof tools. A hammer and one small adjustable wrench are usually the limit of the ones that may be needed. Emergency rescue vehicles often carry a few to use in extricating people from wrecked vehicles and other possible explosive situations.

Many other types of safety equipment are available, and lease pumpers should determine what types of equipment will help make the job safer for their specific situation. For example, some lease pumpers choose to wear back protection belts if they are expected to do a great deal of lifting. Lease pumpers should occasionally examine the safety equipment that is available and assess which items would benefit their work situations. Often the company will be willing to provide those safety items that the lease pumper believes to be necessary.

The Lease Pumper's Handbook

Chapter 3
Safety

Section B

HYDROGEN SULFIDE AND NATURAL GAS SAFETY

B-1. Introduction to Hydrogen Sulfide Gas

Prior to the mid-1950's, very little publicity was given to the dangers of pumping leases with high hydrogen sulfide (H_2S) gas levels. Then improved drilling rigs were built that could drill to 20,000 feet and deeper. With the deeper wells, higher bottom hole pressures were encountered, and more H_2S was present. The natural gas in a few wells contained more than 75% H_2S and had a high sulfur content. A few wells in Canada had H_2S rates that exceeded 90%. Because hydrogen sulfide causes steel to become very brittle, these wells were plugged.

Carbon dioxide reserves were tapped, and the gas was injected into wells for enhanced recovery. But this also causes steel to become very brittle, so producers turned to waterflood injection to push petroleum fluids. However, during this process and during well workover, sulfate-reducing bacteria enter the well and begin generating H_2S. Thus, wells that had never produced H_2S before exhibited hydrogen sulfide problems. The number of deaths resulting from these gases increased dramatically over a 20-year period.

By 1975 regulations were being written to protect the worker from this growing danger. H_2S is common throughout the world where oil has been discovered, so the problem is not limited to the United States or Canada. To be able to work wells with high H_2S concentration, special additives, such as iron oxides, have been added to drilling muds to absorb hydrogen sulfide. Iron Sponge is one such patented absorber.

In earlier times, if a lease pumper died from exposure to hydrogen sulfide, the lease pumper's survivors were awarded a pension of six months to two years of the deceased's salary. With growing concern for worker safety and revised laws and regulations, as well as court judgments that may award enormous sums of money when negligence can be proven, companies now have better equipment, training, literature, and exposure considerations.

B-2. What Is Hydrogen Sulfide?

Hydrogen sulfide is a naturally occurring gas that is produced along with natural gas and crude oil. It can be fatal if breathed. Tanks that contain a deadly amount of this gas are usually marked with a star or some other indication of the presence of hydrogen sulfide. With this warning, the lease pumper may be required to wear a fresh air gas mask when gauging or sampling the crude oil.

B-3. Properties of Hydrogen Sulfide.

It is important to understand the physical properties of hydrogen sulfide in order to understand why it acts the way it does. Physical properties of H_2S are:

- A colorless gas with a composition of two parts hydrogen and one part sulfur.
- Slightly heavier than air; it seeks lower areas, especially pits and cellars.
- Odor of rotten eggs in small doses. Higher concentrations cause paralysis of the olfactory nerve within 60 seconds so that no odor is detected.
- Extremely toxic (poisonous).
- Explosive in air.
- Soluble in water.
- Boiling point -75° F.
- Melting point -119° F.
- Density of liquid 0.790 @ 60° F.
- API gravity 47.6.
- Burns with a blue flame.
- Attacks most metals to form sulfides, which are usually insoluble precipitates.
- Dissolves in water to form a weak hydro-sulfurous acid.

B-4. The Dangers of Breathing H_2S.

The toxicity levels of H_2S are generally given as the number of parts per million (ppm) in air. This means that for a 10 ppm concentration of H_2S, there would be ten liters of H_2S in a million liters of air. How a given concentration will affect a specific person depends on a number of factors, such as the person's health and personal susceptibility, how active they are when exposed, air temperature and humidity, and many other factors. The following values are intended as general guidelines only.

1	ppm	= 0.0001% (1/10,000 of 1%) Can be smelled.
10	ppm	= 0.001% (1/1,000 of 1%) 8-hour exposure permitted.
100	ppm	= 0.01% (1/100 of 1%) Numbs smell in 3-15 minutes. May burn eyes and throat.
200	ppm	= 0.02% (2/100 of 1%) Numbs smell rapidly and burns eyes and throat.
500	ppm	= 0.05% (5/100 of 1%) Causes loss of reasoning and balance. Results in respiratory disturbances in 2-15 minutes. Requires prompt artificial resuscitation.
700	ppm	= 0.07% (7/100 of 1%) Causes loss of consciousness quickly. Breathing will stop and death results immediately if not rescued promptly.
1,000	ppm	= 0.10% (1/10 of 1%) Unconsciousness occurs at once. Permanent brain damage may result if not rescued promptly.

Monitors are available to measure a person's exposure to H_2S (Figure 1).

Figure 1. Hydrogen sulfide exposure meters.
(courtesy Mine Safety Equipment Co.)

B-5. Safe Working Procedures in Gaseous Areas.

When the lease pumper must enter gaseous areas alone, there are definite safeguards to use. The lease pumper should always observe extra safety margins because there is no backup. Safety equipment should be on before entering the area (Figure 2). The lease pumper should wear the equipment until the contaminated area is exited.

Figure 2. A warning gate that indicates the presence of H_2S and the requirement for breathing apparatus.

Safety training programs for working around hydrogen sulfide. Safety training programs are available for working in H_2S environments. It is important for lease pumpers to take this training. Formal training will usually result in better understanding than just receiving a pamphlet to read in some spare time. The lease pumper also gains experience practicing with safety equipment, H_2S detectors, monitors, exposure recorders, 30-minute backpacks, the 5-minute emergency escape pack, and many situations rarely seen in the field. In addition, trainees visit with others who have had different experiences.

When working in a group, someone within the group is required to have had training so that this knowledge is available to the group. When working alone, however, the lease pumper must have had this formal training.

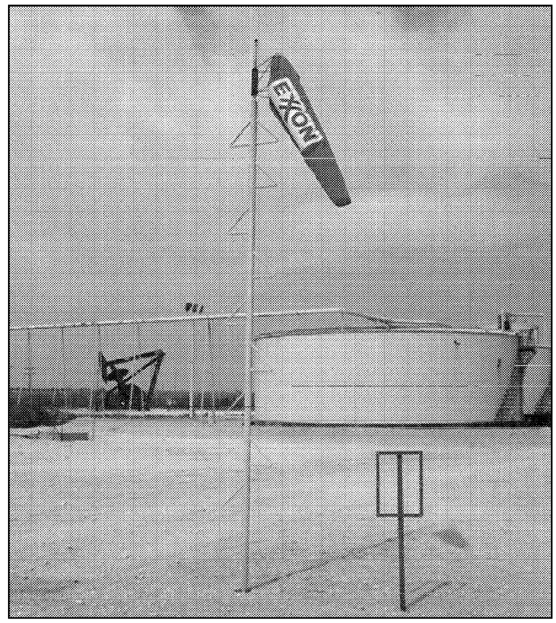

Figure 3. The windsock on the site shows the direction of the wind and whether H_2S buildup is likely.

Where will the lease pumper encounter hydrogen sulfide? Some of the common areas that H_2S can be encountered:

- Pits or low areas on still days (Figure 3).
- Drilling muds.
- Gauging tanks.
- Closed tanks and vessels.
- Pump leaks.
- Contaminated sulfur.
- Injection of sour gas.
- Tank bottoms.
- Water injection.
- Vapor recovery units.
- Acidizing wells.

As this list indicates, H_2S can be almost anywhere on the lease. This does not mean that lease pumpers must fear H_2S while on the job, but it does mean that they must respect and understand the conditions under which H_2S may be found and never take chances.

B-6. Breathing Apparatus.

Fresh air systems can be quite simple to elaborate. The most common system is just a portable air pack. Others may involve an industrial size fresh air bottle strapped into the bed of a pickup with a long hose on a reel either in the pickup or on a stand near the bottom step of the tank battery walkway. Because this system can save lives, the lease pumper should use it and take care of the equipment.

When trying to decide what type of breathing apparatus will be best and the most practical for the lease, the lease pumper must first understand the job duties and know where and under what conditions H_2S may occur.

Individual fresh air packs. When working in the oil fields, there are times when it is essential to have fresh air available. Before the development of modern equipment, hand-driven fresh air systems were used. While such systems supplied breathable air, they had serious limitations. For each job within a high-risk area or if a rescue or assistance was needed, at least one additional person was required to pump fresh air.

Today, even the self-contained fresh air system continues to undergo improvement. For example, at one time fresh air containers were heavy steel. The newer aluminum and fiberglass containers are only a fraction of the weight of the former ones. Today's control systems are also lighter and more compact. With proper equipment, the lease pumper can perform many field duties where gas is present safely without any back-up.

The four most popular fresh air units and systems for use in oil fields are:

- The five-minute air pack (Figure 4).
- The thirty-minute air pack (Figure 4).
- The models utilizing large industrial size bottles.
- The trailer-mounted standby units.

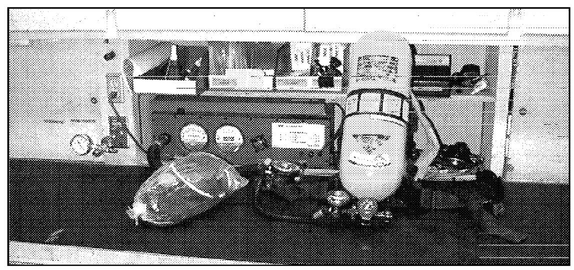

Figure 4. Five-minute and 30-minute air packs on a service bench.
(courtesy Marathon Safety Department, Iraan, Texas)

The five-minute air pack. The-five minute air pack is widely recognized as a safety backup system. Even in areas where air packs are marginally needed, the five-minute pack can be worn for emergency escape.

When working in areas such as derricks when pulling oil wells, cleaning inside tanks, and other situations where air is being continuously supplied by a long hose, the lease pumper should wear five-minute pack as a backup. If the lease pumper must work in an area where more than just a few seconds away, a backup systems should always be carried.

The thirty-minute backpack. The thirty-minute fresh air unit is widely used by lease pumpers. Since it takes only a few minutes to gauge tanks, the backpack can last for a week or more before it must be refilled. It comes in a form-fitting box and should be stored there at all times when not in use. The air pack as well as the inside of the box should be kept clean. The lease pumper should carry one or two replacement parts such as the head strap or *spider*. When one strap breaks, it should be replaced before the backpack is worn again.

Compressing fresh air. Air bottles can be filled in most towns for a fee at fire stations. In areas where much fresh air is consumed, such as towns with nearby oil fields, companies sell this refill service.

When a company consumes a large amount of fresh air, the owners will install their own refilling equipment (Figure 5). The compressor utilizes ambient air to refill the bottles. The compressor will first compress the air by injecting it into a series of industrial sized bottles. This group of bottles acts as a volume tank, and, since they are filled in advance, this reduces the time needed to refill bottles.

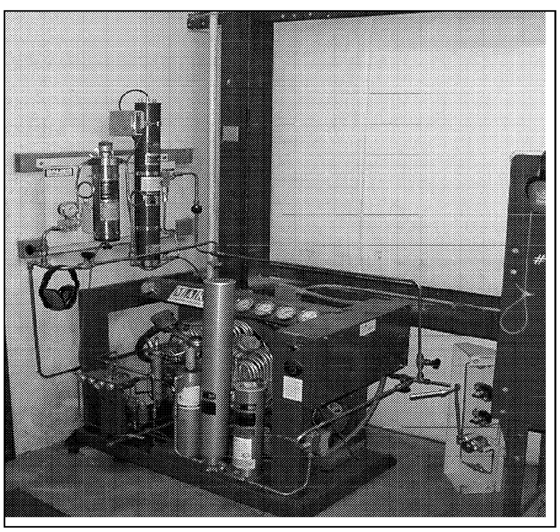

Figure 5. An air compressor used to fill air bottles.
(courtesy Marathon Safety Department, Iraan, Texas)

Because of the heat generated when refilling small bottles, such as the 30-minute bottles, the bottles are immersed in a water tank while being refilled.

The 30-minute bottle is stamped with a date. It must be periodically inspected and, after a set time has passed, it is against the law to refill it. The bottle must be replaced with one that meets the inspection test. A heavy fine is imposed, so when the bottle is condemned it must not be refilled.

The industrial-sized bottle and hose. The industrial-sized bottle with air line and face mask is a valuable fresh air system when large volumes of air are needed (Figure 6). It can be rigged up countless ways at the tank battery, in the pickup, or on a trailer.

Figure 6. Industrial-sized bottles awaiting to be refilled. The water tank to the left is used to cool smaller bottles when they are being filled.
(courtesy Marathon Safety Department, Iraan, Texas)

Since the bottle is too large and heavy to wear, an air hose is used to pipe air from the bottle to the user. A fresh air mask is utilized by the person breathing the air (Figure 7). When pulling some wells, all of the well servicing crew will be breathing air from masks and hoses. Often it is just on stand-by and, if a horn goes off indicating gas conditions, then the masks will be used while rigging up to kill the well again. Cleaning tanks is another situation where these bottles are highly used.

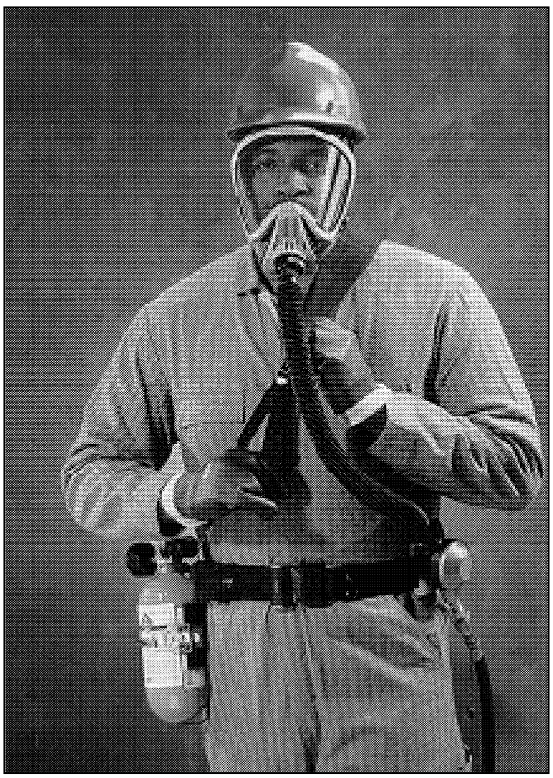

Figure 7. Worker wearing an air mask fed by an industrial bottle. He is also wearing a 5-minute escape pack.
(courtesy Mine Safety Appliance Co.)

The industrial size bottle can be utilized two ways. It may be mounted in a pickup, and a reel hose used from the pickup while gauging. The bottle may be installed at the end of the walkway on the ground.

Trailer-mounted equipment. The air trailer carries the selected equipment needed for well servicing, cleaning tanks, new construction, and other field jobs (Figure 8). This will usually include industrial size bottles, air lines and masks, 30-minute backpacks, 5-minute packs, monitors, sensors, and any other equipment that might be needed for specific jobs. If an emergency should arise on the job, the trailer is the center of the staging area where instructions are issued.

Figure 8. Trailer-mounted fresh air equipment.
(courtesy Marathon Safety Department, Iraan, Texas)

Taking care of air breathing equipment. Judging employees by how well they use and take care of equipment is easy to do. Just visually inspecting equipment and looking at the bottle refill schedule tells most of the story.

As soon as the lease pumper receives the equipment, the first thing to do is to inspect it, then put it on, adjust the straps to fit, open the valves, set the rate, and find out if it works satisfactorily. Since most of the equipment is buckled on with quick connect fittings, all of the adjustments stay set from one wearing to the next. If a supervisor checks the equipment and finds that it is still wrapped as shipped or when checked last, it is obvious that the lease pumper is not using it at all.

This is expensive equipment and will give service according to the way that it is cared for. The lease pumper's work is relatively clean with little exposure to greasier jobs, such as well servicing. Every time the air breathing equipment is used, the lease pumper must take a few moments to be sure that it is clean and properly stored for protection. Anything less is not satisfactory personal work attitude and action.

The Lease Pumper's Handbook

CHAPTER 4

UNDERSTANDING THE OIL WELL

- The holddown.

5. Correlating Perforations.
6. A Typical Wellhead.
   - The casing head.
   - The intermediate head with casing hanger.
   - The tubing hanger.

The Lease Pumper's Handbook

Chapter 4
Understanding the Oil Well

Section A

LOOKING DOWNHOLE

The part of the well operation that is underground is generally referred to as *downhole*. There are several reasons why the lease pumper must understand what it is like downhole. This need for understanding begins at a basic level in knowing the procedure for drilling a well, responsibilities of the rig personnel, how decisions are made when drilling, and how the bore hole is finished when casing strings are run and cemented into position. During the production phase, the lease pumper must know what is happening in the formation, the production interval or perforated area, the tubing string, the flow lines, and the processing vessels—from the bottom of the hole all the way to the stock tank.

The lease pumper must also have some knowledge of what causes oil and gas production to slow down or stop and what options may be available to identify or even remedy the problem. With experience, the lease pumper will recognize the symptoms for a wide range of downhole problems as they begin to affect production and will have some knowledge of what can be done to restore production.

Many small operators do their own well servicing, and the lease pumper may work as part of the service crew. This could lead to the lease pumper becoming the well service crew operator when pulling and running rods and tubing.

Even if the company contracts all of the well services to others, quite often the lease pumper acts as a representative of the oil company and supervises the well service operation to ensure that everything is performed to the company's satisfaction. Further, the lease pumper must understand what records must be kept, how to accurately record any changes made downhole, and how to submit change records to the office. This chapter presents information on how a well is drilled and completed. This first section discusses the structure of oil-bearing formations and provides an overview of oil well design.

A-1. Oil-bearing Reservoirs.

The purpose of a well is to bring oil and gas up from underground deposits. Petroleum researchers generally agree that oil and gas consist of the chemical remains of ancient plants and animals. These remains were laid down as deposits on the beds of ancient seas. As layers of sand and other sediments covered these chemical remains, the pressures built up to compress the minerals into rock. The hydrogen and carbon portions of the plant and animal remains combined to form chemical chains referred to as *hydrocarbons*, or natural gas and crude oil.

Over time, more layers of rock will form. Some types of rock, such as sandstone, are *porous*—that is, there are openings between the grains of the rock, and water, oil, and/or gas can sometimes occupy this space. These fluids may remain in the porous rock or, if acted upon by other pressures, they may move from one place in the formation to another. Other types of rocks, like granite, are nonporous.

These layers of porous and nonporous rock are called *strata* (singular, *stratum*). Hydrocarbons remain trapped in the strata of porous rock when the porous rock is enclosed with layers of nonporous rock or when certain types of rock formations keep the oil contained in an area. This area may be referred to as a *reservoir* and the formation as *oil-bearing rock* or sometimes as the *pay section*.

Oil is found in stratified rock that was loose sand at one time before being compressed under pressure into *sedimentary* rock. Igneous rock—that which was formed by heat as from a volcano—is nonporous and never contains oil. Metamorphic formations of sedimentary rock—such as limestone that has metamorphosed to marble—will not usually contain oil. The most common oil-bearing formations consist of:

Stratified rock	**Abbreviation**
Sandstone	S
Limestone	LS
Dolomite	Dolo
Conglomerate	Congl
Unconsolidated sand	US

A-2. Formation Shapes.

An analysis of rock samples and land formations can tell geologists whether a given area is likely to have oil deposits. Through various types of tests that measure the underground formations, petroleum exploration crews can determine the locations of probable petroleum reservoirs. By using special instruments, oil exploration crews can measure the speed of sound associated with the density of underground formations to determine whether those formations are likely to contain oil reservoirs. Great strides have been made in understanding the many shapes of reservoirs since the discovery of overthrust belts in the 1970's. The use of computers and software programs continues to improve the ability of geophysicists and geologists in determining whether hydrocarbons are likely to be found.

After considering numerous factors, the oil company may make the decision that a deposit of petroleum is great enough to justify drilling a well.

There are many formation shapes that can result in underground reservoirs. The characteristics of these formations are sometimes visible along roadcuts, canyons, and other areas where the layering of the earth can be observed. Some of the more important oil-trapping formations include:

Dome formations. Dome formations develop when underground pressures push up against the layers above, causing a fold in the strata to rise dramatically. Underground hydrocarbons may be trapped within the dome or trapped in the donut-shaped formations surrounding the dome. As the reservoir is produced, the oil may be driven toward the center of the dome or, in other situations, it may migrate outward. Another term used for dome reservoirs is *plug traps*. Often the dome formation will consist of salt.

Anticline formations. An anticline is an upward fold of the formation. Instead of creating a dome shape, the upward fold spreads across a wide area, often many miles though it may be quite narrow in many areas. An anticline can develop finger-like projections that trap petroleum and that can be very productive if discovered. Some anticlines disappear for many miles then crop up unexpectedly, only to disappear and then reappear perhaps several times. The depths of the reservoirs may vary from shallow to deep over the length of the anticline.

Fault trap formations. Fault traps are formed by the shearing or breaking of the earth at great depths. This break is called a *fault*, and fault lines are frequently the sites of earthquakes as the two split sections of earth shift relative to each other. Faults may be visible on the surface of the ground.

If the formations on each side of the fault move so that the strata on one side of the break no longer line up with the same strata on the other side of the fault, it is possible that a porous layer will become aligned with a nonporous stratum on the other side of the fault. When this occurs, oil and gas can be trapped on the porous side. Oil may be discovered only on one side of the fault or on both sides. Many dry holes have been drilled trying to follow a productive fault line.

Reef trap formations. Reef trap formations were usually developed by great limestone and dolomite deposits. These deposits generally contain the minerals from dead marine plants and animals. Often these minerals are dissolved as water passes through the formation. This can create cavities in which hydrocarbons may become trapped and held.

Lens formations. The term *lens formation* generally refers to any strata in which the oil-bearing rock is penetrated by bands of nonporous rock. This causes the pay section to be broken into small reservoirs. For this reason, lens formations can make it difficult to properly complete and produce a well.

One type of lens formation occurs when an underlying nonporous stratum undergoes extensive folding. The folds may penetrate the oil-bearing layer at intervals like a rumpled blanket. Pockets of oil, water, or gas may become isolated in small sections of the porous layer between the folds of the lens formation. Depending on whether or not the nonporous rock completely separates the oil-bearing layer, hydrocarbons may or may not be able to flow between the pockets. This means that hydrocarbon production may vary slightly or even dramatically from well to well along the oil-bearing stratum. In some cases, each isolated section may have to be drilled separately. Sections will deplete at different rates. It may be difficult to determine how to enhance.

Unconformities. Unconformities were formed by the rock formations being thrust upward and worn off by actions of the elements. After this wearing away occurred, an impervious stratum was laid down to form a cap over the end of the porous layer. These formations trap and preserve oil reservoirs. Some of the most significant oil fields in the world reflect partial unconformities.

A-3. The Anatomy of an Oil Well.

Perhaps the best way to learn about the process of drilling an oil well is to first consider a completed oil well and then review how everything came together to create the finished well.

Figure 1 on the next page shows the well as it is being drilled. With the derrick in place, drill pipe is run into the hole with the bit cutting through the rock formations at the end of the drill pipe. Mud is pumped into the top of the drill pipe and forced out the lower end. This serves several purposes. The mud cools the drill bit and forces the cuttings up the side of the hole and to the top where they are emptied into the mud pit. The mud also reduces the chances of the hole walls crumbling and helps to prevent the uncontrolled release of oil and gas.

As the well is drilled, casing is installed. The drill pipe is removed from the hole and heavy steel pipe is installed in the hole. This pipe is filled with cement and topped with a plug. Mud is then pumped into the casing while the cement is still wet. The pressure of the mud forces the plug and cement down the inside of the casing so that the cement is forced into the space between the casing and walls of the bore hole from the bottom of the casing. The cement will fill this space to the surface of the well. Once the cement hardens, the drilling continues if necessary. The crew switches to a smaller drill bit that will fit inside the casing and drills through the plug at the bottom of the hole and into the next formation.

When the well has been drilled into the oil-bearing rock, the drill pipe is removed and the last string of casing installed and cemented in place. A section of the casing that passes through the reservoir will then be perforated—that is, holes will be created to allow oil and gas to pass into the casing. After the casing has been perforated, tubing is installed. The tubing is smaller diameter pipe that goes down inside the casing. Tubing is used to bring oil and gas to the surface. Once the well goes into production, the derrick is removed and the tubing is topped with a set of control valves known as a *Christmas tree* or wellhead.

This overview should help clarify the more detailed information in the following section.

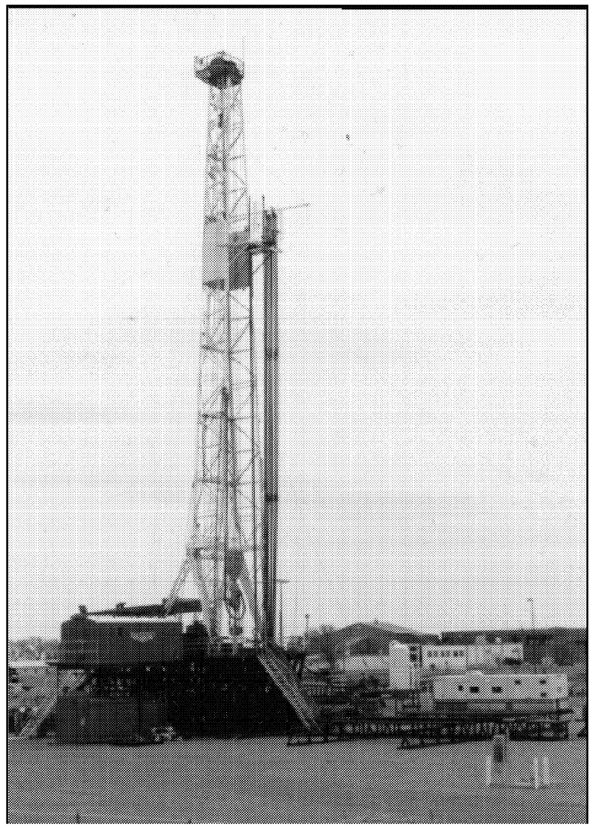

Figure 1. A drilling rig in erected to bore a well. Note the pipe in the rack alongside the derrick.

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Chapter 4
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Section B

DRILLING OPERATIONS

No two wells are alike, even if they are located near each other and are drilled into the same oil-bearing formation. Many variables may enter into the drilling process. People, equipment, procedures, and many other factors affect the drilling operation and can contribute to problems with the completed well. The outcomes of the drilling procedure will forever influence the production of the well. This section provides information to assist the lease pumper in understanding the nature of the drilling operation.

B-1. Contracting the Well to Be Drilled.

When a contract to drill an oil well is signed, many conditions and agreements are included. The drilling rig contractor will have agreed to drill a well to a specified depth. The conditions for payment are included. The contract payment may be based on the time on the location, a set sum of money, or by the foot. Most wells are contracted by the foot, but the contract is likely to make allowances for unforeseen problems and nondrilling activities, such as time spent allowing the casing cement to set.

While the drilling rig is moving in to prepare for drilling, this is referred to as *move in and rig up* (MIRU). Most drilling today is done with a jackknife rig that can be moved to the well location and raised in just a few sections rather than the built-in-place derricks that were once used.

Personnel involved during drilling include:

The tool pusher. The drilling company provides a supervisor for the rig while the well is being drilled. At one time, this individual was called a *tool pusher*. Today, more and more rig crews include petroleum engineers, the terms *drilling engineer*, *production engineer*, and similar titles have become popular. To avoid implying that the position must be held by an engineer, this manual uses the term tool pusher.

The tool pusher is generally in charge of the drilling rig and is in charge of every moving part of the rig. The tool pusher purchases rig supplies and supervises the drilling procedures and rig personnel. Radios and cellular telephones have made communications so easy that the tool pusher may be in charge of two or more rigs at one time and may not always be present on a specific site.

Because of the critical nature of this type of supervision for around-the-clock drilling operations, the tool pusher is often provided with a small mobile home on the well site to remain at the drilling operation for days at a time in the event of problems.

The driller. The *driller* is directly in charge of the drilling four- or five-person rig crew and generally operates the *draw works*, the system of cables and pulleys used to run pipe into the hole and to pull pipe from the well. Normally, the driller will have worked all of the positions on the rig crew over a period of years and is, thus, very experienced. When a large drilling rig is being moved, all four drilling crews are supporting the rig move. The driller may perform the tool pusher's duties when the latter is off.

The derrick worker. The *derrick worker* works high above the floor when the pipe is being pulled or run during regular operations. This position is commonly referred to as a *derrick man*.

On most modern rigs, sections of drill pipe are held vertically in a rack along side the derrick awaiting to be added to the drilling string as the bit works its way deeper into the ground. One of the duties of the derrick worker is to handle pipe that is added to or removed from the drill string. Pipe is added as the drill bit cuts deeper into the ground. Pipe is removed as the drill string is pulled from the ground once the drilling is complete or to replace the bit or to deal with a drilling problem. The pipe is raised and lowered with elevators. The pipe is stored between "fingers" in the rack next to a platform referred to as a *monkey board*.

When the rig is drilling, the derrick worker supervises and assists the two floor workers in maintaining the cleanliness of the rig. The derrick worker generally supervises and assists in equipment repairs and often catches and labels the mud samples. The derrick worker may also operate the draw works to provide the driller with time to fill out reports and perform other duties. This also gives the derrick worker experience in driller duties to prepare for a possible promotion.

The floor workers. There are two *floor workers* on the rig floor while pulling and running pipe. These personnel are also referred to as *floor hands* or *roughnecks.* The more experienced individual is usually referred to as the *lead* and operates the lead tong. The second person on the floor operates the back-up tong and may be referred to as the *back-up*. The floor workers are generally the least experienced members of the crew.

Motor man. If the rig has a five-person crew, the fifth individual may be called the *motor worker* or *motor man*. In this situation, either the motor worker or the derrick worker may have the most experience and relieve the driller during vacation. The motor worker may also be assigned the duty of catching drilling samples.

Company representative. The senior member of the crew, such as the tool pusher, or another person will serve as the official representative of the oil operator. With a small oil company, this may actually be the owner of the company. The company is paying the full cost of drilling the new well and owns it when it is completed. The company representative oversees every aspect of the operation from building the road to being sure that the casing is available when it is needed to the delivery and installation of the wellhead and Christmas tree. In most cases, the company representative makes the final decisions concerning most of the formation tests.

B-2. Drilling the Well.

When the drilling rig is moved onto the lease to begin drilling a new well, the lease pumper, as an employee of the operating company, may have responsibilities related to the operation. Most drilling rigs have suitable steel mud pits, and the operating company may have constructed an earth mud pit with a plastic liner to receive the excess fluids and the drilling cuttings. Although most rigs will have from two to four steel pits, the very first pit will have a shale shaker mounted on top to allow the drilling mud to fall through the screens. The formation cuttings slide down the vibrating inclined screen and fall over the side and directly into the earth mud pit.

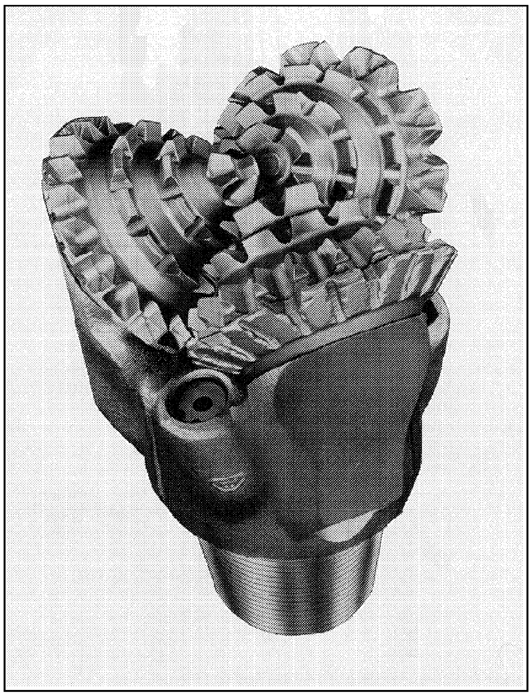

Figure 1. A tri-cone drilling bit.

The lease pumper is likely to be responsible for looking out for the landowner's interests during the drilling operation, especially if the drilling is contracted. If the mud pit is not properly fenced, the land owner's cattle may try to get into the pit to get a drink of water. Occasionally, lost circulation materials are added, and the livestock are attracted to them. The livestock may also try to eat greasy rags, plastic, and other trash that blows away from the rig.

When the hole is finished, it will take several weeks or even months before the mud will dry out enough for the cuttings in the pit to be leveled out on the location. As soon as the rig shuts down, the landowner will expect the lease pumper to maintain a clean, well-fenced pit capable of protecting livestock from harm. Sometimes fence will have to be installed as soon as the drilling starts.

B-3. Downhole Measurements.

The lease pumper is also likely to be responsible for maintaining the well records. One of the most important set of records is the downhole measurements. These measurements record the dimensions of every section of pipe used in the well.

Downhole diameters are important in order to know the sizes of tools, pumps, etc. that will pass through the pipe, as well as couplings and other components required to complete the installation. *Casing* is a name applied to any pipe that is cemented into place. The moveable strings of pipe inside the fixed casing that can be easily pulled and run back in when working the well over are called *tubing*. Casing and tubing are always measured by outside diameter. If the same pipe is used on the surface, it is called *line pipe* and is measured by inside diameter. Casing, tubing, and line pipe do not necessarily refer to the design of the pipe. The purpose of the pipe or where it is used is what determines its name.

Downhole lengths must be known in order to accurately determine the depth of the well, the location of the perforations, and other features vital to good production. As the well is drilled, distances are measured from the top of the **kelly bushing** (**KB**), which is the sliding bushing that sits in the top of the rotary table on the drilling rig floor. The KB allows the drill kelly to slide down through it while the pipe is rotating and the hole is being drilled. The abbreviation KB will appear somewhere on the drilling report records to indicate that this is the initial point from which all downhole measurements are made.

All measurements are made to one-hundredth of a foot. Instead of using inches, each foot is divided into ten parts, and each tenth of a foot is divided into ten parts. Thus, 10’6” is equal to 10 and one-half feet or 10.50’. All rig tapes use this system of measurement, making it easier to add lengths. For example, three lengths of pipe are 19’9¼”, 20’3/32”, and 20”4-5/16”, respectively, when measured with a conventional steel tape. Using hundredths of a foot, the same measurements would be 19.77, 20.09, and 20.36. These are numbers that can be handled by a conventional calculator. As the well is completed, everything that goes downhole, such as tubing, rods, and pumps, is measured in the hundredths of a foot.

After the casing pipe has been set (cemented permanently in the hole) and the braiden head or wellhead has been installed, the distance from the top of the wellhead up to the top of the kelly bushing is measured and then subtracted from all drilling records so that well records are accurate once the drilling rig is gone.

B-4. The Surface String of Casing.

Much of the water that people drink comes from underground reservoirs of fresh water. Protecting the fresh water zones is one of the most important considerations when drilling a new well. The bottom of the string of surface casing must extend well below the fresh water zones. The surface hole is also drilled deep enough to pass through any loose materials until stable rock has been encountered before the surface pipe is set or cemented into place.

Before the surface casing is made up or “run in the hole,” it is carefully measured and inspected. The couplings may also be welded to prevent future leaks. Centralizers and scratchers are installed on the pipe. The centralizers (Figure 2) are bow-shaped strips of steel that will hold the pipe in the center of the hole away from the walls. This permits cement to be forced up through the hole on the outside of the pipe to form a good cement bond.

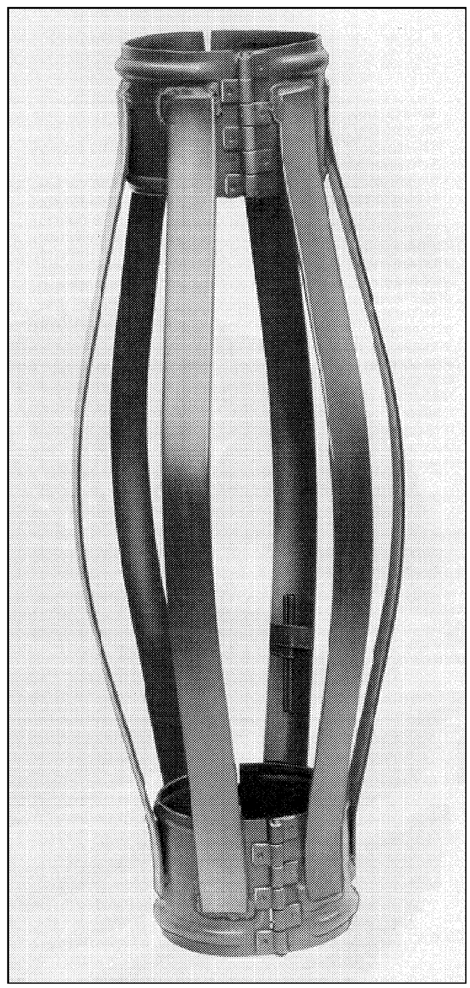

Figure 2. A casing centralizer.

Then scratchers (Figure 3) are put on the pipe to scrape the drilling mud off the walls of the hole. This allows the cement to bond to the pipe and to the walls of the hole. The caked-on drilling mud is removed from the walls of the hole by raising and lowering the pipe several times to scrape it loose. As cement is pumped down into the hole through the casing and out the bottom, it rises toward the surface outside the casing to form a good cement bond completely around the pipe all the way to the surface. When the well is plugged, the pipe is left in place.

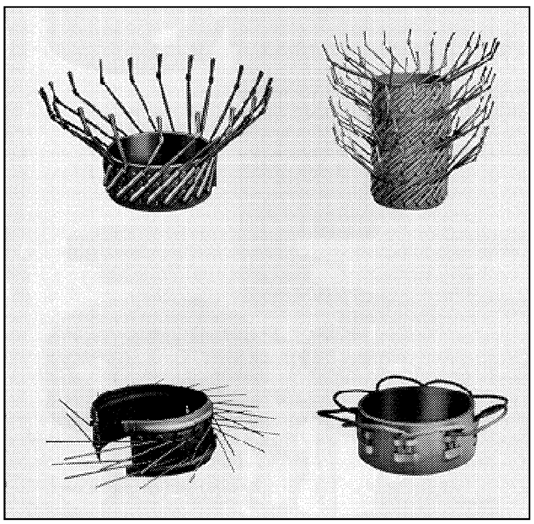

Figure 3. Scratchers used to remove from the walls of the hole.

B-5. Intermediate Strings of Casing.

Some oil wells will be deep enough that a second string of pipe is cemented into the hole above the production reservoir. This string is often installed to correct adverse hole conditions such as sloughing, heaving, high-pressure gas, or lost circulation zones. Each time a string of casing is added, a smaller bit is used, small enough to go inside the new casing and drill out the bottom, usually down to the reservoir.

Occasionally, in deep wells, a tapered string of casing is installed, consisting of strings of casing with successively smaller diameters. This is done because of economics or physical limits of the casing string. First, a relatively large casing is set that reaches from the surface and part of the way down the hole toward the reservoir. Then a slightly smaller bit and string of drill pipe is used. A casing hanger is installed at the bottom of each string of casing to allow the next size of pipe to be lowered through that section before it is securely attached and cemented into place. As the casing is run, it may be periodically filled with drilling mud to keep it from collapsing from the excessive external pressure. This is referred to as *floating the pipe in*.

B-6. Drill Stem Tests and Drilling Breaks.

One of the most important decisions that the drilling supervisor makes is determining what to do when a *drilling break* occurs. A drilling break is a sudden increase in the rate at which the bit cuts through the earth and it indicates that the formation is more porous. A porous layer may contain hydrocarbons, such as crude oil or natural gas.

By taking into consideration how fast the mud pump is operating, the distance to the bottom of the well, and the volume of the space outside of the drill pipe, the crew can calculate how long it will be before cuttings from the drilling break zone reach the surface. When the cuttings from the zone the drilling break occurred in arrive, the person catching samples will test the cuttings under an ultraviolet light or *black light*. Should crude oil be present, the sample will glow under the black light.

High mud pressures may prevent a good sample from reaching the surface, and the solution might be to run a drill stem test. In this test, the drill pipe takes the place of the tubing string.

The production company decides if the test is to be run. The rig must stop drilling new hole until the test is over, and an hourly rate may used until drilling begins again.

Allowances are made in the contract to provide time to run pipe and cement it into position. When the rig stops drilling to run pipe, the lease operator will pay by the hour, or some other appropriate amount to compensate for rig expense during the time spent running casing, cementing, and waiting on the cement to set and get hard.

The time while the cement sets is referred to as WOC or *waiting on cement* on the drilling report. During this time, the rig crew is busy cleaning the rig floor, rearranging the drill pipe on the racks, and getting a smaller drill bit ready to begin drilling again. The new drilling bit will be considerably smaller than the previous bit because the drill bit and pipe must be small enough to go through the casing to reach the bottom or cemented pipe and drill beyond it to extend the depth of the hole toward the oil reservoir.

B-7. Keeping the Hole Full Gauge and the Packed Hole Assembly.

The bit wears in diameter as well as tooth sharpness as the hole is drilled. As the bit diameter shrinks, so does the hole diameter. To overcome this problem, a reamer is run right behind the bit. A series of rolling cones rotate as the bit is turned and these cones ream the hole slightly larger. Reaming the hole one time is usually sufficient. The bit also wears on the shoulders, and, without a reamer, when the crew pulls the drill pipe to run a new bit, the new bit will have trouble getting back to bottom.

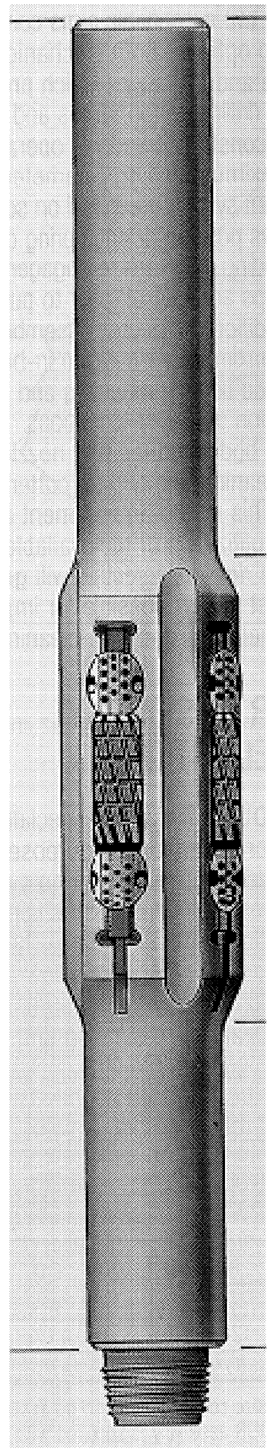

Figure 4. A reamer used to maintain hole diameter as the bit wears.

B-8. Drilling a Straight Hole.

It is not generally possible to drill a straight hole from the surface all the way to the oil reservoir. Factors such as the density of the formation, uneven wear on the bit, flexing of the drill pipe, and other conditions may result in the hole becoming deviated off true vertical depth (TVD). Generally, the hole is still usable for oil production.

Drilling the hole involves a continuous series of decisions to adjust the drilling technique to obtain the best results. Considerations include obtaining a good, usable hole, getting good performance and life from the bit, and making good drilling progress. The two principal means of controlling these factors are the rotational speed of the bit and the amount of weight applied. Maximum penetration rate and a straight hole is maintained by varying the amount of drill pipe weight applied to the bit and the r.p.m. of the bit. A good balance of the two must be determined, and that balance may have to be adjusted as conditions, such as the density of the formation or the depth of the hole, change.

As the bit encounters formations that are not horizontal, it will have a tendency to climb uphill. To help solve this problem, more drill collars will be run on top of the reamer. Drill collars add weight and make the pipe more rigid.

Even the use of collars will not solve all drilling problems. Another common problem is having the bit get stuck in grooves that can develop in the sides of the hole. These grooves, called *key seats*, are formed as the drill pipe flexes under pressure and rubs the side of the hole. The threaded ends of the drill pipe are known as *connections* and are larger in diameter than the body or tube of the drill pipe. These connections, being larger in diameter than the rest of the pipe, sometimes become stuck in the key seats, especially when the crew starts pulling the bit out of the hole.

Another problem that may develop can be caused by the *corkscrew* profile of the drilled hole. Because the formations are not of the same density all the way down to the production zone and the bit wears and the drill pipe flexes, the hole rarely goes straight down but instead has a twisted profile like a corkscrew. However, the tubing string tends to hang vertically in the hole, meaning that it is likely to rub against the casing as it comes into contact with the bends in the corkscrew. This contact can lead to holes being worn in the casing and in the tubing. Tubing collars can wear to the point that they fracture, allowing the tubing string to collapse into the well. Methods of addressing some of these problems are addressed in the Well Servicing and Workover section of this handbook.

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Section C

COMPLETING THE WELL

As noted in the previous section, once the well has been drilled and the casing cemented in, tubing is installed to bring oil and gas up from the reservoir. The tubing connects to the wellhead where a control valve system such as a Christmas tree is installed to permit control over the rate and direction of flow of the products raised from the reservoir. The valve assembly is often referred to as the wellhead. This section provides more details about tubing and wellheads.

C-1. The Final String of Casing.

Some oil wells only have two strings of casing—that is, the surface pipe and the final string that reaches from the surface all the way through the reservoir to the bottom of the hole. This final string is also referred to as the *oil string* or *long string*.

If the well is deep, the upper joints of the final string may be designed to have more tensile strength and the lower joints may be designed for collapse strength. If the lower joints are heavier than any other joint in the long string, a similar joint is placed at the top so that any tool that will go through the first joint will go through them all. This top joint is sometimes referred to as a *gauge joint*.

Cased-hole completion. As the bit drills through the reservoir that contains hydrocarbons, an analysis of the cuttings assists in determining what type of completion will be done. Most oil wells are completed by running the casing all of the way through the reservoir. Enough cement is then pumped down through the inside of the casing and up between the casing and the open rock formation to cement the string in place all the way through the producing zone and to a selected distance above the impervious cap.

Open-hole completion. In some wells, casing is not run through the reservoir. Instead, the well is drilled to immediately above the oil producing reservoir. Casing is then run and cemented into place. After the cement has set, the well is *drilled in.* The drilling in procedure involves drilling through the reservoir and leaving the reservoir open, creating what is referred to as an *open-hole completion*.

C-2. Perforating and Completion.

After the cement has set in the final string of a cased hole completion, the next step is to perforate the casing. In the early days of drilling, a charge of nitroglycerin was set off in the well bottom to create fractures in the reservoir formation.

Later, the bullet perforating gun was used. It fired .50-caliber shells through the walls of the casing, but proved dangerous because accidental discharges before the gun was placed into the well occasionally killed people. Also, flow paths created by the bullet tended to fill in with crushed rock.

The jet gun now in use can penetrate much deeper as it is required to perforate the wall of the casing, the cement, and many inches into the rock of the formation.

When preparing to perforate, the crew needs to know the bottomhole pressure inside the pipe and the anticipated pressure inside the formation. If the pressure is much greater in the formation than inside the casing, the instant that the perforations are established through the pipe, fluids driven by the bottomhole pressure will rush into the casing and blow the perforating gun up the hole at a tremendous speed, wadding up the electric line ahead of it and creating numerous problems.

C-3. Tubing.

True tubing is seamless, not welded, pipe. This construction increases its strength and reduces the possibility of production loss due to split tubing. Tubing pipe was once produced with 10-pitch V-threads, but most of this has been replaced by improved tubing with 8-pitch round threads, generally referred to as *8 round*. The round threads are rolled into the pipe, not cut by a threading machine. The 8 round tubing is much stronger and easier to make up with less danger of cross threading.

Tubing is classified according to its wall thickness and the quality of the metal used to make it. The tubing must be matched to the installation, including the depth of the well and factors such as high gas pressures. Typically, tubing is designated with a letter and a number. For example, H-40 is an economical tubing used for shallow wells, J-55 may be used for wells to about 7,000 feet, and P-105 is a heavy-duty pipe often used for deep wells. Exotic metallurgies are used in problem wells

Because tubing must reach an exact depth in the well and be installed without being cut and threaded, tubing is available in random lengths from 28-32 feet and in shorter lengths called *pup joints*. Pup joints (Figure 1) are available in even two-foot lengths of 2, 4, 6, 8, 10, or 12 feet and are added at the top of the tubing string for final spacing.

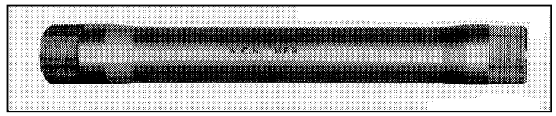

Figure 1. A tubing pup joint.
(courtesy Dover Corporation, Norris Division)

Additional information about tubing is provided in Chapter 17C and included in Appendix D, Pipe, Tubing, and Casing.

C-4. The Tubing String.

The tubing string is run in the well after the casing has been cemented into place and the reservoir has been opened to the well bore. A typical tubing string consists of the following items from the bottom up:

- Mud anchor.
- Perforated subs.
- Seating nipple.
- Pup joint (optional).
- Packer or holddown (optional).
- Safety joint (optional).
- Tubing.
- Pup joints (as needed).
- Tubing hanger or slips and seal.
- Spacer pup joints.

The mud anchor. The mud anchor is basically a joint of tubing at the bottom of the string that is used to:

- Collect fine silt or mud that is removed each time that the tubing string is pulled.
- Provide a protected place to contain the pump gas anchor while the pump is in the hole.
- Allow the tubing string to be set on the well bottom without damaging the string or plugging the intake of the rod pump.

A mud anchor is a full joint of tubing but may be cut off to be no more than 16-24 feet long. Some companies use a tubing cap plug or a collar and bull plug to close off the bottom end. Others cut off the bottom upset section and weld the opening closed with any acceptable method so that it has no external protrusions that may get stuck or collect scale. Still others will slice the bottom four ways then heat and close the bottom by folding the four flaps over with a large steel hammer.

Perforations. A portion of the tubing string in the reservoir must be perforated so that oil and water may enter. The perforations in a string of tubing may be arranged in any of several ways. Some of these options are to:

- Install a perforated pup joint (Figure 2) above the mud anchor by using a collar in between. Perforated pup joints may be as short as 2 feet or up to about 12 feet long. The typical length selected is 3 or 4 feet. The holes are ½ inch in diameter and spaced a few inches apart on all four sides. These small holes prevent large objects from entering the tubing.

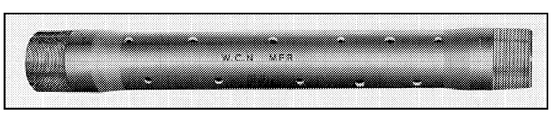

Figure 2. A perforated pup joint.
(courtesy Dover Corporation, Norris Division)

- Leave the bottom of the pipe open below the seating nipple or use a short joint. Very few operators use this approach because large objects may enter and cause the pump to stop functioning.
- Perforate the mud anchor with an electric drill or by cutting holes with an oxyacetylene torch. These holes begin no farther than 6 inches below the upset on all four sides and extend 2-4 feet. The holes are 3-6 inches apart.

Seating nipples. The seating nipple provides a connection for the pump while sealing the pump to the tubing. This seal permits fluid to be produced up through the seating nipple and pumped to the surface. Cup- and mechanical-type seats are used. The cup-type requires a seating distance of about 6 inches. Either three or four cups will be placed on the pump. A larger no-go ring of metal above the cups prevents the pump from sliding through the seating nipple.

Cup-type seating nipples are reversible. A reversible seating nipple is 12-16 inches long. When scoring or other damage that may cause the seat to leak occurs, the nipple can be reversed to provide a new seating surface.

The mechanical-type seating nipple is about 8-10 inches long and is not reversible. The seat is usually tapered at the top to accept a metal-to-metal seat. The seat on the pump is made of a metal that gives slightly to ensure that the seating nipple seals.

The packer. Flowing wells may be completed with or without a packer. A packer provides a seal downhole that can block the flow of fluids between the tubing and the wellbore wall or casing. The packer is installed in a tubing string near the bottom and is set just above the casing perforations.

The packer can help the well flow reducing the cross-sectional area of the opening, increasing the flow velocity. If a well does not have high bottom hole pressure, the gas pressure in the *annular space* or *annulus*—that is, the space between the tubing and the casing—will bleed into the tubing perforations as the casing empties of liquid. This casing pressure acts as a flow cushion while liquid accumulates once more in the well. A packer can reduce this erratic change in pressure.

The holddown. A holddown is similar to a packer in that it latches the tubing to the casing near the bottom of the well just above the casing perforations. However, the holddown does not form a seal between the casing and the tubing in the annular space; therefore, fluids may pass by it freely in either direction without restriction.

If the well is deep and is to be completed as a pumping well, the holddown will be installed to prevent *breathing*—that is, the up and down movement of the bottom of the tubing with each stroke of the rods. Breathing is reviewed in detail in Chapter 6.

C-5. Correlating Perforations.

When running the tubing in the hole, one of the most important tasks is setting the perforations in the casing at the most desirable depth from the surface. This will affect the performance of the well, the number of barrels of fluid produced, the amount of gas produced, as well as how much gas is retained in the formation.

There are several options for correlating perforations, and operators must reach their own conclusions as to which is best for a particular well and for reaching their production goals.

C-6. A Typical Wellhead.

As each string of casing is run into the well, an appropriate wellhead section must be installed. Figure 3 shows a wellhead with a Christmas tree mounted on top. This configuration would be satisfactory for a flowing well. Below the Christmas tree, the wellhead consists of two sections: the casing head (labeled A in the drawing) and the intermediate head (labeled B).

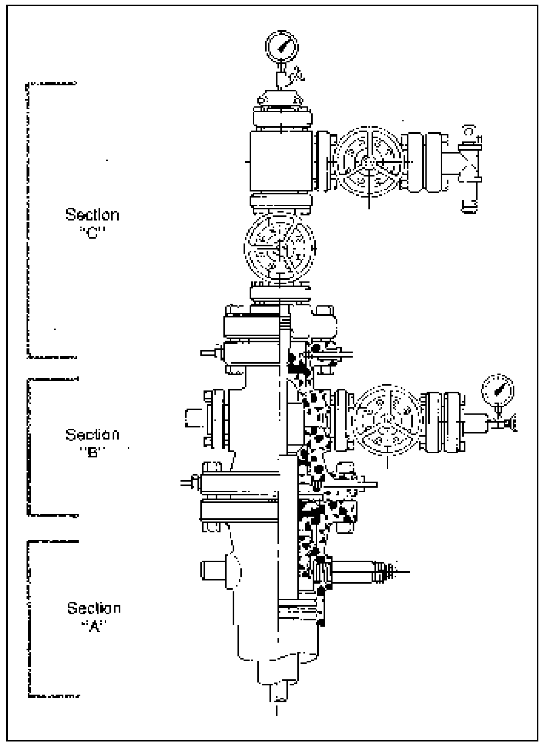

Figure 3. A typical wellhead and Christmas tree.

The casing head (A). The unit illustrated may have external threads, internal threads, or a slip-on collar for welding directly to the casing. The welded installation allows the tubing string to be positioned at a precise level. This is especially important for a pumping unit installation. A plug, a ball valve, or gate valve may be installed on one side, and a 2-inch bleeder valve is installed on the other side. The valve that is installed on the surface pipe is left open to prevent pressure from developing that might threaten the fresh water zone. Typically, the wellhead will use a gate valve, which is one of the three multiple round opening styles of valves: the gate, needle, and globe. Such a valve is often referred to merely as a *gate*.

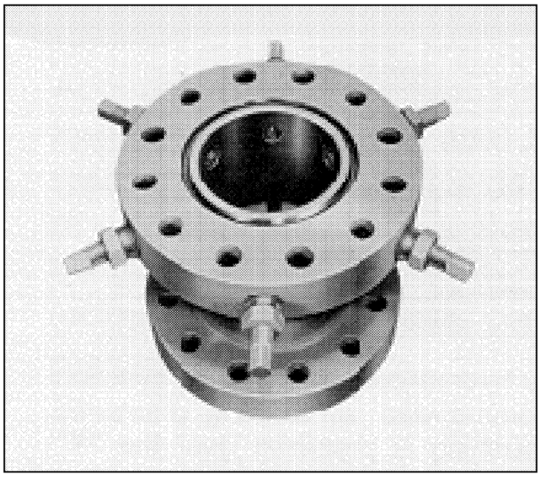

Figure 4. A casing hanger with hanger locking devices shown.

The intermediate head with casing hanger. The final string of casing will usually be suspended from the intermediate head. The casing hanger bolts on top of the casing head generally have a metal seal ring and 12 or more studs with nuts. Some casing hangers, such as the one shown in Figure 4, provide a means of attaching the tubing string to the casing hanger. If the final string is attached to the casing hanger, there will be two openings on the sides with valves screwed into the sides. One will usually be available and the second side will be connected to the flow line going to the tank battery.

The tubing hanger. The final step in running tubing is to install the tubing hanger, popularly called the *donut*. The tubing hanger should be cleaned and covered with a lubricant or thread compound before being lowered into the hole. The *dogs* or locking devices should be run in snugly to hold the top tapered edge firmly down. This allows the safe removal of the Christmas tree with pressure still on the casing.

Figure 5. A tubing hanger.

Additional information about wellheads and their use is presented in later chapters.

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CHAPTER 5

FLOWING WELLS AND PLUNGER LIFT

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The Lease Pumper's Handbook

Chapter 5
Flowing Wells and Plunger Lift

Section A

PRODUCING FLOWING WELLS

The gas and water in a formation may create a pressure that forces fluids from the rock when an opening, such as the well, is created. This pressure can be strong enough to force the fluids to the surface. In this case, the well may be referred to as a *flowing well*. If this level of pressure is less, a pump or lift system must be installed to bring the water, oil, and gas to the surface. Many wells start out as flowing wells but must be worked over to install a lift system in the later years of their production lives.

This chapter discusses both flowing wells and wells with plunger lift systems. However, before considering how oil is brought to the surface, the regulation of production is discussed.

A-1. Allowables.

Generally, a lease operator would like to produce as much oil and gas as possible because that is what leads to revenues from the well. However, maximum production rates may not be in the best interests of the reservoir or the environment or the economy or other considerations beyond the financial interests of the lease operator. Because the lease operator may not be aware of all the factors that should be considered or may not voluntarily do what is in the best interests of the nation and others, agencies have been established to regulate the production of oil and gas. At a state or local level, such an agency may be called a Petroleum Commission, Oil Commission, Railroad Commission, or other name. These agencies assist petroleum producers in understanding reservoir problems and promote operator cooperation. One of their primary tasks is to regulate the amount of production allowed for a reservoir, often with limits set for both oil and gas. These production limits, commonly called *allowables*, prevent production abuses in reservoirs through the following objectives:

- **Protecting the reservoir.** Allowables and regulations are aimed first at protecting the longevity and stability of the reservoir. Good production practices can add years to the producing life of the reservoir and result in a much higher final production from the field.
- **Protecting the rights of other operators.** Allowables protect the lives of the wells of all operators who have producing wells in a reservoir. Regulating the amount of gas that may be produced can preserve bottomhole pressure, meaning that producers do not have to resort to lift systems as soon. Because of oil production regulation, reservoirs are not depleted as quickly or unevenly, even when more than one lease operator is producing from the reservoir.

Coning wells and pulling in gas and water. Some wells are capable of producing much more oil than is allowed. If the well is water-driven—that is, bottom pressure is supplied by water carrying oil into the casing—the lease pumper may be tempted to over-produce the well. This temptation is especially severe if equipment breakdowns or other problems have put the lease behind its production goals. However, doing so may damage the well's production capability. Fluids under pressure move to areas of lower pressure. In this case, the low pressure is at the bottom of the well bore, causing fluids to rush from every direction. Oil flows in from each area of the reservoir, unwanted gas forces its way down through the oil bearing sands from above, and water pushes upward into the oil zone from below.

Very soon a situation develops where the gas cone stays in position even when the well is at rest. When the lease pumper opens the valve, more gas than usual will be produced, sweeping water into the well. This water will stay in this position while the well is at rest. As water surges up, it drives out the oil. The small differences in weight require many years to fall back naturally so that the oil can return to its original level. The lease pumper can reduce the production capacity of the well to a fraction of its uncontrolled production rate.

Effects of poor production techniques. It really does not matter who has decided to overproduce the well: the owner, field supervisor, or the lease pumper. The well has been damaged, and the company must pay the price with lowered production. Treating the well more gently will not casually restore it to the former level of production. The recommended practice is not to overproduce a well by more than ten percent of its maximum daily production potential. This means that if a day of production is lost, it will require ten days to make up the loss. The well may reach the end of the month still short. However, this is much better than damaging the well capability because continued overproduction will soon result in being short every month.

Occasionally a lease pumper may hear other pumpers talk with pride of their abilities as a pumper because they make up for lost production in one well by overproducing other wells on the sly. When the production problems get corrected, they have managed to maintain full production overall. Even their supervisors may be extremely pleased. In fact, all this effort has actually accomplished is to shorten the lives of the wells and dramatically reduce their long-range capabilities.

A-2. Several Operators Owning Wells in the Same Reservoir.

The United States is one of the few countries in the world where mineral rights can be owned by individuals, companies, trusts, states, and the government. As a result, occasionally the production practices of one lease operator may cause extreme production problems for *offset wells*—that is, wells operating near the first lease. This reduction can become so severe that nearby wells are *killed*, meaning that they no longer produce oil or gas, because hydrocarbons are pulled away from the outer areas of the reservoir where the offset wells may be.

If the reservoir is high in some areas and low in others, wells in the higher elevations may produce only gas. Wells drilled in the lowest area may produce extremely high volumes of water and very little oil. Wells in the middle range may produce high volumes of oil with very little gas and virtually no water.

If the operator of the wells in the higher area produces high volumes of gas and lowers the reservoir pressure, the wells producing a high volume of oil will gradually stop producing oil. If the lease operator owning wells in the lower zones produces massive amounts of water, this will stimulate the water drive and, with the lowered formation pressure, allow the water table to rise so that production from the high oil-production wells falls off.

Many lawsuits have been filed from these types of problems. The best solution is for the operators involved to agree to a production plan for the whole reservoir so that it can be produced efficiently for the benefit of all the operators.

A-3. What Makes a Well Flow Naturally?

A well flows naturally when it has a sufficiently high bottomhole pressure to force the fluids to flow from the formation all the way to the stock tank without external or internal assistance. Most naturally flowing wells receive their bottomhole pressure from *water drive*, which is the pressure created by the movement of water within the formation. As oil and gas are removed from the formation, water may fill the space vacated by the hydrocarbons due to the lower pressures in that area. This is a relatively slow process taking many years to occur.

For the well to flow, the bottomhole pressure must be great enough to lift the column of fluid in the tubing to the wellhead, push the fluid through the flow line to the tank battery into a pressurized separating vessel, and still retain enough pressure to push it through any additional treating vessels and into the sales or stock tank. So how much pressure is required?

A common rule of thumb is that if the well has a wellhead pressure of about 100 pounds with a standing column of liquid in the tubing, this is usually sufficient pressure to allow the well to flow. The higher the pressure, the higher the volume capacity and the ease of flow.

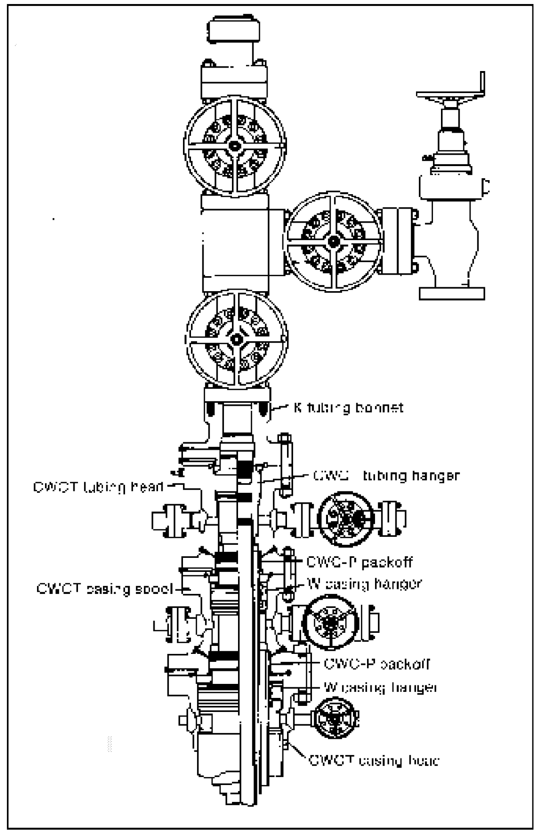

Figure 1. A typical wellhead for a naturally flowing well.
(courtesy ABB Vetco Gray)

Packers are placed near the bottom of the tubing string in the annulus of flowing wells to prevent the surge effect that will occur if no packer is present. The flowing well without a high bottomhole pressure will produce erratically without a packer. As an illustration, if a flowing well without a packer produces mostly gas with very little liquid for a short period of time, most of the liquid in the tubing and casing will be produced toward the tank battery. As the casing is emptied of liquid, the gas pressure contained in the annulus will *break around* into the tubing perforations. This sudden surge of gas will empty most of the liquid out of the well all of the way to the tank battery. This loss of gas will reduce the gas pressure dramatically in the casing all of the way through the system.

After this pressure has blown down, and liquid once more begins to accumulate in the bottom of the well, the casing pressure acts as a flow cushion or as a pressure surge tank. The casing pressure must build back up to a level that will allow the well to develop enough bottomhole pressure to cause it to flow again. This erratic action of flowing wells can be reduced or eliminated by placing a packer in the well near the bottom. Very high volume flowing wells may be produced through the casing, however, and these wells do not have packers.

Packer removal. When a well will not flow and is converted from a flowing well to a pumping well, the packer may be removed, and the casing valve is eventually opened to the tank battery at all times to remove bottomhole formation pressure. A check valve is placed in the casing line near the wellhead to prevent the oil that is being pumped out of the tubing from circulating back into and down the casing.

The bottomhole pressure of the well has now been reduced to the separator pressure plus flow line resistance, plus the weight of the column of fluid in the annulus. The lease pumper must always be aware of any situation that might change this balance, because every change will affect the oil production from the well. If the pumper raises the separator pressure by 5 pounds, the formation pressure has been raised by 5 pounds, and oil production will decline accordingly, especially for a short period of time. When the gas production has been reduced to the *traces* classification, the casing valve may be open to the atmosphere.

A-4. Producing a Flowing Well.

The typical flowing well will have a Christmas tree composed of a master gate valve, a pressure gauge, a wing valve, and a choke. The Christmas tree may also have one or more check valves. The functions of these devices are explained in the following paragraphs.

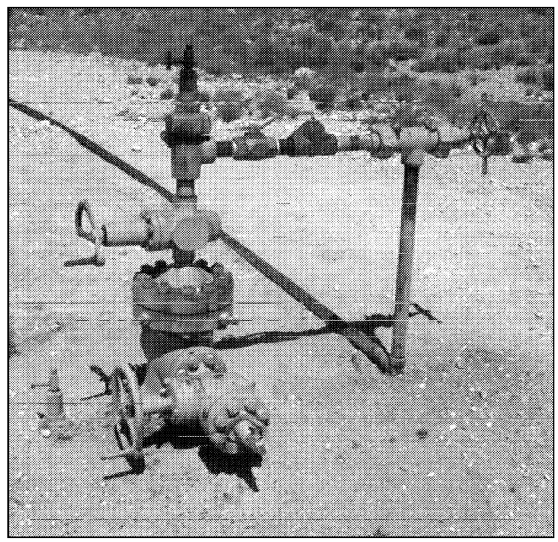

Figure 2. A typical flowing well configuration with a Christmas tree, master gate valve, wing valve, check valve, variable choke, and flow line.

Master gate valve. The master gate valve is a high quality valve. It will provide *full opening*, which means that it opens to the same inside diameter as the tubing so that specialized tools may be run through it. It must be capable of holding the full pressure of the well safely for all anticipated purposes. This valve is usually left fully open and is not used as a throttling valve to control flow.

The pressure gauge. A high-pressure steel tee is placed above the master gate valve. A tapped bull plug and a ½-inch needle valve with gauge are placed on top of the well. The high-pressure needle valves are available in both straight (180-degree) and ell (90-degree) configurations where the valve pressure can be read from a convenient angle.

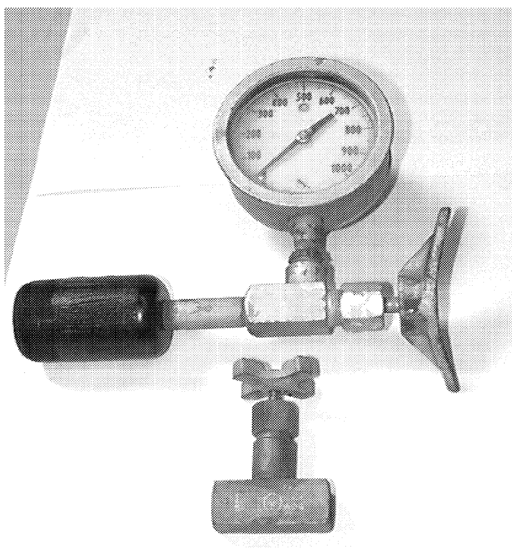

Figure 3. Pressure gauge and valves used on top of the well.

The wing valve. The wing valve can be a multi-round opening valve similar to the master gate valve or it can be a quarter-round opening. Plug valves are sometimes used, though the ball valve is becoming popular because of the ease of operation. Further, it is easy to determine even from a distance if the valve is open or closed. Ball valves cannot collect water in the bottom of the valve as can some plug valves. Ball valves are usually also more economical to purchase. When shutting in the well, the wing gate or valve is normally used so that the tubing pressure can be easily read.

The check valve. Almost without exception, a check valve is installed in the flow line as it leaves the well. A second one is installed at the tank battery just before the line enters the tank battery separator header. Occasionally, an operator will prefer to install the check valve just after the wing valve but before the choke. Other operators install the check valve on the ground, after the line has turned toward the tank battery. This optional union and a ground-level check valve may be installed to permit easy removal of the Christmas tree and riser pipe for well workover. Some operators will install all three.

The casing valve. Even if a packer has been installed in the annular space near the bottom of the well, the casing will usually be connected to the Christmas tree and the line going to the tank battery. This will permit the casing to be opened, closed, bled down, and, in some cases, allow the flowing well to be produced through the casing as well as the tubing. If a packer is installed, this line connection serves no purpose until the packer is turned loose or is completely removed by a well servicing crew. The casing valve is usually a multiple round opening gate valve and can withstand high pressure. Like the wing valve, it does not have to be full opening. This valve can be used to determine packer leaks or determine if the tubing has developed leaks.

The variable flow choke valve. The variable flow choke valve is typically a very large needle valve. Its calibrated opening is adjustable in 1/64 inch increments. Chokes are available in steel, stainless steel, and tungsten carbide steel and are, therefore, expensive. High-quality steel is used in order to withstand the high-speed flow of abrasive materials that pass through the choke, usually for many years, with little damage except to the dart or seat.

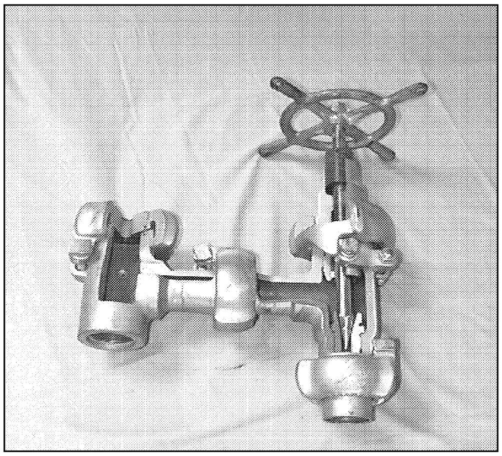

Figure 4. A unibolt design variable flow choke valve. A portion of the valve has been cut away to show the high-quality steel construction and the flow path.
(courtesy Cooper Cameron Valves)

The valve pictured in Figure 4 is of the unibolt design. The seal where the two halves of the union joints is a seal ring similar to the ones where the wellhead sections and the Christmas tree join the wellhead. This is a high-pressure steel seal and will withstand several thousand pounds. The unibolt union is often referred to as the *wellhead union*. The variable choke valve can be installed where the production flows *with* the dart, or running, or it can be installed where it flows *against* the pointed end of the dart or stem. As pictured, the unibolt choke has been installed to flow with the point of the dart. The choke valve in Figure 3 is installed so that the well flows against the point.

Because of the expense of the valve and the amount of fluid produced, the ¾-inch variable choke is very popular. Chokes of 1 inch or more are available but are practical only for very high producing wells.

Choke valves are marked to show the size of the opening. If the valve is fully opened, the last number will indicate its size. For example, if the last number is 48, then the valve is 48/64ths or a ¾-inch choke. If the final number is 64, then it is a 1-inch choke and can be opened to 64/64ths. The indicator sleeve can be loosened, usually with a set screw, and the setting corrected while the valve is closed.

If the well flows oil that may have a little paraffin, salt water, and scale, production may slowly drop as the orifice becomes clogged. Periodically opening the choke to a higher setting for a short period of time, then closing it, then opening it back up to flush the seat clean, and finally slowly pinching it back to the original setting may eliminate the scale that can collect in the choke.

Occasionally, the choke valve will be set at a rate of production that allows water to fall back down the tubing string and collect at the bottom of the well or in the matrix area. As this water builds up, it will begin to restrict oil production. It may even *kill the well*. This will require a swabbing unit to be called out to swab the water blanket up to the tank battery to allow the well to continue to flow. The use of soap sticks is a common means of stimulating flow from a well loaded up with water. Opening the choke to an increased flow rate for a short period of time occasionally, then setting it back at its usual setting may prevent this problem.

In order to monitor this situation, the lease pumper will need to write down the well head pressure before beginning and for at least one or two more periods to determine if the flow characteristics of the well have improved. Another solution is to conduct a productivity test to determine if other flow cycles would be more appropriate.

The positive choke. The positive choke may be located at the well on the Christmas tree (Figure 5) or on the inlet manifold just ahead of the first separating vessel (Figure 6). In many situations, there will be a positive choke at both locations. When the positive choke is located at both the wellhead and at the tank battery, it gives positive benefits.

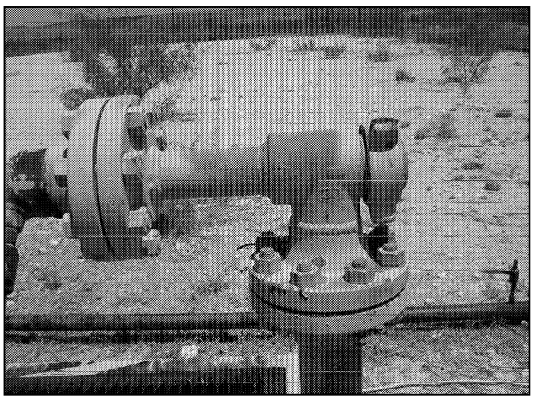

Figure 5. A positive choke installed on the wellhead.

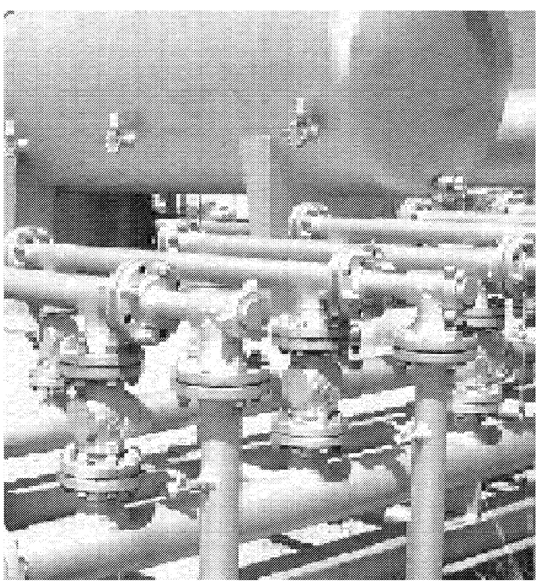

Figure 6. A positive choke installed at the tank battery.

One of the distinct advantages of the variable choke over the positive choke is the ease with which the setting can be changed. Flow through positive chokes is regulated by choosing a properly sized *flow bean* that will allow the well to produce the correct amount of oil daily. The chart in Figure 7 offers 74 sizes of beans shut-in to 14/64ths of an inch. These flow beans are sized to permit 5% and 10% increases in flowing rates.

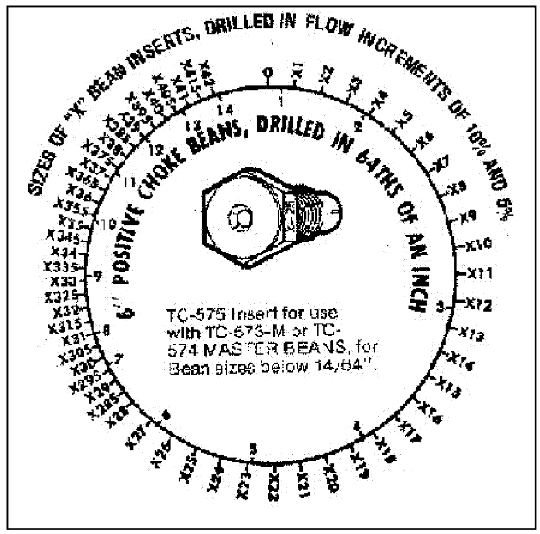

Figure 7. Chart showing sizes of available flow bean inserts for positive choke valves.
(courtesy Cooper Cameron Valves)

If the orifice size in the flow bean is a little larger at the well than at the tank battery to allow for expansion of the fluids. The final expansion occurs at the tank battery. The fluids will undergo a temperature reduction at the wellhead and also at the tank battery. Permitting this pressure reduction to occur in two steps instead of one can reduce the possibility of the line freezing.

The intermittent control for all wells is at the tank battery, and this centralizes the automation at one location instead of being at each wellhead. When the positive choke is at the wellhead, a wing gate is installed between it and the wellhead. A second valve is installed after the positive choke. This allows the choke to be easily isolated, bled down, and repaired or changed.

A-5. The Skilled Pumper and Marginally Flowing Wells.

As bottomhole pressure declines, there will be a corresponding decline in oil and gas production. During this period of reduced production or as the hydrocarbons in the reservoir are nearing depletion, the well is referred to as a *stripper well* or a *marginally producing* well. Much of the nation's oil production comes from marginally producing wells.

As production from a flowing well declines, the lease operator will have to make a decision as to whether an artificial lift system should be installed. To a large degree, the maximum life of a flowing well before it must be converted to artificial lift is controlled by the lease pumper. One of the most important skills of a lease pumper is the ability to make the correct decisions of how to produce each well in the marginally producing period before it goes on artificial lift. Some people have the interest, experience, patience, and ability to understand what is going on downhole, and the skill to make a flowing well produce for months or even years longer than other people. Some people never truly develop this skill.

A skilled lease pumper, who takes time to learn how to *rock a well*, alternately opening and closing the tubing bleeder and occasionally the casing valve, may bring a well back to life and do an outstanding job in obtaining a satisfactory volume of production with limited down time. This ability can extend the life of a flowing well before artificial lift is necessary.

The Lease Pumper's Handbook

Chapter 5
Flowing Wells and Plunger Lift

Section B

PLUNGER LIFT

The use of plunger lifts has increased dramatically during the past decade and has led to increased oil production. Improved technology, computers, better equipment dependability, and additional services have contributed to this increased use. Plunger lift is available in complex computer-controlled models and simple basic systems. This section discusses the use of plunger lift.

B-1. The Cost of Changing a Well to Mechanical Lift.

Once the bottomhole pressure in a well is no longer adequate to cause it to flow, the operator must determine if it will be worthwhile to install a lift system. The initial costs can be substantial, even with a minimum installation. The actual transition of a well from flowing to pumping requires:

- A well servicing crew to rig up and remove the packer, possibly install a hold-down in the casing, reinstall the tubing string, and run the rod string.
- The purchase of a downhole pump.
- The purchase of a string of rods.
- The purchase of a pumping unit.
- Construct a base and have it set.
- Install and line up the pumping unit on the base and over the hole.
- Remove the Christmas tree and rebuild the wellhead (Figure 1).
- Provide a source of power to run the pump either by running electricity to the location or providing an engine and a source of fuel. An electrical setup will require an automatic control and an electric motor. A engine may operate on gas from the well or from stored fuels.

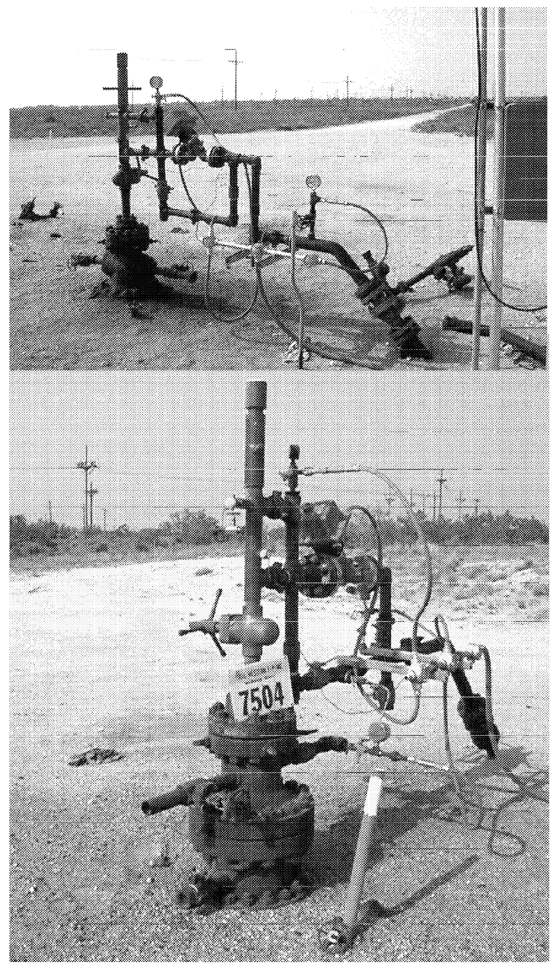

Figure 1. Two typical wellhead designs for wells using plunger lift.

B-2. How Plunger Lift Works.

A wing valve control on the wellhead closes the flow line to the tank battery, and this stops the flow of fluids up through the tubing to the tank battery. The bumper housing and catcher on the wellhead release a free falling **gas lift plunger**, which drops by gravity from the wellhead downward through the tubing. An open valve in the plunger allows fluids from below to pass through it as it falls. Gravity continues to make the plunger fall all the way to the bottom of the well.

When the gas lift plunger strikes bottom, it makes contact with a footpiece spring, closing the valve. Downhole pressure continues to build up and also allows oil and water to accumulate on top of the plunger. After a specified time or tubing pressure level, the controller causes a flow line motor valve at the surface on the wellhead to open, allowing the gas and fluids accumulated in the tubing to flow toward the tank battery.

The differential pressure change across the plunger lift valve causes the plunger to travel toward the surface at a rate of 500-1,000 feet per minute, depending on adjustable choke settings, fluid loads, and bottomhole pressure. As the plunger moves upward pushed by the built-up formation pressure below it, the fluid above the plunger is lifted to the surface.

On oil wells and weak gas wells, the arrival of the plunger at the surface activates a magnetically controlled sensor that immediately closes the flow line motor valve, conserving tubing and formation gas pressure until the next cycle. The catcher in the bumper housing releases the plunger. The plunger again starts falling, and the cycle begins again, repeating itself as often as the settings and pressures allow.

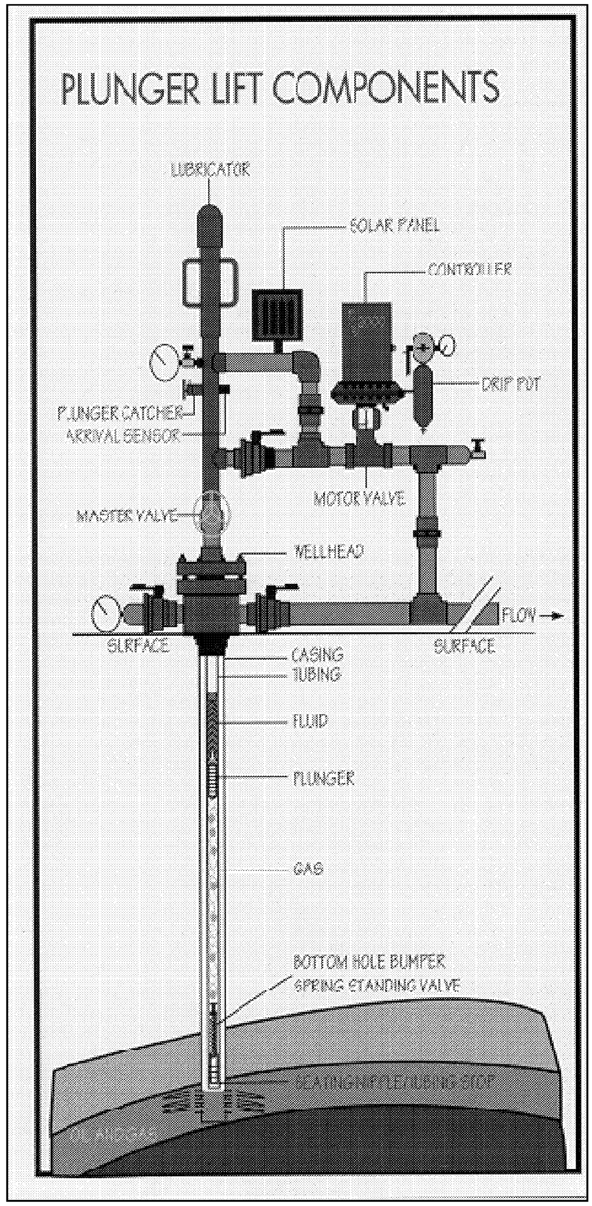

Figure 2. Plunger lift system.
(courtesy of Production Control Services, Inc.)

B-3. Benefits of Plunger Lift.

The benefits of converting a marginally producing flowing well to a lift system can be enormous in many situations. Some of reasons for choosing a plunger lift system over other type include:

- Reduce lifting costs.
- Conserve formation gas pressure.
- Increase production.
- Produce with a low casing pressure.
- Prevent water buildup.
- Avoid gas-locked pump problems.
- Reduce gas/oil ratio.
- Scrape tubing paraffin.
- Improve ease of operation.
- Use pneumatic or electronic controllers.
- Reduce installation and operating costs.

Note: When a plunger system is installed, a gauge ring of the same size as the proposed mandrel to be used in the plunger lift system should be run down the well. This will identify any problems that could prevent the plunger from free-falling through the tubing.

Reduce lifting costs. Plunger lift has a lower lifting cost than most other systems of artificial lift. The well itself supplies the gas pressure needed for operation. The more complex electrical systems require very little power and this can be supplied with a solar panel.

Conserve formation gas pressure. As quickly as the plunger arrives at the bumper housing at the surface, the flow line is shut in, stopping any additional formation gas from flowing to the tank battery and into the gas system. The gas needs to remain in the formation as long as possible to drive additional oil to the well bore in the future. When the formation gas is gone, the well will stop producing. The conservation of formation gas is one of the outstanding benefits of plunger lift, and no other lift system can offer this advantage.

Increase production. Through productivity testing where the well is produced under many different time limits and situations, the most productive parameters can be determined and followed to result in the highest possible production. By reducing the column of fluid lifted and lifting it more often, production can usually be increased.

Produce with a low casing pressure. Plunger lift allows a well to continue to flow with less than 100 pounds of casing pressure. The plunger will stay on bottom until sufficient lifting pressure has built up. The signal to open the flow line valve will be transmitted to the surface through the casing pressure.

Prevent water buildup. When a well is flowing by choke control and the lifting pressure has become so marginal that the well will barely flow, the produced water, being heavier than oil, will have a tendency to allow the oil and gas to flow with the water falling back to the bottom of the hole. This water buildup will cause the well to become waterlogged and stop flowing until the water has been blown or swabbed off. With plunger lift the water is produced along with the oil every time the plunger makes a trip to the surface, and water does not accumulate at the bottom of the well.

Avoid gas-locked pump problems. When a well with high gas production is put on a mechanical pumping unit, the pump can develop a tendency to gas lock and stop the well from producing. The plunger lift system does not have this problem.

Reduce gas/oil ratio. In some fields, oil production is regulated by the amount of gas that is produced with each barrel of oil. The goal is to retain as much gas in the reservoir as possible to push oil to the wellbore. Some fields have allowables adjusted to reflect the amount of gas produced daily. Plunger lift does well in reducing gas production, which results in increased oil allowables. This will dramatically extend the production life of the reservoir and the amount of oil produced.

Scrape tubing paraffin. While the plunger is traveling up the tubing each cycle, it acts as an excellent wiper to remove paraffin that may cling to the tubing. Paraffin leaves the formation suspended in the oil. As the wellbore temperature drops, the paraffin comes out of solution and is deposited in the tubing. The plunger can also remove scale that is still soft.

Improve ease of operation. The basic operation of plunger lift systems is simple. Even the more complex systems are becoming easier to operate with new developments in technology. Advances in personal computers and electronic miniaturization allow controllers to perform functions that were not possible a few years ago, almost to the point of making decisions.

Use pneumatic or electronic controllers. Automatic controls allow the pumping time of the well to be precisely controlled to allow the most efficient use of energy and to reduce the loss of gas.

Reduce installation and operating costs. Plunger systems generally cost less to install, operate, and maintain than other lift systems.

B-4. Plunger Selection.

There are five main types of plungers: solid, brush, metal pad, wobble washer, and flexible (Figure 3).

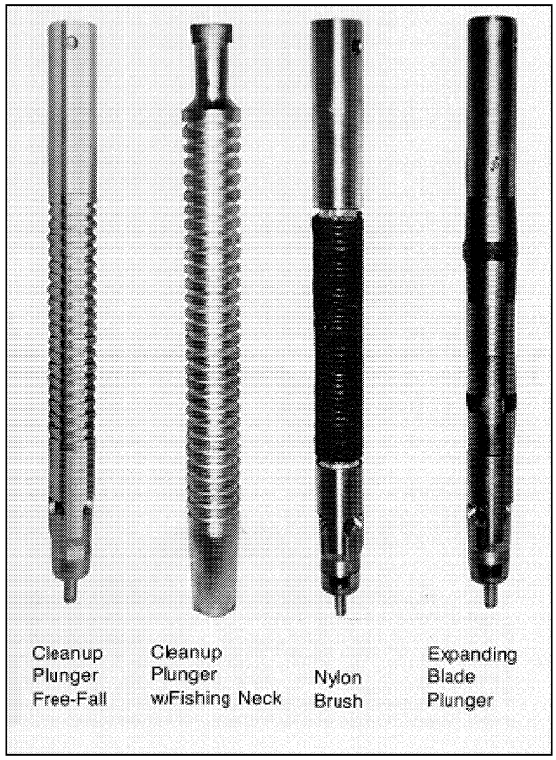

Figure 3. Some of the types of plungers available.
(courtesy of McLean & Sons, Inc.)

Solid. The solid plunger is a solid steel cylinder with a smooth or grooved surface. Gas passing around the plunger during its trip upward must have a velocity much greater than the plunger and liquid load. The gas passing the plunger wipes the tubing clean of liquids and reduces liquid fallback.

Brush. A brush plunger consists of a mandrel and a brush segment that may or may not be replaceable. The brush segment is oversized with respect to the tubing internal diameter, and this characteristic creates the sealing mechanism. Brush plungers are particularly good for wells that suffer from sand flowback or tubing imperfections.

Metal pad. The metal pad plunger has several spring-activated metal pads that conform to the internal tubing diameter. These plungers may have one or several concentric sets of pads along the body arranged in various patterns. Pad plungers provide the highest level of mechanical seal when properly sized.

Wobble washer. The wobble washer plunger is designed to keep tubing free of paraffin, salt, and scale. It is constructed of shifting steel rings or washers mounted along a solid mandrel. The washers wipe the tubing clean, removing the unwanted product before it has a chance to crystallize.

Flexible. New on the market are plungers built with a flexible mandrel for deviated hole and coiled tubing applications. Articulated cup and brush plungers are available with this new design feature. These flexible plungers range in size from ¾ inch to 2-7/8 inches. Many times a flexible plunger will run in a standard tubing string that has bends or crimps, reducing the need to pull tubing.

Clean-up plungers. Among the plungers pictured in Figure 3 is a clean-up free-fall plunger with a fishing neck. These are frequently used to handle formation sand, frac sand, scale, and so forth. The clean-up plunger is usually replaced with the expanding blade plunger when the well has cleaned itself. If the plunger should stick in the tubing during the clean-up procedure, the fishing neck makes it easier to retrieve.

B-5. Bumper Housings and Catcher.

The bumper housing and catcher perform several functions. The bumper provides a cushioned bumper to stop the plunger from moving as it reaches the top of its travel and enters the housing. The housing also helps provide lubrication.

The arrival unit recognizes that the plunger has arrived at the top of its travel and sends a signal to the control panel, or controller, which sends a signal to the flowline valve, causing it to close.

The lease pumper can engage the catcher, which will catch the plunger the next time that it arrives at the surface. This will permit the plunger to be removed, inspected, serviced, and placed back into operation at the pumper's convenience.

Figure 4. Common components of a plunger lift system: (left to right) a controller, plunger, bumper, and housing with lubricator and electronic sensor. *(courtesy of Production Control Services, Inc.)*

B-6. Controllers.

Most controllers (Figure 5) can be operated with time control or with pressure cycles. Timers may be set for straight timed shut-in or operated with high/low pressure measurements through the use of flow line throttle pilot pressure and a differential pressure switch. With this type of flexibility available to the lease pumper, plunger lift can be an ideal method for operating wells. By reducing the loss of formation gas, a great deal of additional oil may be recovered.

Figure 5. An electronic controller.
(courtesy of Production Control Services, Inc.)

B-7. Plunger Lift Configurations.

It should be evident from this section that plunger lift systems can be configured in a number of ways to meet the needs of a specific well. By matching the components and the controller settings to conditions of an individual well, the lease pumper can come close to maximizing the efficiency of the well.

Note the plunger lift shown in Figure 6. A full opening gate valve is located just under the oil well bumper housing and arrival unit and catcher. This particular installation was powered by a solar panel located to the right, just out of the picture. The casing valve has a pressure gauge and connection providing pressure to the controller. Just to the right of the bumper housing is a line that controls the shut-in of the flow line.

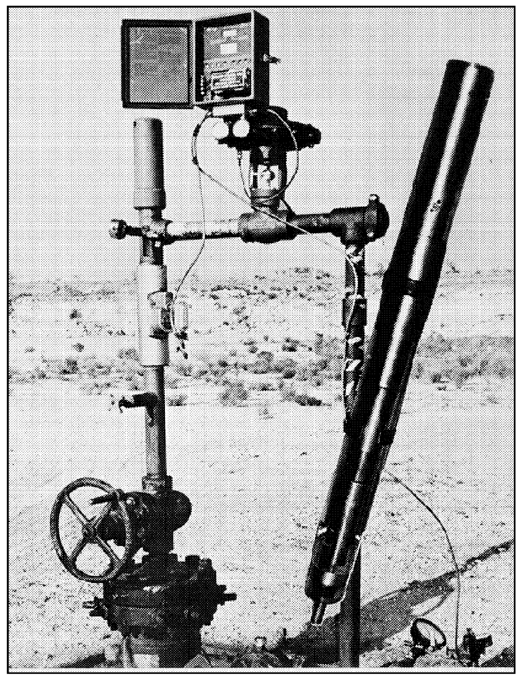

Figure 6. A plunger lift wellhead showing the bumper housing, arrival unit, catcher, and controller.
(courtesy of McLean & Sons, Inc.)

Plunger lift is one method of artificial lift. Other techniques are presented later in this handbook, but many of the objectives and considerations described here are applicable to other lift methods as well.

The Lease Pumper's Handbook

CHAPTER 6

MECHANICAL LIFT

- Plunger.
- Traveling valve.
- Holddown seal assembly.

2. Pumps Designs.
   - Insert pumps.
   - Tubing pumps.
   - Other styles of pumps.

The Lease Pumper's Handbook

Chapter 6
Mechanical Lift

Section A

PUMP OPERATION

There are four types of power that are commonly used to provide artificial lift in the oil field. There are:

- Mechanical lift powered by a motor or engine on the surface
- Hydraulic lift, where oil or water is pumped down into the well to operate a hydraulic pump
- Electric submersible pump, where a pump at the bottom of the well is driven by electricity from the surface
- Gas lift, where natural gas injected into the tubing at intervals lightens the weight of the fluid, helping it rise to the surface

All four of these systems offer advantages and disadvantages for specific situations. During the life of a well, more than one of these systems may be used. Occasionally the same type of system may be installed a second time on the same well. Mechanical lift is one of the more commonly used forms of artificial lift and is the subject of this section. The other types of lift are discussed in the next three chapters.

A-1. Application of Mechanical Pumping.

The mechanical pumping unit remains as one of the best ways to produce artificial lift wells. It is also satisfactory for marginally producing wells, and the majority of all artificial lift wells use mechanical lift.

This system of pumping works well for low production because the surface equipment requires very little daily attention. Each installation is an independent system, is economical to maintain, is easily automated, and is ideal for both intermittent as well as continuous production.

Other lift methods may be more appropriate for a specific situation and for higher production rates, but for many applications mechanical lift is ideal, including in shallow offshore wells.

A-2. How Mechanical Lift Works.

The mechanical pumping unit works on the same operating principles as a windmill or any water well that has a string of sucker rods, a standing and a traveling ball on the bottom, and power at the top. Figure 1 shows a typical pumping unit. These systems, sometimes called *rod pumping* units, work with an up and down reciprocating motion.

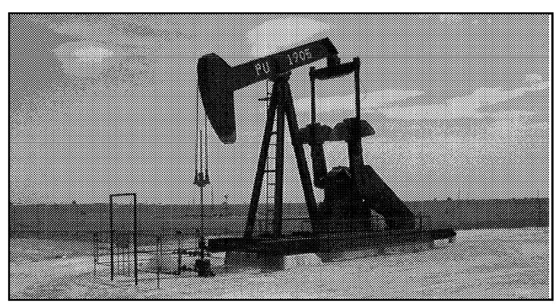

Figure 1. A conventional beam-style pumping unit.

The crank of the pumping unit is driven in a circular motion by the rotation of the *sheaves* or pulleys, belts, and gearbox. The gearbox is driven by the *prime mover*, generally a gas-powered engine or an electric motor. The pitman arms are connected to the walking beam, and the rotary action is converted into reciprocating power to the walking beam and the horse head. A set of counterweights offsets the weight of the string of rods and part of the weight of the fluid in the tubing. The string of rods usually extends through the tubing to the bottom of the well, and a pump is installed below the fluid level at the bottom of the hole. By using a ball-and-seat style of standing and traveling valves, the liquid—usually a combination of oil and water—is pumped from the bottom of the oil well to the surface, through the flow line, and into the tank battery.

As the pumping unit starts, the head of the pumping unit moves upward, lifting the sucker rod string and the plunger in the pump. The traveling ball or valve closes so that oil cannot pass through the plunger as it moves upward. This action lifts the fluid in the tubing string toward the surface, while also creating reduced pressure below the plunger. The standing valve in the bottom of the pump opens due to the reduced pressure, allowing additional fluid to enter the bottom of the pump.

As the rod string starts moving downward, the increased pressure from above closes the standing valve in the bottom of the pump. This prevents the oil that has entered the pump barrel from flowing back into the formation and allows pressure to build up between the valves, which opens the traveling valve as the pressure between the valves grows greater than the weight of the fluid in the tubing. The plunger passes down through the fluid that entered the pump barrel during the upstroke, trapping it on top of the plunger once the traveling valve closes as the next upstroke begins, and the cycle will be repeated. The time required for each cycle is determined by how the pumping unit is configured, including the speed of the prime mover, the ratio of gears in the gearbox, and the sizes of the sheaves or pulleys. This cycle time is referred to as *strokes per minute* (SPM) and is partially determined by the *revolutions per minute* (RPM) of the prime mover.

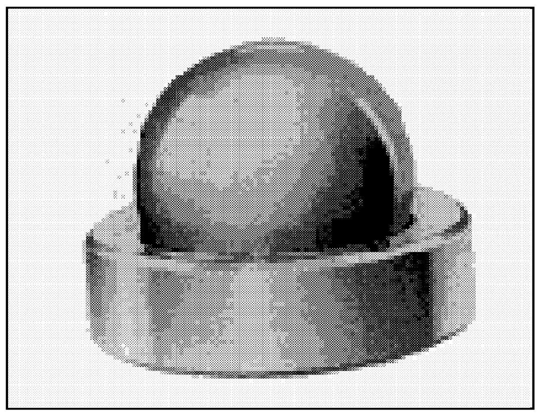

Figure 2. A ball and seat valve, a design commonly used for the standing and traveling valves in mechanical lift systems.

This description of mechanical pumping action shows that the unit lifts liquids to the surface only on the upstroke. On the other hand, the plunger in a hydraulic lift pump lifts liquid on the upstroke and also on the downstroke. Since no rods are moving, this pump can also move much more rapidly than the rod pump, so it is capable of lifting a much higher volume of liquid.

The electric submersible pump and gas lift systems also lift continuously while in operation. Thus, these three systems are capable of lifting a higher volume per day than mechanical lift systems. However, since most wells do not run continuously, whether lift occurs during the whole operation or only half of the cycle is not necessarily the most important consideration in the choice of an artificial lift system.

As the rod string moves up and down during the pumping cycle, many changes occur downhole.

- *As the rod string moves upward*, the weight of the column of oil in the tubing is transferred from the standing valve to the traveling valve.
- The length of the rod string grows longer as the plunger tries to lift the weight of the liquid above and tries to overcome the friction and surface tension between the oil and tubing.
- As the weight of the column of liquid is lifted, there is less weight on the tubing, and the length of the tubing string gets shorter—that is, the bottom of the tubing string moves up the hole a short distance.
- The friction of the upward-moving oil also exerts a small lifting force on the tubing.
- *As the plunger moves downward,* the weight of the column of oil in the tubing is transferred from the traveling valve back to the standing valve.
- The length of the rod string grows shorter as it pushes back down against the freshly accumulated fluid.
- With the traveling valve open, the weight of the column of liquid rests on the standing valve and is exerted against the tubing string. This increased load causes the tubing string to become longer. The bottom of the tubing string moves downward, from a few inches to several feet, depending on the depth of the well, the weight of the column of fluid, and the size of the tubing.
- The downward movement of the tubing results in *over-traveling* of the pump—that is, the pump is moving away from the surface and accumulating additional fluid during the downstroke.

The action of the rods and tubing in response to these changing forces is called the *cyclic load factor*, and the up and down movement of the tubing in the hole is referred to as *breathing*. These changes in the length of the rod string and the tubing string can be computed so that the length of the surface stroke can be adjusted accordingly.

A-3. Problems Caused by the Cyclic Load Factor.

Several problems can result from the cyclic loading and breathing action of the rod string and tubing string. Some are:

- As the tubing and collars move up and down in the casing, holes may wear in the casing and cause a casing leak.
- The collars or tubing may wear to the point that the string begins leaking liquid from inside the tubing back into the casing, where it falls back to the bottom of the hole. In extreme situations the tubing string can separate. Wear is especially high when the tubing or collar is rubbing at the bends or *dog legs* in the casing that are a natural result of the drilling process.
- The stretching of the rods and shortening of the tubing results in a shorter relative stroke length inside the pump than the travel of the rod string at the surface. This results in lower pumping efficiency and reduced production. The lease pumper must pump the well longer to overcome this loss in pump stroke. For a shallow

marginal well, this is usually not a great problem because the typical well does not pump a full twenty-four hours per day.

A *tubing holddown* can be installed near the bottom of the tubing string to reduce the up and down movement at the bottom of the string. A tubing holddown is similar to a packer except that it does not have rubber to seal against the casing. Fluids may move freely by the holddown. To prevent movement in the upper area of the tubing string, it may be necessary to pull several thousand pounds of tension on the tubing string. As an illustration, a 10,000-foot well with 2-7/8-inch tubing may have a tension of 25,000 pounds pulled on it above the weight of the string. The installation of holddowns is routine in all deeper wells.

A-4. Pumping at the Wrong Speed.

Problems created by the cyclic load factor can also be compounded by pumping the unit at the wrong speed. On medium to deep wells, as the top rods begin moving downward at the surface, the pump traveling valve at the bottom is still moving up. The problem reverses when the top rod starts moving up and the pump traveling valve is still going down. This problem can become exaggerated if the pumping operation is not carefully planned so that the SPM, RPM, sheave diameter, and other factors are not carefully matched to the characteristics of the well, such as depth and fluid weight and viscosity. If the cyclic load factor is large—that is, there is a great deal of stretch in the rod and tubing strings and their travel relative to each other is out of synchronization—pumping efficiency can be greatly reduced. In such a case, increasing the number of strokes per minute may actually decrease the length of the stroke at the bottom of the hole. Although SPM has increased, the amount of fluid produced has decreased.

Most pump companies provide a service through which they will calculate the proper arrangement of the pump components based on the pumping conditions, such as the depth of the well, size of rods, length of stroke, and strokes per minute.

Such planning, when properly matched to the characteristics of the well, will help to ensure that mechanical lift is suitable for the lease. The remaining sections of this chapter discuss the operation and maintenance of mechanical lift systems, while other lift methods are discussed in the chapters that follow.

The Lease Pumper's Handbook

Chapter 6
Mechanical Lift

Section B

OPERATING AND SERVICING THE PUMPING UNIT

Most active oil wells are marginally producing wells that have been converted to lift systems. The percentage of wells on mechanical lift is so great that all of the wells on many leases are on pumping units. This method of artificial lift is so dependable and easy to operate that many lease pumpers prefer mechanical lift over any other artificial lift system. This section covers the operation and maintenance of a mechanical lift system.

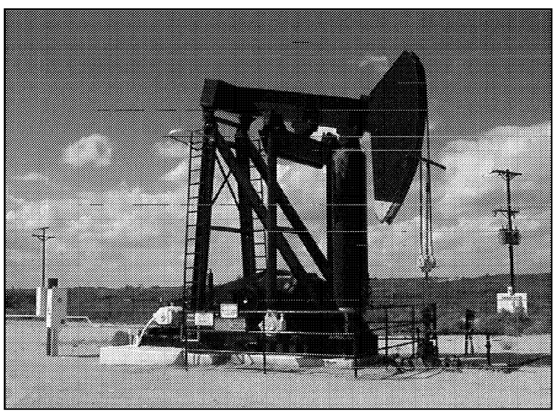

Figure 1. A pumping unit driven by an electric motor. Note the power control box on the power line pole. Two others are on the far side of the pumping unit.

B-1. Mechanical Lift with Electric Prime Movers.

Wells with electric motors as their prime movers are easily programmed to operate on full automation and easy to learn to operate. In a typical installation with electrical controls, such as that shown in Figure 1, the power line brings electricity to a spot near the location but outside of the guy line area. A fuse panel is installed and the power line is run underground, usually to the back of the pumping unit. On a post, a second electrical panel is installed with an on/off switch. An automatic control box is also attached to the post. The lease pumper must fully understand how to operate these components and be aware of problems that may develop.

B-2. Mechanical Lift with Natural Gas Engines.

Operating pumping units with natural gas engines are quite different from producing wells that utilize electrical prime movers. This is especially true when the fuel supply is gas from that well. Under these conditions, the lease pumper vents the gas not used for fuel and tries to maintain the formation back pressure as close as possible to zero. Information on this procedure is provided in Chapter 11, Section B, Engines.

Normally, the lease pumper is on the site for no more than 8 hours each day. Thus, if the pumping unit is started and stopped manually, there are a limited number of pumping schedules that can be used. The pumping unit can run around the clock, though, as will be explained later, this will not necessarily result in more oil production. A second option is for the lease pumper to start the pumping unit just before leaving the lease and shutting it off upon returning the next day. That would result in the unit running for approximately 16 hours, which again means little effective oil production. Finally, the lease pumper can run the pumping unit during normal working hours. The lease pumper could, thus, have the pumping unit run continuously during that time or could cycle the pumping unit on and off during the 8 hours.

A more efficient approach is to use an engine control. These devices allow the engine to start and stop without the lease pumper being present.

Engines offer opportunities that are not available with electric motors. The pump can be set to within 1 inch of tapping bottom. Thus, when the pump no longer pumps oil, increasing the RPM of the engine will allow the pump to tap bottom due to the rod having stretched. Once the pump has been restored, the RPM can be readjusted to prevent the pump from tapping bottom.

Pumping unit engines must be properly tuned at a level of dependable operation. A poor maintenance program will result in lost production and add a lot of duties to the lease pumper's busy schedule.

B-3. Pumping Schedules.

Determining how long to run the pump during a 24-hour period and the ideal cycling schedule can be difficult. For example, if operating a well that produces oil and water 12 hours per day leads to maximum oil production, there are a number of ways to achieve a 12-hour runtime, including:

- 12 hours on and 12 hours off
- 6 hours on and 6 hours off in two cycles
- 2 hours on and 2 hours off in six cycles
- 1 hour on and 1 hour off in 12 cycles
- 30 minutes on and 30 minutes off around the clock
- 15 minutes on and 15 minutes off around the clock

While the well is off, the liquid level builds up in the bottom of the hole in the casing. As it builds higher, the weight of the column builds up backpressure. As backpressure increases, the rate at which oil enters the well from the formation will slow until the backpressure equals the hydrostatic pressure of the formation, at which time all movement will stop. So there is an ideal amount of time to allow fluid to accumulate, for beyond that time no more oil will flow into the well. Thus, running the pump for just 20 minutes each hour, may result in the same oil production as running the pump for 12 hours each day and would require only 8 hours of runtime.

By the same token, if the system can pump the full accumulation of oil to the surface with 30 minutes of operation, there is no point in running the pump for an hour at a time.

On the other hand, if the pump is run without allowing the full accumulation of fluid, the reduced backpressure may allow a steadier flow of hydrocarbons into the well. For example, if the rate of formation flow into the well drops by approximately half each hour until the flow ceases after 18 hours and then it takes 6 hours of pump operation to remove the accumulated fluid, one pumping plan would be to run the pump 6 hours straight each day. However, by running the pump more frequently to keep the backpressure from building up, a higher formation flow rate may be maintained. For example, running the pump for 15 minutes each hour would still total 6 hours of operation each day and formation flow would not cease during the day. As a result, overall production may be higher.

There are other economic factors that may also need to be considered. In Chapter 14, Well Testing, additional information is included concerning productivity testing to determine the best way to produce a well.

B-4. Automatic Controls.

There are two general types of timing controls for pump operation. A 24-hour clock may be used to set the on and off periods during one day or a percentage timer can be used to regulate the percentage of time that the pump is on within a given period. Percentage timers are often found in the newer automatic control boxes instead of 24-hour clocks, although both still have their place and will continue to be available for special applications.

There are several styles of the 24-hour clock. Some are controllable in 15-minute on-and-off cycles, while others can be controlled for intervals of 5 minutes or less. These clocks are well suited for setting pumps to run at a specific time of day or with irregular pumping cycles.

Percentage timers are available in cycles of 15 minutes or more. Percentage timers have one control dial that allows the timer to be set to run a selected percentage of the timer cycle. Thus, if a 15-minute timer is set for a 50-percent runtime, the pumping unit will operate for 7½ minutes and then be off for 7½ minutes during each 15-minute cycle. Because there are 96 15-minute cycles in a day, the unit will run 7½ minutes through each of the 96 cycles in a day.

Similarly, if a 2-hour timer is used with the dial set for 25%, the unit will come on for 30 minutes and then turn off for 1 hour and 30 minutes, and then come on again. This cycle will be repeated 12 times per day, and the unit will run 12 times per day for a total runtime of 6 hours or 25% of a day.

B-5. Maintaining the Pumping Unit.

The first step in maintaining the pumping unit is to set up a good maintenance schedule in the lease records book and to follow it. One reason that the record book is so important is that it helps the lease pumper to use the correct maintenance procedures. For example, the typical supply store will have many types of lubricants, in various weights, with different additives, and available in tubes, buckets, and other styles of containers. For each application at the lease site, a limited number of lubricants will be appropriate to use, and often only one that is truly suitable. The lease pumper cannot be expected to remember each type of lubricant that is required and where it should be used. By maintaining complete and accurate records, the lease pumper can be assured of using the correct type and amount of lubricant and will know when equipment has been lubricated or will next require the lubricant to be changed. Further, the lease pumper can avoid mixing lubricants that may not be compatible with each other.

The daily inspection. Oil field equipment is very dependable and can operate for years between serious problems. Still, the daily inspection can extend the life of the unit by locating problems before damage has occurred. When making any inspection, the lease pumper should listen carefully with the vehicle radio volume turned completely down because the sounds a pumping unit makes can tell a lot about its condition. The inspection should also include a check for lubricating oil leaks, as well as looking on the ground for loose objects, such as bolts, nuts, and washers.

The weekly inspection. The steps of the weekly inspection include:

1. Perform the steps of the daily inspection.
2. Walk completely around the pumping unit and observe it in operation.
3. Stop at good observation points to watch assembled parts for one complete revolution, looking for unusual motion and vibration and listening for noises.

4. Check to see that the white line on the pitman arm safety pins is properly aligned. (See "Pitman arm and gearbox problems" below.)

The monthly inspection. The steps of the monthly inspection include:

1. Complete the steps of the weekly inspection.
2. Check the fluid level in the gearbox if there is evidence of a leak (Figure 2).

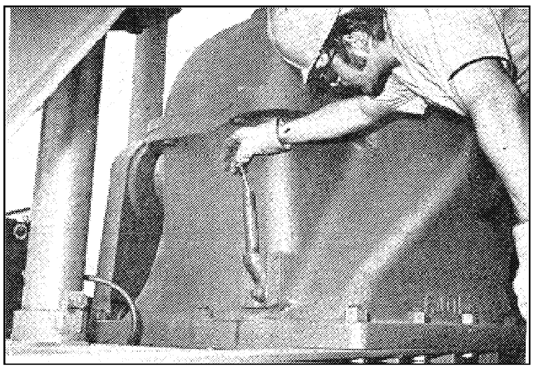

Figure 2. Checking the oil level and condition in the gearbox.
(courtesy of Lufkin Industries, Inc.)

3. Lubricate worn saddle, tail, and pitman arm bearings (Figure 3).

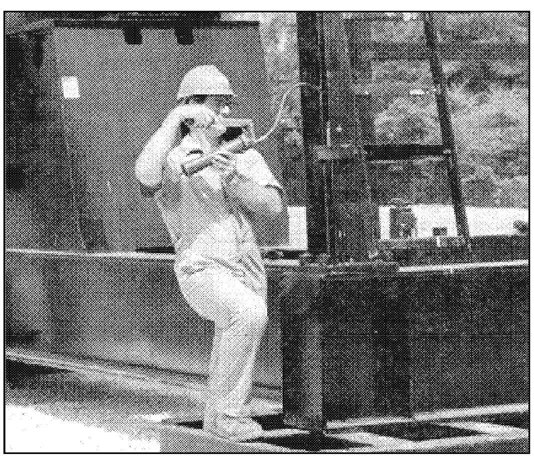

Figure 3. Lubricating the saddle and tail bearings.
(courtesy of Lufkin Industries, Inc.)

The three- and six-month inspection. The three- and six-month inspections are especially important. Some new pumping units need to be fully lubricated every six months (Figure 4). As the unit gets worn, this interval needs to be shortened to every five months and then four months and then three months. With some units, lubrication may be necessary every month, with special maintenance attention in between. A part of these inspections is performed with the pumping unit in motion, and part of it is performed with the unit shut down and the brake lever set.

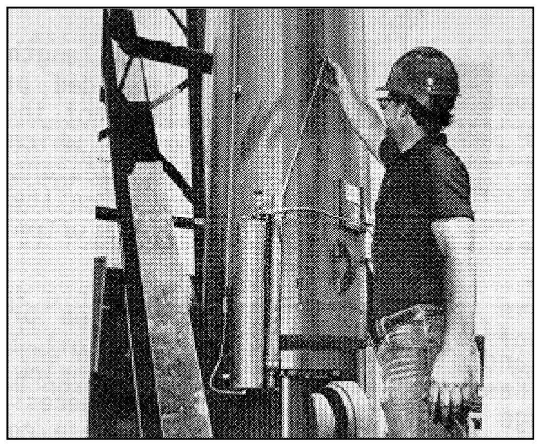

Figure 4. Checking the oil level in the air cylinder on an air-balanced unit.
(courtesy of Lufkin Industries, Inc.)

Pitman arm and gearbox problems. Two of the most damaging situations that may occur to the pumping unit are a pitman arm coming loose and the stripping of gear teeth in the gearbox.

When the stroke length of a pumping unit is changed (Figure 5), extreme care should be given to correctly cleaning, lubricating, keying, and tightening the wrist pin on the crank pin bearing. If the nut should work loose and come off, the hole in the crank will be damaged, the walking beam twisted, and the wrist pin destroyed.

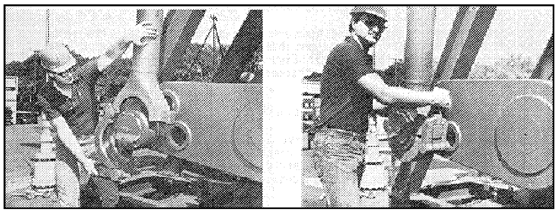

Figure 5. Changing the stroke length.
(courtesy of Lufkin Industries, Inc.)

A white line should be painted across one face of the nut from the safety pin to the counterweight, and a line drawn for several inches on the crank. This line allows the lease pumper to recognize any change in the alignment of the components, even if the crank is in motion. During the daily inspections afterward, the pumper should note the smallest changes that may indicate that the nut is loosening. In the first week after changing the stroke length, these nuts should be checked for movement every day.

When checking the oil level in the gearbox, the lease pumper should pay special attention for the presence of metal flakes in the oil. Small samples can be obtained from the lower petcock or plug. By wiping the oil on a clean cloth, any metal cuttings can usually be detected. When metal cuttings are detected, the cover should be removed, the gearbox flushed out and cleaned, and new oil added.

Periodically, but at least once per year, the gearbox cover should be removed and the interior closely examined with a flashlight. Figure 6) This is especially true of chain-driven units. Lubrication troughs should be checked to ensure that all of the bearings are receiving a sufficient amount of oil and that the oil level is high enough to engage the oil dippers and gears. The oil should be changed and the filter cleaned on a periodic basis. Gearboxes can also collect water and sludge that should be removed periodically for maximum bearing and chain or gear life.

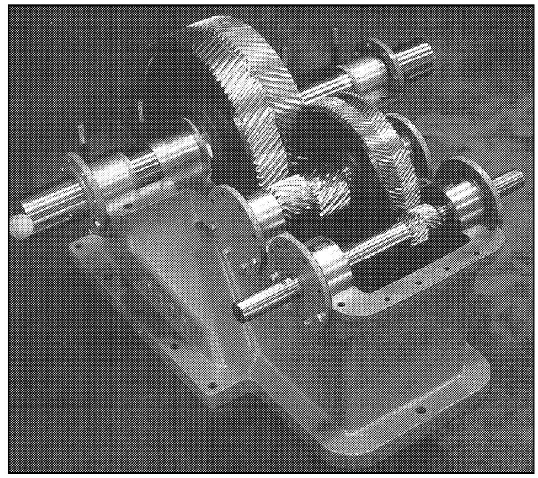

Figure 6. A gearbox with the cover removed for inspection.
(courtesy of Lufkin Industries, Inc.)

B-6. Direction of Rotation.

For conventional gear-driven, walking beam pumping units, some companies change the direction of rotation every six months or annually so that the forces that wear the gears are applied to the opposite sides of the gear teeth. This change of the direction of rotation is achieved by reversing the connection of any two wires of the three-phase motor. Consequently, this service is not possible on pumping units driven by natural gas engines. With the Mark series pumping units (see Appendix B), the pumping unit weights must be rising toward the well head as the pumping unit is running. Chain drive gearboxes also usually require that the unit counterweights move in a specific direction in order for the gearbox to receive lubrication. The direction of rotation of each pumping unit should be recorded in the pumper's field manual so that when an electric motor is replaced, the lease pumper can tell the person replacing the motor which direction the pumping unit was rotating before the problem occurred.

B-7. Gearbox Oil.

Different styles and sizes of pumping units require different types of oil in the gearbox. There are also several types of gearboxes. These include single-gear drives, double-gear drives, and chain drives. The gears also have dippers that pick up oil on each revolution, carry it up, and pour it into a trough so that it can lubricate the four shaft bearings.

Some of the problems that are caused by poor maintenance are:

- Poor lubrication due to low oil level
- Rust as a result of water in the oil
- Starting difficulty due to low oil or overly viscous oil, especially in cold weather
- Poor lubrication due to the gearbox being overfilled, resulting in foam
- Sludge accumulation because different types of oil have been mixed, because of incorrect additives, or because the oil has aged
- Poor coverage of the gear surfaces because the oil is too thin or overheated
- Gear wear due to contaminants such as dirt and bits of metal in the oil

Most of the listed problems can be cured by a proper gearbox flush and oil change.

B-8. Typical Pumping Unit Problems.

There are many indications of problems with a pumping unit that the lease pumper must recognize and know how to correct.

Chapter 11 includes information about electricity, automated control panels, electrical problems, and engines as prime movers.

Appendix B provides a review of pumping unit maintenance information (Figure 7). This appendix includes topics such as styles and sizes of pumping units, setting and maintenance requirements, procedures for changing the stroke and balance, and other adjustments.

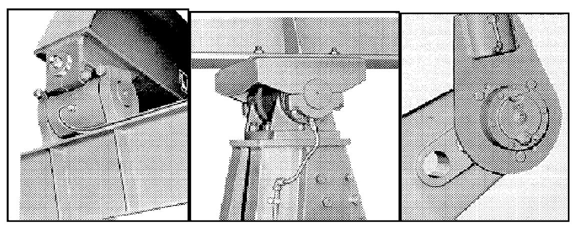

Figure 7. Well component manufacturers and suppliers can provide helpful information about equipment maintenance, such as the lubricating points shown here.

Appendix F includes mathematical calculations needed for topics such as computing belt lengths, sheave sizes, and strokes per minute.

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Chapter 6
Mechanical Lift

Section C

WELLHEAD DESIGN AND THE POLISHED ROD

When a flowing well is converted to a mechanical pumping arrangement, any downhole packers must be removed and a tubing holddown installed as required according to pumping depth requirements. The packer must be removed to lower the formation pressure to stimulate fluids to flow to the well bore because of reduced bottom hole pressure.

A second need is to rebuild the wellhead to meet pumping needs. Occasionally, a pumping unit is installed just to lift water blankets off the matrix area so that the well will flow again. In this situation, a choke valve will remain after the wing valve and will be used to control well production.

Special downhole pumps can be installed to handle natural gas along with any oil and water produced, but in this section a standard pumping arrangement is reviewed.

C-1. Preparing the Well for Pumping Downhole.

Packers are usually removed when the well is being prepared for mechanical pumping. Packers are removed to permit gas to be produced up through the annular space. Some style of holddown is required to prevent breathing of the tubing when the well is pumping. Occasionally, if it is not desirable to remove the packer, it can just be released to allow gas to pass beside it and left in the hole. The operation of holddowns was reviewed in Section A of this chapter and will be discussed further in Chapter 17, Well Servicing and Well Workover.

C-2. Pumping Wellheads.

Figure 1 shows one method of connecting the pumping wellhead on the well. The Christmas tree has been removed and an adapter flange or *bonnet* has been installed with a pumping tee mounted on top. A quarter-round opening valve and a check valve have been installed in the pumping tee and the annular wellhead. These are connected together with nipples and unions.

The four-way tee on the tubing header pictured has a flow line pressure safety shut-in mounted on top. If the flow line should become plugged, freeze, or break, the safety switch will shut the well in until it receives proper attention. The controls reset when the well is placed back into production.

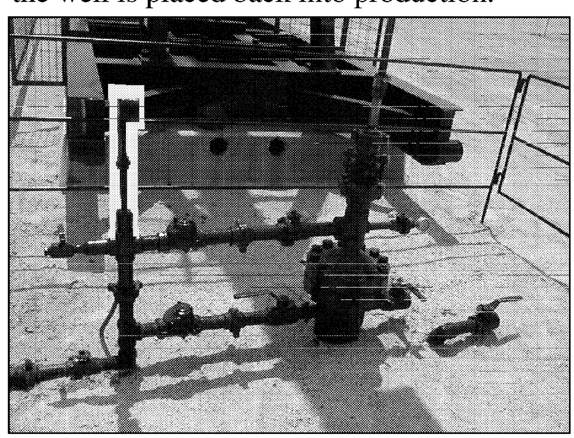

Figure 1. Wellhead with tubing and casing connection and shut-in control.

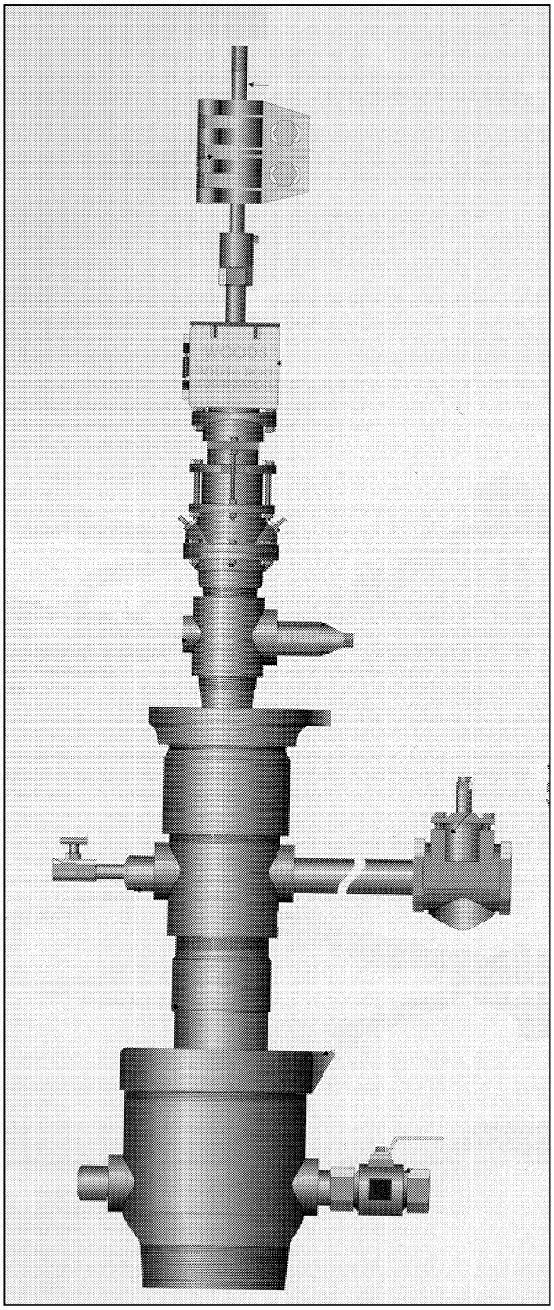

Figure 2. A typical pumping wellhead that includes a polished rod, polished rod clamp, polished rod liner, rod lubricator, stuffing box, pumping tee, tubing head, and casing head.
(courtesy of Dandy Specialties and Larkin Products)

C-3. Selection of Polished Rods, Clamps, Liners, and Stuffing Boxes.

When selecting the polished rod and other wellhead equipment (Figure 2) several factors need to be considered. Some of these are:

Polished rod. When selecting polished rods, many people purchase them too short. When working on troublesome wells, the crew will encounter problems when it becomes necessary to lower the rod string to tag or tap bottom and perform other servicing functions

The polished rod needs to be long enough to be able to lower the polished rod liner all the way to the top of the stuffing box with the horse head at the **top** of the stroke. The top of the rod needs to extend through the bridle carrier bar with room to install a suitable clamp and additional room above the clamp to allow the string to be lowered enough to tag bottom.

With the horse head still at the top and the maximum amount of rod out of the hole, the polished rod must extend below the stuffing box far enough to lower the liner all the way down against the stuffing box.

The polished rod liner. The polished rod liner is placed on the polished rod to protect it from wear. It is easier to prevent stuffing box packing leakage with a larger diameter liner. The polished rod liner should be as long as the maximum stroke length plus at least two feet. If it is too short, it will have a tendency to hang on obstacles in the wellhead on the upstroke or will create problems when trying to tag bottom.

When the clamp above the stuffing box is adjusted, the polished rod clamp on the liner must NEVER be tightened. Every time this clamp is tightened on the liner, it puts a series of indentations in the liner. With every stroke of the pumping unit, a small amount of oil and compressed gas is lost to the atmosphere when the damaged section of the polished rod liner comes up through the stuffing box. This leakage will continue as long as the liner is used. The lost oil is continuously running down on the stuffing box and wellhead, creating constant cleaning problems. The one moment of carelessness that put the indentations in the liner can cause problems, time loss, and unnecessary replacement expenses.

The polished rod clamp. The polished rod clamp (Figure 3) is used to support the rod string while the weight is being carried by the bridle and carrier bar. These clamps are available with one bolt or up to four or five bolts to match the rod load. Occasionally two clamps are used on a polished rod for safety. There may also be a polished rod clamp below the carrier bar. This is a common practice on wells that have a history of polished rod failures with the rod breaking at the carrier bar. This safety clamp is installed to prevent the rod string from going through the stuffing box where the well may flow. Several spills have been prevented by this practice.

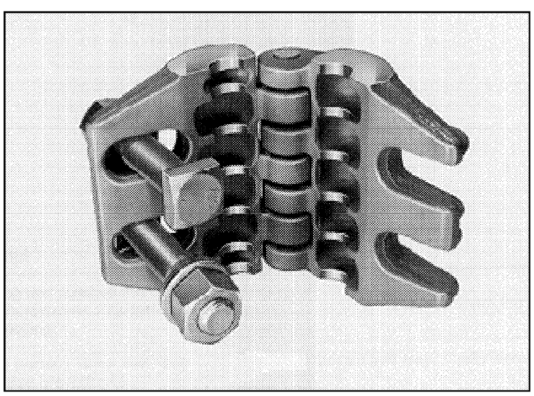

Figure 3. A two-bolt polished rod clamp.

The stuffing box. In the earlier years of the petroleum industry, most stuffing boxes used donut-shaped packing. It was manufactured with many types of additives, such as graphite and lead, to improve its efficiency.

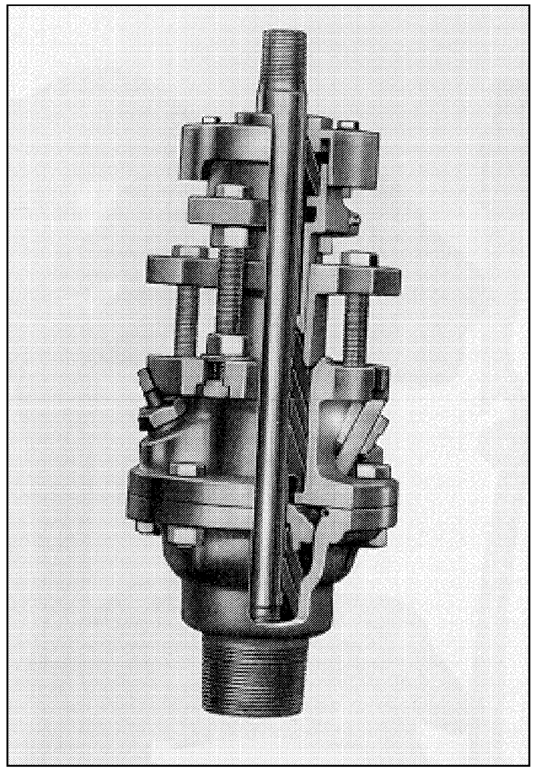

Figure 4. Stuffing box with cone style packing.
(courtesy of Trico Industries, Inc.)

During recent years, cone-shaped packing (Figure 4) has become very popular, and many thousands of packing boxes with cone-shaped packing are in service across the industry. An improved model is on the market that is virtually leak-proof, though its cost may not be justified for marginal stripper wells.

With a marginal well of medium to shallow depth, the cone style is still highly satisfactory. If common sense and caution are used when installing and periodically tightening the packing, a set of packing can last for several years and have almost no leakage. Various qualities of packing are available. By keeping careful records and tracking costs, a lease pumper can determine which is the most economical practice in the selection and maintenance of packing. The most important action, though, is to keep the pumping unit carrier bar well centered over the hole.

Most stuffing boxes have a grease fitting on the side of the box. If the stuffing box is made so this fitting points toward the pumping unit, the lease pumper must get between the stuffing box and the pumping unit to lubricate the box. Since this is done while the unit is running, the edge of the horse head can strike the worker on the downstroke. People have been seriously wounded in this situation. Even on large units, the fitting should always point out or to the side.

The polished rod lubricator. A free-floating polished rod lubricator with wick-action felt wiper pads may be installed on the polished rod just above the stuffing box. This device supplies additional lubrication to the polished rod and extends the life of the packing. When no oil is being produced, this lubrication prevents the polished rod from heating up and damaging the packing, so such a lubricator is particularly helpful on wells that produce erratically. An inexpensive non-detergent oil is satisfactory for use.

The rod rotator. One of the by-products of oil production is paraffin. Paraffin is a waxy mixture of hydrocarbons that can coat rods, tubing, valves, and surface pipe internally as the fluids come into contact with them. At depths, the heat of the earth will maintain the paraffin in a liquid state. However, as the paraffin rises in the hole with the production fluids, it hardens. Paraffin will turn from a liquid to a solid and be deposited in the tubing and on rods.

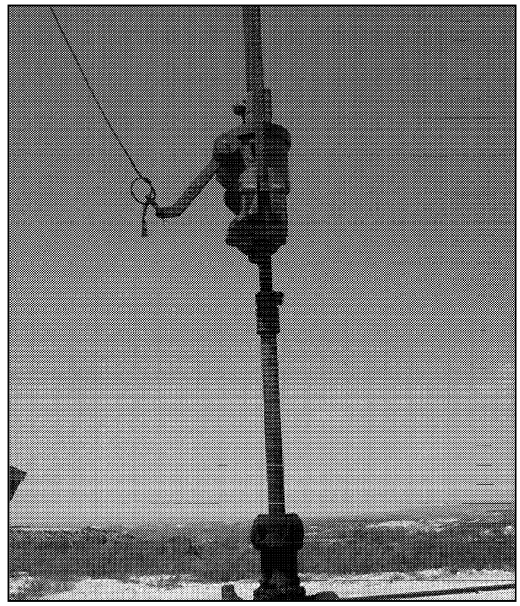

Figure 5. A rod rotator used to remove paraffin and scale.

One way of combating paraffin buildup is the use of a rod rotator (Figure 5). The rod rotator is installed on the wellhead and connected to the walking beam. With each stroke of the pumping unit, the rotator will rotate the rods a fraction of one revolution. Scrapers are fixed to the rods close enough to have a slight over-travel with each stroke. As the rods are rotated, paraffin is scraped off. There are many styles of paraffin-cutting paddles, most of which are flat or circular.

Other methods of dealing with paraffin include the injection of chemicals and running hot oil down the well. Once paraffin reaches the surface with the oil, it is generally addressed with chemicals and/or heat from a heater/treater. Steam is often used to remove paraffin from parts such as rods and tubing after it has been pulled and laid out on racks.

C-4. Tubing, Casing, and Flow Line Check Valves.

Another possible source of problems at a wellhead are check valves. When trash or scale accumulates under the seat of the check valve or an internal failure occurs, the check valve may lose its ability to seal and allow fluid to leak back into the wellbore.

Two wellheads are shown in Figure 6. The one on the left has a working pressure of 300-500 pounds. The one on the right has a working pressure of 2,000 pounds. The pressure rating of a valve and screw connections can be determined by observing the embossed numbers molded into the forgings. Every lease pumper must be able to determine fitting pressure ratings by casual examination.

Both illustrations show all three wellhead check valves. One is located on the upper horizontal line from the tubing just after the wing valve. The second is located directly below the upper one in the line from the casing. This line also has a wing valve. After both lines come together and are directed toward the tank battery, a third valve and check valve are installed.

The tubing check valve. During certain types of productivity tests, it is necessary to check the downhole pressure applied to the tubing. For the test to be accurate, this pressure must be isolated from casing pressures. The check valve just past the tubing wing valve prevents casing pressures from flowing back through the bleeder valve when the downhole pump action is checked at the 1-inch bleeder valve next to the pumping tee.

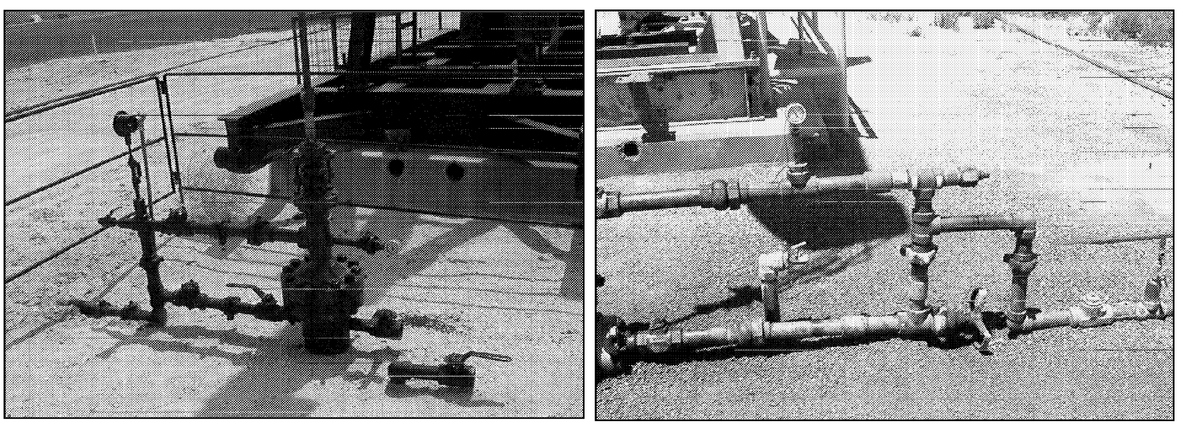

Figure 6. Two pumping wellheads. The one on the left is a medium-pressure unit and the one on the right is a high-pressure unit.

The casing check valve. The casing check valve allows the produced gas from the casing to flow to the tank battery. This action is essential to allow new production to migrate from the formation into the well bore, where the gas flows to the tank battery through the casing and the liquid is pumped to the tank battery through the tubing.

The casing check valve prevents the produced liquids pumped out of the tubing—both oil and water—from circulating back to the bottom of the well.

Even a slight leak in this check valve will result in loss of new production and will confuse the pumper as to the amount of oil being produced.

The flow line check valve. The check valve in the flow line near the wellhead prevents several problems from occurring in the event that one or both of the wellhead check valves fail. If the tubing should develop a leak, then the weight of the column may draw the oil in the flow line back into the bottom of the well. These check valves can also prevent produced oil in the header from flowing back to the well, and the production from all wells flowing back into the formation.

By configuring these check valves properly, the lease pumper can gain a more accurate picture of what is occurring at the well.

The Lease Pumper's Handbook

Chapter 6
Mechanical Lift

Section D

THE DOWNHOLE PUMP

In a mechanical lift system, a pump of some configuration is required to transfer the oil from the production zone to the surface. Several styles of pumps are used, but they all have the same basic components. The styles of pumps are then distinguished from each other by the way the components are assembled and how they function. This section focuses on the similarities and differences among the basic styles of mechanical lift pumps.

D-1. Basic Components of the Pump.

The five basic components of downhole pumps are:

- Standing valve.
- Barrel tube.
- Plunger.
- Traveling valve.
- Holddown seal assembly.

Standing valve. The standing valve, at the bottom of the pump, is a one-way valve that allows fluid to flow from the formation into the barrel. A standing valve consists of a ball that rests on a narrow-lipped seat (Figure 1). This ball and seat assembly is contained in a valve cage with the ball on top or up as it is installed in the well. Pressure from below can unseat the ball and allow fluid to move past the valve. However, pressure from above keeps the ball seated so that fluid does not leak back past the valve.

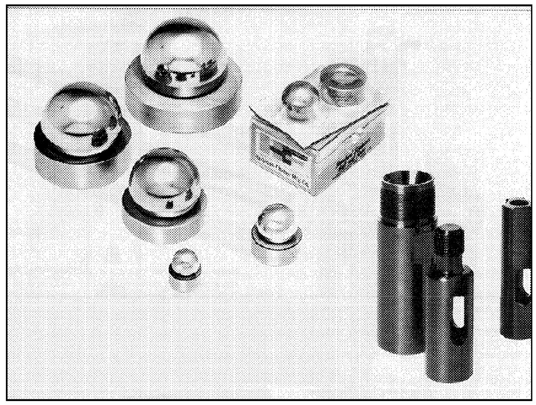

Figure 1. Components of a ball and seat standing valve.
(courtesy of Harbison Fischer)

The ball and seat are finished to seal against each other as a set and sealed together as a unit. These paired components should always be kept together. Two sizes of balls are available with each size of seat. These are the standard American Petroleum Institute (API) size and a smaller alternate size that allows viscous fluids and debris to pass between the valve guides and the ball. Occasionally double valves are installed to try to solve specific problems.

Barrel tube. The barrel is the portion of the pump into which fluid from the formation flows. The barrel may be a separate component that is inserted into the tubing or it may be a portion of the tubing, depending on the pump design. Otherwise the principal differences between different barrels is the type and thickness of metal used and how the barrel accommodates the plunger used. Typically, pump barrel tubes are available in three thicknesses: thin wall, standard wall, and heavy wall. The wall material may be various grades of carbon steel, stainless steel, brass, or Monel and may have chrome plating. The metal may also be treated for protection against corrosion and chemicals and hardened for extra strength.

The barrel tubing must be machined for the installation. This will include the thread design and the proper clearances for the type of plunger used. Some pumps also use liners, which must be accommodated in the barrel design.

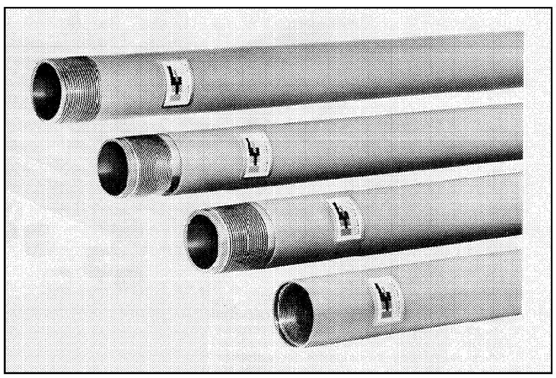

Figure 2. Examples of barrel tubes.
(courtesy of Harbison Fischer)

Plunger. The plunger moves the fluid from the bottom of the pump to the top of the pump. This movement may be a result of the plunger moving within the barrel or due to the barrel moving around the plunger. Plungers are classified as *metallic* or *non-metallic*. Metallic plungers are available in a wide range of metal compositions and treating procedures similar those used for barrels.

Clearances between the barrel and metallic plungers are very precise. The clearances must be correct after installation in the hole with the pump temperature normalized to the bottom hole temperatures.

Barrels and plungers are also selected to resist CO_2 and H_2S corrosion. The plunger may also be grooved or non-grooved according to well conditions.

The non-metallic plungers or *soft-pack* plungers come in various designs of cups and rings. Ring designs may be referred to as regular flexite, wide flexite, composition ring, soft-packed, and other terms. The soft-pack cup composition and method of assembly is selected based on well conditions such as poor lubrication, fluids with high corrosive or abrasive properties, temperature, and fluid gravity.

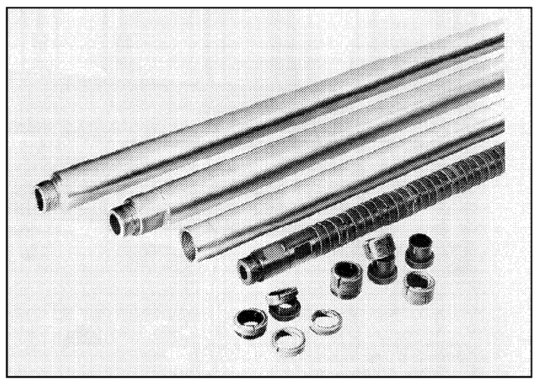

Figure 3. Examples of plungers.
(courtesy of Harbison Fischer)

Traveling valve. The traveling valve is at the top of the pump. Like the standing valve, it is a one-way valve. It allows oil to flow out of the barrel and keeps the fluid from flowing back into the barrel. Although the standing valve and traveling valve are separate parts, for a given pump, these two valves may be the same size, have the same composition, and be interchangeable. Consequently, the construction and operation are the same as that described above with regard to standing valves.

Holddown seal assembly. The holddown seal assembly or simply *holddown* creates a seal between the pump and the tubing. There are three types of holddown assemblies: two mechanical and one cup type. These three styles are shown in Figure 3. Each must be installed with an appropriate seating nipple in the tubing string. The seating nipples for the cup-type assembly are available in two lengths. The short model provides one seating area, while the longer model is reversible and can be turned around in the tubing to provide a new seating area if the other has been damaged.

Both mechanical and cup styles of holddowns are satisfactory for many installations, but if the bottom hole temperature is 250° F. or greater, a mechanical holddown should be used.

Figure 4. Holddown seal assemblies. The two on the left are mechanical types while the one on the right is a cup type.
(courtesy of Trico Industries, Inc.)

D-2. Pumps Designs.

There are four basic downhole pump designs, including three styles of insert pumps and one tubing pump (Figure 5).

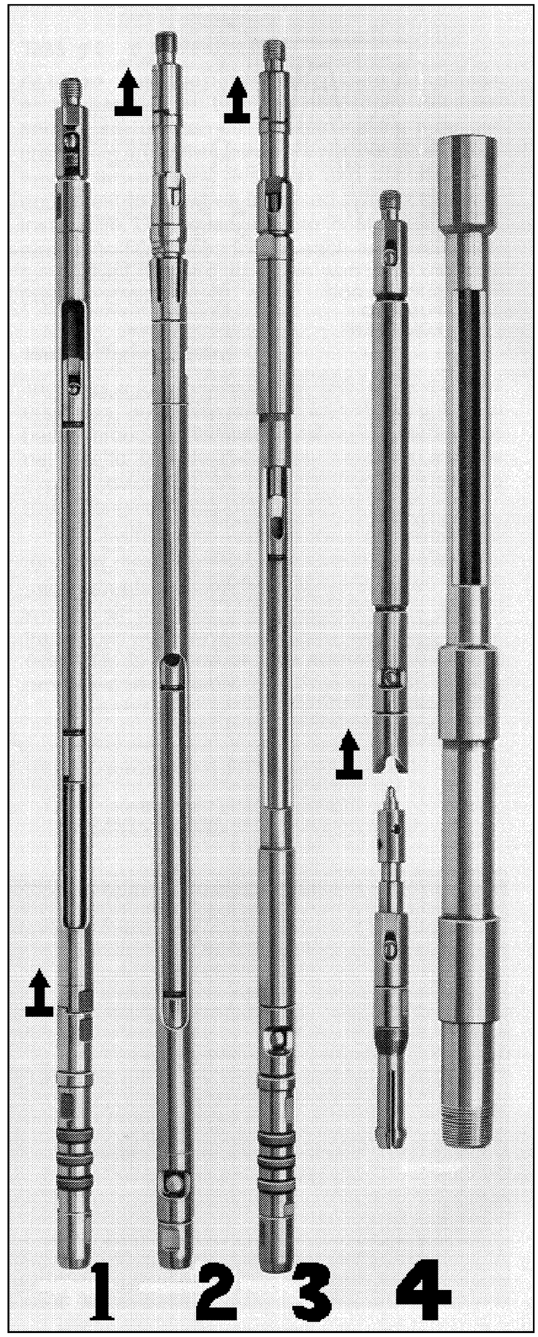

Figure 5. Four styles of downhole pumps.
(courtesy of Trico Industries, Inc.)

Insert pumps. The term *insert* indicates that the pump has been assembled as a complete functional pump and inserted into the tubing string. An insert pump may have a moving or a stationary barrel and it may be anchored at the top or the bottom. Thus, the three styles of insert pumps include designs with:

- Traveling barrel, bottom anchor.
- Stationary barrel, top anchor.
- Stationary barrel, bottom anchor.

- **Traveling barrel, bottom anchor insert pump.** The traveling barrel is very versatile. It will operate in normal wells, sandy wells, and corrosive wells with good results. With each stroke, it surges the fluids around the bottom of the pump which reduces the possibility of sand sticking the pump in the hole. The open-style valve cages provide less restriction when pumping heavy crude oils. The traveling barrel has a greater resistance against bursting, especially when a heavy barrel is used. One of the disadvantages of this pump design is that it will gas lock easier than the models with the stationary barrel because the standing valve is smaller than the traveling barrel. It is less efficient in crooked holes because the outside of the barrel wears during operation; therefore, a guide above the pump may be necessary.
- **Stationary barrel, top anchor insert pump.** With this pump, the holddown is at the top of the pump, so most of the pump hangs below the seating nipple and tubing perforations. This is a good configuration with sandy wells because of the swirling action of the fluids around the top of the pump while it is in operation. The pressure inside the pump barrel is much greater than the casing pressure outside the pump. This is because the inside must withstand the pressure generated by the column of fluid. This limits the depth at which the pump can be safely run. Gas pounding can also cause the barrel to split. With shallow (less than 5,000 feet in depth), sandy wells, this pump design can give good performance.
- **Stationary barrel, bottom anchor insert pump.** The stationary barrel, bottom anchor pump is subject to corrosion and sanding conditions on the outside of the barrel, but this is generally the most satisfactory of all of the insert pumps. Because of its design, the standing valve can be larger than the traveling valve. The column of fluid inside the tubing supports the outside of the pump barrel at all times. This reduction in differential pressure results in longer pump life and improved efficiency. This pump is used in shallow to very deep wells. Sand settling around the barrel and scale can make it difficult to pull the pump. This can generally be solved by *stripping the well*—that is, pulling the rods and tubing at the same time; also referred to as a *stripper job*.

Tubing pumps. The tubing pump is different from the insert pump because the barrel of the pump is run in the hole as part of the tubing string. Usually the standing valve and the traveling valve are run in on the rod string. After the standing valve is lowered to the bottom of the hole, the rods turn to release it. The rods are then positioned up a few inches, and the pump is ready to begin pumping. The standing valve can be reattached for pulling, servicing, and re-running when pulling rods.

An up-arrow has been added to Figure 5 to indicate the location of the clutch and also where the pump separates to allow it to pump. The part above this arrow is the action section. It moves up and down with each stroke of the pump and contains the traveling valve and plunger. The section below this arrow is the stationary section of the pump and contains the standing valve.

There are obvious advantages to running a tubing pump, such as pumping large volumes in water flood projects. One of the disadvantages is the necessity of pulling the tubing string to service the pump barrel The second disadvantage is the high fluid load on the rod string. This results in additional rod stretch and loss of bottom hole stroke.

Other styles of pumps. Other designs of downhole pumps exist. Some are just variations of those described, while others meet the needs of specific installations. The assistance of a pump manufacturer is invaluable when planning pump installations, especially for special needs.

Appendices A-1 and A-2 provide additional information about API number designations.

The Lease Pumper's Handbook

CHAPTER 7

ELECTRICAL SUBMERSIBLE LIFT

The Lease Pumper's Handbook

Chapter 7
Electrical Submersible Lift

Section A

ELECTRIC SUBMERSIBLE LIFT

The previous chapter explained the use of mechanical lift as a means of bringing fluids to the surface when bottom hole pressure is not adequate in a new or previously naturally flowing well. With time, production may decline to the point that mechanical lift is no longer effective. The lease operator may try changing the mechanical lift system to compensate for the declining production by adjusting the length of stroke on the pumping unit and changing the sheaves to increase the number of strokes per minute. A long-stroke pumping unit with lighter counterweights may be installed.

As the production of natural gas and crude oil continues to diminish and water production increases, particularly in water-driven reservoirs, the lease operator may begin *waterflood*, an enhanced recovery method in which water is injected into the reservoir at one well to drive hydrocarbons to other wells (see Chapter 15). However, with time oil production will continue to fall and water production will increase. As this occurs, the pumping time is increased until the lease pumper is producing the well twenty-four hours a day.

At this time, the most practical way to improve production is to install a system with greater production capability. One of the choices, especially in high-volume waterflood operations, is the electrically driven submersible pump. A submersible pump is one that is lowered into the fluid to be pumped.

A-1. Advantages and Disadvantages of the Electrical Submersible Lift System.

Advantages. One of the most important advantages to this system is its ability to pump very large volumes of fluid at shallow to medium depths. Casing size is also not important to being able to pump these high volumes. As waterflood volumes increase, it is common to pump several thousand barrels of fluid a day while trying to improve formation sweep efficiency.

This system is easy to adapt to automation and can pump intermittently or continuously.

For shallow wells, the investment is relatively low.

Disadvantages. The buildup of scale deposits or *gyp* can interfere with the operation of submersible pumps. Also, the cost of electricity can also be very high, especially in remote areas. The system has limited flexibility under some producing conditions, and the entire system in the well must be pulled when a problem is encountered.

A-2. Electrical Submersible Pumps.

An electric submersible pumping unit consists of an electric motor and a pump (Figure 1). The motor is on the bottom of the assembly, and the pump is on top. An electrical line is strapped to the outside of the tubing, and the whole assembly is lowered into the hole with the pump and motor set below the liquid level. As the motor turns, it rotates a stack of liquid-lifting cups or disks in the pump. The more cups that are added, the higher it will lift the liquid.

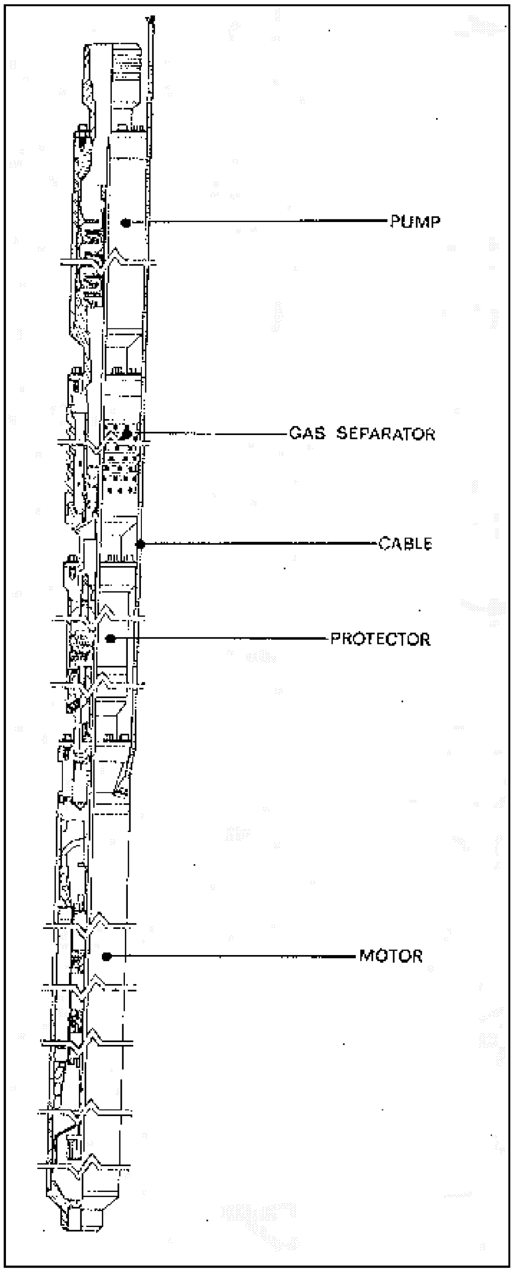

Figure 1. A motor and pump assembly.
(courtesy of Reda Pump Company)

A-3. Downhole Components.

Motor. The first component that is lowered into the well is the electric motor. The motor size is designed to lift the estimated volume of production.

Protector. The protector is attached to the top of the pump to seal the motor and allow a drive shaft in the center to drive the pump.

Gas separator. A gas separator separates the gas and liquid for pumping.

Pump. The pump is designed to carry the fluid load. The shaft may be of Monel, and the stages be made of a corrosion- and wear-resistant material. The pump has a rotary centrifugal action.

Cable. A cable leads out of the top of the motor, up the side of the pump, is strapped to the outside of every joint of tubing from the motor to the surface of the well, and is extended on the surface to the control junction box.

The cable consists of three strands of continuous wire. The cable is flat with the wires side-by-side as it reaches from the motor up beside the pump to the tubing, at which point it becomes round. The cable may have a metal shield to protect it from damage.

A-4. Surface Components.

Tubing head. The tubing head is designed to support the tubing string and provide a seal to permit the electrical line to pass through the head. This seal is usually designed to hold a minimum of 3,000psi.

Chart meter. An optional component, the chart meter records the daily performance of the well that is easily read and can provide information that helps to identify a host of operational problems that may occur.

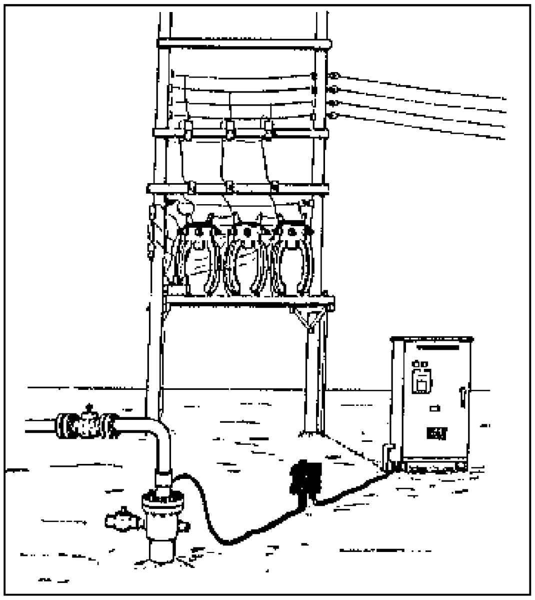

Figure 2. The surface equipment, including the power line, transformers, control box, meter chart, and wellhead.
(courtesy of Reda Pump Company)

Control box. The control box controls the flow of electricity to the pump motor. It allows the well to be operated continuously or intermittently or to be shut off. It also provides protection from surges or changes in the electricity that may occur.

Transformers. The transformers are usually located at the edge of the lease site. They transform the electricity provided over the power lines so that it is the correct voltage and amperage to operate the pump motor.

Electrical supply system. This is generally the commercial power distribution system. The highest available voltage produces the most efficient performance.

A-5. Special Surface Considerations.

Many operators are very innovative when installing a new system. A joint of pipe from the well to the control panel will provide a conduit through which to run the power cable. It will be possible to run vehicles over the conduit, yet not damage the cable.

A post and hanger near the control panel may provide a place to hang a few extra loops of the pump cable so that the pump can be positioned lower without having to splice the cable.

The Lease Pumper's Handbook

Chapter 7
Electrical Submersible Lift

Section B

OPERATING ELECTRICAL SUBMERSIBLE LIFT

B-1. Well Operation and Automatic Controls.

The amount of fluid being produced from a well may require continuous operation all day or it may only require operation for a part of a day. The volume of fluid that needs to be produced daily from the well and the well capacity will indicate the best operating practices.

A few years ago most of the automated controls looked very much alike. With the tremendous surge in computer technology and miniaturization of automation components, new designs come out every few months so that equipment controls may not be recognized without special instructions.

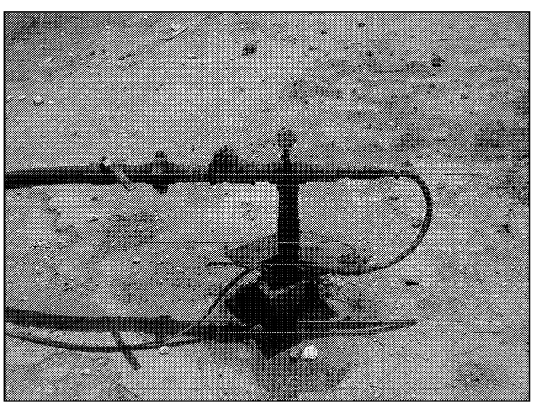

Figure 1. A wellhead for an electrical submersible pump with a pressure gauge, check valve, union, ball valve, and a hose for checking production.

The check valve on the wellhead must hold when operating the electrical submersible pump. If the check valve leaks, the liquid can drain back into the formation. This can cause the pump to turn counterclockwise while the well is shut in. If the power is turned back on while the pump is spinning in the reverse direction, the sudden torque can cause shaft failure. The pump would then have to be pulled, repaired, and replaced to restore service. The wellhead gauge will usually indicate if a problem is developing.

B-2. The Electrical Submersible Pump Well.

The well installation and controls may be exceedingly simple or more elaborate, depending on well depth, type of equipment, and volumes of fluids produced. Figure 1 shows an electrical submersible pump well that is about as simple as a system can be. It has everything that it needs to operate but, on a marginally producing well, would have a minor impact on the lease income in the event of problems. Higher producing wells will have more elaborate systems to allow the pumper to recognize and analyze production problems quickly and more accurately in order to reduce downtime.

B-3. Continuous Operation.

A chart can be installed at the wellhead to indicate pump and well performance. When the pump is operating continuously, the chart will have two steady lines on it, one indicating the casing pressure while it is running, and the other the tubing pressure in the flow line.

When the well is operating normally, the lease pumper should note the normal reading. When the well has problems, the recording chart will aid in identifying the type of problem that has occurred and when it began. Without this chart, analysis of pump performance is more difficult.

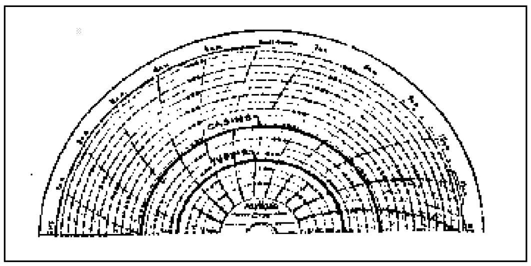

Figure 2. A chart graph monitoring continuous operation.
(courtesy of Reda Pump Company)

B-4. Intermittent Operation.

When the well is operating intermittently, the casing pressure will increase while the well is at rest, and the tubing pressure will be lower. When the well comes on, the casing pressure will drop as the liquid level in the casing falls, and the line pressure on the tubing will increase. A whole series of diagrams is available for reference to assist the lease pumper in making logical decisions when the lines on the chart do not follow the normal operating pattern.

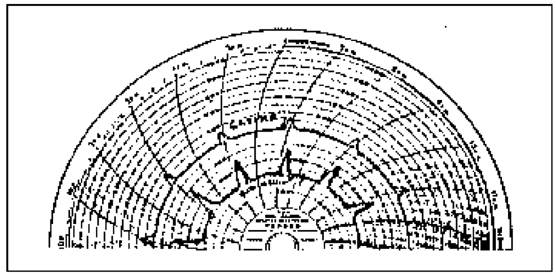

Figure 3. A chart graph monitoring intermittent operation.
(courtesy of Reda Pump Company)

B-5. Servicing the Well When Problems Occur.

Special equipment must be brought to the location when servicing the well. It is also recommended that a special experienced technician be present to make decisions when questions arise and to direct the workover procedure in order to solve problems.

As the tubing is pulled, the cable clamps and bands must be removed and the electric line spooled onto a special trailer that has been brought to the lease for the workover. As it is run back into the hole after the pump has been serviced, the electric line is re-clamped to the outside of the tubing.

The Lease Pumper's Handbook

CHAPTER 8

HYDRAULIC LIFT

The Lease Pumper's Handbook

Chapter 8
Hydraulic Lift

Section A

INTRODUCTION TO HYDRAULIC LIFT

A-1. Principles of Hydraulic Lift.

Hydraulic lift is a system where a liquid, usually crude oil, is pumped downhole under high pressure to operate a reciprocating pump or a jet pump. This is a very flexible pumping system and can be used to produce low- to high-volume wells. This system is capable of producing a higher volume of fluid than the mechanical lift pump.

Hydraulic lift uses a triplex plunger style pump (Figure 1) and pumps oil or water under very high pressure. The pump pressure is usually between 2,000-5,000 pounds per square inch (PSI) and pushes the liquid to the wellhead and downhole to operate the pump.

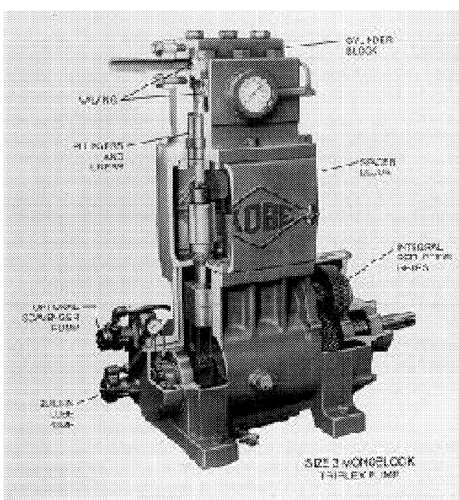

Figure1. A high-pressure central triplex.
(courtesy of Trico Industries, Inc.)

When liquid reaches the bottom of the well, it enters the top of the hydraulically operated reciprocating pump (Figure 2). The reciprocating action of the pump will pull new oil from the annular space and combine it with the power oil. It is then forced back to the surface and through the flow line to the tank battery.

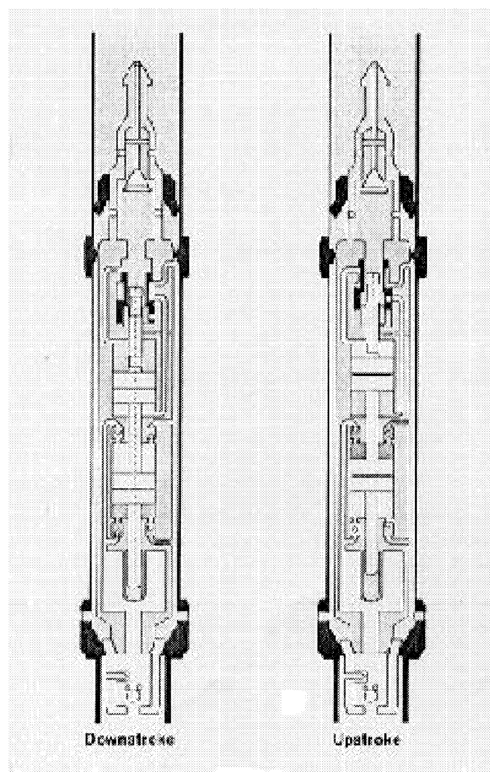

Figure2. Illustration of the downstroke and the upstroke of a hydraulic pump.
(courtesy of Trico Industries, Inc.)

The required power oil or produced water is reclaimed and reused to continue operating the wells. As an illustration, for each three barrels of liquid pumped down hole, five barrels will be produced back to the surface. The additional oil produced represents new production and is treated and sold The pump produces oil on both the upstroke and the downstroke, or 100 percent of the time. The pump stroke speed is easily adjustable by turning a valve.

A-2. Designing and Installing Hydraulic Lift Systems at the Wellhead.

The hydraulic lift system can be installed in any of several different ways in placing the liquid under pressure and in wellhead and downhole arrangements. These include:

- Fixed insert.
- Fixed casing.
- Free parallel.
- Free casing.
- Jet pump.
- Commingled power fluids.
- Closed power fluid.

This chapter covers the **fixed insert** and the **free parallel** pump, plus a brief review of the **jet pump**.

A-3. The Insert Pump.

When the first well on the lease is designed to operate by hydraulic lift, the operator must decide if it is to be operated downhole by a fixed insert or a free parallel system. The actual pump is the same regardless of the system selected, but major changes are made in how the two strings of moveable pipe are installed and in the wellhead selected.

With the insert design, the pump is attached to the bottom of a small string of tubing, possibly ¾ inch, and is lowered into the hole inside the 2-3/8-inch tubing. A metal-to-metal seat on the bottom of the pump seats against the tubing seating nipple. The weight of the small string holds the seat in place. A packer is not used so the gas is produced up through the annulus, just as with the mechanical pumping well. It is then commingled back with the power and produced fluids at the wellhead and enters the flow line.

Since the hydraulic pump is lowered into the well on the bottom of a small string of upset tubing, a pulling unit is required to pull this small string to change the pump in the well.

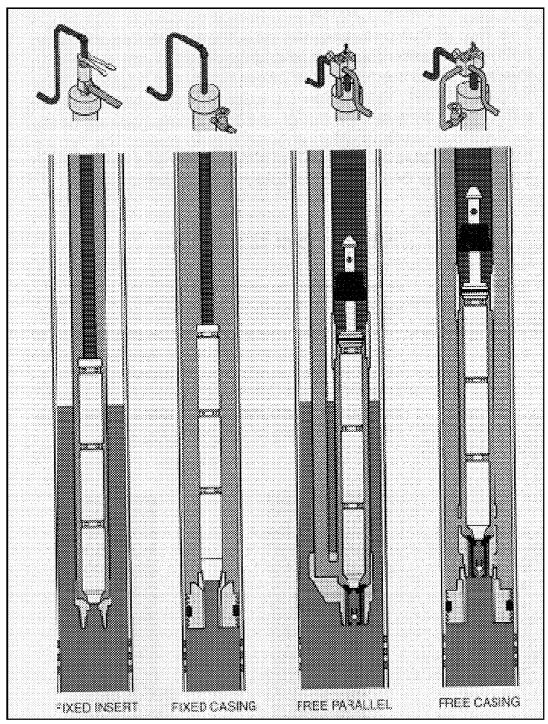

Figure 3. Hydraulic pump designs, including a fixed insert design (left) and a free parallel pump (third from left).
(courtesy of Trico Industries, Inc.)

Occasionally the pump may collect debris or *trash* (any solid objects are referred to as trash) under the pump seat and production will lessen or cease. Even the column of fluid inside the 2-3/8-inch tubing may be lost back into the formation. A lift piston can be attached above the top of the wellhead so that power oil may be diverted in under this piston to be able to raise and drop the small tubing string and pump to reseat the pump. This will remove the trash, and the pump will begin to operate normally again. This action by the pumper may be necessary many times in the life of a pump.

The pumping wellhead valve is designed so that a quarter turn of the valve handle changes both valve openings to the correct position to achieve this action. Changing it back will restore it to the standard producing position and allow the pump and small string of tubing to drop back to the bottom and re-seat.

A-4. The Free Parallel Pump.

With the free parallel pump system, a small string of tubing is strapped to the outside of the tubing string and both strings of pipe are lowered into the hole at the same time. After the two strings of pipe have been lowered into the hole and the wellhead installed, a plug or cap can be removed from the wellhead and the pump dropped free-fall into the tubing.

When the hydraulic valve is opened for the power fluid to flow into the well, the power fluid will carry the pump to the bottom. As soon as it seats in the seating nipple, it will begin to pump.

The power fluid and the produced fluids will flow over at the bottom of the tubing string and be produced to the surface through the small string of pipe that was attached to the outside of the tubing. The natural gas that is being produced will travel to the surface through the annulus space, will be commingled back with the power fluid and produced fluids as it leaves the wellhead and will flow to the tank battery just as it would with any pumping well.

One of the leading advantages of the free pump over the fixed or insert pump is that no well servicing unit is needed to change the pump. It can be pumped to the surface by switching one valve on the wellhead and can be changed by one person. After the pump has been pumped to the surface, a catcher mechanism will secure the pump and a small hoist can be used to lift it out of the hole.

When the pump becomes unseated on the bottom due to trash, the same valve can be used to kick the pump up the hole and clear the trash. The valve is then turned back to its original position to allow the pump to reseat. This action may be necessary many times in the life of the pump before it must go to the repair shop.

A-5. The Jet Pump.

Jet action is achieved by the use of a venturi tube, which is cone shaped narrowing of the flow path. This causes an increased flow rate of the fluid, which creates a low-pressure area that draws fluids to it.

The jet pump (Figure 4) offers several advantages over the fixed and free pump in special situations. It has been installed in many offshore wells where space is at a premium, and one triplex unit can support the need for power oil to several wells. Jet pumps can also be used in horizontal completions and with continuous coiled tubing.

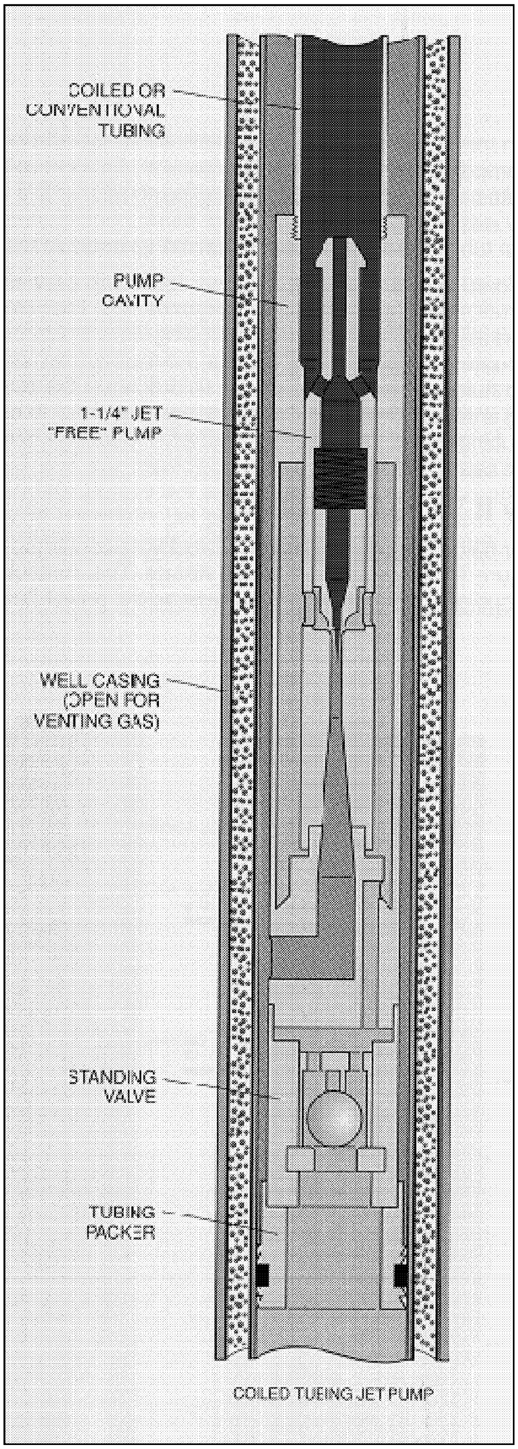

Figure 4. Components of a jet pump.
(courtesy of Trico Industries, Inc.)

A-6. Advantages and Disadvantages of Hydraulic Lift.

Advantages. There are some advantages over other high production systems by using hydraulic lift. One of them is the ease in changing the volume of fluid being pumped. A wide range of crosshead plungers and liners are available to change the volume of power fluid pumped.

Another advantage includes the high volume of production that the pump will handle each day. With the free pump, the lease pumper or a field technician can also change the pump without the need for calling out a well servicing crew and unit.

Disadvantages. Some of the disadvantages may be problems in maintaining a satisfactory supply of clean power fluid, downtime due to equipment failure, and the complexity of the operations. Multiple tubing strings are also needed as well as hydraulic power lines.

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Chapter 8
Hydraulic Lift

Section B

THE ONE-WELL HYDRAULIC LIFT SYSTEM

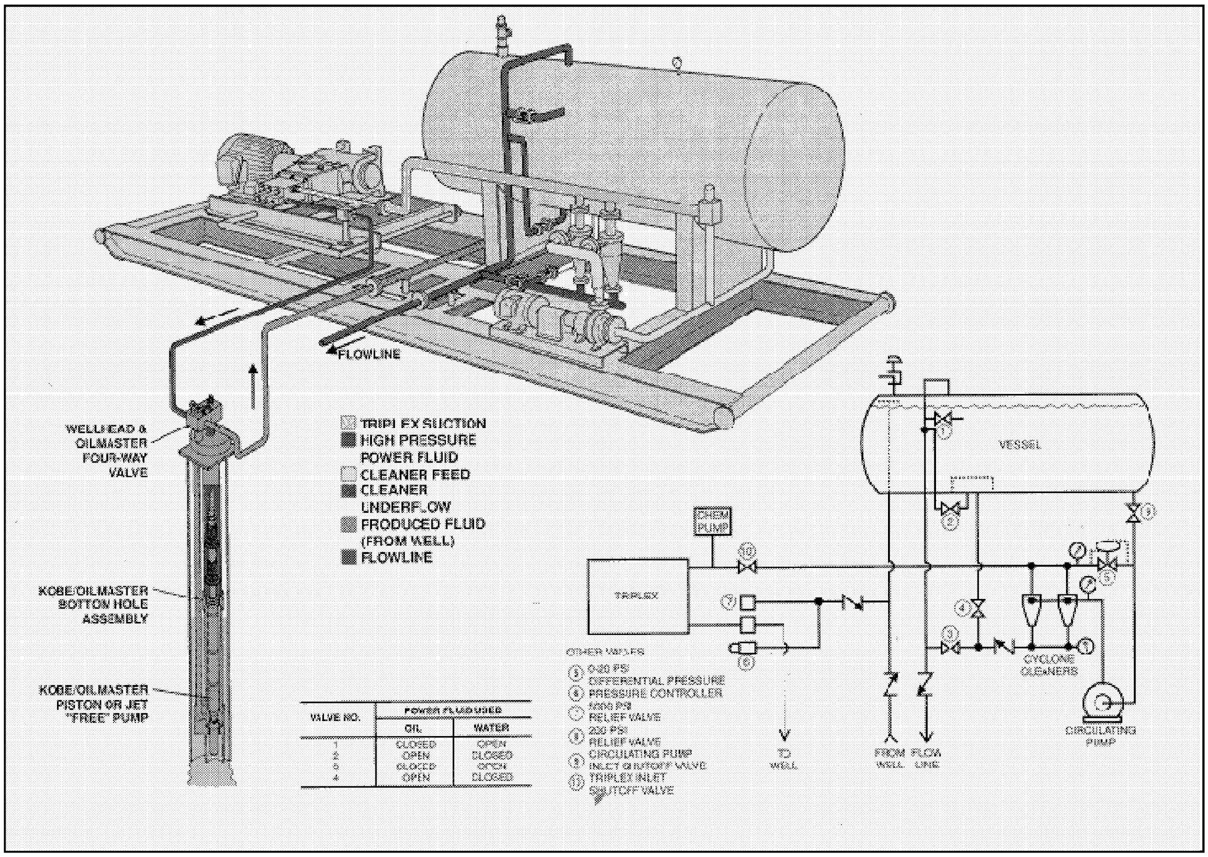

Figure 1. A single well unidraulic system.
(courtesy of Trico Industries, Inc.)

B-1. The One-Well Hydraulic System.

Hydraulic systems are available to serve a single well or as a central power system that serves two or more wells. With the one-well system (Figure 1), the hydraulic triplex system is placed on the edge of the location. The power line is run from the hydraulic unit to the wellhead. The produced fluid line, including the commingled power oil, is returned to the hydraulic system vessel. The vessel is a three-stage separator. The water falls to the bottom and by line height automation is dumped into the flow line along with the produced gas to be directed to the tank battery. The gas comes off the top of the vessel.

The oil in the vessel is first utilized to operate the hydraulic lift system through a special line from the vessel to the triplex pump. It is placed under high pressure by the triplex pump, piped from the edge of the location to the wellhead, and downhole to operate the pump. The downhole pump, which lifts oil on both the upstroke and the downstroke, pulls fluid from the formation, where it combines or commingles with the power oil, and is pumped back to the vessel at the edge of the location.

Any oil above the amount needed to operate the pump automatically flows out and is commingled with the produced gas and water into the flow line to flow to the tank battery.

To place the system into service, enough oil must be transported from the tank battery to fill the tubing with oil, operate the system until it is full of fluid, and send produced oil to the tank battery. A small truck transport will haul enough oil to activate the system. Manifold bypass systems can be installed at the tank battery and at the well to make the transport unnecessary.

After the system has been activated, a small horizontal vessel will separate the produced gas and excess liquid and dump it into the flow line. The vessel retains enough liquid above the operating system needs to allow the system to operate for a short time without running out of liquid. This reduces the need for pumping or hauling oil back from the tank battery.

B-2. The Advantages and Disadvantages of the One-Well System.

Advantages. There are several advantages to operating a one-well system over the central power type. One is that the triplex equipment is smaller.

A second advantage is that when a triplex problem occurs and the unit must be shut in for repairs, only one well is shut in. The other wells on the lease are independent and continue as usual.

The length of the power oil line is reduced from the distance to the tank battery, to just the distance across the location.

Disadvantages. A disadvantage is that a triplex must be installed at each location. This also requires a prime mover at every location, either mechanical or electric. If it is electric, a power line must be run to every location.

Another disadvantage is the purchasing and maintenance of many pieces of identical equipment that will require maintenance and repairs.

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Chapter 8
Hydraulic Lift

Section C

THE CENTRAL POWER HYDRAULIC LIFT SYSTEM

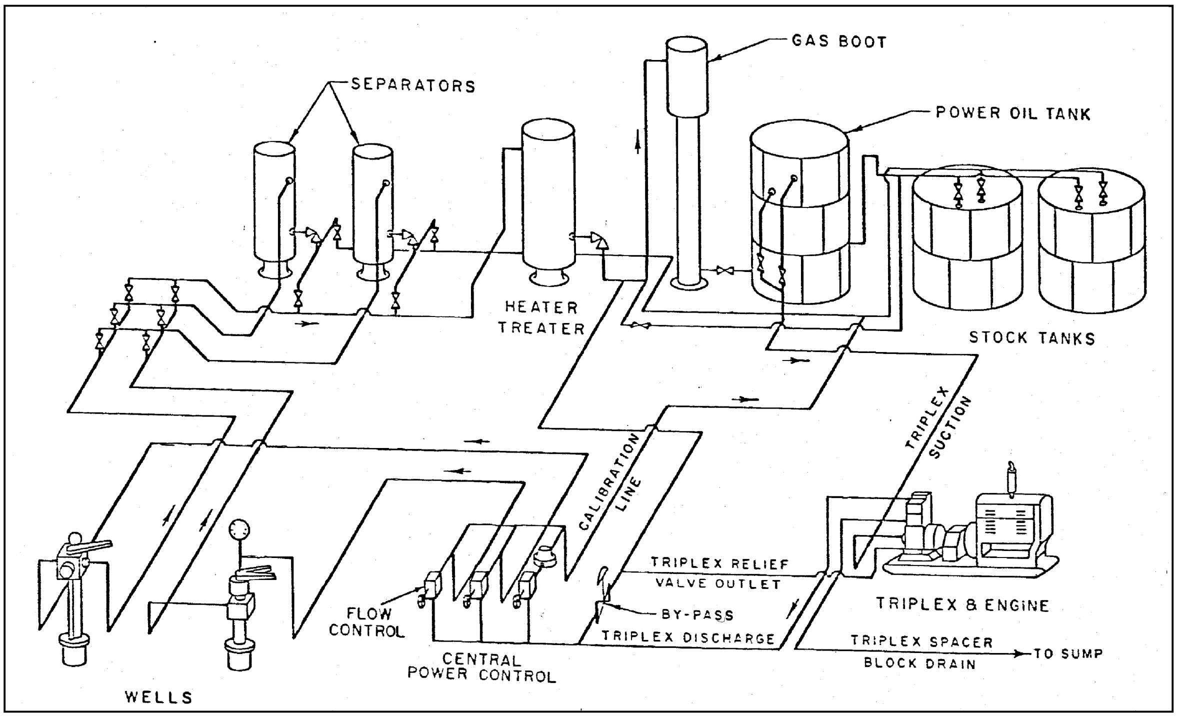

Figure 1. Diagram of a central power hydraulic lift system.

C-1. Central Power System from the Tank Battery.

Some operators prefer to use a central hydraulic power system over providing each individual well with a separate system. One triplex pump may supply power oil for as many as eight wells, depending upon the required power oil volume needed. The gas boot in Figure 1 is usually part of the heater/treater, so a power oil tank is needed. The power oil tank is the last tank in the oil processing system and is located just before the crude oil stock or sales tanks.

C-2. Crude Oil for Power.

Crude oil is the most common source of hydraulic power for hydraulic lift. A special tank to supply this oil is installed in the battery at the end of the treating system, but just ahead of the oil sales system.

The supply line from this tank is located about two feet below the line where excess production equalizes over as sellable production. To achieve this reserve the power oil tank in Figure 1 is taller than the sales tanks.

An emergency power oil supply line is provided with a valve located about two feet below the regular supply line. This gives emergency operating oil for use by opening a valve. After the emergency is over and produced oil begins to equalize into the sales tanks again, this lower line is closed again until needed. When needed, additional oil can be pumped back from a sales tank.

The power oil lines. The hydraulic triplex system is located near the tank battery (Figure 2). After the header has been installed near the triplex, a separate power oil supply line is run to each oil well. Usually a 1-inch line is satisfactory. A flow line is then run from the well back to the tank battery. This means that two lines connect each well into the system.

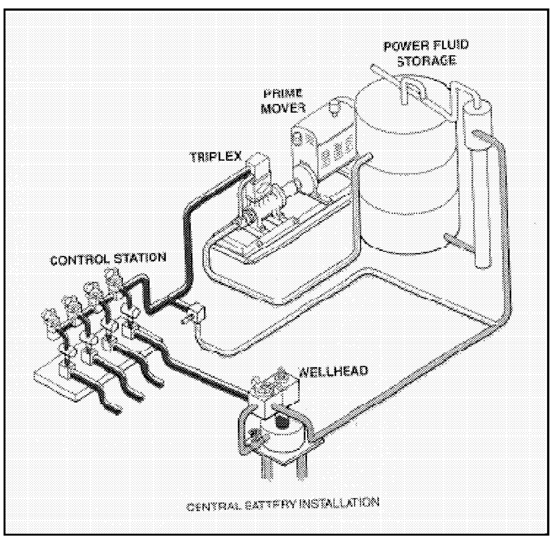

Figure 2. The central power system showing the oil lines to individual wells.
(courtesy of Trico Industries, Inc.)

C-3. Produced Water for Power.

Some operators have been very successful utilizing produced water for hydraulic power. However, to be suitable, the water must not contain scale and corrosive compounds that can not be satisfactorily controlled.

The advantages of this type of system are obvious at a glance. Water is much easier to control or neutralize than oil. The system can draw water by installing a special fitting on the heater/treater or by tapping directly into the produced water disposal system. The tank battery does not need to be modified, and the power oil tank does not have to be installed.

C-4. Closed Power Oil Systems.

By the addition of a third line installed from the surface to the hydraulic pump at the bottom of the well, the power oil is contained in a sealed system and is retained and used over and over again.

This type of system can make the well perform satisfactorily when the produced fluids are too corrosive to be used for power. This system requires that a special power oil tank be installed near the triplex unit to be able to pull power oil as needed, as well as to be able to return it to the tank for re-use.

C-5. Analyzing Production and Testing the Wells.

To be able to know where production is coming from and identify production problems as they occur, a satisfactory distribution manifold must be assembled. The diagram on the next page (Figure 3) illustrates a typical installation.

The power oil enters the manifold from the front lower right corner as shown in the illustration. The first low manifold on the right is the automatic bypass. The second header from the right is the individual well test line. By opening this system, the power oil will first go through volume regulating valves, then through a meter that tracks the number of barrels that have gone through it in a given period of time. After the oil goes through the back line and comes forward again to the selected well header, that valve is opened and the front valve closed so that the test can begin. After the test has been completed, the valves must be returned to their original settings.

The five front risers from the left side of the manifold are the five wells being supplied with power oil from this manifold. The sixth riser from the left is the test line, which was described above.

Modifications to the manifold. The header may be modified in many ways to meet the needs of the lease operator. As an example, openings can be added to allow the injection of soluble plugs or scrapers to combat paraffin buildup. Treating chemicals may also be easily added.

Advantages and disadvantages. Many of the advantages, such as having to maintain only one system, can also be disadvantages, because when shut in for repairs or maintenance, all systems are down.

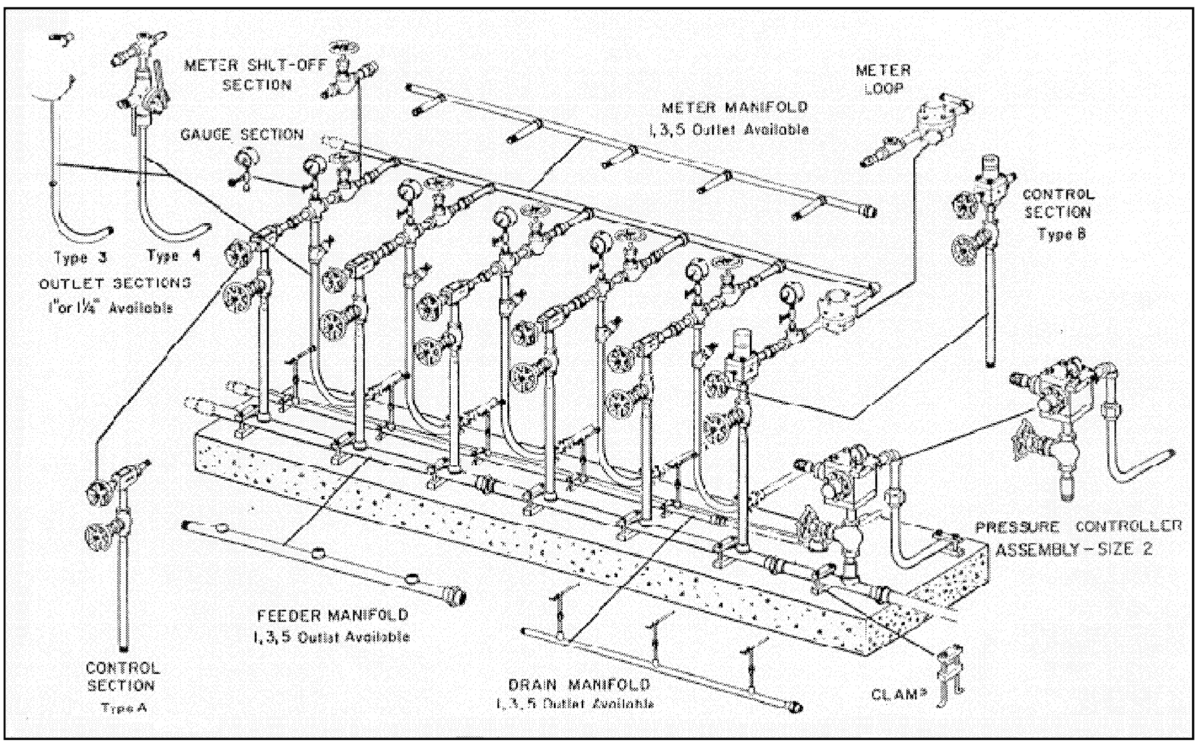

Figure 3. Diagram of a central power system supporting five wells. The manifold has provisions for testing the wells along with an automatic bypass to use when wells have problems.

(courtesy of Trico Industries, Inc.)

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CHAPTER 9

GAS LIFT

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Chapter 9
Gas Lift

Section A

INTRODUCTION TO GAS LIFT

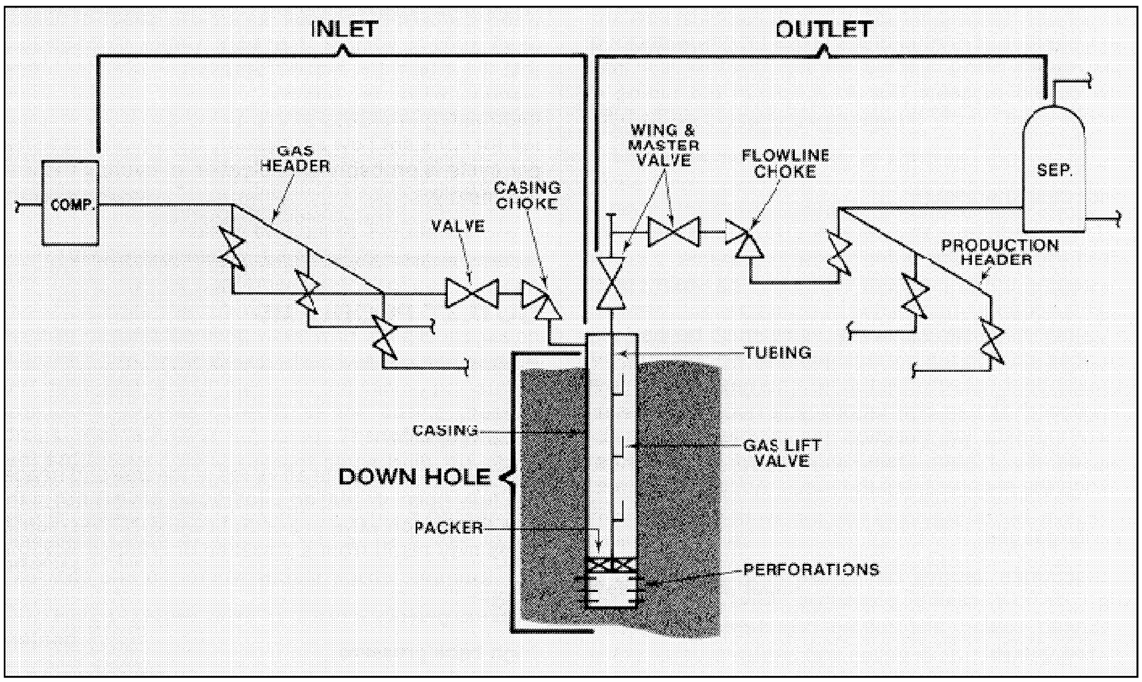

Figure 1. Diagram of a typical gas lift system.
(courtesy of McMurry-Macco Lift Systems)

A-1. The Use of Gas Lift.

Many wells flow naturally without artificial stimulation when the well is first drilled. As time passes and the reservoir gas pressure drops, oil production begins to slow down, and the number of barrels of oil produced daily begins to decline. When gas is introduced into the tubing below the level of liquid in the hole, the column of fluid in the tubing weighs less than the bottom hole pressure, and the well begins to flow again. Where gas is available, gas lift is used extensively in producing wells. This additional stimulation allows the wells to flow again. It is especially popular for wells that have marginal flow, providing a little boost in the daily production that can amount to several barrels.

In offshore production, where every square foot of platform costs thousands of dollars to construct and space is limited, gas lift is often used. Gas lift occupies very little space at the wellhead, and many directional wells can be drilled close together and easily produced. This system is a common choice when lift stimulation is desired offshore.

In other situations, gas lift again becomes a favored option in order:

- To assist a flowing well by increasing production.
- To produce wells that will not flow without assistance.
- To unload a well that accumulates heads of water so that, after unloading, the well will then flow naturally.
- To produce high volumes of water to be used in waterflood.
- To remove solids by back flowing disposal wells.

This system is also utilized to stimulate wells with a low bottom hole pressure, and where water or oil may overload the system and kill the well. Gas is also used for many other purposes in different wells, such as chemical injection and water flood.

A-2. Advantages in Using Gas Lift.

Many advantages can be realized with gas lift. No gas is lost to the atmosphere in this production process, and the same gas can be utilized over and over. It is not uncommon for a gas lift well to produce as few as 40 barrels of fluid a day or more than 20,000 barrels by producing through the annulus rather than through the tubing. This makes gas lift a very flexible system. There are also other advantages to the gas lift system, such as:

- Initial equipment costs may be lower than other systems.
- It costs less to maintain the system.
- Equipment is easily installed and serviced.
- It allows intermittent operation for low production wells.
- The system adapts easily to wells producing sand that may damage other systems.
- Gas lift is well suited for deviated wells where rod wear will occur.

A-3. Setting Up a Gas Lift System.

Three major sets of components are necessary to set up a gas lift system:

- **Inlet.** A supply of dry, high-pressure gas.
- **Downhole.** Appropriate downhole well arrangements
- **Outlet.** An appropriate production handling facility.

Gas compression and distribution. The first step in installing a gas lift system is having a large, satisfactory supply of dry, high-pressure gas. If wet field gas is to be used, a scrubber must be installed to remove condensate and water and a compressor to step the gas pressure up high enough for lease distribution and injection. Drip pots may also have to be installed to remove fallout condensate and water that will separate under line pressure. The ideal situation is to pipe the wet or rich natural gas to a processing facility to remove all liquids. Then the dry or lean gas is piped back to the gas lift lease for compression and injection. A lease distribution system must supply the gas to each of the gas lift wells.

Control valve. Near to where the line from the compressor is connected to the wellhead, a valve is installed in the line to open or close the gas to the well. A second choke valve is installed next to the wellhead to regulate or throttle the gas that is being injected. This valve will be choked to permit the pumper to inject the minimum amount of gas to obtain maximum production.

Packer. A packer is run just above the casing perforations to isolate the annular space above the casing and tubing perforations.

Tubing valves. As the tubing is run into the hole, several valves are installed in the tubing string at specific predetermined locations along the string. All of these valves are located below the fluid level in the tubing and are spaced several hundred feet apart. The pressure required to open each of these valves is pre-determined by the manufacturer by injecting nitrogen into each valve.

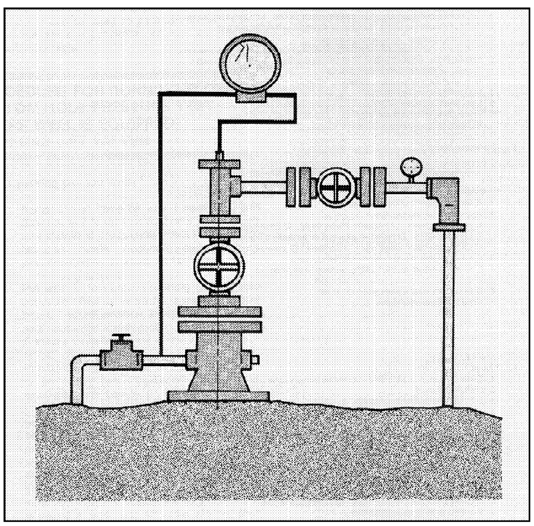

Figure 2. Diagram of a wellhead with a two-pin pressure recorder.
(courtesy of McMurry-Macco Lift Systems)

The wellhead and the two-pin recorder. A two-pin pressure recorder can be located on the wellhead to track the gas lift operation in the casing and in the tubing. It can record the pressures in the sequencing of the gas lift valves during the unloading sequence and allow the efficiency of the operation to be monitored.

The chart is used to calculate how much gas is being injected, and a choke is used to set the injection rate on the desired volume. Many problems can be detected by examining the charts—such as low production, cycles that are too long or short, freezing in the injection gas line, etc.

A-4. How Gas Lift Works.

The objective of **gas lift** is to **reduce the weight of the column of fluid in the tubing** so that the bottom hole pressure of the well is adequate to lift the column and to overcome the resistance of the tubing, pipes, and connections. With this reduced weight, natural flow may begin or production may increase. The well will continue to flow as long as fluid enters the well from the formation, and the weight of the column is maintained light enough to be lifted by the bottom hole pressure.

Sequences in unloading the well. As gas pressure is injected into the casing, the first or highest gas lift valve opens. As gas is injected into the column of liquid, the column becomes lighter and part of the liquid flows to the tank battery. After this first stage action, the second valve opens, and another *slug* or column of oil is lifted out.

After the second column has been lifted out of the tubing the third valve opens, and the procedure continues until the column of fluid in the tubing weighs less than the bottom hole pressure. At this point, the well will begin to flow.

A-5. Tank Battery Arrangements for Gas Lift.

When changing from a mechanical lift system to gas lift, changes may have to be made at the tank battery to be able to handle the increased production of natural gas, crude oil, and formation water. A comparison should be made on all three of these handling systems to be sure that the tank battery can handle the increase of fluids without overloading any of these systems.

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Chapter 9
Gas Lift

Section B

CONVENTIONAL MANDRELS

When installing the gas lift system, the first decision is in selecting either the conventional or side-pocket mandrel arrangement. This section reviews the conventional system, and Section C discusses side-pocket mandrels.

B-1. Conventional Mandrel and Tubing Arrangements.

Conventional gas lift tubing mandrels (Figure 1) have external ported lugs to accept the gas valves. The valves are installed on the outside of the gas lift mandrel, which is inserted at appropriate depths in the tubing string. The mandrel and gas lift valves are run into the well as part of the tubing string. To service these valves, the tubing string must be pulled out of the hole by a well servicing crew.

The conventional gas lift system will also have a packer located just above the casing and tubing perforations. The annular space is closed on bottom, so that gas injected into this area from the gas compressor located on the surface will cause the system to function.

B-2. Placing the Tubing and Valves in Order.

The gas lift valves will be a specified distance apart and a specified distance off bottom. Before the tubing string is hauled to the location, the pipe is usually rolled out on a rack and the joints measured and selected to allow a specific length for each valve group.

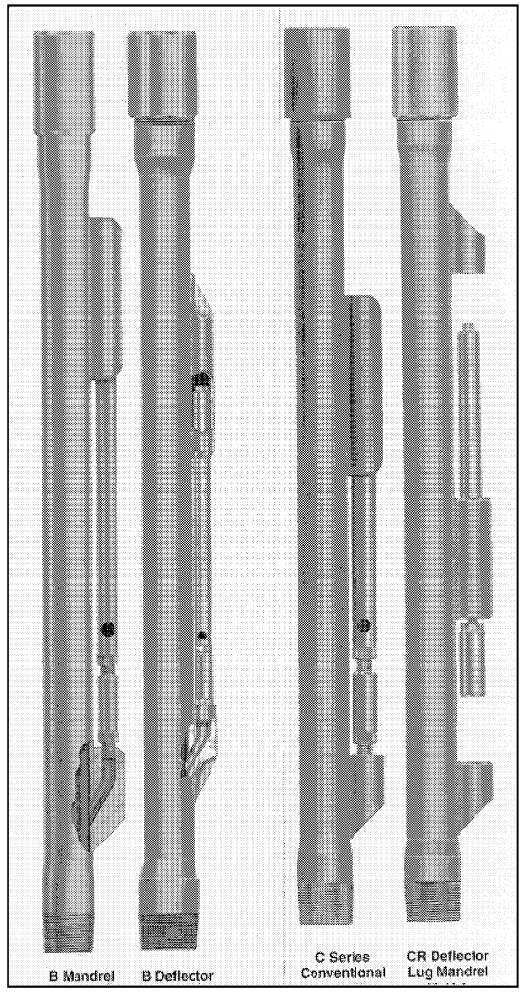

Figure 1. Examples of conventional gas lift mandrels.
(courtesy of Camco Products and Services Company)

When the selected pipe is loaded on the truck, a number 1 is written on each joint. A soft rope is laid across the loaded pipe to separate and identify it because this is the first pipe that will be run in the hole. The joints that are selected for the second valve group to be run are then separated. This pipe is loaded and a number 2 written on each joint.

The truck is progressively loaded with groups 3, 4, and so forth until the full string of tubing has been measured and selected. Every gas lift mandrel will also be identified as the valves are assembled and installed on the mandrel before it leaves the shop.

As this string of pipe and mandrels are run into the well, each joint is again measured and listed in the order that they are run. This group order is maintained every time that the tubing string is pulled and the valves serviced. This maintains the correct valve spacing to assure that the well will flow correctly after the service job has been completed, and that the correct valve is in the designated location. Each gas lift valve will be custom serviced for a particular well and must be run into the well in a specific order to obtain the desired service.

B-3. The Gas Lift Valve.

The gas lift valve must be set to open under a specified pressure. This may be automated by the use of a spring or, more often, a gas-operated bellows.

The upper chamber of the gas lift valve is an open chamber filled with a neutral gas under pressure. The fill valve is similar to a tire valve core and is set to a specified pressure, then sealed with a plug.

The lower section of the valve is a bellows with a round end that is pushed against a seat by the neutral gas pressure on the inside.

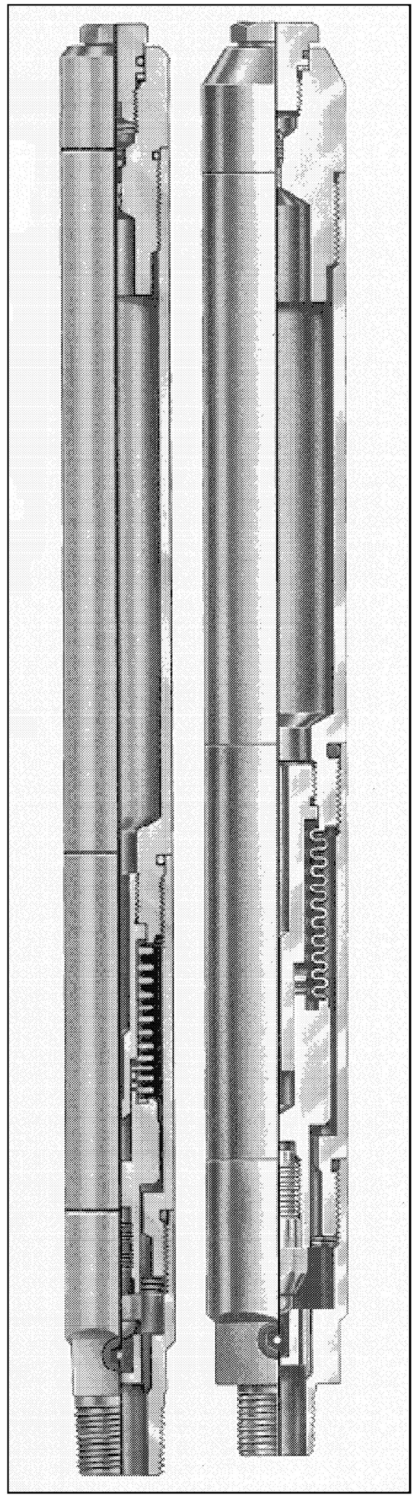

Figure 2. Examples of gas lift valves.
(courtesy of CAMCO)

This lower valve is exposed to the annulus pressure of the well. The casing pressure opens the valve to permit gas to enter the well to commingle with the fluid and make it lighter.

As the second valve opens and begins unloading the second section, the upper gas lift valve closes, and all of the lift gas enters the tubing through the lower valve. As the third valve opens, the second valve closes, so that the only valve open is the third or lowest valve. This continues until the gas enters the tubing through the lowest valve, and all of the others above this valve are closed. The well will continue to remain in an unloaded condition as long as gas is being injected continuously.

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Chapter 9
Gas Lift

Section C

SIDE-POCKET MANDRELS

C-1. The Side-Pocket Mandrel System.

The side-pocket mandrel system is popular because the valves can be pulled, serviced, and run by using a wireline machine. The well servicing unit is not needed, and it is not necessary to pull the tubing string. This is especially popular offshore because of the reduced equipment and personnel requirements. The procedures for running and pulling and valves from side pocket mandrels are included in Appendices A-4 and A-5.

C-2. Producing Oil Through the Casing.

For low- to medium-volume gas lift wells, the gas is injected down the casing annular space, and the oil is produced up through the tubing. This is the most common arrangement for gas lift, and this system can be used on wells producing less than 50 barrels of oil per day to those that produce several thousand.

For high- and extremely high-volume wells, the gas will be injected down the tubing and the oil will be produced up the casing through the annulus. When producing through the casing, a packer is not needed. Some wells using this arrangement may produce more than 25,000 barrels of oil a day. This system can be especially productive in waterflood situations where the amount of water being produced daily keeps increasing.

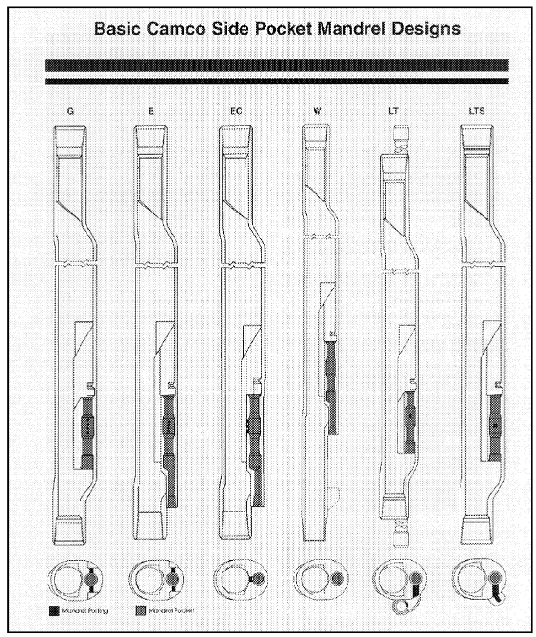

Figure 1. Examples of side-pocket mandrels.
(courtesy of CAMCO Products and Services Company)

C-3. Continuous and Intermittent Gas Lift.

Continuous operation is the easiest method to use in gas lift. With some wells, especially when they produce a high volume of water, an unloading procedure must be used to make the well flow again. If the flowing condition can be maintained without having to unload the well again, continuous operation will be more effective (Figure 2).

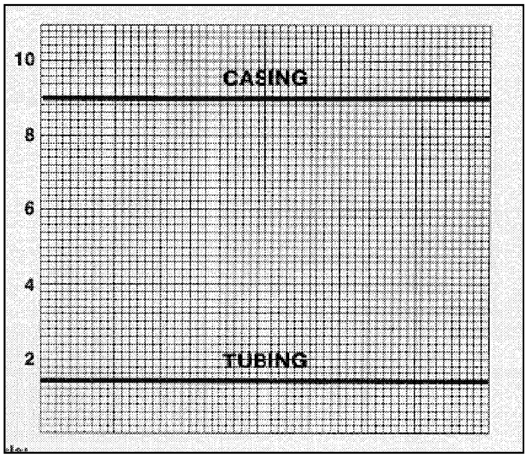

Figure 2. Chart of continuous gas lift operation.
(courtesy of McMurry-Macco)

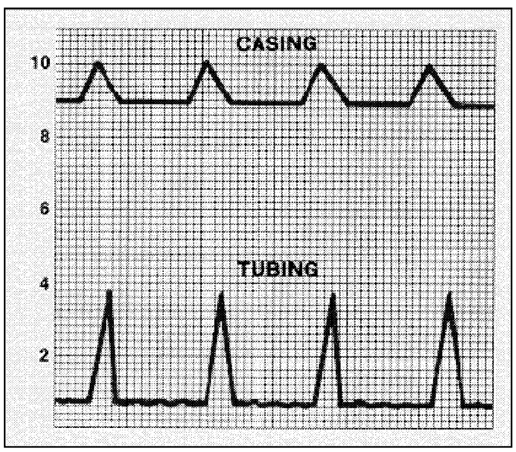

Figure 3. Chart of intermittent gas lift operation.
(courtesy of McMurry-Macco)

For low producing wells where the column build-up between cycles is not very great, intermittent operation is satisfactory (Figure 3).

C-4. The Wireline Machine and Wireline Safety.

The wireline machine can be utilized to work on well maintenance problems other than just pulling and running gas lift valves. The wireline tools can also be used to cut paraffin, bail sand, and remove scale without pulling the tubing. In flowing wells where paraffin is a problem, the paraffin can be cut daily between flow cycles without interrupting production. Safety valves can also be serviced.

With high production wells, especially offshore units where the well might be difficult to approach in the event of a blowout or fire, additional safety equipment is installed. By running two strings of tubing into the top of the well, safety valves can be installed below the surface to permit the well to be controlled in case of an emergency.

When working with a wireline machine regardless of the type of work being performed (servicing gas lift wells, servicing safety valves, or running well surveys), the lease pumper must respect the wireline. Never approach it when it is running. A wire loop is dangerous.

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CHAPTER 10

THE TANK BATTERY

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Chapter 10
The Tank Battery

Section A

BASIC TANK BATTERY SYSTEMS

A-1. Oil Storage at the Drilling Site.

The most logical place to begin studying the tank battery is at the wellhead and the drilling rig where the whole process begins.

Even before running casing, a **drill stem test** may be run on a well. This is a procedure intended to produce the well through the drill pipe. At this point, a **test tank** is normally used as a substitute for a tank battery. If the test shows that the well may have commercial potential—that is, the well will eventually pay for the drilling and operating costs and make the company a profit—the casing will be run and set.

After casing has been cemented into place and perforated and the well has been treated, production can begin. If it is a flowing well, the production may begin by simply opening a choke valve.

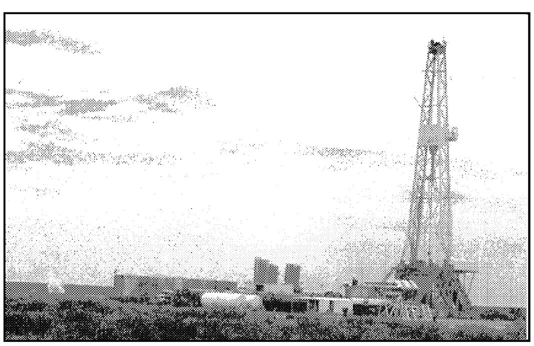


Figure 1. A drill stem test is being run at this drilling rig. Note that gas is being vented in a flare in the left side of the photograph.

With some wells, however, the lease operator must begin production by calling out a swabbing unit to swab or lift a blanket (or column) of liquid—either water or oil—out of the tubing to reduce the bottom hole pressure. This action is intended to reduce the weight of the standing column of fluid in the tubing so that it is less than the formation pressure, allowing new fluid to enter the well bore at the casing perforation. The weight generated by a column of oil is less than the weight of an identical column of salt water. By swabbing the water out and allowing the lighter oil to enter at the perforations, the reduced weight of the column may allow the bottom hole pressure to cause the well to flow. If the bottom hole pressure is higher than the weight of the column of standing fluid, the well may start flowing without further stimulation.

As the well is swabbed or flowed into a vessel, the first tank gauging will usually be done or supervised by the company drilling or production supervisor or possibly by a well servicing employee. In the end, however, it will become the responsibility of the lease pumper to track production, recording the amount of gas, oil, and water produced, even if the gas is vented.

Gas will usually be lost to the atmosphere or, in some cases, burned as it is flared. A pin recorder with an orifice plate can be installed to measure the true volume.

Since the lease pumper must account for all oil and water produced, these liquids will be produced to a tank and gauged often. The fluid produced will be measured and the number of produced barrels determined several times a day until the well has been cleaned up and a rate of production for the oil, gas, and water has been determined.

A-2. The Natural Production Curve for a New Well.

When a new well is put on line or begins to produce oil, the pressure around the well bore is equal to the pressure throughout the reservoir. As production continues, the pressure in the matrix area and around the well bore decreases, while the time that it takes for the pressure to build back up to initial formation pressure increases, according to formation porosity. As this occurs, any new fluids produced must be pushed farther and farther through the formation to enter the well bore. The farther the oil must travel, the more time it takes to get to the well bore. The gas may bypass great pockets of oil unless the reservoir is very porous and good production practices are followed by the lease pumper. Pressure at the wellhead will be reduced, and the amount of oil produced will decline.

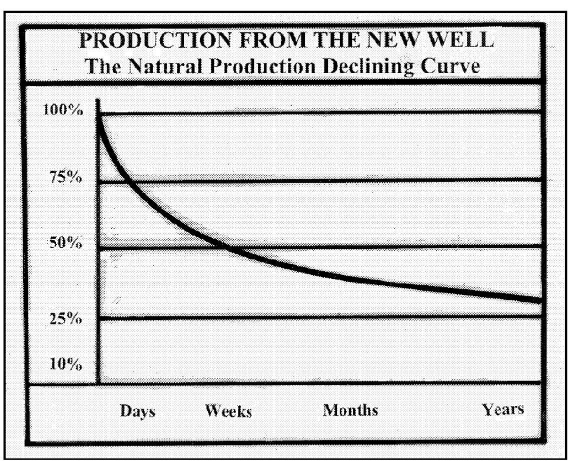


Figure 2. Oil production curve.

This is a natural flowing condition for all wells described by the curve in Figure 2. The rates of change will be controlled by formation pressure, the type of drive, thickness of the pay zone, porosity of the rock, viscosity of the oil, and many other factors.

A-3. The Very First Production.

When producing a new well or an existing well that has been worked over, chemicals or muds may initially be produced that should not be fed into the tank battery system because the mud may fill the total tank battery facilities and cut off tank operation. For this reason, an open top tank or other vessel on location may be utilized to hold the initial production.

Gauging new production at the well location. The gauging and accounting for produced oil usually begins at the well site. The use of Kolor Kut or some suitable gauge line paste will assist in determining the oil/water interface level. As the production first begins, the thief will assist the lease pumper in checking the oil/water ratio and indicate the condition of the tank bottom. The gas production can be measured with a single-pen recorder and orifice plate at the end of the gas line.

Storing oil in rectangular tanks. Rectangular storage tanks may not have a top. A set of steps will assist in allowing comfortable gauging of the vessel and checking of the produced liquids. If no steps are available, they can be constructed very economically or temporarily borrowed from another lease facility.

Safety in gauging and testing oil in round vertical tanks. Instead of a walkway, round, vertical tanks used to temporarily store oil usually have a ladder bolted to the side centered on the thief hatch. A metal hoop or band about 30 inches across installed at the top of the ladder allows the lease pumper to have both hands free for gauging the amount of liquid, using Kolor Kut paste to determine the oil/water interface level, taking a hydrometer reading to check API gravity, obtaining water samples to determine water weight, and thieving the tank to determine emulsion buildup on the bottom.

If a metal hoop is not on the tank, one can be built for only a few dollars. The hoop can be removed and stored and used again when needed. A second option is to utilize a safety belt with side snaps that can be fastened to the ladder. The safety belt is easy to carry and store.

		Ft.		Ft.		Ft.	
	.00	1	14.02	2	28.04	3	42.07
¼	.29	¼	14.31	¼	28.34	¼	42.36
½	.58	½	14.61	½	28.63	½	42.65
¾	.88	¾	14.90	¾	28.92	¾	42.94
1	1.17	1	15.19	1	29.21	1	43.23
¼	1.46	¼	15.48	¼	29.50	¼	43.52
½	1.75	½	15.77	½	29.80	½	43.81
¾	2.04	¾	16.07	¾	30.09	¾	44.10
2	2.34	2	16.36	2	30.38	2	44.39
¼	2.63	¼	16.65	¼	30.67	¼	44.68
½	2.92	½	16.94	½	30.96	½	44.97
¾	3.21	¾	17.24	¾	31.26	¾	45.26
3	3.51	3	17.53	3	31.55	3	45.55
¼	3.80	¼	17.82	¼	31.84	¼	45.84
½	4.09	½	18.11	½	32.13	½	46.13
¾	4.38	¾	18.40	¾	32.43	¾	46.42
4	4.67	4	18.70	4	32.72	4	46.72
¼	4.97	¼	18.99	¼	33.01	¼	47.01
½	5.26	½	19.28	½	33.30	½	47.30
¾	5.55	¾	19.57	¾	33.59	¾	47.59
5	5.84	5	19.86	5	33.89	5	47.88
¼	[illegible]	¼	[illegible]	¼	[illegible]	¼	[illegible]

Figure 3. A portion of a tank chart for a 210-barrel tank.

Gauging procedures and tank charts. As shown in the tank chart in Figure 3, tanks are usually gauged to the nearest ¼ of an inch. For a high producing well, gauging may be done to the nearest inch. On the other hand, a very low producing well may be gauged to the nearest 1/8 of an inch. This will permit better tracking of how the well is producing every day and will aid in indicating production problems. Gauging procedures are covered very extensively in Chapter 12.

Gauging the holding tank on the location. The steps for gauging the holding tank include:

1. Gauge and record the total amount of liquid in the holding tank.
2. Determine the oil/water interface level by using Kulor Kut.
3. Thief the tank if necessary to check water level, bottom emulsion build-up, and to check the API gravity.

   Note: Obtaining the gravity, temperature, and water weight may be necessary only one time or periodically to establish the quality of oil produced and to identify problems in treating.

4. Sample the oil to determine BS&W content.
5. Obtain a water sample to determine water weight per gallon.
6. Record each gauging time.
7. Compute oil and water produced.

Tank charts may not be available for temporary rectangular or a round, vertical tanks. A tank chart can be developed in a few minutes that will be accurate enough for the initial calculation of estimated production. If the oil is sold by transport direct from the location, the oil will be estimated by a chart when loaded, but accurately metered for number of barrels as it is unloaded. In Appendix F, in the math section, computations for making a tank chart are included. For round horizontal tanks, a chart is required. Companies that lease tanks have charts available.

A-4. Storing and Accounting for Produced Crude Oil and Salt Water.

The lease operator is required to give a daily, weekly, and/or monthly accounting of all oil, water, and natural gas that is produced from every well. This accounting record begins the first day that the well produces fluid and ends when the well is plugged or taken out of service. Records are maintained by regulating agencies that record cumulative lists of all oil, gas, and water that has been produced during the life of the well.

Temporary tanks are likely to be used until a decision has been made concerning the size of permanent tanks to be installed and where the tank battery will be located. This will depend upon the amount of oil being produced, how large the lease acreage is, and the immediate availability of additional drilling funds in the event that the well is a good producer.

When the fluids begin to be produced from the well, the lease pumper will become responsible for gauging the tank on a regular schedule and accounting for all fluids produced. (See Chapter 19, Record Keeping).

A-5. What Is Produced from the Well?

The goal is to produce and sell crude oil and natural gas. Along with these two fluids, the well will produce BS&W, or *basic sediment and water*, which is primarily water and a little formation sand as well as other compounds and elements. Figure 4 illustrates a small part of the byproducts. Some of these byproducts are valuable and are readily purchased by the petrochemical industry. Asphalt is used in highway construction, and natural gas can be converted to synthetic rubber and used to generate electricity. The textile and dye industries depend heavily on petroleum, and paraffin is used by many industries. Sulfur and water contribute to the formation of acids in the well and tank battery and cause corrosion.

Since all of these elements are produced in varying amounts from each well, specific vessels within the tank batteries are designed to accommodate and solve varying processing problems and procedures.

When a well produces a high level of hydrogen sulfide gas, special gauging procedures must be followed for employee safety. These precautions are in addition to the usual standards for working around natural gas. The lease pumper must be especially aware of the dangers of working with natural gas and hydrogen sulfide, since the pumper works alone most of the time.

A-6. Designing a Tank Battery.

There are many factors to be considered when a tank battery is constructed. The tank battery must be of a sufficient size to handle the amount of fluid produced but also to handle the many problems that might be caused by the quality of the fluid produced.

The wells from one reservoir have many conditions in common, such as the gravity of the oil and temperature. Each reservoir will have its own characteristics, and each tank battery is designed to accommodate whatever is produced to that tank battery only. If a reservoir is structured at an angle or on an incline, the upper wells may produce oil and gas only, while the wells at the lower zone may be water drive and produce a lot of water. Wells in the upper zone may have pressure maintenance while those in the lower zone use water drive. When a reservoir is several miles long, the wells at one side and depth vary greatly from wells at the other side and depth.

Therefore, a number of factors influence the design of the tank battery. The lease pumper must:

- Understand the purpose for the various vessels that make up a tank battery as well as what vessels are available for consideration.
- Know how each vessel is constructed on the inside.
- Know the location of each vessel within the system.
- Know how the vessels operate.
- Know problems that the vessels can solve.
- Have good problem-solving skills.

How the tank battery works. The ability of the lease pumper to understand and operate the typical tank battery begins by fully understanding the most common tank battery components and systems, the primary purpose of each part within the system, what problems that it is solving, and how each part works. This is the purpose of the information in this chapter. Additional information about tank batteries is described in Appendix C, Additional Tank Battery Information.

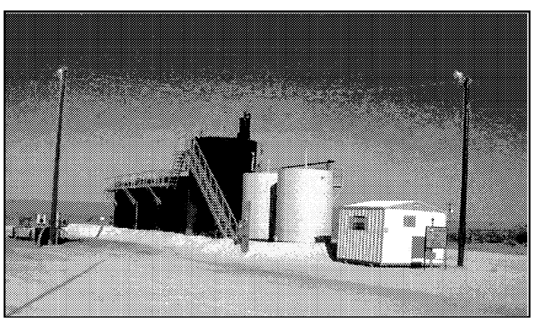


Figure 4. A tank battery with two water tanks (black), a gun barrel, and two oil stock tanks (gray).

Basic tank battery components. The most common components in the average or basic tank battery include:

Lines from the wells to the vessels:
- Flow lines from the wells.
- Headers or manifolds to connect the wells to the separators.
- Lines to connect various vessels.

The basic vessels:
- Production and the test separators.
- Heater/treater.
- Gun barrel or wash tank.
- Stock tanks.
- Water disposal tank.
- Earth pits or slush pit.
- The firewall, dike, or berm.

The equipment:
- Circulating pump.
- Chemical injection pump(s).
- Vapor recovery unit.
- LACT unit (if connected to a pipeline).
- Gas measurement and test system.
- Containers for end of sales lines (if the oil is transported by truck).

Appropriate line systems and fittings:
- Flow lines from the wells.
- Inlet header or manifold to separators.
- Crude oil lines from separators to the heater/treater, gun barrel, and stock tanks. Equalizer lines.
- The high-pressure gas system. Gas lines from the separators and heater/treaters to the sales outlet.
- The low-pressure gas system and the vapor recovery unit.
- The water collection system from the various vessels to the water disposal tank and the pit.
- The circulating and vessel emptying or filling system.
- Sales systems. LACT or truck transport.
- Water disposal systems.
- Special purpose systems.

Flow lines. Flow lines may be made of steel, plastic, or fiberglass. Steel lines may be welded, made of threaded regular line pipe, or upset tubing that has been removed from a well and downgraded. Some lines have grooved clamps instead of collars. When the line may be subjected to high pressure from the well, steel will usually be used.

Fiberglass is frequently used in extremely corrosive conditions, or polyethylene may be used for lower pressure conditions. Polyethylene has become extreme popular because of its low price, ease of use, and long life.

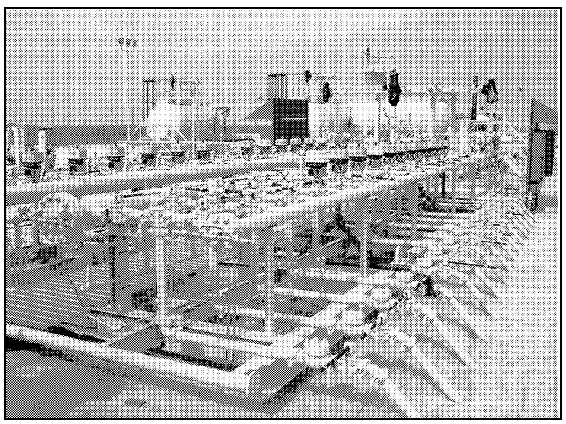


Figure 5. The header system at a large tank battery.

Header lines from the wells. As the flow lines from each well enter the tank battery, they are lined up to come in parallel to each other, and a header is constructed to receive these lines.

The header pictured in Figure 5 has the lines entering from the lower right. The fluid flows through a valve, a check valve, then turns up through an ell. As the fluid reaches the top of the header, a tee is in the line with valves to the right and to the left. The right-hand line goes to the test separator, and the left-hand line goes to the production separator. Each line has a painted number or a metal plate on it that identifies the well. Note that all of the valves are quarter-round opening. As the lease pumper walks along the header, it is clear at a glance which valves are open, which valves are closed, which wells are shut in, and which well is on test. This is a good construction practice.

As the wells leave the header to enter the processing vessels, the vessel may be bypassed or the flow may be directed through the vessel. At this point, chemical is added. By injecting the chemical after the header but before the emulsion reaches the separator, the treating process really begins. The second alternative is to inject the chemical at the wellhead. For additional information about chemical injection and treatment, see Chapter 13, Testing, Treating and Selling Crude Oil, and Appendix E, Chemical Treatment.

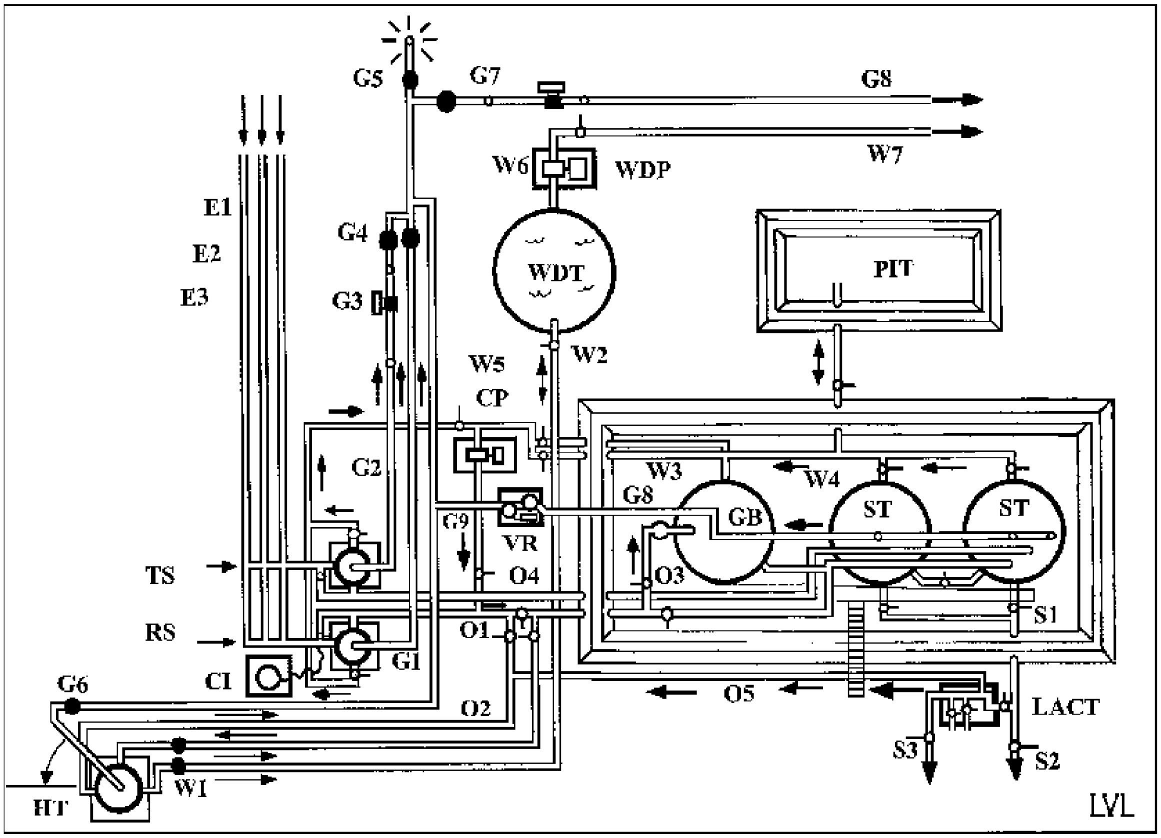
Vessels. The basic vessels are:

- **The regular and test separator.** Pressurized. Separates gas and liquid. The test separator is utilized to test individual wells and the two-phase separators are more common than three-phase.
- **The heater/treater.** May be pressurized or atmospheric. Heat treats and separates oil, water, and gas. It is a three-phase vessel.
- **The gun barrel or wash tank.** Separates oil, water, and small amounts of gas. Atmospheric. A three-phase vessel.
- **The stock tank (s).** Stores oil until sold. Atmospheric.
- **The water disposal tank.** Stores water until it is disposed of or re-injected. Atmospheric.
- **The circulating pump.** Circulates oil to remove water, clean tank bottoms, and empty and fill vessels.

- **The lined slush pit.** Stores produced water. Limited use now. An emergency overflow vessel in some situations.
- **The firewall or dike around atmospheric vessels.** Although the dike is not a formal tank, it is required around many vessels as an emergency open air tank in the event of leaks and must be capable of containing 1½ times the total capacity of all tanks.

Through most of the earlier days of the oilfields, these were the first specialized vessels and components included in a standard tank battery. Today the possibility of having a tank battery with exactly these eight components only is rather low. The rule of thumb of what components will be used is governed by the one basic rule: the components that are needed to produce and sell the oil and gas. By the end of the life of an oilfield, wells may have been produced by two or more methods of artificial lift, and the tank battery arrangement may have been altered or changed several times. The stock tanks may have been reduced to just one. As production becomes very low and if the formation gas pressure has been almost depleted, the high-pressure separator is no longer needed and is removed. As the reservoir is depleted, the expensive heater/treater may give way to a wash tank or gun barrel or even just a stock tank with a water boot attached to the side to separate the produced water. Many wash tanks are shop-made out of a piece of casing and can be very small. They are always taller than the stock tank and are easily identified. They may be set on a platform for atmospheric operation. As water flood is added to stimulate production, these new capabilities must be added, and, as a rule, water flood is the most common of most enhanced recovery operations.

Regardless of the controlling factors, the lease pumper must fully understand the operation of the basic tank battery. On the following two pages is a diagram that shows how these and other components may be connected in a typical tank battery.



Drawing Legend.

VESSELS.

GB	Gun Barrel.
HT	Heater/Treater.
PIT	Water Pit.
RS	Regular Separator.
ST	Stock Tank.
TS	Test Separator.
WDT	Water Disposal Tank.
_	Fire Wall——No Letters

SUPPORT EQUIPMENT.

CI	Chemical Injection.
CP	Circulating Pump.
LACT	Lease Automatic Custody Transfer.
VR	Vapor Recovery.

LINES.

E.	**Emulsion.**
E-1	Flow Line # 1. Emulsion entering the tank battery from well 1.
E-2	Flow Line # 2. Emulsion entering the tank battery from well 2.
E-3	Flow Line # 3. Emulsion entering the tank battery from well 3.

O.	**Oil.**
O-1.	Oil line from the regular separator. May be produced to the heater/treater, gun barrel, or stock tank, according to the way the lease pumper has switched the line.
O-2.	Oil line switched to flow the oil from the regular separator to the heater/treater.
O-3.	Oil line switched to flow the oil to the gun barrel, then to the stock tanks.
O-4.	Test separator flowing the oil directly to the stock tanks since 2nd heater/treater has not been installed. No other options are available.
O-5	Rejected oil from the LACT sales unit being diverted back to the heater/treater.
G.	**Gas.**
G-1.	Gas from the regular separator flows directly into the gas sales system.
G-2.	Gas from the test separator flows directly to the meter run.
G-3.	Gas from the test separator flows through the gas meter for cubic foot measurement.
G-4.	Gas from both separators flows through independent back pressure valves.
G-5.	A gas vent is provided where in an emergency the gas will vent. This pressure is set above all other back pressure valves, including the gas company sales valve.
G-6.	Gas line and backpressure valve from the heater/treater toward the sales line.
G-7.	Gas purchasing company meter and back pressure valve.
G-8.	Gas line leaving the tank battery to enter the gas company gathering system.
W.	**Water Disposal System.**
W-1.	Water disposal system, beginning at the heater/treater.
W-2.	The water disposal line from the heater/treater to the water disposal tank.
W-3.	Water from the water disposal leg of the gun barrel to the water disposal tank.
W-4.	Water from the stock tanks to the pit and to the circulating pump.
W-5.	Circulating pump to the heater/treater for cleaning the oil, picking water up from the pit, and pumping fluid out of the stock tanks and heater/treater for system repairs.
W-6.	Pump to automatically send accumulated water to the disposal system.
W-7	Water line from the tank battery to the water disposal or flood system.
S.	**Oil Sales System.**
S-1.	The oil sales line located one foot from the bottom of the front of the stock tanks.
S-2.	The truck transport sales line from the front of the tank battery.
S-3.	The Lease Automatic Custody Transfer (LACT), where the oil is sold and the custody of that oil is transferred to the pipeline or transportation company.
O-5	If the LACT unit rejects the oil, it will go to the heater/treater for re-treatment.

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Chapter 10
The Tank Battery

Section B

PRESSURIZED VESSELS

This section focuses on the pressurized vessels and related equipment commonly used for tank batteries:

- **The flow line.** From the well to the tank battery.
- **The header.** A manifold of all flow lines to the first pressurized vessel.
- **The separator.** Typically, the first pressurized vessel in the system.
- **The heater/treater.** Typically, the second pressurized vessel in the system.

The information presented in this section is general in nature due to the many variations in equipment configurations and specific uses by different companies.

B-1. The Flow Line.

A flow line is laid from the well to the tank battery. Where there is a long distance to the tank battery and the production is low, the lines may be joined at some convenient spot so that one line is laid from that point to the tank battery. This does not present a problem except when one of the wells needs to be tested. To test wells individually, a well tester, mounted on a small double-axle trailer, can be brought to each location. The second option is to shut one well in while the other is being tested. Limiting one flow line to several wells is never an ideal situation but may be the cheapest alternative.

The material selected for the flow lines depends on many factors. Options include:

- Steel is usually preferred for high-pressure and flowing wells. It can be standard line pipe, heavy-duty line pipe, or new or used upset tubing. It can also be welded, use pipeline couplings, or have groove clamps. Steel can be plastic-coated to combat corrosion and scale accumulation.
- Polyethylene may be selected for medium- to low-pressure lines and can be practical also when paraffin or scale is present. It is especially satisfactory when steel lines deteriorate rapidly.
- Fiberglass can also be considered when extremely corrosive conditions are encountered.

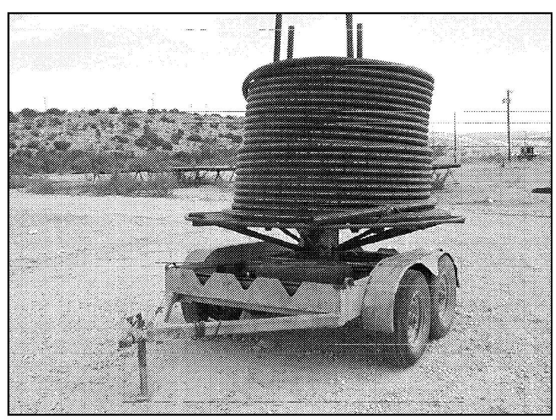

Figure 1. Polyethylene line to be laid as a flow line.

Laying new flow lines. When laying new flow lines, the weather must be considered. If a line is laid straight from one point to another in hot weather, when it gets cool it will shrink several feet in length. When it gets extremely cold it will shrink many feet in length. This will cause it to pull so hard that it will part, or in extremely hot situations it may buckle. Placing correct slow bends in flow lines can accommodate this problem, with plastic pipe add a few slow curves to provide extra line near the destination points and road crossings.

Road crossings. When crossing a lease with a flow line, it is always best to lay a joint of casing across the road and run the line through it (Figure 2). If the ends of the casing are to be sealed or buried, a vent is welded to the casing to remove gasses in event of a line leak. A riser is welded into the conduit line at each end before it is buried to allow this to occur. All steel lines that go through a conduit should be coated and wrapped.

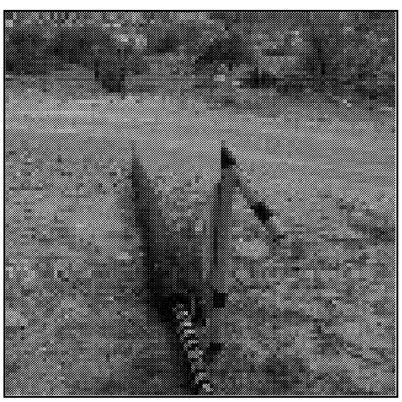

Figure 2. A road crossing for flow line.

B-2. The Header.

As the flow lines approach the tank battery, they are lined up about 18 inches apart and enter the tank battery parallel to each other. As they come up through a riser, a check valve is installed. In the event a hole should develop in a flow line and this check valve does not seal, all of the production entering the header can flow back through this line and result in a large oil spill. If the check valve on the casing of the well should become locked open, not only will the well begin to circulate by losing the produced oil back down the well, but produced oil from the header can flow back down the flow line and also be lost down the well.

A tee will be installed in multiple well batteries, so that the flow may be diverted into the production or the test separator. The line to the heater/treater will have a connection in it to allow the injection of treating chemical. When injecting the chemical at the tank battery instead of at the well, it is always injected into the header and usually after the header but before the first vessel. This is standard procedure.

Quarter-round opening valves—either plug or ball—are more appropriate for the tank battery than multiple round opening valves because the lease pumper can determine if they are open or closed at a glance.

The header should also have a line installed to permit the flow to the separator to be diverted through a bypass around the vessel. Most vessels must be bypassed while repairs or changes are made.

B-3. Pressurized Vessels.

Tank battery typical operating pressures.

- **Separators.** Separators will have a maximum operating pressure of about 100 pounds with a test pressure of 150 pounds. Normal operating pressure is from 15-50 pounds, 25-35 pounds is about average. The pressure must be great enough to push the liquid from the separator into the heater/treater with a small safety margin.

- **Heater/treaters.** These vessels are larger around than separators, so it takes a thicker shell to hold the same pressure. Thicker shells raise the cost of the vessel to a much higher level. Fifty pounds operating pressure is about average with a test pressure of less than 100 pounds for a heater/treater. A higher pressure separator is usually located ahead of it to lower the operating pressures to save money during construction. Vertical heater/treaters are taller than the stock tank and the oil outlet is about the same height. One pound of pressure will lift oil about three feet, so 10-15 pounds of pressure will usually be satisfactory at the heater/treater.

There are several openings and lines that all pressurized vessels have in common (Figure 3). There are also a few openings and lines that are normally limited in use and are installed on specific purpose vessels. A good understanding of the purpose and locations of specific special purpose lines for pressurized vessels is important to the lease pumper.

The emulsion inlet. The emulsion inlet is located on the side of the vessel near the top and above the fluid level in the vessel. Some pressurized vessels, such as the separator, will have a diverter plate on the inside to give the fluids a swirling motion upon entry. This allows the gas to break out of the liquid phase and reduce liquid carryover into the gas sales. Emulsion inlet lines are usually above the operating liquid level to prevent loss of liquids from the vessel in the event of line leaks before the line gets to the vessel and siphoning effects.

The gas outlet. The gas outlet is always located at the center of the top. A mist extractor will be installed inside the vessel to further limit liquid carryover.

The drain outlet. The drain outlet is located in the center of the bottom.

The high oil outlet (optional). If the oil outlet is located high on the upper side of the pressurized vessel as it is in the heater/treater, this will be the oil outlet and also the height of the fluid in the vessel.

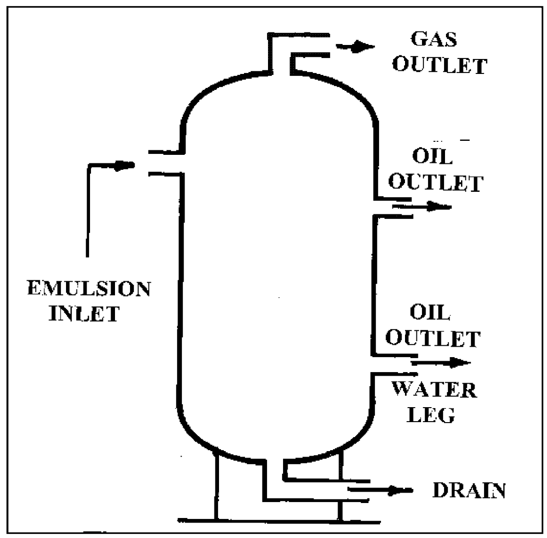

Figure 3. Typical line Openings in a pressurized vessel.

The lower liquid outlet or water leg. If a liquid outlet is located near the bottom on the side of the vessel and is utilized as a water leg, this will indicate that the vessel is a three-stage separator. The fluid will be separated into the base contents, gas, oil, and water. If a fire tube is also added for heat, then it will become a heater/treater. Heater/treaters are also three stage separators.

During the summer months, most companies try to use the heater/treater as a three stage separator, operating it without heat with only chemical treating in order to save and sell the gas. This procedure works well for lighter (higher API gravity crude) oils. If the crude oil is heavy and has a high paraffin and water content, the oil may not treat without heat.

Floats. Floats in vessels may be discriminate or indiscriminate, according to need and design. The purpose of a float is to control the level of liquid inside a vessel by means of an outside arm or pneumatic mechanism.

- **Indiscriminate floats.** Indiscriminate floats are made to float on both oil or water indiscriminately. The size of the float depends upon the power that it takes to operate the control arm, the turbulence of the liquid, the volume moving through the vessel, the length of the arm, the weight of the ball, and several other factors. The ball float is the most common indiscriminate float.
- **Discriminate floats.** Discriminate floats in the oilfield are floats that have a density or weight that will allow them to sink in oil but float on water. The float will operate on this interface. Since the weight per gallon of oil will vary according to the viscosity of the oil, and the weight of water will vary according to how much salt is contained in the water, discriminate floats are available with several densities. Oil will weigh over 7 pounds per gallon and water will weigh 8.3-9.6 pounds per gallon. Fresh water weighs 8.3 pounds per gallon and at about 9.6 pounds it begins to reach maximum natural salt saturation.

Ball floats are usually weighted with sand to allow them to sink through the oil phase but float in the water phase.

B-4. The Separator.

There are several styles of separators, which are classified by shape and by separation method. The basic shapes of separators are:

- Vertical separators
- Spherical separators
- Horizontal separators

The basic separation methods are:

- Two-stage
- Three-stage
- Metering

Operation of the two-stage vertical separator. Two-stage vertical separators have historically been manufactured in three styles: right-hand, left-hand, and the combination. The combination vessel has two identical emulsion inlet openings, located opposite of each other about two-thirds of the way up the sides of the vessel. All of the other openings are standard and this is the only difference between them. One of the inlet openings will be selected as the most appropriate to face the inlet manifold, and the other will be plugged, usually with a four inch bull plug. The right and the left hand separators will only have one inlet opening, and these are opposite from the other. The design of a two-stage vertical separator is shown as a cutaway drawing in Figure 4 and as a photograph in Figure 5 on the next page.

The gas will rise to the top, go through a mist extractor which is built into the top of the separator, and enter the **gas line**. This gas pressure is not really high pressure in a literal sense, because it is usually no more than 20-50 pounds.

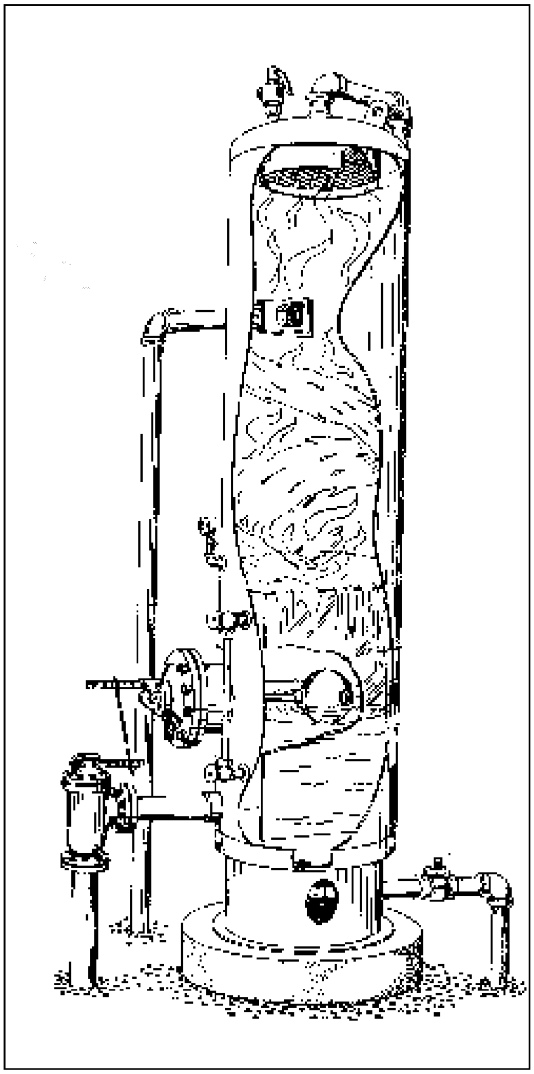

Figure 4. Cutaway drawing of a vertical separator showing the operation of the vessel.

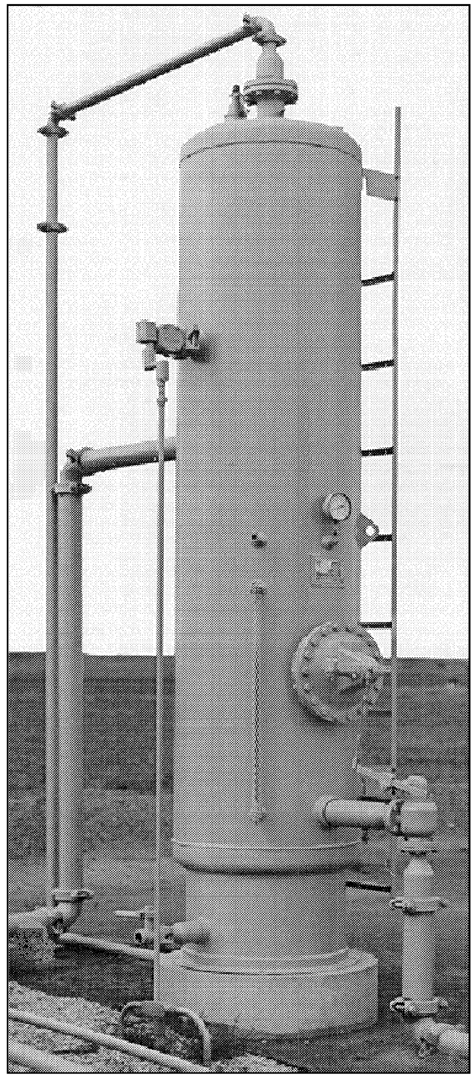

Figure 5. A typical two-stage vertical separator with a high liquid level alarm.

Since the atmospheric vessels will have no more than a few ounces of backpressure—usually 2-4 ounces—the pressure is high in relation to the atmospheric vessels, and this pressure is never directed toward an atmospheric pressured vessel.

The dumping of oil and water is regulated by a float-controlled **dump valve**. In newer designs, this valve draws the liquid from much closer to the bottom than previous styles, reducing corrosion problems. This was achieved by adding a short line inside the separator that ends near the bottom, reducing the amount of corrosive water that is present below the dump valve outlet.

A **pressure gauge** is added above the dump valve and a sight gauge glass is mounted to the left of the dump valve. The pressure gauge line turns upward inside a second short section of pipe that has a cap on top. If the liquid level rises all the way to the gas outlet, none will enter the gauge. A hail guard is added to protect the sight gauge glass from being accidentally broken by people, animals, or hail. An O-ring is placed on a new sight glass at the fluid level. A glance at this periodically gives an instant reference to several operating problems. A string may be tied on the glass to replace the O-ring when it becomes weather cracked and drops off.

The **emulsion inlet** has a device that forces the oil to swirl as it enters. This circular action creates turbulence in the liquid phase and accelerates gas breakout from the liquid. This lowers the amount of mist lost into the gas line.

As the fluid is dumped out of the separator, it will be directed toward the heater/treater, gun barrel, or a stock tank. The dump valve should be gently tested by hand periodically to be sure that it is still working freely and is not becoming frozen in one position. Care must be exercised, because a harsh push may break the float off, necessitating repairs.

The two valves on the sight glass have a built-in reamer on the valve seat to keep the hole into the tank open and to remove paraffin or scale that might accumulate. These should be carefully closed and opened periodically to ream them clean and to keep the fluid level in the gauge accurate. The lease pumper can close the bottom gauge valve and leave the top one open, then open the drain cock that is screwed into the bottom opening of the bottom valve to flush out the gauge glass. Experience at each separator will help determine how often this may be required. It may be necessary to occasionally adjust a valve stem packing if leakage or oil staining should occur.

Some separators have **pneumatic** instead of mechanical controls (Figure 6). Note the gas line coming off the top of the vessel to supply gas pressure to operate the diaphragm operated dump valve. Since the diaphragm is a medium- to low-pressure automation device, a pressure regulator is installed in the line to reduce the pressure and protect the valve.

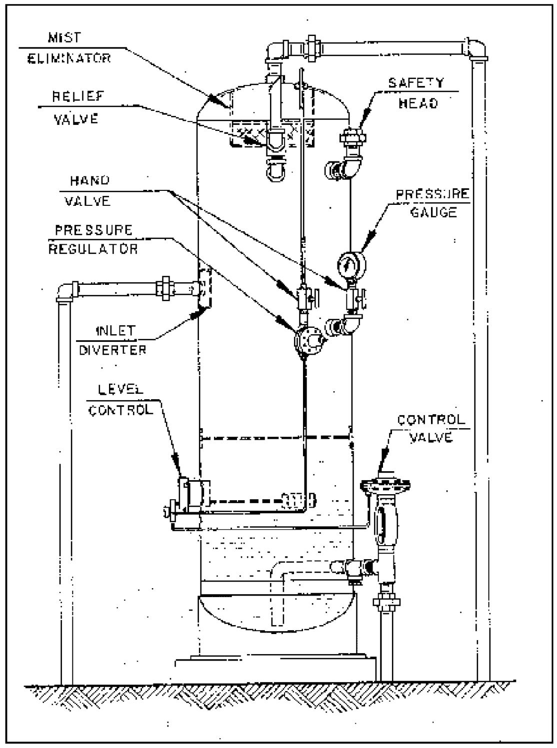

Figure 6. A separator with pneumatic controls.

Pressure safety devices. Two types of safety devices are placed on top of pressurized vessels: the *pop-off* or relief valve and the rupture disc or safety head (see Figure 7 on the next page).

The pop-off valve is set near the limit or maximum pressure that might cause the vessel to become dangerous. The pop-off valve has stainless steel springs, ball and seat, and other parts to prevent rust from changing the setting or making them fail to operate correctly. The pop-off valve can release the excessive pressure and has the ability to automatically shut off when the pressure returns to a safe level. It is an automatic valve requiring little or no maintenance.

The safety rupture disc is a thin, dome-shaped disc made of stainless steel, aluminum, or, in the case of some older separators, brass. The rupture pressure of the disc is several pounds higher than the safety release valve. When the safety release valve fails to open and the pressure continues to rise above a safe limit, the rupture disc will burst, releasing the pressure on the vessel. When the rupture disc bursts, the pressure will continue to be released into the atmosphere until the lease pumper comes by and shuts in the well or switches from the vessel. For this reason a line from the rupture disc may be run to the pit to prevent ground contamination. But if a line is plumbed from the rupture disc to a pit, it must be run so that there are no low places where water can collect and freeze during cold weather.

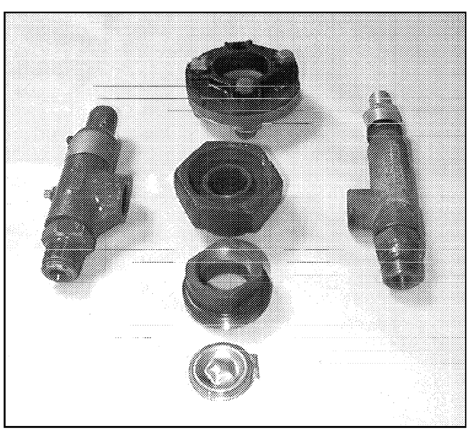

Figure7. Examples of safety release valves and pressure rupture discs.

B-5. The Heater/Treater.

The heater/treater (Figure 8) is a three-stage, pressurized vessel with heating capabilities, although they are also manufactured as atmospheric vessels. To be atmospheric, the stock tanks must be low enough to allow the oil and water to gravity flow to the stock tank and the water disposal system.

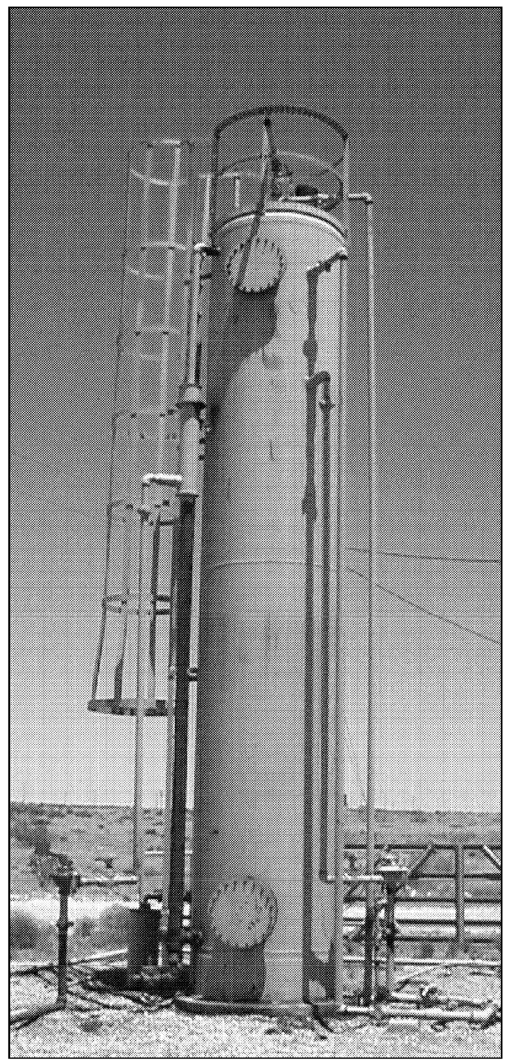

Figure 8. A typical vertical heater/treater. The lines can be seen entering the vessel. The site gauges and firebox are on the opposite side.

Three stage means the fluid is removed through three lines. In the heater/treater pictured nearby, the oil, water, gas emulsion coming into the vessel enters through the highest line on the right side of the vessel. This should not be confused with the gas line that comes off the center of the top.

The **natural gas** flows out through the gas line coming off the center of the top of the vessel through the line to the right. A backpressure valve is installed nearby to control the pressure inside the vessel.

The **produced oil** flows out the lower line on the right side of the vessel. about eight feet from the top. This is the fluid level inside the vessel. Note that a liquid valve with a back pressure weight is installed approximately four feet from the ground. This valve controls the amount of oil standing in the down comer line and does not control the height of the liquid in the tank.

The **water** comes out of a line on the lower left side of the vessel at 90 degrees from the other lines, and the water goes up and spills over the water leg a small distance lower than the oil outlet. The height of the water in the water leg is controlled by a valve identical to the oil outlet control valve.

The heater/treater is usually the only pressurized vessel in the tank battery system where the heights of the fluids in the vessel are **controlled by line height.** The fluid levels in the gun barrel are also controlled by line height. The water level in the bottom of the heater/treater is maintained at approximately one foot above the fire tube. Oil does, however, come into contact with the fire tube.

Most operators try to heat the produced crude oil only in the winter. The use of appropriate chemicals and the heat from the sun is usually satisfactory for treating oil in the summer months. The firebox can consume a lot of gas. Selling the gas provides income toward the purchase of the chemicals. It is a give-and-take situation in determining when heat is necessary.

Controlling the height of the water. Earlier, the use of the beam balance scale in weighing water and oil was reviewed. Calculations for computing the height of the water leg is reviewed in Appendix F, Mathematics.

The height of the **water** in the heater/treater should be approximately one foot above the top of the fire tube.

The amount of water in the heater/treater is controlled by raising or lowering the height of the side boot on the water leg. If the weir nipple is raised in the water leg boot, the amount of water retained inside the heater/treater will be higher. If the weir nipple is lowered, the water retained will be lower. The total fluid column height will remain constant, controlled by the height of the oil outlet opening.

The fluid sight glasses. The lower fluid level sight glass should display water in the lower half and oil in the top half. If the lower valve is occasionally closed, it is a good practice to close and re-open the top valve, and then bleed the lower petcock into a container. This will effectively clean the glass to allow the liquid level to correct itself. Tie a small rag at this level to indicate future level changes.

The top sight glass will have oil in the bottom and gas in the top. It can be cleaned in the same manner.

Backpressure valves for pressurized vessels. The Kimray diaphragm-operated backpressure valves are widely accepted by the petroleum industry as a dependable automatic operating valve (Figure 9). It is a very popular selection for controlling the back pressure for the separator, the heater/treater, the emergency vent line, and the gas purchasing company, and on several other vessels where a back pressure valve is installed. The term **backpressure** refers to the pressure in **back** of the valve. The valve that controls pressure after the backpressure valve or downstream is usually referred to as a **regulator.**

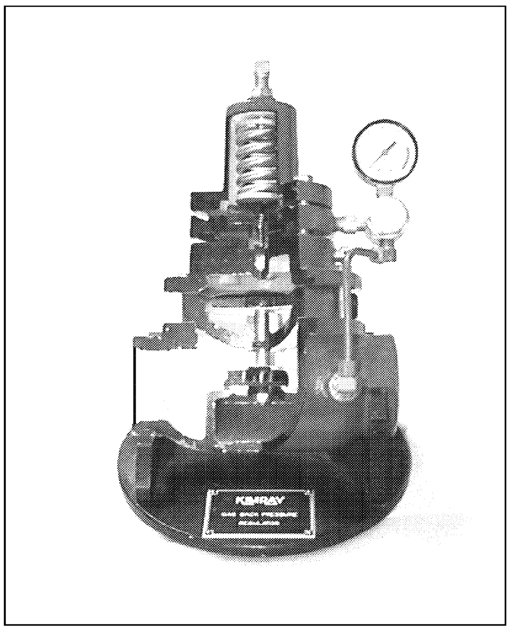

Figure 9. A diaphragm-operated backpressure valve.
(courtesy Kimray, Inc.)

The treater oil and water valves (Figure 10) are used to control the dumping of oil toward the stock tanks and the water toward the water disposal and injection system. These are basically liquid dump valves. The installation of the valve is shown in Figure 11. The drawing shows one method of securing the necessary gas pressure to the oil or water valve that prevents fluctuations in gas pressure from affecting the operation of the valve.

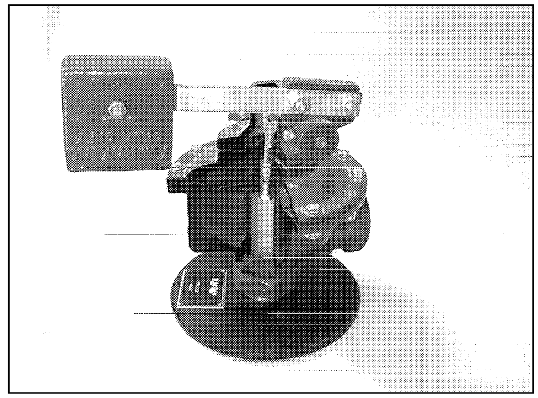

Figure 10. Treater oil and water valves.
(courtesy Kimray, Inc.)

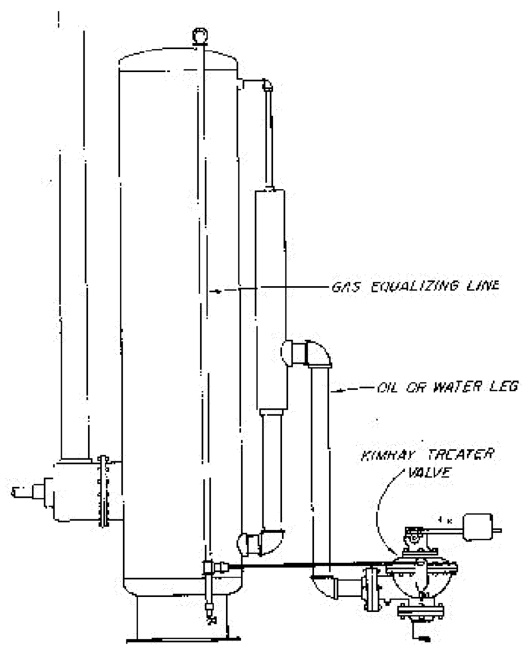

Figure 11. How the treater liquid valve is installed.
(courtesy Kimray, Inc.)

As the oil spills out of the heater/treater into the oil line, or water spills over the equalizer riser on the water outlet line, these liquids create a downward pressure against the valve. When the column of liquid builds up to about four or five feet in the line, the valve opens, allowing part of it to flow toward the next vessel. The height of the line, not the valve, controls the liquid level in the vessel. As the pressure gets lower, the valve closes again.

A gas line comes off the top of the vessel and connects to this valve. The purpose of this line is to equalize the gas pressure inside the vessel across the liquid dump valve. If a flowing well opens up or someone opens a valve and a surge of additional pressure comes into the vessel through the inlet line, this change in pressure will also occur on both sides of the diaphragm. This change in pressure will have no effect upon the operation of the valve.

The height of the water leg is determined by the weight per square inch of the column of salt water and the weight of the oil on top of the water. The height of this column of liquid is from the oil overflow outlet to the bottom of the vessel.

In Appendix F, Mathematics, the procedure for calculating the height of water legs is reviewed.

The float-controlled **separator dump valve** pictured in Figure 12 is a popular valve. The pressure below the seat of the valve is transferred to the top mechanism of the valve. This removes any stress or unusual pressures from being exerted against the diaphragms in the valve and results in smooth and dependable valve action.

If the dump valve arm needs to operate in the opposite direction, remove the bolts in the top, rotate the top one-half turn, and replace the bolts. Now the mechanism will operate in the opposite direction. The direction of the arm can also be turned in the opposite direction according to need.

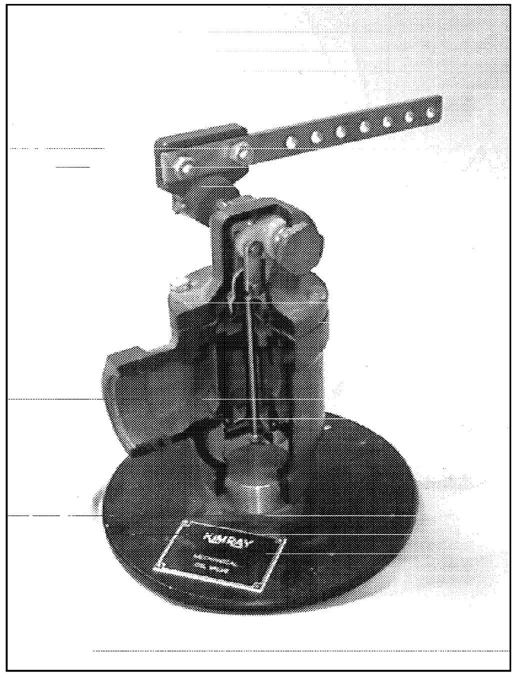

Figure 12. A float-controlled separator dump valve.
(courtesy Kimray, Inc.)

B-6. Interior Design of the Vertical Heater/Treater.

In the past, two types of heater/treaters have been constructed. During the past few years, several innovative changes have made the basic design more efficient, so only one type is illustrated as Figure 13 on the next page. This style is designed for high water production.

Inlet line. The inlet line enters above the fluid level. The gas, being lighter, flash separates and goes up through the mist extractor and into the gas line. The liquid falls to the bottom of the vessel through a tube.

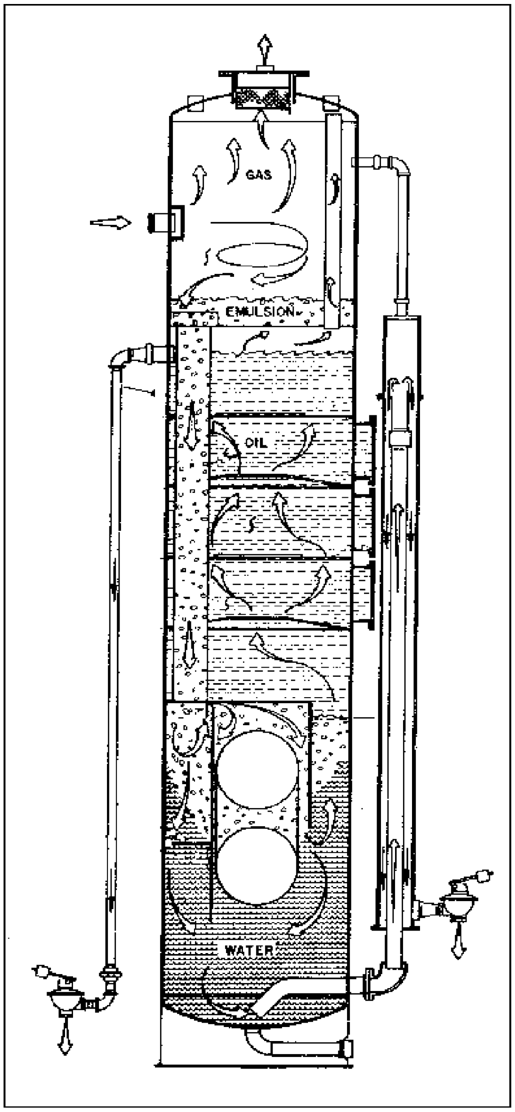

Figure 13. Interior view of a heater/treater.
(courtesy of Sivalls, Inc.)

At the bottom. At the bottom, the free water that has flash separated continues on down and out of the vessel through the water leg, absorbing very little of the vessel heat. The oil migrates up through the water section, past the fire tube, and is heated as it continues to migrate up to the oil section of the heater/treater.

The oil trip upward. As the oil travels upward, it moves from one side to the other passing upward through openings, while any suspended water contacts the plates, separates, and moves back downward toward the water leg and on to the disposal system. When the oil reaches the top, it falls into the oil outlet and on to the gun barrel or the stock tank. Any new gas that breaks out passes upward through a provided tube up to the mist extractor and into the gas system. This tube also equalizes pressure between the upper and the lower section of the vessel.

The water leg. The operation of the water leg is also visible, and the weight of the water in the water leg is exactly the weight of the water and oil column inside this vessel. This three-stage separation is fully controlled by line heights instead of a discriminate float as it is in the free water knockout. This vessel is one of the most useful vessels in oilfields.

The Lease Pumper's Handbook

Chapter 10
The Tank Battery

Section C

ATMOSPHERIC VESSELS

Atmospheric vessels operate at the pressure of the surrounding air. Atmospheric pressure at sea level is 14.7 pounds per square inch or 29.92 inches of mercury. Atmospheric pressure decreases with rising elevation. Thus, air pressure on top of a mountain is less than that at sea level. This is referred to as PSIA, or pounds per square inch, absolute.

Atmospheric vessels form the *low-pressure gas system.* Every time the pressure is reduced on hydrocarbons or the liquid is placed in motion, additional gases break out. This goes on continuously. A small amount of gas is even entrained within the produced water. To reduce the loss of the light-end petroleum products from evaporation and to allow the gas to be recovered, atmospheric vessels operate with a gas backpressure of 2 to no more than 8 ounces. The thief hatch has a built-in pressure safety release. The vent line will usually have a 2-4 ounce safety back pressure release valve.

All atmospheric vessels are capable of withstanding the pressures generated by the weight of the liquid in the vessel. The weight of a column of fluid can be summarized as follows:

- **Oil.** As a rule of thumb, oil weighs 1/3 pound per square inch (psi) times the depth of the column or depth in feet. If a tank has 15 feet of oil in it and has a 2-ounce backpressure valve, the weight at the bottom of the tank is about 5 pounds, 2 ounces per square inch, thus:

  (1/3 lb/ft x 15 feet) + 2 oz. of backpressure = 5 lbs-2 oz. psi

- **Water.** As a rule of thumb, water weighs ½ pound per square inch times the depth or height of the column in feet. If a tank has 15 feet of water in it and has a 2-ounce backpressure valve, the weight at the bottom of the tank is about 7 pounds, 10 ounces per square inch.

  (½ lb/ft x 15 feet) + 2 oz. backpressure = 7½ lbs + 2 oz psi = 7 lbs.-10 oz. psi

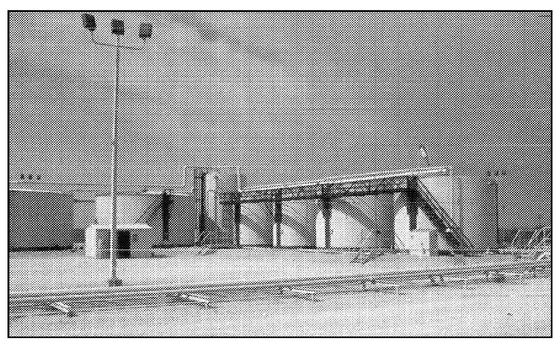

Figure 1. Tank battery atmospheric vessels including a gun barrel, four oil storage tanks, and two water tanks.

C-1. Major Low-Pressure Gas System Components.

The major components of the low-pressure gas system (Figure 1) include:

- **Gun barrel** or **wash tank.** A large three-stage atmospheric separator designed to separate the fluid produced from the oil well into oil, gas, and water, as well as being the first vessel in the low-pressure gas system (Figure 2).
- **Stock tank.** Acts as a surge tank at the same time when a LACT unit is operating. A vessel to store produced oil until enough has been accumulated to sell to the pipeline or transport.

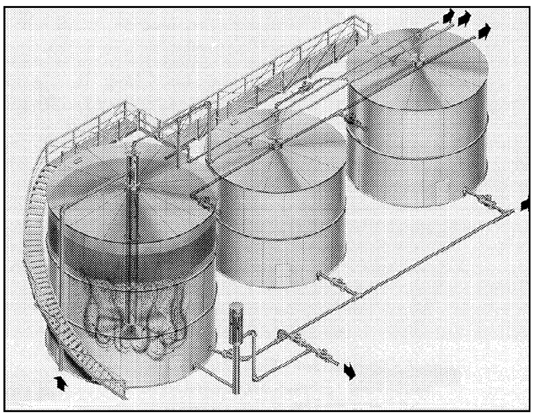

Figure 2. A common arrangement of the gun barrel and stock tanks.
(courtesy of National Tank Company)

- **Water disposal tank.** A vessel utilized to hold the produced water (usually salty) until it is re-injected into some underground formation.
- **The lined pit.** Formerly called a *slush pit* when BS&W was drained into the pit and the emulsion burned. Presently, some lined pits are still used to produce water if only a few barrels are produced daily. Under current regulations the pit still has a use as an overflow facility.
- **The dike or firewall or escarpment**. The dike is an earthen wall built around the tank battery atmospheric vessels, designed to contain liquid spills.

C-2. Styles of Atmospheric Vessels.

Atmospheric vessels were made of redwood for many years. Redwood vessels were very stable and were not greatly affected by corrosion. They did have problems, however, in maintaining a water blanket on top of them and in the grooves between the staves. Woodpeckers sometimes made holes in them. The steel bands had to be tightened periodically, and the tanks had to be re-strapped occasionally to determine the tank's capacity. The few redwood tanks that remain in the oilfields today are generally used as water tanks or gun barrels.

Bolted steel tanks—such as the stock tanks shown in Figure 2—later replaced redwood tanks, and welded tanks (Figure 3, left) have taken the place of most of the bolted tanks. Fiberglass tanks (Figure 3, right) are being widely used, but may not withstand high winds when empty. The low, wide fiberglass tank is popular for water disposal. Guy lines are placed on most of these tanks for safety. Rubber and fiberglass liners are often placed in steel tanks to combat corrosion. Some paints aid in extending tank life.

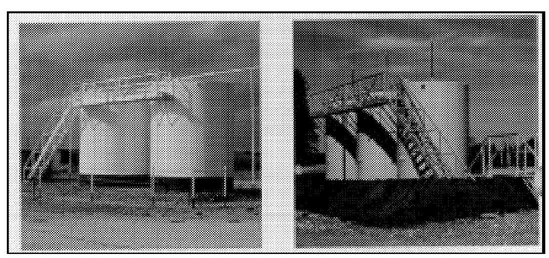

Figure 3. Examples of welded tanks (left) and fiberglass tanks (right).

Atmospheric tanks are selected on the basis of need for the site and in a size that is appropriate to the production volumes from the well. Common capacities include:

Capacity of selected standard bolted oil field tanks.

Nominal Size in Barrels	Dimensions Dia. x Height	Barrels per Foot
Low 250	15' 4-5/8 x 8' 1/2"	33.11
Low 500	21' 6-1/2" x 8' 1/2"	64.91
High 500	15' 4-5/8 x 16' 1"	33.11
High 1000	21' 6-1/2" x 16' 1"	64.91

Capacity of selected standard welded oil field tanks (Fiberglass tanks are similar in size).

Nominal Size in Barrels	Dimensions Dia. x Height	Barrels per Foot
100	8' x 10'	8.95
200	12' x 10'	20.14
210	10' x 15'	13.99
295	11' x 17.6'	16.93
400	12' x 20'	20.14

C-3. Common Lines and Openings of Atmospheric Vessels.

Figure 4 shows a diagram of an atmospheric vessel with the typical openings indicated and labeled. Each opening and common design variations are discussed in the following paragraphs.

The emulsion inlet. The emulsion inlet is usually located on the top of the tank. A walkway is usually provided and the line has a quarter-round opening valve, either a plug- or ball-type. A down-comer line is often installed inside the tank to reduce light-end evaporation and static electricity and the resulting metal loss from electrolysis. When several wells are producing to the same tank battery, there will also be a second emulsion inlet from the test three-stage vessel.

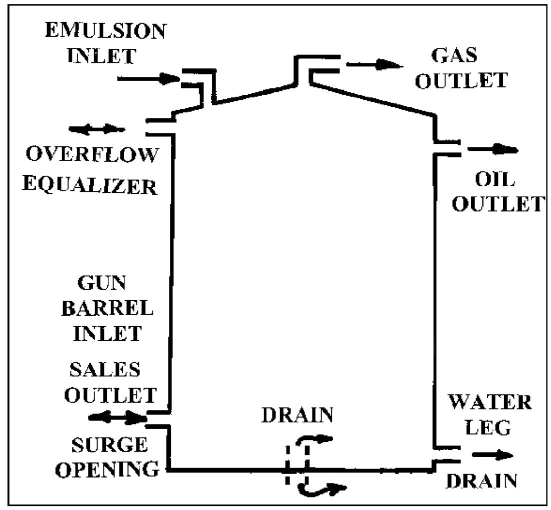

Figure 4. Line openings typically used in atmospheric vessels.

The equalizer inlet or outlet (Option 1). This is the highest opening on the side of the vessel. When it is used as an equalizer, it allows one tank to be completely filled before the fluid flows through the equalizer line and begins to fill the second tank. This usually occurs while the lease pumper is not on site, providing an easy means of topping off tanks.

The overflow line (Option 2). This is a second option for the use of the highest opening on the side of the vessel. When it is used as an overflow line, the liquids can be directed toward a lined pit or even the water disposal tank. This may be a good option when production is erratic or when automated equipment fails to function.

The gas outlet. The gas outlet line is located in the center of the top of the vessel. It is connected to the low-pressure vent system and has a 2-ounce backpressure valve to reduce light-end evaporation. Without this backpressure, some gas wells will build production up to a partially full level and then will gradually begin evaporating all of the additional liquid production. The lease records will indicate this problem, and corrective mechanical adjustments can be performed to stop this loss of production and income. The second function of the valve is to prevent the tank from filling with oxygenated air when the tank is emptied. This can result in an explosive mixture. The safe tank is one filled with natural gas.

The oil outlet. This outlet is used as an oil outlet when the vessel is used as a gun barrel and determines the liquid operating level. It is also used as an oil outlet whenever the tank is used as a skimmer tank for final oil or water removal. Skimmer tanks can be hooked up several ways to meet lease needs and resemble a wash tank in assembly.

The side drain outlet (Option 1). Side outlet. The side drain outlet is used for several important functions such as removing water accumulated from production or well testing, cleaning oil to lower the BS&W level, and cleaning heavy tank bottoms.

The side drain outlet (Option 2). Another use of the side drain outlet is for the water leg when the tank is used as a gun barrel.

The bottom drain outlet. There are three styles of tank bottoms. The most common style is flat with the drain line on the side. The two styles of cone-bottomed tanks are reviewed later in this chapter.

C-4. The Gun Barrel or Wash Tank.

An advantage of the wash tank over the gun barrel is that it slows the oil down as it goes through the vessel. The oil stays in the wash tank much longer, allowing more time for the water to drop out. The oil and water flow into the central flume or side boot, travel downward through a spreader, then work their way upward. The water falls to the bottom and is removed through the water leg. Any gas that continues to break out goes up into the low-pressure gas system.

The gun barrel washes the oil to remove as much water as possible before the oil goes through the oil line to the stock tank. Water will continue to drop out of the oil as long as it remains in the tank battery. Even though the system may treat the oil to less than one percent BS&W before it goes to the stock tank, the stock tanks will need to be circulated periodically to keep the bottoms clean. *Clean* in reference to tank bottoms indicates that there is less emulsion on the bottom than the level that the pipeline or transport company requires at the time that the oil is purchased and removed.

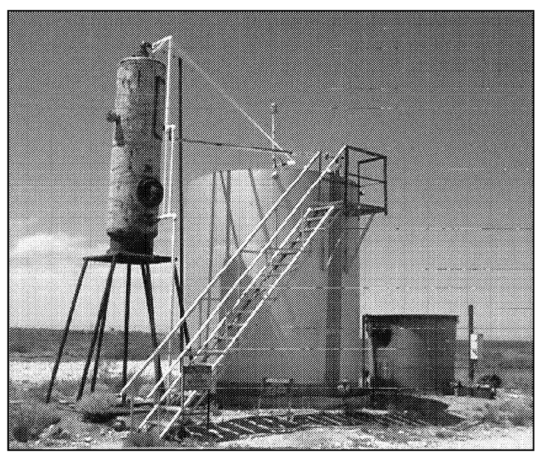

Figure 5. Atmospheric gun barrel made from a vertical separator and a pipe platform.

The water leg operates in the same manner as the water leg on the heater/treater. In the system shown in Figure 5, the gun barrel was shop manufactured from a used vertical separator. The operator brought the production line down through the former gas line to the bottom on the inside. The water leg is made from white PVC line, and the gas line was installed at an angle to the top center of the welded 210-barrel stock tank through the former safety pop-off opening.

The gun barrel with side boot (Figure 6) has become one of the more popular gun barrel installations. The emulsion enters the boot located high on the right side where the liquid and gas separate. The liquid falls to the bottom in the tube and enters the vessel in the bottom perforated header where the oil will begin to make its way to the upper oil area. The water remains in the water area at the bottom and goes out through the side combination outlet—that is, the drain and water leg. If the gun barrel uses a standard stock tank, it must be elevated on a mound of fill to approximately one foot higher than the stock tanks.

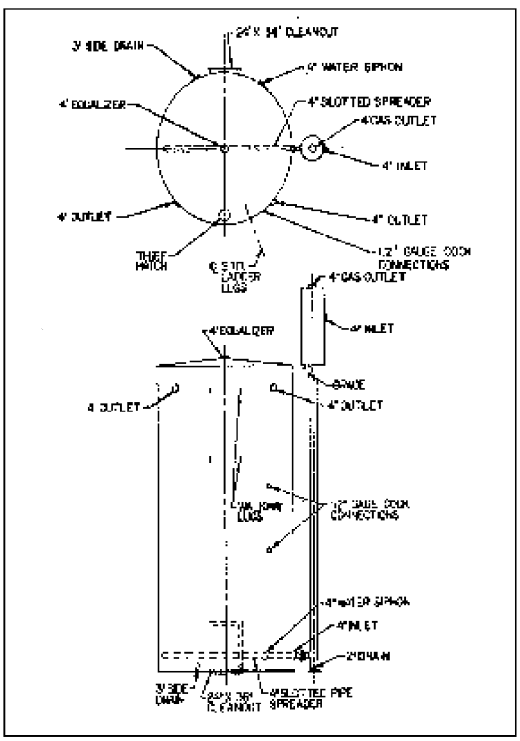

Figure 6. Diagram of a gun barrel with a side boot.

C-5. The Stock Tank.

The stock tank is similar to the gun barrel. Most stock tanks, however, have a strike plate directly under the thief hatch. This is a plate that the gauge line plumb bob will strike or bump against each time the tank is gauged. The purpose of this plate is to prevent damaging or punching holes in the bottom while gauging the tank.

There are three styles of stock tank bottoms available: a standard flat bottom and two styles of cone-bottomed tanks.

Cone-bottomed tanks. Cone-shaped bottoms are excellent for circulating and treating the *bottoms* (emulsion in the bottom of the tank) for leases with paraffin and a low API gravity oil.

To prepare the site for a cone-bottomed tank, the ground must be tapered at the correct angle and a small hole dug exactly in the center to hold the bottom projection (sump). A satisfactory layer of pea gravel or sand and a double layer of 120-pound felt (tar paper) or other suitable barrier may be placed on the ground prior to setting the tank. This is a good corrosion barrier and allows the tank to *breathe* under the bottom, allowing moisture to evaporate.

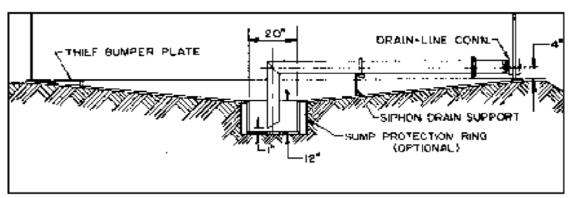

Figure 7. Style 1 cone-bottomed tank.

The style of tank shown in Figure 7 is often used, though it is not obviously a cone-bottomed tank. A check of the tank chart will show that the tank has a cone-shaped bottom because the first ¼-inch reading will contain several barrels of oil. This is because the reading must include the capacity of the cone bottom.

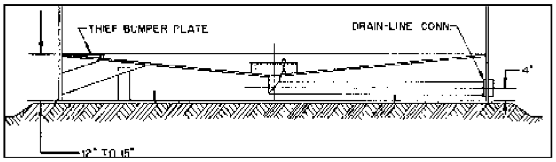

Figure 8. Style 2 cone-bottomed tank.

Figure 8 shows a cone-bottomed tank that actually has an air space under it. There is also a metal plate several inches wide that the vessel rests on to prevent it from sinking into the ground from the weight of the oil. This design is easily recognized because the pipeline connection must be elevated to allow one foot for BS&W and emulsion (Figure 9). These styles of tanks are popular with the lease pumper because of the ease they present when circulating and cleaning bad tank bottoms.

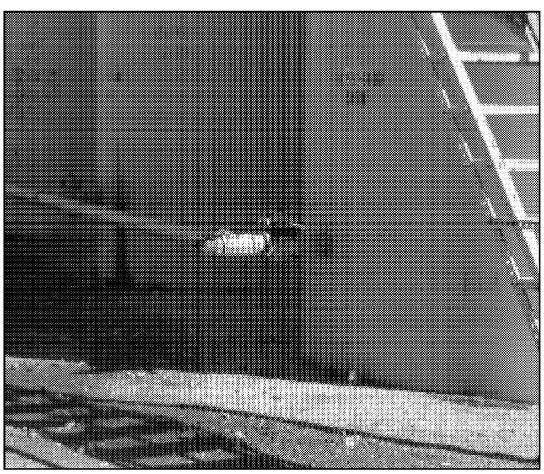

Figure 9. A Style 2 cone-bottomed tank showing how the sales outlet is raised above the BS&W level.

The stock tank openings. The stock tank is an atmospheric vessel designed to hold the crude oil until enough production has been accumulated to sell. This may be accumulated in a few days or may require many weeks. This is usually a minimum of one transport load, which requires a 210-barrel tank. This allows approximately 160-180 barrels to be sold and approaches the maximum weight allowed to be hauled on the highway. Stock tanks can be purchased as small or as large as needed.

The stock tank has four possible openings on the sides. One opening, 12 inches off the bottom, faces the front. This is the opening provided to install the oil sales line. Oil may be sold by pipeline or by the truck transport load. Illustrations of these two systems are included in Chapter 13.

On the back of the tank, approximately 4 inches from bottom, is a 4-inch drain opening. This line is connected to the drain and circulating system.

On the front near the top of the tank and at 45 degrees, there are one or two 4-inch openings provided to connect the tanks together with equalizing lines. This will allow a tank to *top out* or finish filling during the hours that the pumper is not present, and any additional oil produced will gravity feed over to the next selected tank. When the pumper comes back to the tank battery, the fill lines are switched so that the full tank of oil is isolated for final testing, treating if needed, and made ready to be sold.

The oil inlet line. Some companies install a down-comer line inside the tank on the inlet line. Since some welded tanks do not have threads on the inside of the vessel, the line is welded inside a nipple where it can be lowered inside through the top. One or two ½-inch holes are drilled into the down-comer near the top to prevent a siphon effect and to allow any free gas to escape. The line goes down to within a foot of the bottom.

There are several benefits to this line. It eliminates much of the static electricity caused by oil dumping into the tank violently and thus lessens corrosion by electrolysis. A second benefit is that it stops the high *splatter* effect of the incoming oil striking the liquid surface and reduces the amount of light-ends going out the low-pressure gas line. A third, and possibly the most important benefit, is that when oil is circulated, the high volume of liquid entering the tank sweeps up or stirs up the accumulated BS&W that piles up under the inlet area and assists greatly in keeping the bottoms clean. The rolling action stimulates treatment and water fallout.

The drain line inside the tank. The drain line opening is located on the back of the tank approximately 4 inches from the bottom. This line should extend inside the tank until it is within a foot or so of being under the thief hatch opening. Actually, a series of very small holes drilled in the bottom can be beneficial. An ell is screwed on the end or the end is turned down to place the opening within 1 inch of bottom.

When the well produces paraffin, some of it clings to the tubing and entrains a small amount of water. Eventually, the paraffin becomes heavier than oil and settles to the bottom when it enters the tank. This emulsion can build up many inches thick on bottom. When the bottom of the tank is circulated, a small amount of this emulsion is pulled up. As the less viscous upper oil channels down, it vacuums out a small pocket and most of the bottom emulsion never moves or requires hours to shift.

C-6. The Water Disposal Tank.

The disposal tank (Figure 10) is usually a short tank that holds a minimum of one transport load of water or about 200 barrels. This water will usually be pumped down a disposal or a water flood well. The tank is short to aid in water removal from the tank battery system. Some are manufactured in two matching halves for easy shipment and assembly. More extensive information about water disposal tanks is contained in Chapter 15, Enhancing Oil Recovery.

The water disposal tank has replaced the pit as a general disposal system. This has become common because of environmental regulations.

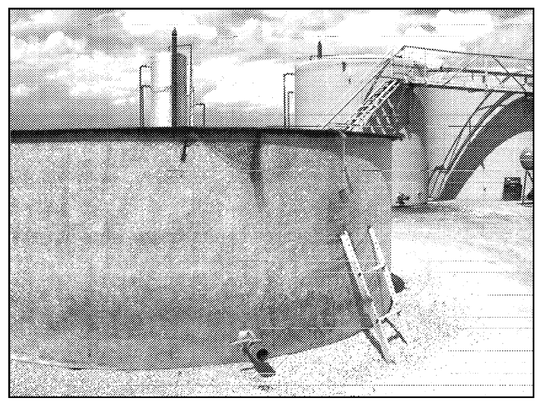

Figure 10. A water disposal tank.

C-7. The Pit.

The pit is an atmospheric open tank with earth walls to hold produced water. Many years ago it was called a slush pit. The word *slush* implies a thick emulsion or one with high paraffin content. This word is not used as often as in earlier years. Historically, the term slush pit has also been used in reference to the drilling rig pit.

The newer style pits have a plastic liner or membrane that prevents the earth from becoming contaminated by the salt and other compounds contained in the water. Frequently, pits are covered with a net mesh for wildlife safety. Pits will continue to be used in the future for both drilling and production operations because they serve as an excellent holding tank in the event of vessel overflow and may enclose emergency gas flares.

C-8. The Dike.

In some areas, an earthen dike is required around all vessels that contain fluid that might contaminate the ground. The holding capacity of these dikes is usually one and one-half times the capacity of all the vessels inside the dike. When a dike is constructed, steps should be installed over the top as walk paths to prevent people from walking across the dike at odd points. Walking across these dikes causes continuous damage to the dike so that the top edge wears away. If the walkway is high, safety hand rails should also be provided.

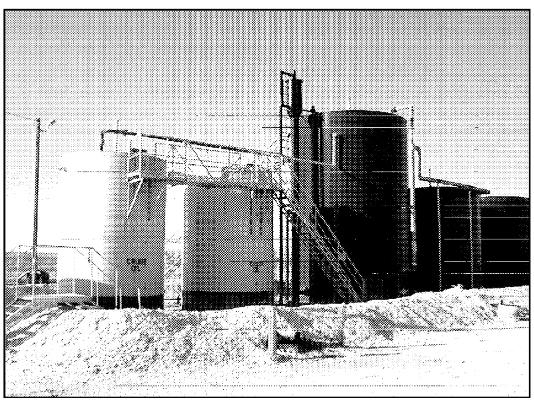

Figure 11. The dike around a tank battery should be able to hold a volume one-and-one-half times the capacity of all of the vessels.

C-9. Vessels Solve Unusual Problems.

Some identical vessels may be installed in two or more different locations within the battery or on the lease in order to solve completely different, unrelated processing problems. These uses are not always apparent, especially when a specific type of vessel is installed in an unusual location. Though the vessel will certainly be there to accommodate a need and solve a specific problem, but that problem may be unique to that battery. The lease pumper should never be reluctant to ask what the purpose of a vessel is and why that style of vessel was selected. Understanding these solutions may help the lease pumper to solve similar problems at a different tank battery.

Consider a few examples. A small vessel or riser may be installed ahead of a liquid meter just to prevent a slug of gas from hitting the meter. This is a solution similar to placing the gas eliminator ahead of the meter in the LACT unit. A line heater may be used to thin fluids near the wells so that thick emulsion can flow to the tank battery. A line heater may be installed between the header and the two-stage separator to prevent ice from forming in separators and causing them to overflow in cold weather. A stock tank may be utilized as a gun barrel. A separator may be used as a scrubber for cleaning firebox gas.

The list of unusual installations contains many possibilities. It is limited only by the lease pumper's imagination and knowledge of vessel performance.

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Section D

EMULSION LINE SYSTEMS

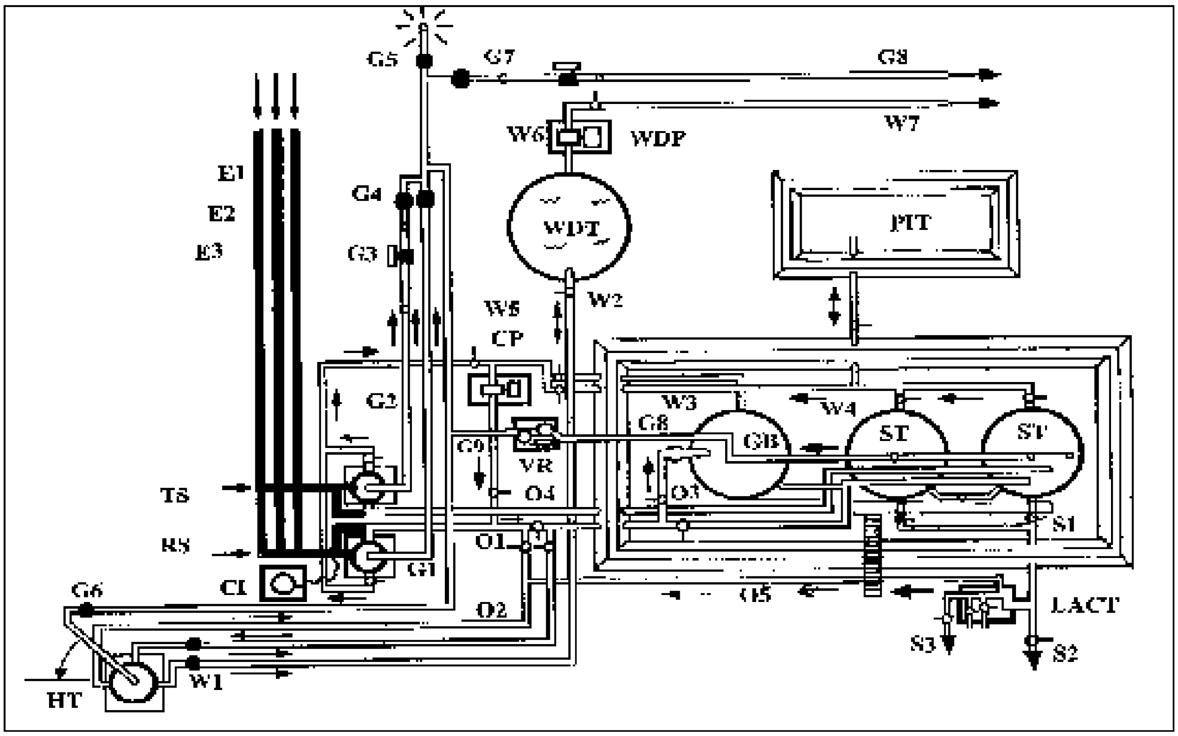

Figure 1. Diagram of tank battery lines with emulsion lines indicated by an *E*.

D-1. Emulsion from the Well.

When an oil well produces fluid—crude oil, natural gas, water, and other compounds—it is generally referred to as an ***emulsion***. When this term is used, it generally refers to everything that comes out of the well before the separation process begins. After the **gas** is removed, the remaining liquid is usually referred to as **crude oil**. This crude oil will possibly contain a little or a great amount of **water**. Water removal is the next step in the treating process in preparing the crude oil for sale.

The emulsion from the oil well or the gas well determines what the tank battery looks like, which vessels will be installed, and the sizes of those vessels. A few of the factors that control the design of the tank battery include the volume of oil and gas that is being produced daily, the number of wells to be drilled and produced to the tank battery, the gravity of the crude oil, the amount of water being produced, the amount of paraffin, the anticipated life of the reservoir, difficulties in treating, and other factors.

One of the most important factors that must be determined from the beginning is how hard it will be to remove enough water to sell the oil. If the API gravity of the produced oil is high, this separation is usually relatively simple because the crude oil is thin and flows easily. A three-stage separator or the addition of a wash tank is all that is needed.

If the crude oil has a low gravity, very little water is flash removed (removed in just a few seconds or minutes) or is difficult to remove. Additional vessels and processes will have to be considered for the operation. Once the installation requirements are determined, the flow line can be laid and construction of the tank battery can begin.

D-2. The Flow Lines and Header.

As the flow lines enter the tank battery, they are usually aligned and oriented with the vessels so that they are parallel to each other and approximately 18 inches apart. The distance apart is governed by the makeup arrangement of the header. By using a 12-inch nipple and two tees as the header is made up, the line separation will be established at 18 inches. Flow lines may be of steel, plastic, or fiberglass. The last fittings in the flow line before it connects to the header are an optional valve, a 6-inch nipple, a union, another 6-inch nipple, a required check valve, and another 6-inch nipple. At this point, the flow line enters the header tee.

When an oil leak or line break occurs in the flow line, the check valve is the only safety device to prevent the emulsions from all of the wells that produce through the header from flowing back and being lost on the ground. If the check valve at the tank battery header should fail and the casing check valve at a near-by pumping well also fail, it is not unusual for most of the daily production from all wells to be lost downhole into the offending well. In addition, there are no indications of any problem when inspecting the system. The well will show good, strong pump action at the bleeder valve, although the well is just circulating.

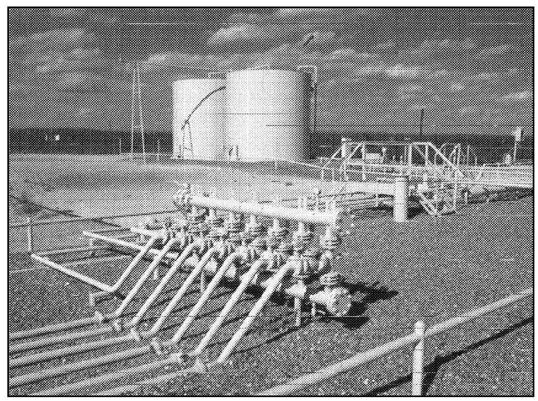

Figure 2. Flow lines entering the header. Often the lines are numbered like these for easy identification.

The header. The purpose of the header is to control which crude oil system each well flows through as the oil progresses through the system on its way to the oil holding tanks.

When the tank battery has only one well, a simple system is provided. When it is a marginally producing well, the system is small, and, because a lot of time is available to treat oil, the lease pumper can usually treat and sell the oil successfully with minimal facilities.

When all of the production is marginal, the cost of constructing a second production system may never be justified, and the treating system is a barrel test, a bucket test, or an individual well tester.

The important consideration in designing the header is to stand the valves up where they can be inspected at a glance to determine if each valve is open or closed. If the valves are controlled by automation, a *tattletale* or indicator of some style is usually included in the valve design for visual inspection in determining if it is open or closed. As a rule, multiple round opening valves are never used when designing a header because they lead to mistakes in settings and production problems, loss of production, and spills. Well numbers should be indicated on all header lines.

There are several popular styles of headers, and many of them are described in this manual. Any chosen style is good as long as the valves are easy to understand. Normally, headers are designed with only a **production** header and a **test** header. When a great number of wells are producing to a single battery, this number will be increased to three with the wells producing through two **production headers**, and **one test header**.

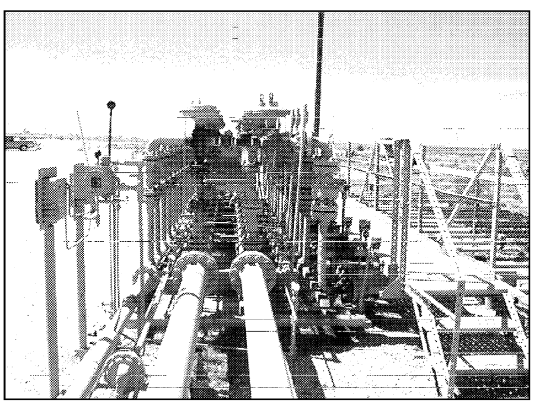

Figure 3. A three-line header with a four-inch test line (left).

D-3. Chemical Injection at the Header.

Chemical is injected at the tank battery at a location after the header but before the first vessel. This is usually just ahead of the separator. The chemical is added after the header to ensure that the produced oil gets chemical in the event one or two wells are shut in. On large, high-production installations, the chemical will be mixed well regardless of where it is injected.

Some chemical injectors are simple injectors attached to a barrel on a stand. With stripper production, this is still common. The larger installations being connected at tank batteries today have a low tub to catch any drips that may develop. Federal law requires that any tank with a volume of 600 gallons or greater have secondary containment. The chemical is usually in fiberglass tanks on a stand. A sign instructs the field personnel on the type of chemical being used, and a tube storing written literature about the chemical is attached to the stand. A truck will come by on a schedule and add chemical to the tank as needed.

Two chemical injection systems are shown in Figures 4 and 5. The first features the simple pump system that has been common for more than the past fifty years.

Figure 4. A chemical injection system using a barrel and pump.

The system shown in Figure 5 represents the latest style of installation that meets present requirements for high-volume installations. Note that the system includes several features to enhance safety and environmental protection. Beneath the chemical tanks is a drip and leak collection pan. The sign beneath the tank on the right identifies the chemicals and warns of their hazards. Additional information is contained in a tube next to the tank. This system works particularly well with large headers. Chemical treatment is always required for hard-to-treat oil, so this system will continue to be used for many more years.

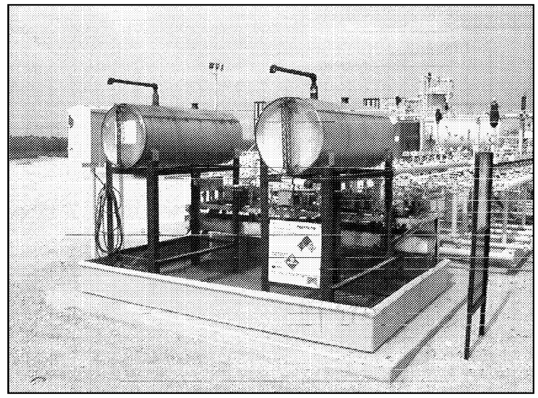

Figure 5. The chemical injection system for a large tank battery with injection at the header.

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Section E

CRUDE OIL LINE SYSTEMS AND EQUIPMENT

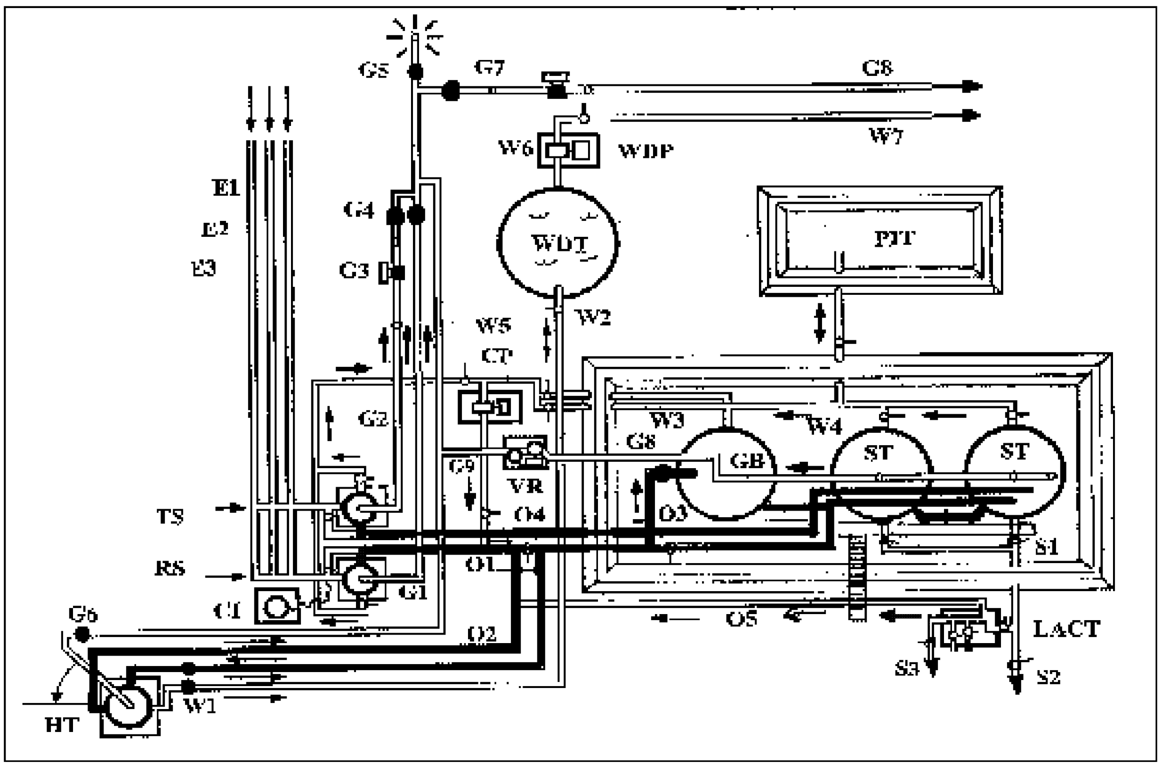

Figure 1. The crude oil lines in this diagram of a tank battery are labeled with an *O*.

E-1. Lines from the Separator.

Crude oil lines from the separator should lead directly to the stock tank. A diverter manifold is assembled in the line to provide line openings for connections to lead to and from specialized vessels, such as a heater/treater or a gun barrel. The crude oil then continues on toward the stock tank. The specialized vessel can then be utilized or bypassed according to need. When water and paraffin are also produced with medium- to low-gravity oil, the second vessel in the system will probably be a heater/treater.

E-2. Lines from the Separator to the Heater/Treater.

For fire safety the heater/treater is located a minimum of 100 feet from the nearest hatch that contains gas. Although the outside air supporting the flame in the heater/treater must travel through a flame arrester (for fire safety), this distance is always maintained.

The lines to and from a conventional style heater/treater (Figure 2) are obvious. The highest side line on the right is the inlet. The second line down as seen from this angle is the oil outlet, and the water comes out the lower left opening. The gas comes off the top. On the vessel in the background of the photograph, the right line is the inlet, the second line to the left is the oil outlet, the third line is the gas line, and the fourth (the one on the left) is the water disposal line.

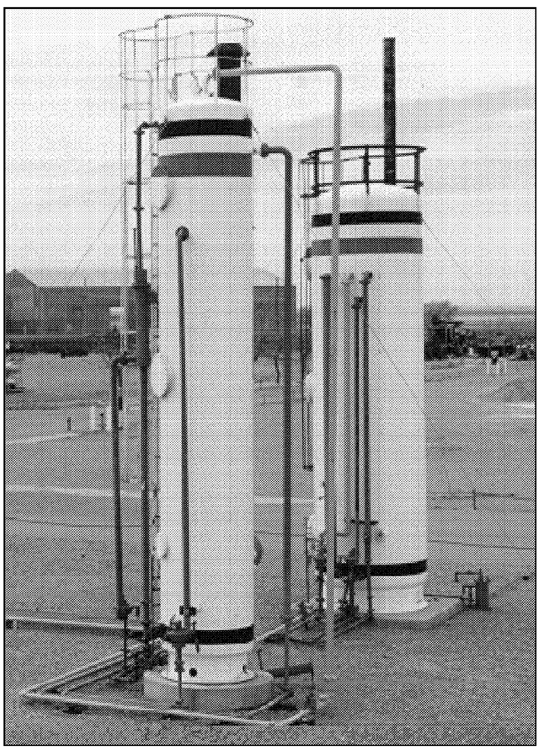

Figure 2. The lines on these heater/treaters are color-coded to identify the fluids they contain.

For the lease pumper, understanding the use of each line does not create any problem, even if the lines are buried because each one serves a different purpose. Even a casual examination of the line and the connections that make up that line will allow the lease pumper to easily identify the purpose of each line. However, during installation of the vessel, it may be necessary to remove a round manway plate and examine the inside using a spark-proof flashlight to verify the purpose of each outlet. The manufacturer will also be able to provide this information.

When the crude oil enters the vertical heater/treater, it travels down to contact a spreader baffle in the lower section of the vessel. A plate welded in the vessel just below the inlet channels the incoming oil down a tube, allowing the water to drop to the bottom of the vessel and out. The oil migrates up through the water section, contacts the heated tube, and moves upward through the wash section. There, the baffle plates remove most of the remaining water. Water continues to drop out of the oil until the time that it enters the sales line.

The horizontal heater/treater, which uses electricity to separate water and oil, dramatically increases the efficiency of the operation. This type of heater/treater is described in Chapter 13, Testing, Treating, and Selling Crude Oil.

E-3. Lines from the Heater/Treater to the Gun Barrel.

If a gun barrel is the next vessel in the system, the oil outlet line from the heater/treater drops to ground level and travels to the gun barrel. The line enters the gun barrel down through a central flume or through an external boot arrangement (Figure 3). In this system, the crude oil inlet line comes in from the back side, travels up through the 2-inch line, and enters the gas boot from the left side. The flash separator (the large container on top) allows the gas to break out of the liquid and travel upward and into the low-pressure gas system.

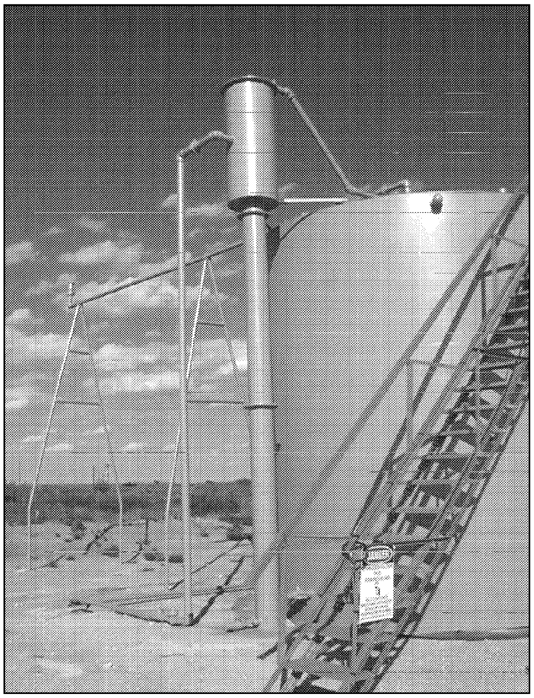

Figure 3. The gun barrel crude oil inlet boot (center).

The oil then travels down through the inlet boot, enters the vessel at about the 12-inch level, and travels across the spreader. The spreader is a long horizontal pipe crossing the bottom of the gun barrel with many small holes in it to distribute crude oil all the way across the vessel. The oil comes out of the holes and works its way up through the water in droplet form. Free water remains in the lower part of the gun barrel and travels through the water leg to the disposal system.

As shown in Figure 3, additional support is often provided to the boot by braces, such as the V-shaped brace attached to the top edge of the tank to stabilize the boot. A second stabilizer is welded to the boot down-comer and the side of the tank for additional support.

The line system from the separator should always provide a means of producing directly to the stock tanks without going through the heater/treater or the gun barrel.

E-4. Lines from the Gun Barrel to the Stock Tanks.

The oil outlet line from the upper side of the gun barrel to the stock tank is normally installed directly to the top of the stock tanks. This line may come off the gun barrel at a 45° angle, so the distance is usually only a few feet away to the first stock tank.

Figure 4 illustrates how the line is installed to allow the oil to flow by gravity feed to the stock tank. A shutoff valve is normally installed just above the stock tank as shown. The line must be of sufficient size to avoid restrictions and to accommodate production.

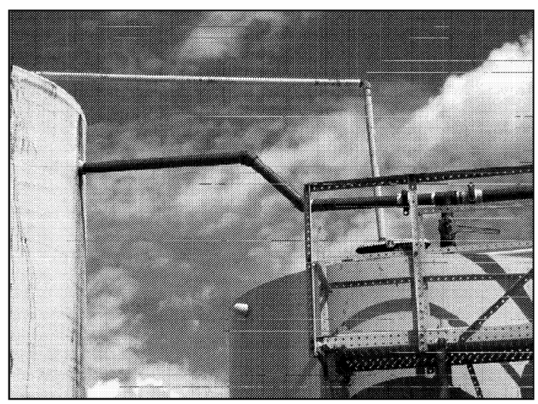

Figure 4. The oil line from the gun barrel (left) to the stock tank. Note that the handle of the valve is perpendicular to the flow of the line, meaning that the valve is closed.

E-5. The Equalizer Line from Stock Tank to Stock Tank.

The equalizer line is a line located near the top edge of the tank at an angle of 45° to the side and approximately 10 inches down.

This line connects the two stock tanks. This equalizer line allows the lease pumper to ***top out a tank*** (fill it almost full) during any time of the day or during the hours that the lease pumper is off so that the tank is full of oil when the lines are switched. This saves the pumper much time, and the tank is always full when the oil is sold.

There are two ways of installing an equalizer line. Figures 5 and 6 show both systems. In the system in Figure 5, the oil must go to the next tank, while in the system shown in Figure 6, the oil can go to any selected tank. Most walkways, however, fit snugly to the tank so that the second approach is not always available. The pipe would occupy part of the walkway space, and this would be a safety hazard.

When the crude oil is sold through a pipeline, several valves will have to be closed, a seal inserted, and the valve handle locked in a closed position. There are two common styles of seals. One is a flat strap that locks together, and the second is a wire and lead seal.

The gauger will probably seal both the drain line and the oil inlet. The seal on the sales line will then have to be broken to remove the valve handle. These seals will have the name of the pipeline company and a serial number stamped on them in raised letters for identification. After the oil has been sold, the valve is closed and a new seal is put in place to make sure that this valve remains closed when oil is not being purchased. All seal numbers are accounted for, and occasionally the company will require that the used seals accompany the sales ticket when it is turned in to the office.

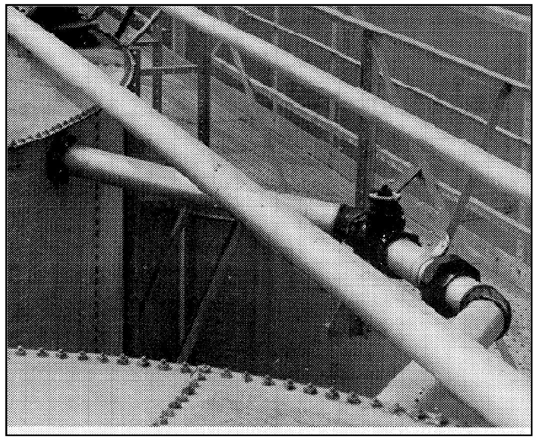

Figure 5. An equalizer system in which equalizing can be done only to the next tank.

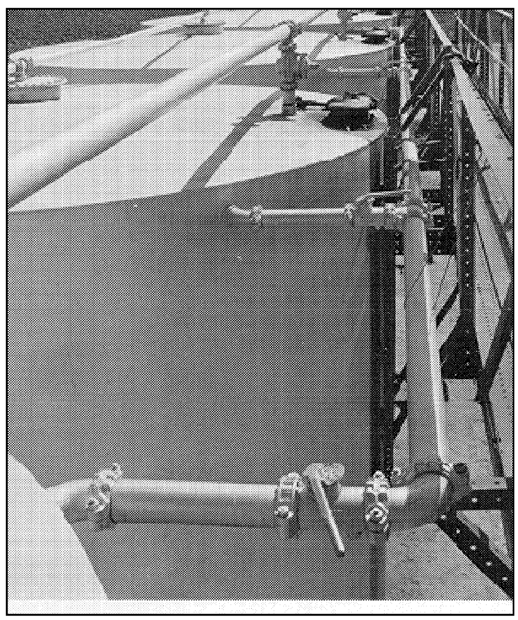

Figure 6. An equalizer system in which any of several tanks can be selected for filling next.

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Section F

CIRCULATING AND WATER DISPOSAL SYSTEMS

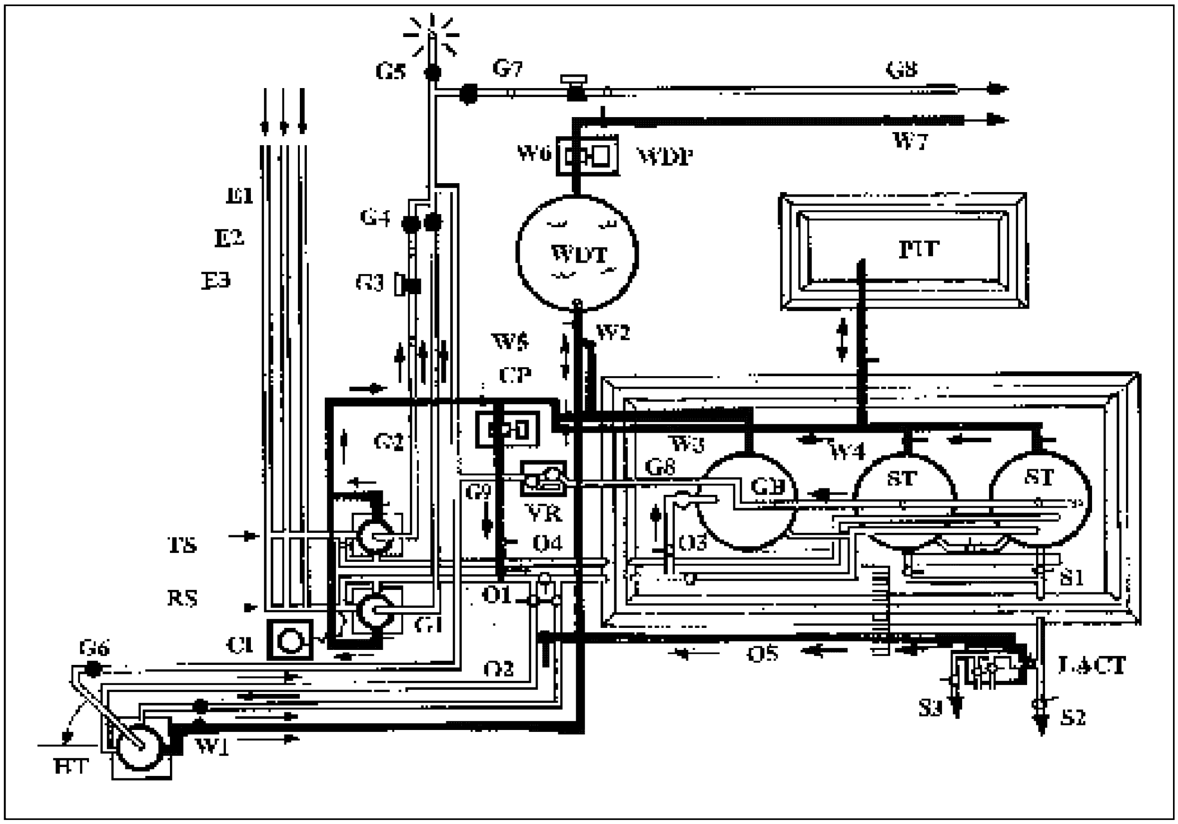

Figure 1. Diagram of the circulating and water disposal systems. Water lines are marked with a *W*.

F-1. Produced Water at the Tank Battery.

Many reservoirs are water driven, so producing water along with the oil and gas is a common situation. As the amount of water produced to the tank battery increases or is difficult to remove, special vessels, lines, and systems are installed and operated to assist in the removal and disposal of the additional water. (Figure 1) Water is removed by the heater/treater and the gun barrel by separating the incoming emulsion into natural gas, crude oil, and water. There are several other vessels that automatically separate out water, but these specialized vessels are beyond the scope of this study.

By raising or lowering the water leg a few inches, the lease pumper can change the oil/water interface level dramatically inside the vessel, reducing or increasing the amount of oil held in the vessel. This also changes the treating ability. Occasionally the heater/treater or gun barrel water leg must be adjusted to obtain the best results.

F-2. Water Separation from the Heater/Treater and the Gun Barrel.

The heater/treater and the gun barrel utilize natural forces to separate the oil and water by line height. With the heater/treater pictured in Figure 2, the crude oil inlet line is the upper line on the right side.

After the emulsion enters the vessel, most of the gas flash separates, and the oil and water flows downward through a tube. The water continues down and out through the water leg, and the emulsified oil passes by the firebox on its way back up to the upper oil level at the top. The gas goes out the center of the top, then down through the outer right line. The cleaned oil comes out the lower right or inside line.

The water comes out the lower left line, travels up through the inner tube, spills over the top, and falls down through the outer tube. The upper connection on this line contains only gas and equalizes the pressure between the vessel and the top of the water leg. This connection also stabilizes the line and holds it upright. To compute the height of the water leg line, refer to Appendix F, Mathematics.

The height of the liquid inside the oil and the water outlet lines remains constant at about 4 feet above the automatic diaphragm control valve. This valve is located within a few feet of the ground and is controlled by a weight on an arm. Additional weight can be added but is seldom needed. The level of oil and water inside the vessel is controlled by line height, not by the dump valves. Additional weight is occasionally added to the liquid dump valve when problems have been experienced.

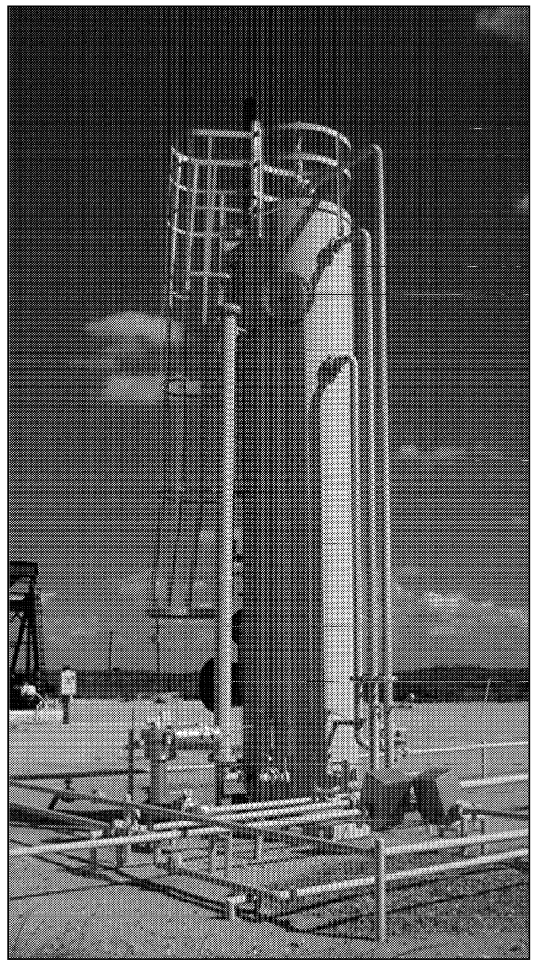

Figure 2. A vertical heater/treater with the water leg and other lines shown.

The gun barrel. As shown in Figure 3, the emulsion enters the gun barrel through the line on the left side of the flume. The gas breaks out in the large boot at the top and enters the gas system in the top of the vessel. The liquid emulsion falls down through the large tube below the boot to the bottom. It then enters the vessel through a spreader across the bottom, where the oil works its way upward through the water inside.

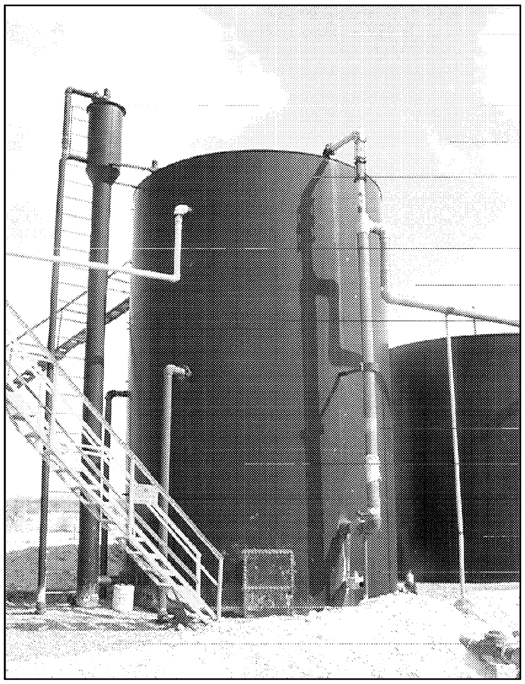

Figure 3. A gun barrel installed as part of an automated circulating system.

The produced oil flows out through the line on the upper left side close to the top and flows to the stock tank. The water comes out the lower line in the front, moves upward through the water leg, spills over to the right, and flows to the water tank to the right. Since the lines are not made of steel, a stiff arm stands out from the center of the side of the tank. Vertical pipe saddle/clamps support the weight of the line and liquid to prevent leaks. The two lines on the left center of the vessel are special purpose, such as for steaming, hot oiling, pulling oil off to use in treating the wells, injecting water into the system to be cleaned before disposal, and other special procedures.

F-3. The Circulating System.

The circulating system (Figure 4) moves oil from the stock tanks back through the heater/treater or gun barrel to remove excessive BS&W from the oil.

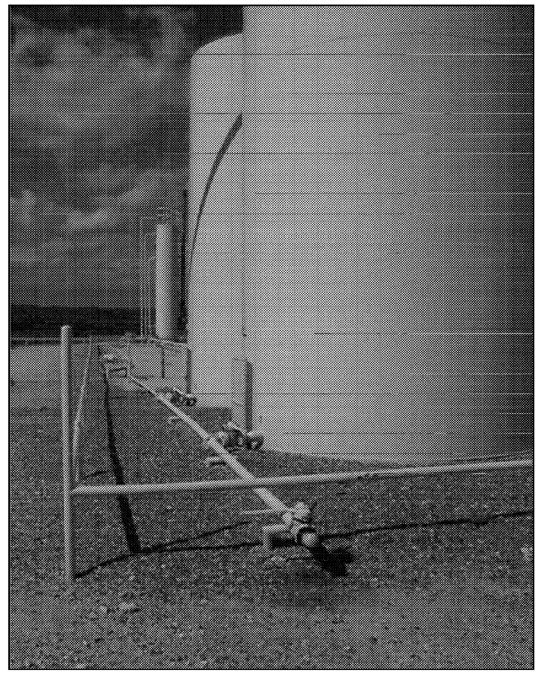

Figure 4. The stock tank drains are in the foreground while the heater/treater and circulating pump are in the background.

The circulating system is usually operated manually for low-volume stripper production. In high-production wells with difficult-to-treat oil, the system equipment, lines, and vessels are upgraded. The pump will come on automatically and circulate the tank bottom back through the heater/treater for a short period of time. The frequency and duration of circulation must be based on production needs. This procedure is continued day and night until the tank of oil is full and has been isolated for sale. Because of the risk of high-volume fluid loss, the system must be kept in top condition. Spills can be expensive to clean up. The benefits, however, are enormous in saved treating time and chemical consumption. Frequent circulation alone can often reduce chemical costs dramatically.

F-4. The Water Disposal Tank.

The water disposal tank for a small battery usually holds the equivalent of one transport load or about 250 barrels. It is usually made of fiberglass, stands 8 feet high, and has net material or a fiberglass dome across the top for bird safety. Large tank batteries and large water flood projects may have 20-foot tall water tanks that hold 2,000 barrels.

A satisfactory set of steps for inspecting and gauging the tank is a necessity. Inspections are to check water levels and the accumulation of crude oil in the system. In some closed systems, an oil blanket is preserved over the water to prevent oxygen saturation, oxygen corrosion, and plugging problems downhole. This oil blanket assists in blocking oxygen/water contact.

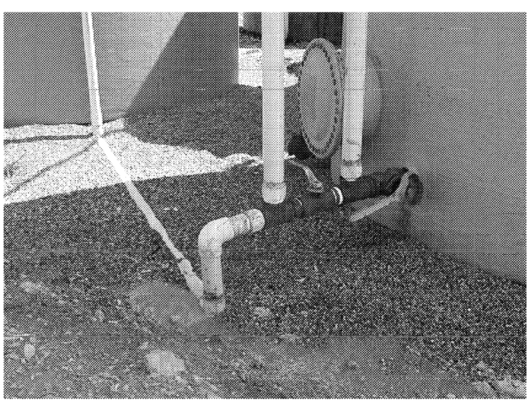

Figure 5. The basic water disposal system involves draining the water from the gun barrel and moving it through a line to the water disposal tank.

F-5. Solving Circulating and Disposal Problems.

Three processes occur in the water system and may be going on at the same time:

- The heater/treater and gun barrel are producing water into the water disposal tank or the pit.
- A stock tank is circulating the bottom of the tank being produced into.
- The water flood pump is injecting water back into the formation.

All of these operations occur automatically for planned intervals and durations. Yet the lease pumper must be able to override the systems, engage the pump to empty any vessel on location, refill and reactivate any vessel on the location, and possibly perform other functions according to the need of the moment. This requires careful consideration when designing the systems. Some systems are designed for single-purpose conditions and have no flexibility of action. Other systems are very complex to achieve the desired objectives.

It is not usually possible to solve every problem easily, but some of the common problems that may be encountered are:

Circulating oil while removing water from the system. A good installation allows circulation of a tank bottom without interfering with the normal water disposal operation. The discharge of water from the three-stage separation vessels (the heater/treater and the gun barrel) to the disposal tank should be able to continue without interruption while the circulating is in process.

During this dual operation, the lease pumper must ensure that liquids do not build up in these vessels faster than the vessel can handle them. This results in excessive volumes of water flowing to the disposal tank. After the circulating is finished, too much oil and not enough water are contained in the vessels, throwing them out-of-balance and possibly causing oil to go down the disposal system line.

Out-of-balance conditions can occur due to several reasons, such as:

- Undersized or restricted oil lines.
- Undersized or restricted water lines.
- Circulating too long in one cycle.
- Not enough time between cycles to permit the vessels to re-balance.
- Water production is low so it takes a long time to re-balance
- Water leg is set at wrong level.
- Water flood has caused the weight of the water to change, and the water leg has not been re-set to compensate for this change.

Automatic circulation from the LACT unit. When the BS&W level goes up beyond the set percentage in the LACT unit, the three-way diverter valve will automatically open and send the oil back through the heater/treater for re-cleaning or BS&W removal. When the BS&W level is reduced, the oil will automatically be diverted back through the barrel counter and sales line. The volume of oil diverted must be low enough for the heater/treater to function with this new volume, in addition to the regular volume produced, and still remain in balance.

Emptying vessels for maintenance. Any vessel in the system may need to be emptied for repairs. This can be done by opening and closing the correct valves. When drain lines are installed to every vessel, this capability to empty any vessel in the system individually is built-in. This saves time and expense when repairs become necessary. Operating without such lines can cause much higher maintenance expenses and will lead to a system that is inefficient and frustrating to operate as it consumes too much of the lease pumper's time every time a minor problem occurs.

Cleaning tank bottoms. Cleaning tank bottoms without removing the manway plate usually involves extensive use of the circulating pump. This function requires different procedures from the routine circulating procedure. It might even require the use of a flexible hose and a pipe extension that will reach the bottom of the tank and extend out through the thief hatch. It may also require forcing the liquid alternately in both directions—into the tank through the line stirring up the bottom—and vacuuming the liquid out for cleaning. This may require a portable pump with hoses.

F-6. The Circulating Pump.

The circulating pump is an essential tool to maintain clean tank bottoms and for selling crude oil with an acceptable level of BS&W. Most of the time it is used for cleaning crude oil, but it can also pump all of the liquid out of any vessel when that vessel must be opened for cleaning or repair. It is also utilized to pump liquid back into some vessels as needed when placing them back into service after repairs. By use of the circulating pump, the operation of these vessels may be balanced within hours.

It may also be used to pump all oil contained in several vessels as well as tank bottoms into one tank in order to sell as much oil as possible each month. With proper installation, for small batteries and limited operations, it may also be used to pump the produced water back into the reservoir for water flood or water disposal. Methods of connecting the pump to allow operation in either direction are reviewed in Chapter 17, in the surface pump section.

F-7. Hauling the Water by Truck.

Produced water is often hauled by truck to the nearest injection well, which may have tanks located nearby to receive water. The load of water will range from 160-200 barrels. The operator may pay someone else to dispose of the water or do this on the lease as a water disposal or a water flood project. Hauling liquids by truck transport is reviewed in Chapter 15, Enhancing Oil Recovery.

F-8. Water Injection.

For the small water injection project, the total project may be operated by a simple water-level control switch to turn the pump on and off. A typical disposal tank switch is illustrated in Figure 6. The pump moves the water to one or more injection wells. Some of the latest technology involves water injection into a currently producing well. Water injection is reviewed in Chapter 15, Enhancing Oil Recovery.

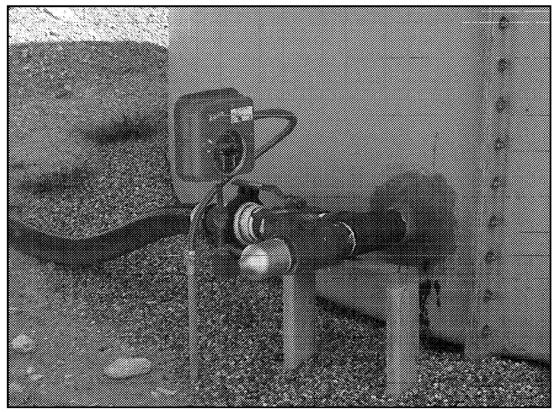

Figure 6. A typical water injection control.

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Chapter 10
The Tank Battery

Section G

THE CRUDE OIL SALES SYSTEM

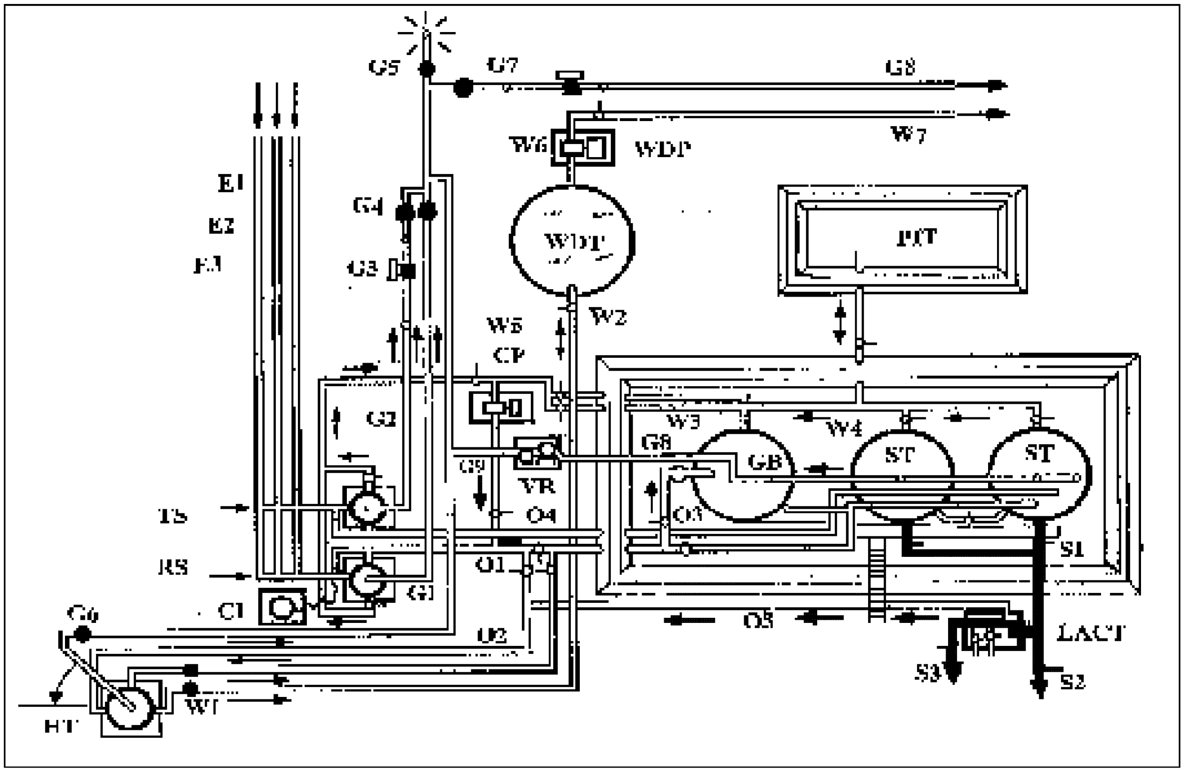


Figure 1. Components of the crude oil sales system are marked with an *S*.

G-1. The Oil Sales System.

The oil sales system (Figure 1) is one part of the tank battery system that must meet specific regulations. This is because a part of the oil contained in the vessel is owned by the well operator, but some of it belongs the mineral rights owner(s). The oil purchaser, pipeline, or transportation company pays each of these parties separately for the oil purchased. Regulations governing the accumulation and sale of crude oil are very rigid to protect the interests of both parties.

All valves below the liquid level line may be required to have seals on them, but the sales valves have recorded seals that cannot be removed without accounting for every seal. These seals are placed on the sales valves by the crude oil purchaser, and, if any are removed, they may have to be saved and turned in to the office for accounting to the transportation company as to why it was removed.

The sales line openings are usually located 12 inches above the bottom of the tank. This provides sufficient room below the opening for the emulsion that accumulates on the bottom and cannot be sold. The normal field tank has sales openings for 4-inch pipe and, normally, 4-inch pipe is used in the full sales system.

G-2. Selling Oil by Truck Transport.

Oil is sold by transport when a pipeline is not available or the cost of installing a pipeline cannot be justified. The transport truck supplies the flexible hoses utilized to complete the connection from the truck to the line opening. A good truck driver will not lose more than a few drops of oil when the loading has been completed.

The tank battery pictured in Figure 2 has two tanks, one for water and one for storing produced oil. The two lines are connected to the tank at the 12-inch level. The oil tank has a seal that was placed on it by the contracted oil purchaser, but if the water tank has a seal, it would be put on by the oil operator.

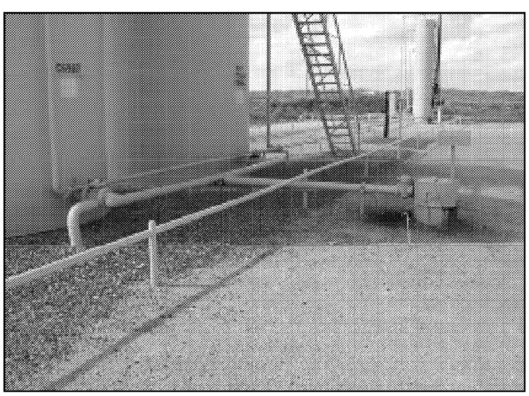


Figure 2. A tank battery set up for transporting oil by truck.

Both tanks have separate lines and a box to catch any spilled oil or water from the loading process. Most operators require their lease pumper to be present when oil is sold. When water is hauled, it is not necessary that the lease pumper be present.

A mailbox (Figure 3) is provided for the convenience of the transport driver and the lease pumper so that they can communicate with each other. The transport driver has a place to leave the load ticket, and the pumper can communicate where and when the next load will be available.

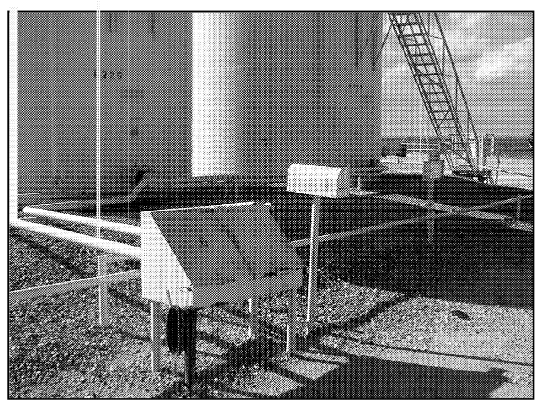


Figure 3. A mailbox is provided to allow communication between the transport driver and the lease pumper.

Note that a riser is located to the left of the oil sales line valve on both tanks. This allows the tanks to be switched from the ground and reduces the amount of time that the lease pumper must spend near the thief hatch opening, especially when the tank contains a high level of hydrogen sulfide.

A grounding post is provided near the hose connection box to give the truck driver a good, stable connection to ground the truck before the oil or water loading process begins. This reduces the possibility of a spark occurring in the area of the liquid opening.

G-3. Selling Oil with the LACT Unit.

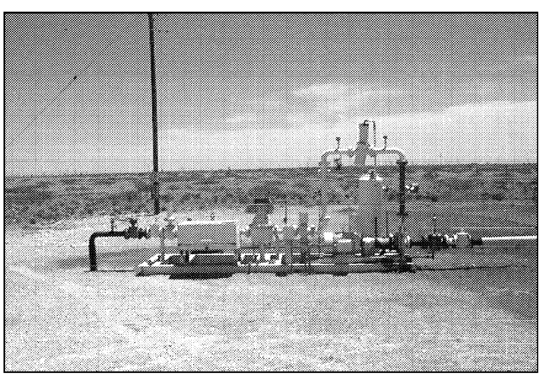
Selling oil by the use of a Lease Automatic Custody Transfer Unit (Figure 4) is an ideal method for selling oil. In this system, the oil sales line is always left open to the stock tanks. The stock tank then acts as a surge tank since the LACT will operate intermittently. As fluid builds up in the tank, a switch sends a signal to the LACT unit so that it will come on and begin selling oil. As the fluid gets low in the tank, it will shut the unit in, and no more oil will be sold until the level comes back up and the cycle begins again.

The sale cycle will continue as long as the tank battery is producing *pipeline oil*. This term indicates that the BS&W level is low enough for the oil to be acceptable. If the BS&W level should get high enough that the oil is no longer acceptable pipeline oil, the BS&W diverter valve will open and send the oil back to the heater/treater.

The detector probe on the riser of the inlet line of the unit will continue to reject the purchase of additional oil until pipeline oil is again detected. At that time the detector probe will send a signal to the diverter valve to change to the sales position, and sales will begin again.

The reading on the sales meter will be recorded daily. The BS&W sampler must be blended or mixed periodically and the average determined. This correction factor will be effective for all oil sold since the last time that it was averaged. Since the oil contained in the sampler is owned by the production operator, the sample will be circulated back into the upstream sales line or stock tank.

A second factor that must be used to determine how much oil has been sold is the positive displacement meter test. The number should approach 1.0000 but will generally be a little over or a little under, such as 0.9997 or 1.0009. These tests are performed by a meter testing company using a trailer-mounted meter prover or a master meter with its own meter factor. The oil sales opening is normally placed one foot above the bottom of the tank. The primary automatic on/off control switch for the LACT unit is usually installed on the side of the tank approximately 2 feet off bottom. This allows the pump to operate without danger of drawing natural gas into the sales lines. For safety purposes a secondary control switch may be placed 1-2 feet above the primary switch. This added safety generally results in a dependable system.



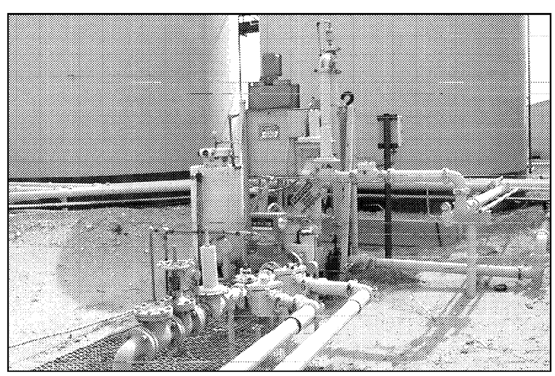


Figure 4. Two views of a Lease Automatic Custody Transfer System.

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Chapter 10
The Tank Battery

Section H

TANK BATTERY DESIGN REVIEW

H-1. What Does a Tank Battery Look Like?

As indicated throughout this chapter, a tank battery is designed to meet the particular needs of the hydrocarbons coming into it. Part of the production characteristics that affect the design of the tank battery include:

- How many barrels of oil are produced each day? This regulates the size of the tanks installed.
- How is the oil sold? How long is the tank unavailable due to being sold by pipe line? This helps determine how many vessels are needed.
- How much gas is being produced and what is the shut-in pressure? This regulates how many pressurized vessels will be required, and what pressure range the vessels may be subjected to. The amount of gas also determines whether pressurized vessels are required at all.
- How much water is being produced and what is the salt content?
- What is the gravity of the oil? Is it thin and fluid or thick and viscous when it is produced cold? How much paraffin, asphalt, or sand is being produced? How difficult is it to remove the sand, especially fine sand with paraffin? How difficult is it to treat the oil?
- How corrosive is the water and what other unique problems are encountered?

H-2. No Atmospheric Vessels.

When wells produce pipeline oil with no water or paraffin, they can be flowed directly through the separator, through a LACT unit, and into the pipeline. The tank battery in Figure 1 contains a large horizontal standard separator, a test separator, and a LACT unit. There are eleven flowing or gas lift wells and no atmospheric vessels. It also eliminates the need for the circulating pump, water disposal and injection system, and all of the problems associated with oil treating.

The daily production is automatically transmitted to a computer and, if anything unusual occurs in the daily production, an alarm will be automatically recorded.

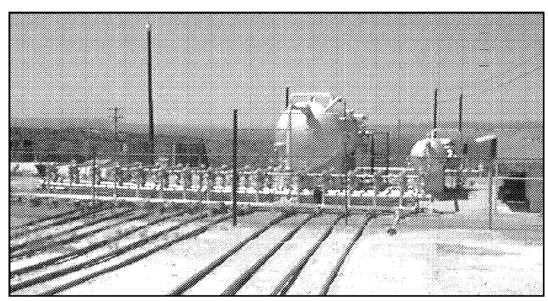

Figure 1. An 11-well tank battery that has no stock tanks due to selling the oil directly through a LACT unit.

Figure 2 shows a second view of the same tank battery displaying the positive chokes located on the upper left corner of the header, the two separator lines with the smaller test line, and an innovative installation. An oil-saver hopper is located on the vertical line just below the positive choke. Any residue oil can be poured into the hopper and re-injected into the system by gas pressure through the 2-inch line acting as a volume tank by closing the choke valve and opening another.

Figure 2. A close up of the header and the oil-saver hopper used on the tank battery shown in Figure 1.

H-3. The Tank Battery Producing No Gas or Water.

The tank battery pictured in Figure 3 shows the classic design for a one-vessel tank battery. It illustrates how simple a tank battery can be. The oil is hauled by transport. Only traces of gas are produced because none is being sold. The well does not produce any water and has a deluxe ladder and walkway installation. At the same time, it is not apparent whether the unit is an oil tank battery, a distillate (or condensate) tank battery, or a water tank battery from a gas well. A gas well that produces water but does not produce any distillate or condensate will look exactly like the pictured tank battery so that it will be necessary to read the sign on it or thief the tank or check the lease records to determine what type of tank battery it is.

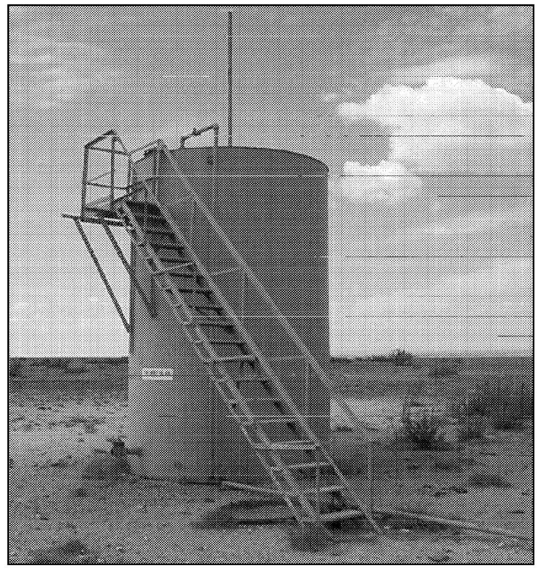

Figure 3. A single vessel tank battery.

H-4. The Tank Battery Requiring a Gun Barrel.

Figure 4 illustrates a tank battery with a gun barrel, two stock tanks, and one water tank. An air tank is installed with a reel-type hose for connecting to the breather mask. The low battery walkway has ladders at both ends, and the ladder on the gun barrel is designed to permit easy analysis of this vessel. The warning gate for the gun barrel is not installed.

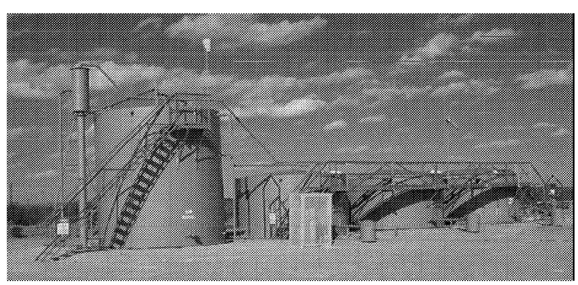

Figure 4. A gun barrel with two stock tanks and a water tank.

H-5. Tank Battery with Two Heater/Treaters and Two Stock Tanks.

The tank battery in Figure 5 is designed with two heater/treaters and no gun barrel. The heater/treaters are of different sizes, so the smaller one is the test vessel. Since only two tanks are on the location and the surface lines indicate that the tank battery produces water, it is easy to tell which tank is for oil tank and which is for water.

In all likelihood, the crude oil being produced to this tank battery has an API gravity of 30 or less. The oil is probably relatively difficult to treat, and heat would possibly be needed all winter but not during the summer months. If the emulsion were slow to break, a gun barrel would also be needed.

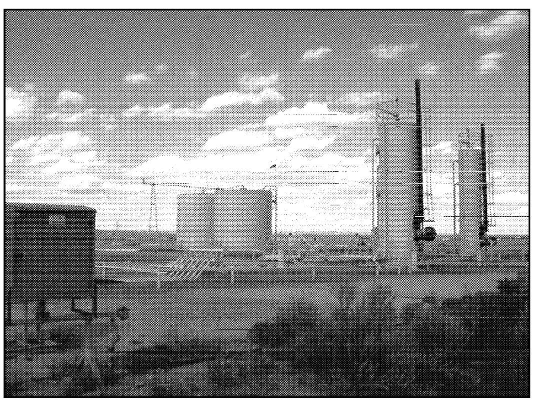

Figure 5. A tank battery with two 500-barrel stock tanks, two heater/treaters, and two gas sales meters.

H-6. Single Tank with Shop-Made Gun Barrel on Stand.

This method (Figure 6) is used with extremely low producing tank battery with only one well. The operation of the shop-made gun barrel is easy to trace, and the lease pumper will understand the operation of the system at a glance with no instruction.

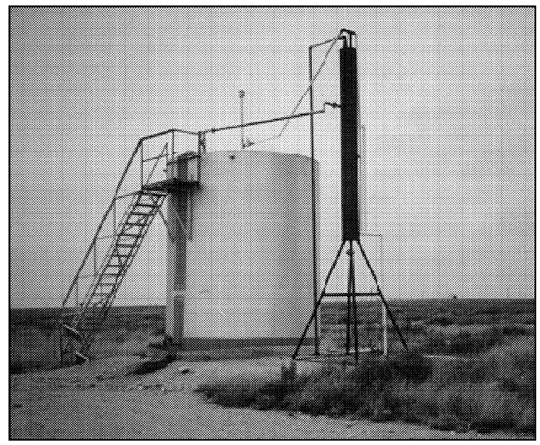

Figure 6. A single vessel tank battery with a shop-made gun barrel and a covered pit.

The single-tank does have a backpressure ounce valve on the gas line to reduce liquid loss and the resulting reduction of gravity because of this loss.

A tank battery is designed to meet the needs of each group of wells, so that each installation is somewhat unique, though well-planned tank battery vessels are installed in a specific order.

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CHAPTER 11

MOTORS, ENGINES, PUMPS, AND COMPRESSORS

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Chapter 11
Motors, Engines, Pumps, and Compressors

Section A

MOTORS

A-1. Fundamentals of Electricity.

There are three characteristics of electrical power that must be matched to a piece of equipment. First, the equipment will require either *direct current* or *alternating current*. Electricity that flows in one direction is called direct current (DC). Battery-powered equipment, including flashlights and radios, operate on direct current. Most equipment that runs on electricity from commercial power lines uses alternating current (AC). Electricity in an AC power system rapidly switches flow direction as it moves through a circuit. AC power generates less heat than DC, so for transmitting current over high lines for a long distance, AC is used.

How quickly AC power switches direction is referred to as its cycle rate. In the United States, electricity operates at 60 cycles per second. A cycle consists of two changes in direction, so 60-cycle current changes direction 120 times per second.

In Europe and many other countries, electricity operates at 50 cycles per second. Electrical equipment will not operate at the correct speed or may not operate at all if the correct cycle rate is not used.

The third concern is that the voltage of the electricity and the voltage requirements of the equipment match. The typical house voltage in the U.S. is 110 volts, though 220-volt power is used for some appliances such as heating and air conditioning systems, clothes dryers, and water heaters. At the well site, electrical lighting and standard power outlets will generally operate on 110 volts, though larger equipment such as pump motors will often use 220 or even 440 volts. System voltage is changed through the use of transformers. The electricity being carried through power lines over long distances will be at voltages of several thousand volts. A transformer on the lease site power pole will step the power down to the level to be used by the site equipment.

Electrical plugs and outlets with different voltage ratings will differ to prevent equipment from being plugged into the wrong system. Standard electrical systems in some foreign countries are 220 volts.

A-2. The Lease Electrical System.

Most higher voltage equipment (220 V and above) operate on three-phase power. Three-phase power has to be converted to single phase to power common consumer items such as drills, lights, etc. A network of electrical lines distribute power to each installation and equipment across the lease. Occasionally, a system will have four overhead lines, but a three-line system is more common and is described in this section.

This network of pole-mounted high lines originates from generators miles away. It distributes electricity to surrounding areas for many hundreds of square miles. The amount of electricity consumed on a lease is insignificant compared to the overall amount of electricity supplied to an area. Consequently, if the lease suffers a loss of electricity, the power company will not be aware of the problem until they are telephoned or otherwise notified.

After the electrical power line enters the lease, it is distributed to poles containing three fuses and appropriate step-down transformers suitable to operate the wells (Figure 1). As voltage is stepped down through a transformer in a direct ratio, the amperage, a measure of how much work electricity can do, is stepped up. Electric motors run on 110, 220, or 440 volts. Occasionally, a different voltage will be encountered.

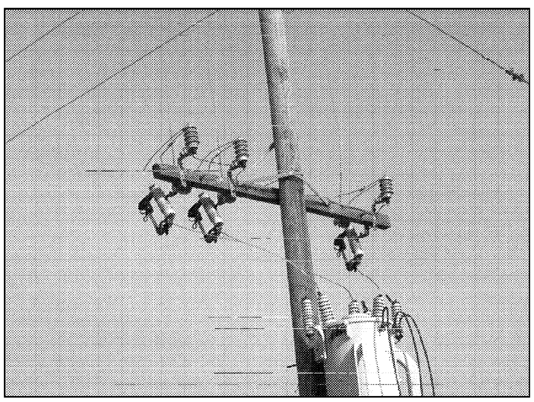

Figure 1. Typical line fuses and step-down transformer common to most leases.

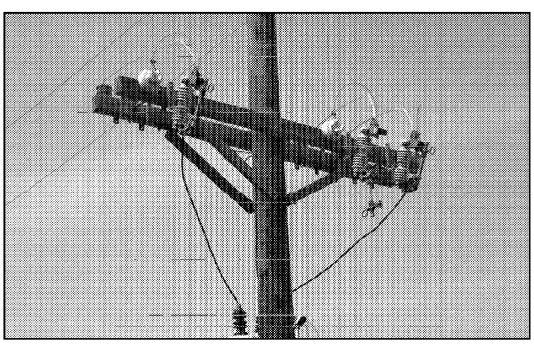

Figure 2. Pole with one fuse out of service.

As shown in Figures 1 and 2, there are three fuses on the electrical pole. Figure 2 shows a blown fuse. A blown fuse is easy to identify because fuses are spring-loaded and, when blown, will usually trip loose and hang down. If this should occur, all equipment downstream from the circuit served by those fuses should be removed from service as quickly as possible and left out of service until the fuse has been replaced. This prevents equipment burnout.

The electric company that owns the line must be notified when a fuse is out. They are generally understanding of the severity of the situation and respond quickly to replace it.

A-3. Control Boxes and Equipment Fuses.

The last high line pole should be installed far outside of the well servicing guy line area for safety reasons. The power line trails down the pole into a fuse box, with an adjacent disconnect lever to electrically isolate the site while performing major repairs. The electrical line continues down the pole and runs underground in galvanized waterproof pipe (conduit) to the pumping unit or other equipment.

An automatic control box (Figure 3, on the next page) is mounted near the installation to operate the equipment. In the photograph, the control box is located near the upper edge of the picture. The equipment fuses are the cylindrical objects in the lower front of the box. When performing any services or workover operations at the well, the breaker arm on the control box should always be pulled to electrically isolate the equipment and locked out in order to prevent electrical accidents at the well or installation. The installation illustrated also contains two timers, one automated and one manual.

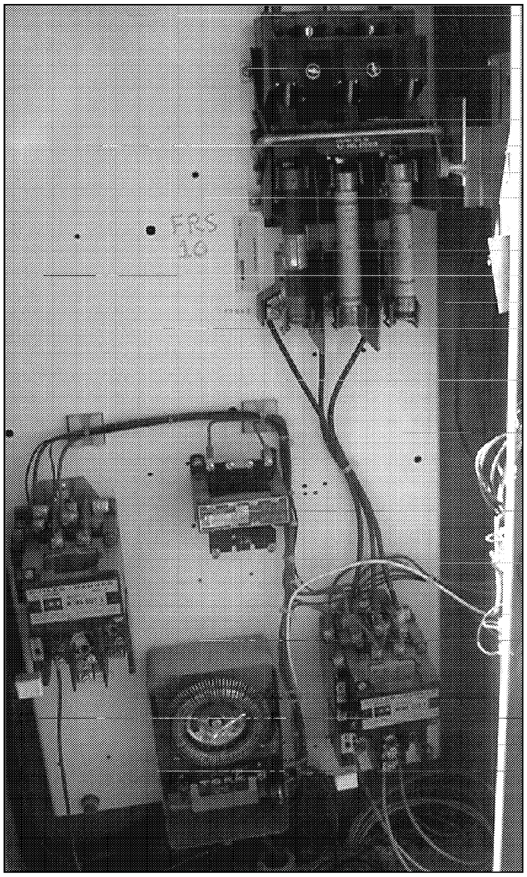

Figure 3. Control box containing one automated 24-hour time controller and one manual controller.

A-4. The Automated Control Box.

The lease pumper needs to understand the basic functions of the automated control box. In a typical unit, electricity enters the bottom of the box and is run to the upper right corner as it progresses through the box. The first wiring is diverted to a lightning arrester located outside the box. The box contains a breaker to disconnect the electricity and remove a unit from service.

Three fuses are located just below the breaker. This is the first line of defense to protect a system from overload. Two wires, one from a side lead and the second from the center wire, are connected to a small 110-volt transformer. These two wires then lead to the control switch located on the outside of the box.

The control switch has three positions. When turned to the **on** position, the equipment will run continuously. When the control is set to **off**, the equipment is turned off until the control is changed. If set to **automatic,** the time clock will control operation. This device has three leads to it from the fuses on the top side, and the leads from the bottom run out of the box and are connected to the power motor. Setting the time clock to a **run** or **on** position will engage electromagnetic units in the power control unit and the equipment will run. When the timer hits an off cycle, the power to the electromagnets is turned off, and springs separate or disengage the leads to turn the equipment off.

The power control usually has a carbon stack reset button and three heat safety controls that shut the unit in to protect the motor. With a minimum of instruction, the operator can troubleshoot simple problems, such as resetting the carbon stack or changing a fuse.

A-5. Time Clocks and Percentage Timers.

There are many styles of time controllers, but most can be categorized as either time clocks or percentage timers. The time clock is normally mounted in a metal box approximately 6 inches wide by 10 inches high by 3 inches deep. The percentage timer is a much smaller plastic control with one dial.

The 24-hour time clock. This type of clock is divided into 24 one-hour increments. Normally, the day half of the clock is portrayed in silver while the night half is painted black. Most of these clocks have pins for on/off control in 15-minute increments. Running time can be divided around the clock or restricted to when the pumper is physically on the lease. A few timers are controlled in five-minute increments. For marginal wells, the timer is set to pump a certain portion of each hour on the time clock. With the well not pumping for extended time periods, the fluid buildup will prevent additional fluid from entering the wellbore.

The percentage timer. This timer allows the pumper to run a unit a certain percentage of the day. Typical percentage timers operate based on an interval of time, such as 15 minutes or 1 hour. The time is set for a percentage of that time interval. For example, if the timer has a 15-minute interval and is set for 50%, it will run 7½ minutes and be off 7½ minutes. This will happen every 15 minutes or 96 times each day. Overall, the pump will run a total of 12 hours in a 24-hour period or 50% of the time.

A-6. Electric Motors.

As noted earlier, electric motors on the lease are usually rated at 110, 220, or 440 volts. While electric motors can be wound to run at many speeds, they typically operate at 1100, 1400, 1725, or 3450 rpm.

Most pumping unit electric motors have nine wires leading out of the motor and into the wiring box on the side of the motor (Figure 4). Each of these wires will be numbered, and instructions on the plate will indicate that they should be grouped into three sets of three. These three lead groups will then be attached to the three wires from the control panel. If the motor is running in the wrong direction when the power is turned back on, any two leads can be loosened and reversed to change the rotation of the motor.

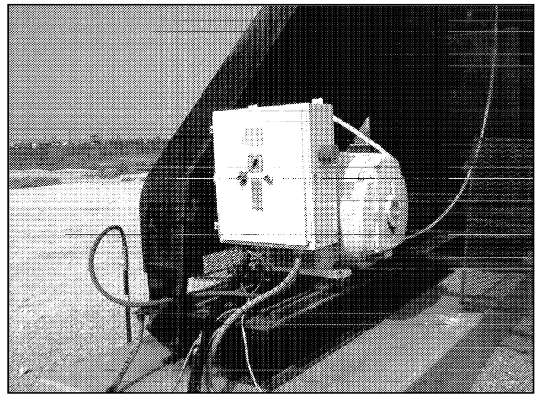

Figure 4. Electric motor and control box. The motor wiring can be changed to use three different motor speeds.

Some motors can accept either 220 volts or 440 volts. If this is true of the motor being installed, instructions on the motor's side plate will indicate which three wires go in each group for a specific voltages. If these instructions are not on the plate, the motor must be placed in service using the voltage stamped on the plate.

A-7. Electrical Safety.

The operator must always respect the lease electrical system. If handled improperly, it can be dangerous or deadly. This does not imply that electricity is too dangerous to use, but it does mean that good work habits must be developed and always followed. When a pumper is at work, there is usually no one within sight or hearing. The pumper must operate electrically powered equipment, change fuses, make minor changes, and operate automated controls with no one to help if trouble arises.

The best way a pumper can be protected is to be knowledgeable about handling electricity and to use good work habits. These include:

- Having a good pair of insulated work gloves to wear when handling electricity. They should not be used for any other purpose and should be kept clean.
- Isolating a system from electrical power before performing any service.
- Learning the correct way to perform electrical work duties.
- Not taking chances.
- Locking the electricity out of service as needed.

A-7. Costs of Electricity.

The company pays for the electricity delivered to the lease as part of the operating costs for producing oil. Generally, there are two major cost concerns in providing electricity to the lease: the initial cost of obtaining electrical service and the cost for the electricity consumed. These considerations can determine whether a marginal well is profitable and should be carefully managed.

Power companies may have a five-year minimum billing to cover part of the costs of installing the line to a new well. The production company will occasionally lay a temporary electric line on top of the ground from another well to run new wells until their productivity has been determined.

Power companies do not charge the same rate for electricity at all times of the day. Most charge a higher rate during normal office hours, such as 8 a.m. to 5 p.m. This is called their *peak hours rate*. Similarly the power company may charge a higher rate for periods of high usage, which is called their *peak load rate*. The lease pumper can help reduce costs by avoiding electrical usage that results in peak hour or peak load charges. For example, pumping units draw much more current when starting up than when they are running. This may favor running the pumps for a few long cycles rather than lots of short cycles if production can be maintained. The operator should alternate running units and stagger starting times in order to reduce billing. If possible, electrical equipment should run more during non-peak hours. The lease pumper may want to circulate tank bottoms and other functions while on the site during peak hours. This may be offset by running pumps during periods of cheaper power costs.

The operation supervisor should be aware of electrical billing practices and can provide advice in this matter.

The Lease Pumper's Handbook

Chapter 11
Motors, Engines, Pumps, and Compressors

Section B

ENGINES

B-1. Introduction to Engines.

Engines have been used as prime movers since the first wells were drilled. Since they continue to play a major role today, the pumper must have a basic knowledge of how to operate and maintain many types of engines.

When no electricity is available to a new well that has insufficient gas pressure to flow, a mechanical pumping unit with a natural gas engine will probably be installed, at least temporarily. This is especially true for a wildcat well where the only knowledge available is that it produces enough oil to justify completing it. Regardless, the pumper must operate and maintain an engine that will run 24 hours a day, probably using casing gas as fuel (Figure 1).

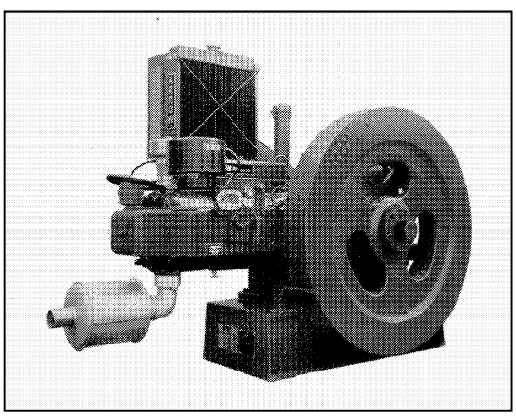

Figure 1. A single-cylinder engine with a flywheel, typical of many engines used in oilfields.
(courtesy Arrow Specialty Co., Inc.)

B-2. Two- and Four-Cycle Engines.

Engines typically used on the lease site are called internal combustion engines because the fuel is burned inside the engine. The fuel is burned in a hollow area of the engine called a *cylinder*. Fuel is allowed into the cylinder through an intake valve and the byproducts of fuel combustion are removed from through an exhaust valve. A piston moves up and down within the cylinder to compress the fuel for more powerful combustion. When the compressed fuel explodes, the piston is driven back down the cylinder. It is this downward movement of the piston that actually produces the power generated by an engine so that it can be used to do work. This whole process is described as a series of four strokes. A stroke is the movement of the piston along its full travel in one direction. The strokes of an internal combustion engine are:

- **Intake stroke.** With the exhaust valve closed and the intake valve open, the piston moves down or away from the cylinder head, drawing a mixture of air and fuel into the cylinder. As the piston reaches bottom, the intake valve closes.
- **Compression stroke.** With both valves closed, the piston moves up or toward the cylinder head, compressing the fuel/air mixture into 1/10 or less of the volume.
- **Power stroke**. With the intake and exhaust valves closed, the spark plug

ignites the fuels, an explosion occurs. The resulting power pushes the piston down or away from the cylinder head.

- **Exhaust stroke.** The exhaust valve opens and as the piston returns to the top or toward the cylinder head, it pushes the byproducts of combustion gas out of the cylinder.

The combustion process just described is called *a four-cycle process* because there are four strokes for each ignition event. Some engines, called *two-cycle* engines, have an ignition event every time the piston comes to the top of the cylinder. With two cycle engines, used in some outboard engines and motorcycles, lubricating oil must be added into the gasoline. With a four-cycle engine, oil circulates outside of the combustion chamber. Almost all field engines are four-cycle. The events of the four-cycle process must occur at the correct time in relation to each other. For example, during the ignition event, the fuel mixture must be compressed and the valves must be closed. This is called *engine timing*.

B-3. What Makes an Engine Run?

The three things that make up the firing triangle of the gasoline or natural gas engine are a heat source, fuel, and compression. For an engine to run, it must have the correct amount of all three with correct timing. When troubleshooting an engine, these are items that must be checked. Additionally, an engine includes two safety systems, one to lubricate moving parts and one to help remove heat from the engine. The lease pumper is expected to have a working knowledge of these systems in order to keep engines operating dependably, including the ability to change and service basic engine components and properly time engines.

A heat source. The usual heat source for an internal combustion engine is electricity—specifically, a spark jumping across the gap of a spark plug. Other electrical components may include a battery, voltage regulator, generator (or alternator), starter, distributor, coil (or low-tension coils), spark plugs, and appropriate wiring. Spark plugs must be the correct size, have the proper gap setting, and be of the correct temperature range, which generally include cold, standard, and hot. Some engines have a magneto electrical system with the coil, distributor, condenser, and points built into the magneto. Some engines have low-tension magnetos, which cost more but can greatly reduce magneto problems. Newer engines may have solid-state ignition systems. Battery maintenance includes ensuring that service-free batteries are not left outside in a rundown condition in freezing weather.

Because engines remain in service for several years, the lease pumper must know how to service all types of heat sources.

Fuel. The fuel system includes a fuel supply, air filter, carburetor, and mixing chamber. Fuel may be gasoline, natural gas, butane, or diesel. The gasoline system requires a carburetor with a float and fuel filter or a fuel injection system. Natural gas and butane systems require a gas or a combination carburetor. Diesel systems use a fuel distributor and a injector system. Pumper duties include air and fuel cleaning systems maintenance, adjustments, and minor repair.

Compression. This involves mechanical parts such as the engine block, pistons, rings, valves, and timing system. Maintenance performed by the pumper in this area depends upon job duties, available time, experience, tool and support availability, and many other factors.

Safety systems. Safety systems to protect the engine include the *lubricating safety system* and the *cooling safety system*. These safety components shut down an engine without damage in the event of emergency conditions. A medium-sized engine will cost several thousand dollars, thus representing a substantial investment. The safety systems must always be kept in operating condition.

The lubricating system circulates oil over moving parts to reduce friction and wear. Two critical aspects of the lubricating system are oil level—that is, the amount of oil in the system—and oil pressure, which is a measure of whether there is enough pressure from the oil pump to move oil throughout the engine. The oil level safety system uses a float to measure how much oil is in the lubricating system. If the oil gets low, the float falls and makes contact with the engine block to ground the ignition and shut down the engine. The oil pressure safety system has a contact that will ground the ignition if the pressure drops too low.

The cooling system circulates coolant—a mixture of water and antifreeze—around the engine parts to remove the heat produced by engine operation. The coolant passes through a radiator, where moving air removes heat from the coolant. A temperature gauge monitors coolant temperature, with a contact that moves with changes in coolant temperature. If the temperature rises to a predetermine level, such as 212° F, the contacts grounds the ignition system and shuts down the engine.

B-4. Engine Oils and Oil Additives.

The lubricating system is filled with oil. The oil must be suited for the engine and operating conditions in terms of viscosity and additives. The term *viscosity* refers to the how quickly a given oil will pour when the oil is cold and when it is hot. Viscosity can be thought of as the thickness of oil and is referred to as weight, such as 10 weight, 30 weight, and 50 weight, with the higher number representing a thicker or higher viscosity oil. Engine oils are available in multiple viscosities, such as 10-40, which means that at a cold temperature, it will flow as quickly as a 10 weight, but when it is hot it will flow as slowly as a 40 weight oil.

Although oils may be similar in appearance, they can vary greatly in contents, especially in the additives they contain. Additives are chemicals that are added to the oil to overcome potential problems. Some of the more common additives include:

- **Sulfur neutralizer** to prevent the elements in the crankcase from combining and forming acids.
- **Anti-wear agents** to reduce engine wear, especially during the warm-up period which is when the most wear occurs.
- **Rust inhibitors** to reduce rust and sludge when the engine is either running or off. Sensitive metals can rust, even below the oil level.
- **Viscosity index improvers** to maximize the ability of oil to adhere to the metal so that components above the oil line retain lubrication for start-up and while running to reduce wear.
- **Homogenizing agents** retain carbon and other foreign agents in suspension so that they are carried to the filter system. While these agents cause the oil to be darker, they actually keep the engine cleaner.

As oil circulates through the engine and is exposed to heat, byproducts of combustion, and the elements, it breaks down, losing its lubricating abilities, and the additives break down. For these reasons, the engine oil and filter must be changed periodically. The replacement oil must be of the proper viscosity and contain the additives recommended by the engine manufacturer.

B-5. Gasoline and Gasoline Additives.

When purchasing gasoline, care must also be taken to obtain the correct grade and quality of product. When selecting quality fuels, considerations include:

- **Sulfur neutralizers** are added to reduce engine wear caused from acids being created within the system through fuels and water condensation.
- **Carburetor cleaners** reduce the varnish buildup that causes carburetor parts to stick and the jet holes to narrow or plug.
- **Water absorbents** break down and remove water that otherwise will accumulate in the gas tank, lines, and carburetor, causing rust and occasionally freezing.
- **Anti-glow agents** prevent carbons deposited in the engine heads from becoming hot (glowing) enough to ignite the fuel. These hot spots can ignite the fuel ahead of the power stroke (knocking) or, after the ignition system has been shut off, keep the engine running (dieseling).
- **Octane improvers**. These improve engine performance and burn slower to reduce rod bearing wear and dramatically extend the life of the engine. The higher the octane, the slower the gasoline will burn. With slower burning high octane fuel, the initial impact on the piston is less severe. This results in more miles per gallon, less damage to the engine, and a cleaner engine inside. It is not unusual to have a lower cost per mile and better performance on an engine when using a higher octane than with regular fuel.

B-6. Antifreeze and Radiators.

There are many benefits to running a good antifreeze in an engine, including:

- **Prevention of rust and corrosion.** Ethylene glycol is a natural rust inhibitor.
- **Lubrication of the water pump**. Ethylene glycol is also a natural lubricant and lubricates the water pump.
- **Transfer of heat more easily.** By transferring heat more easily, the engine runs warmer in the winter and cooler in the summer. The boiling point of antifreeze is 263° F.
- **Prevention of water from freezing.** The primary reason for adding antifreeze to the water is obviously to prevent the water from freezing.

Antifreeze should be maintained in most engines year-round because of the additional protection it gives to the engine other than cold weather protection.

When mixing antifreeze, the basic method is to mix two gallons of water and one gallon of antifreeze, or a 1/3 mixture. This gives protection down to 0° F., or 32 degrees below freezing. In colder climates a 1:1 mixture may be more appropriate.

Antifreeze mixing ratios.

Parts Water	Parts Anti-freeze	%	Freezes at °F	Boils at °F
3	1	25	+10	
2	1	33	0	
20	7	35	-3	
5	2	40	-12	258
20	9	45	-22	
1	1	50	-34	263
20	11	55	-48	266

B-7. Single- and Multiple-Cylinder Engines.

Single-cylinder oilfield engines (Figure 2) are used extensively on circulating pumps (vertical cylinder small engines), and as the prime mover (horizontal cylinder, medium to large engines) for shallow and medium depth oil wells. Engines that are large enough to operate pumping units are slow-running engines with large flywheels that rotate at a speed of 300-500 revolutions per minute. The large flywheels store energy in their movement, which allows the engine to run smoothly. Instead of having several spark plugs and an electrical distributing system, the system is reduced to a magneto, one wire, and a spark plug. This greatly reduces electrical maintenance requirements. The sheave is almost twice as large as those on multiple-cylinder engines, and belts move much slower across the engine sheave. The starting system is usually composed of a portable starter and a pair of jumper cables. It uses a vehicle starting battery.

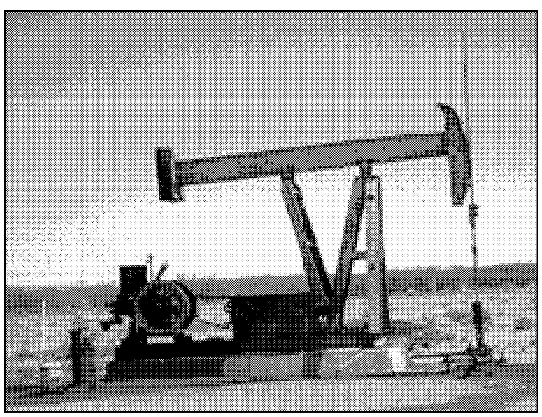

Figure 2. Single-cylinder four-cycle engine using marginal casing gas for power.

Multiple-cylinder engines are more complex, have a large number of parts, and run at speeds of 900-1600 rpm. The electrical system may require a battery, starter, voltage regulator, distributor, possibly a coil for each cylinder, and more spark plugs. Since it does not have large flywheels to store energy, the engine must rotate much faster to run smoothly.

B-8. Diesel Engines.

Diesel engines do not use a spark to ignite the fuel on each power stroke. Instead, the heat generated by engine compression is enough to ignite the fuel. Thus, the compression stroke compresses only air, and as the piston approaches the top of its stroke, diesel fluid is injected into cylinder, and it ignites instantly. Because of the extreme heat generated, diesel fuel contains a lubricant for the cylinder, rings, and valve stems.

Diesel engines are assembled with looser clearances than gasoline engines. Steel expands as it gets hot, and diesel engines generate more heat than gasoline types. As a result, the diesel engine makes more noise when it is first started but grows quieter as it gets warm. If the engine is going to be used again in a short time after becoming idle, the engine is left running. To start the engine in cold weather, the cylinders have *glow plugs* that are turned on a few minutes before the engine is cranked in order to provide ignition heat.

B-9. Natural Gas Fuel Systems.

Natural gas engines can be a very economical way to drive pumps, especially when gas is drawn from a well where a gas engine may be pumping. Figure 3 illustrates the components of a typical gas system. A scrubber and volume tank are installed just ahead of each facility whenever gas is wet. With dry gas, the scrubber is either not required or is much smaller and used simply to trap rust out of the system.

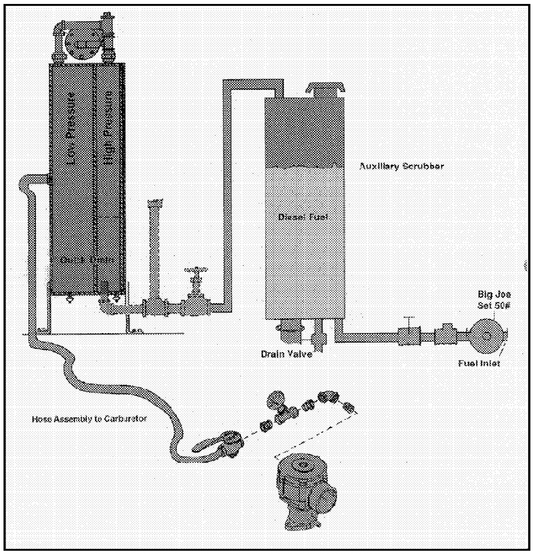

Figure 3. Natural gas supply system including pressure regulators, scrubber, volume tanks, and line system.
(courtesy Arrow Specialties, Co., Inc.)

The system begins with a regulator that reduces the gas pressure to protect the downstream system, followed by a scrubber or wash tank. With small engines this is the complete system, except for an ounce gauge and a flexible connecting hose. Engines will need a fuel pressure of 6-8 ounces.

For larger engines requiring a high volume of gas, a second tank is needed as illustrated in Figure 3 to maintain a sufficient reserve supply volume. The riser between the pictured tanks acts as a shock absorber to protect the vessels and regulators.

Problems with wet gas containing water vapor. When the natural gas supply line contains water vapor and is connected to the casing, problems can be encountered in the winter in keeping the system operational.

In cold weather, warm gas gets cold after it leaves the wellhead, and the vapor condenses into free water. This water collects in the line and, because of slow movement, accumulates and freezes in the riser as the line turns up into the scrubber.

Each night in the winter, this moisture may freeze and shut down the system. A small shop-made blow-down tank can be installed on the inlet line to act as a drip pot to collect this moisture. It will be necessary to occasionally blow down this system as it gets full.

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Chapter 11
Motors, Engines, Pumps, and Compressors

Section C

CIRCULATING PUMPS AND AIR COMPRESSORS

Pumps are used for many purposes on oil and gas the leases, and there are many styles of pumps. Pumps can be classified by their pressure rating: high, medium, or low. Some pumps will pump only very clean liquid, while others are capable of pumping liquids containing mud, small rocks, and other emulsions with very little or minimum pump damage. There are two basic styles of pumps: the *centrifugal pump* and the *positive displacement pump.*

C-1. Tank Battery Circulating Pumps.

The most common pump that the lease pumper operates is the tank battery circulating pump. For medium- and high-volume producing tank batteries, this pump is often permanently installed and the prime mover is an electric motor (Figure 1). On leases where no electricity is available at the tank battery, a single-cylinder gasoline-powered engine is common. When the oil is difficult to treat, the automated electrical pump may circulate the bottom of the tank into which fluid is being produced. This happens for a few minutes every hour.

For marginally producing oil wells, the circulating pump may be a portable model that is gasoline powered and moved from battery to battery as needed. In this event, the pump is either trailer mounted or needs to be small enough to be carried easily with one hand. This is because it must be moved, installed, and operated by one person. The most convenient style pump is the one with the pump mounted to the motor because skid-mounted units are too heavy for one person to hand load on a regular basis.

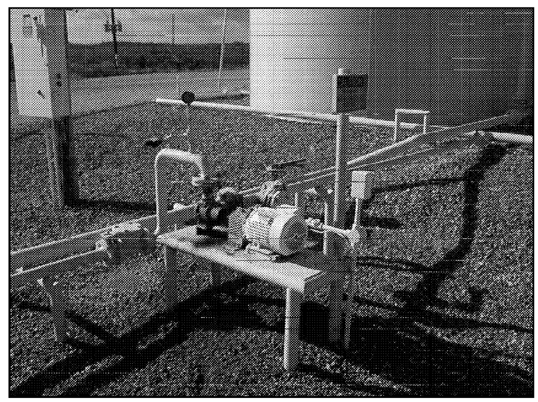

Figure 1. A permanently installed, electrically driven circulating pump with an adjacent control box.

C-2. Installation and Maintenance.

Circulating pumps are located in the system with the inlet connected to the drain system and the outlet piped back to the production line after the separator but ahead of the treating system. If no treating vessels are in the system, the outlet is connected into the oil system just ahead of the stock tanks for circulating.

The ideal arrangement in some tank batteries is to install the pump in the middle of a loop system where it can pump in either direction. Most transport trucks are piped in this manner so that the tanker can both load and unload itself as needed. There can be many reasons for the pumper needing to pump in either direction at the tank battery.

The maintenance of the pump includes lubricating the bearings or changing the shaft packing as needed. The maintenance of the circulating pump engine consists primarily of changing the oil as scheduled, keeping the belt tension correct, and gapping or changing the spark plug as needed. Many of the problems in the carburetion system are caused by allowing water or trash to enter the gas tank—for example, from storing fuel in a rusty and dirty container.

C-3. Understanding Gas Pressure.

One characteristic of gases is that they try to fill all the space in any container into which they are placed. The force that a gas exerts on the walls of its container is referred to as *gas pressure*. If the container is made smaller or if more air is forced into the same volume, then the gas pressure increases. This is referred to as compressing the gas, and it is the same action that occurs when the piston moves up the cylinder, making the volume of the cylinder smaller and compressing the fuel/air mixture. An air compressor simply pumps more air into a container, leading to greater air pressure.

Normal atmospheric pressure at sea level is approximately 14.7 psi. This is basically the pull of gravity or weight of a column of air 1 inch x 1 inch and all the way into outer space. As one goes to a higher elevation, there is less air above each square inch, so atmospheric pressure decreases with altitude. Any container open to the atmosphere will have an inside pressure the same as atmospheric pressure at that location.

Gases tend to move from areas of high pressure to areas of low pressure, and this phenomenon can be used to do work. For example, compressed air has a pressure that is greater than that of the surrounding air. Thus, compressed air can be used to move objects, including control valves.

In a similar way, if there is an area with a pressure less than atmospheric, the surrounding air will try to move in that direction. These areas of lower pressure are referred to as *vacuums*. Vacuums are often used to move gases and liquids. For example, as the piston moves down a cylinder in an engine, a vacuum is created in the cylinder. Because the fuel/air mixture from the carburetor is essentially at atmospheric pressure, when the intake valve opens, the mixture flows into the cylinder where the pressure is lower.

Gas pressure is measured through the use of gauges. Gauges used to measure compressed gases and sometimes vacuum typically provide readings in pounds per square inch (psi). Vacuum gauges usually provide readings as inches of mercury (in. Hg), though it is often referred to as inches of vacuum. This measurement scale is based on the movement of liquid mercury within a glass column. At sea level, absolute vacuum is considered to be 29.92 inches of mercury. This is the greatest vacuum that can be created.

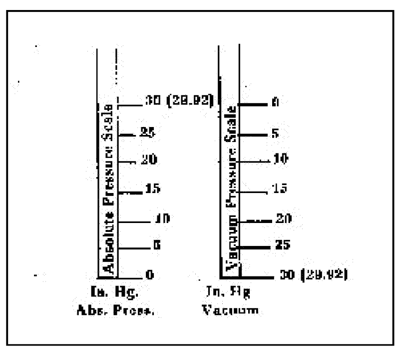

Figure 2. Comparison of vacuum and absolute pressures.

When dealing with gas pressures on an oil lease, there are two common ways of referring to the pressure. *PSIG*, or *pounds per square inch, gauge* is the pressure inside vessels and lines. The accuracy of the pressure reading depends upon the gauge itself. *PSIA*, or *pounds per square inch, absolute*, is the pressure on the outside of the vessels and lines—that is, normal atmospheric pressure.

C-4. Air Compressors.

Air compressors (Figure 3) are installed at tank batteries to supply air to operate automated equipment. Even though automated valves can be controlled by natural gas, several problems can be encountered that will cost the lease operator many times the price of installing and maintaining an air compressor.

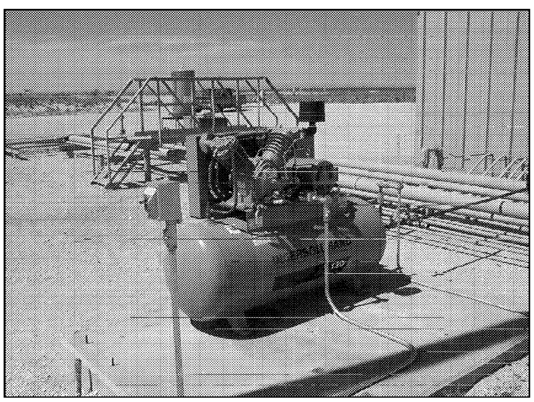

Figure 3. A tank battery air compressor used to provide clean air to operate automation valves and controls.

Natural gas can contain corrosive compounds that are not easily removed by using a scrubber. Expensive controllers can become contaminated, plugged, or corroded by using some natural gases.

Air compressors in the field are usually operated by using an electric motor. Maintenance usually involves maintaining correct belt tension, checking the oil level in the compressor, keeping air filters clean, draining accumulated water from the air tank, and lubricating the bearings.

C-5. Air Compressor Maintenance.

Air compressors are easily maintained because they are fully automated and pump air on demand as it is consumed. One of the maintenance tasks is to make sure that there are no air leaks in the system. Leaks can cause the system to run longer to make up for lost air.

The inlet air filter will need to be checked and cleaned on a maintenance schedule. The oil in the compressor will also need to be checked on a regular basis. The oil will need to be changed according to manufacturer's specifications and be refilled with the recommended oil. Hydraulic or compressor oil is not the same blend as engine oil.

C-6. Gas Compressor Operation.

Tank batteries located near or within city limits or oil storage tanks that vent large quantities of natural gas may include gas compressors. These gas compressors are automatically turned on and off by low-pressure controls. The unit is referred to as a *vapor recovery unit*. This unit takes the low-pressure gas from the tanks, compresses it, and injects it into the high-pressure sales system.

As the gas leaves the tank battery, just ahead of the compressor, it passes through a tank (scrubber) that removes the distillate. This distillate is pumped back into the stock tanks periodically. Low-pressure gas compressors will usually have vane-type compressors that require a lubricating system.

The compressor will probably have an oiling lubricator on it to provide oil for lubrication. The lease pumper must regularly fill this lubricator with oil and keep basic records on oil consumption. This is done to track how much oil is being consumed and to know how often oil must be added.

The sight glasses on the lubricator are filled with a water-soluble glycerine solution. As the oil enters the pump and travels upward through the glass, the number of drops of oil being injected per minute can be counted because the oil is lighter than the glycerine.

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CHAPTER 12

GAUGING AND ANALYZING DAILY PRODUCTION

- Operation of satellite tank batteries.

3. Unitizing Fields Under One Operator.
4. Commingling Different Pay Zones.
5. Unitizing a Reservoir.
    - Problems in production that justify the need for unitization.
    - The effects of unitizing.
6. Commingling Wells with Different Well Operators.
7. Working for More than One Operator.

E. Repairs and Maintenance

1. Effects of Reduced Production.
2. A Reasonable Workload.
3. At the Tank Battery.
4. Leaks in Lines.
    - Upwind precautions when gas is present.
5. Pumping Unit and Wellhead Maintenance.
6. Automation Control Maintenance.

The Lease Pumper's Handbook

Chapter 12
Gauging and Analyzing Daily Production

Section A

LEASE DUTIES

A-1. What Makes an Outstanding Lease Pumper?

Although some lease pumpers are hard working individuals, they may barely achieve satisfactory production levels. Fortunately, the majority are ***good*** lease pumpers. However, a few have an ***outstanding*** ability to produce wells. This ability is built by excellent work habits and the desire to continuously improve their analytical and operational skills.

Skills needed to become an outstanding lease pumper. Outstanding lease pumpers have the ability to understand what is occurring on the lease, in the formation, and how all facets of the operation can be improved. This includes understanding how to coax additional oil out of the formation, superior knowledge of oil treating, and excellent operations management.

Outstanding lease pumpers:

- Have job satisfaction. They enjoy their job and keep an active interest in their profession.
- Show pride in their work. They take pride in their ability, appearance, the appearance of the site, equipment and supply organization, and cleanliness.
- Have the ability to make as much oil as possible. They continuously study how production can be improved.
- Keep tank bottoms clean. This begins even before production is switched into the tank.
- End the month with less than one tank of oil on hand at each tank battery if possible. They schedule tank sales in advance and call the gauger early.
- Put in a full day of constructive work without resentment. Outstanding lease pumpers never get into the habit of leaving the job early.
- Keep lease expenses to a minimum but recognize when a special expenditure will pay dividends.
- Take care of the vehicle and tools.
- Drive conservatively.
- Work well with all types of people.
- Are honest.
- Do not abuse alcohol or drugs.
- Observe good safety practices.

A-2. Beginning the Day on the Lease.

When arriving on the lease in the morning, the pumper should review the work schedule. The scheduled duties should be aggressively worked so that there is time for special projects and challenges.

The pumper must have the ability to stay productive during the entire workday and efficiently identify and solve the day's problems.

Everything should be checked and observed during the morning rounds. Light work should be completed during the morning so that the afternoon can be devoted to outstanding lease needs. This will prevent the need to double back on previously covered ground. Light work includes checking pumping units, observing stuffing boxes, and making sure that everything is operating normally.

The typical work day includes the following activities:

- Tank gauging. Tanks should be gauged as early as possible. Many companies will let the pumper set the starting time.
- Performance of other required daily and scheduled duties.
- Production computation and checking for problems.
- Observing all wells and equipment.
- Identifying and solving problems as they arise while still keeping the regularly scheduled maintenance program.

One or more units should be scheduled to be pumping at the beginning of the day. If a well is pumping, the electrical service is in working order. If not, this is likely the first problem to be corrected. If a well is not pumping, it may be best to turn the electric controller from *automatic* to *manual* to observe it in motion.

A section of a pumping unit should be observed for a full rotation. If an air space opens up, the unusual action will be noted instantly. A white line should be painted on a pitman arm nut and observed at least one time a week. This is to allow the lease pumper to observe any movement of the nut.

After an inspection, the lease pumper should check to see that the controller has been set to the *automatic* position.

Visual inspection. Trash should not be allowed on the ground around pumping units or moving equipment. Debris should be removed from a location after well work has been performed to prevent problems from being obscured. Clean grounds will allow the observation of some problems from inside the vehicle.

Any loose parts on the ground should be noted. Small bolts, nuts, or washers in an area that is regularly cleaned may be an indication of problems. The pumping unit may need to be shut down until the source is identified.

The height of the liquid line on the sight glass of a pressure vessel should be observed every day. A small string can be tied around the sight glass and slid up or down to the exact producing liquid level. When passed on a daily basis, the performance of the vessel can be observed at a glance. This can make a significant difference in the gauge analysis when pumping marginal wells. When the oil level begins creeping upward, it may be an indication of water in the oil line to the tanks. It can also indicate when the vessel develops enough *liquid head* above it to kick part of the water over into the stock tank. When this occurs, the level will go down below the marker level and this cycle will begin the process again.

The pumper should listen while observing. If a pumping unit is squeaking, it either has a problem or may require lubrication.

Observations are only useful when combined with thoughtful analysis. Correctly analyzing problems helps to build a better pumper.

A-3. Planning and Scheduling.

Whether serving a small company or a pumper contractor, outstanding lease pumpers work from a ***planned schedule***.

They understand what makes up a good schedule, develop one, and follow it as closely as possible.

Each detail of work is not planned down to the exact day for most lease work, but some duties are so important that they will be scheduled with clear time objectives. Many projects, such as individual well tests, lubricating pumping units, treating wells, walking flow lines, pressure testing flow lines at the wellhead, filling chemical pumps, lubricating valve stems, and a host of other activities, can be planned and performed on a schedule.

Monthly, quarterly, semiannual, and annual maintenance. Maintenance schedules should be completed and posted in the lease records book (discussed in Chapter 19). Some pages must be custom designed to fit the specific maintenance needs of the lease operation. Tasks will be shared by both regular and relief pumpers. Depending on the specifics of the lease, this may include, but is not limited to, servicing pumping units, checking gearboxes, changing engine oil, and lubricating plug valves.

Monthly Schedule. The lease pumper should have specific maintenance goals that are achieved every month. A monthly pumping plan is easy to develop and begins the same way every month. With time, the plan is fine-tuned and becomes a valuable tool. Monthly activities include:

- Well testing
- Circulating tank bottoms
- Chemical treating
- Planning upcoming tasks

Well testing. Well testing should begin in the first few days of the month, and each well should be tested once per month. The regular pumper must maintain a testing record. This essential task should not be relegated to a relief pumper.

Reviewing the most recent record against those from previous months helps maintain a pulse on the condition of every well. The record reveals when wells are maintaining production, falling, need pulling, or can increase production.

For a one-well battery, a typical day is chosen and recorded as a test. Averaging the month produces invalid results because it usually also includes down time.

Testing procedures are reviewed in Chapter 13, Testing, Treating, and Selling Crude Oil.

Circulating tank bottoms. Every time oil is sold, the bottom must be cleaned. If problems are encountered while treating oil, every time that a tank of oil is sold, the remaining oil and bottom emulsion should be circulated through the treating system and into the receiving tank. If it did not circulate out to a low level it should be switched back and produced there until it accumulates approximately one foot of new oil. It is then circulated out again into the receiving tank. This should be repeated until the bottom is satisfactorily clean.

Bad tank bottoms are often caused by neglect and accumulation. It may sometimes be necessary to pump water into the tank to lift the emulsion and stir so that it can move and treat. Even after tank bottoms are satisfactorily clean, this procedure is repeated with every tank sale. At the beginning of the month when oil selling times are known, the tank should be circulated and kept as clean as possible. This is reviewed in more detail under Chapter 13, Testing, Treating. and Selling Crude Oil.

Chemical treating schedule. Chemical consumption should be computed on a regular schedule. This should be balanced against the barrels of emulsion produced. Treating must be kept on schedule to keep the amount of time and chemical consumed to a minimum. Chemical action is often improved by simply circulating the oil. Movement provides additional conditioning.

Planning upcoming tasks. As the end of the month approaches, the upcoming month's activities should be planned, including those tasks required in the first week of the month. An efficient schedule balances sufficient maintenance time to prevent problems while avoiding the unnecessary expense and time of over-servicing. Planning becomes easier as experience is gained.

Some duties such as well tests should be performed within the first three weeks of the month. This will free the latter part of the month for oil treating and other important duties. Delaying treatment of a tank of oil may result in its not being sold until the next month, and thus payment to the oil company will be delayed for another month.

The Lease Pumper's Handbook

Chapter 12
Gauging and Analyzing Daily Production

Section B

GAUGING DAILY PRODUCTION AND INSPECTING THE TANK BATTERY

B-1. Approaching the Tank Battery.

Over time, the pumper should gain the ability to perform a meticulous but almost automatic review of the tank battery. Before the vehicle has been parked, some problems may have been determined already.

The tank battery is the hub from which most lease pumper activities are controlled each day. When oil production is normal or slightly up, the pumper will feel good and have time to take care of many needs. If production is down, the pumper must check dozens of small potential causes and search for solutions that might have caused the shortage. If production is too high, the pumper is possibly more alarmed than had it been too short and again must investigate many systems in the search for the root cause of the problem.

The visual inspection. An obvious problem that may be seen while approaching the battery is oil or water running across the road. The problem may present itself as a small black streak down the side of a tank or along a line, indicating a pinhole size leak or a loose connection.

If a tank of oil had been available for sale, there may be tire tracks from a gauger's pickup or transport truck. If a sales line valve is open, the gauger has come by and accepted the oil. If tracks are present, then the pumper should also look for a receipt in the communication bottle.

Before leaving the tank battery, the pumper should know:

- How much oil and water are in all of the tanks.
- The height of the fluid levels in all sight glasses.
- The pressures on all gauges.
- The levels of water in the disposal system and pit.
- Whether any oil has been carried over into the water system.

Hopefully, everything will appear normal when looking across from the tank battery walkway.

B-2. Gauging Equipment.

A good gauge line is needed for gauging the tanks. In addition, clean rags or a line wiper are needed to wipe the oil off the gauge line and plumb bob. The lease pumper should never allow oil to drip off the line.

The gauge line. Figure 1 shows a typical gauge line. It consists of a frame, tape, and plumb bob. This is an expensive item, and it must be cared for properly in order to avoid the cost of replacement. Caution must be used to prevent the thief hatch lid from falling on the tape while it is being used and to prevent a kink from developing in the line. The plumb bob is made from ¾-inch brass and weighs 20-22 ounces. This gives it sufficient weight to pull the tape off the reel as it drops toward the striker plate that is mounted in the bottom of the tank. The striker plate prevents holes from being punched in the bottom of the tank over years of gauging. As indicated in Figure 2, several styles of plumb bobs are available.

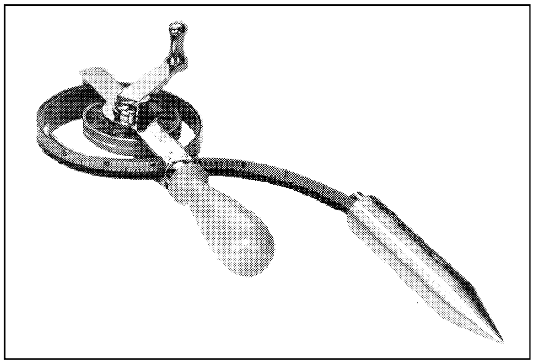


Figure 1. The gauge line with a double-duty tape.
(courtesy of W.L. Walker Company)

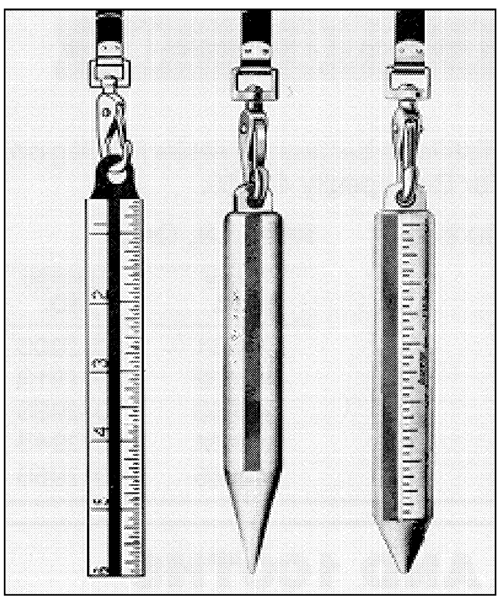


Figure 2. A wide assortment of plumb bobs is available.
(courtesy of W.L. Walker Company)

The line wiper or *little Joe* (Figure 3) is a handy tool. It is mounted on the gauging tool between the handle and the frame. After striking or *tagging* bottom and as the line is reeled, the wiper trigger is squeezed lightly to wipe the line clean. The line wiper pays for itself by dramatically reducing the number of rags consumed while gauging as well as by returning the oil from the line back into the tank.

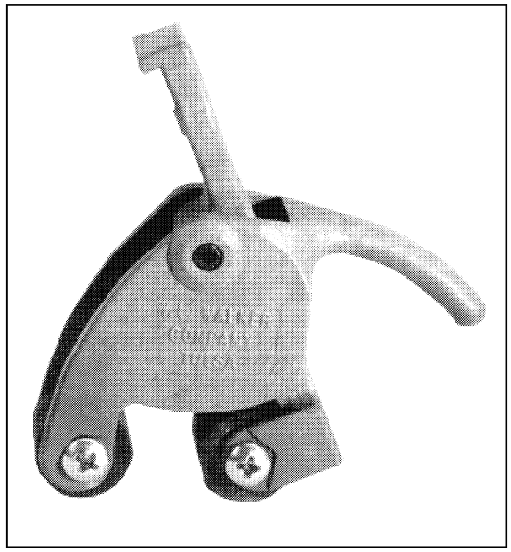


Figure 3. A line wiper or Little Joe.
(courtesy of W.L. Walker Company)

Gauge lines are available in chrome or nubian (black) finishes or a combination of these two finishes as shown in Figure 4. They are available in inch, hundredths of a foot, and metric scales.

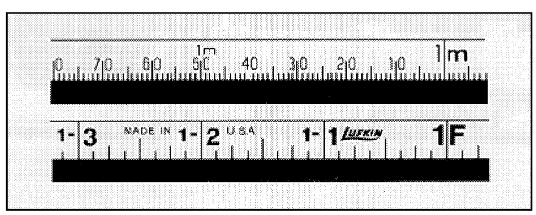


Figure 4. Two styles of gauge lines.
(courtesy of W.L. Walker Company)

Three frames are available. One size holds 18-, 25-, and 33-foot tapes. A second size holds 50-, 66-, and 75-foot tapes. A third size takes 75- and 100-foot tapes. The shorter tapes are more popular for typical lease use.

Chrome-clad tapes are best when gauging heavier, low-gravity crudes. Dark-colored crude stands out distinctly on the chrome line. The chrome-clad line may need to be oiled and dusted to get an accurate reading when gauging lighter crudes.

Nubian lines are best when gauging light crudes and distillates. Distillate or condensate is often so clear that, in a transparent glass, it looks like water. Since it evaporates off the gauge line before the gauge can be read, oil or powder may need to be put on the line before gauging to give a clear reading. Similar problems may also be encountered when gauging water.

Since water will drop out of the crude oil when it is produced into the stock tank, the bottom must be checked occasionally to see how much water is being accumulated. In cold weather, more may be carried over than during the summer months. At appropriate times it must be determined how much free water is in the stock tank. This can be determined by using a *thief* or *gauging paste* on the gauge line.

The thief can quickly determine how much water is on the bottom of a tank. It is dropped into the tank and a bottom sample is pulled. While wearing plastic or rubber gloves, the lease pumper must pour the sample across the palm of one hand while it is over the thief hatch. As it turns from free oil into sludge, the water and BS&W levels can be determined. The thief manufactured by the W. L. Walker Company is commonly used (Figure 5). Use of the thief is covered more extensively in Chapter 13, Testing, Treating, and Selling Crude Oil.

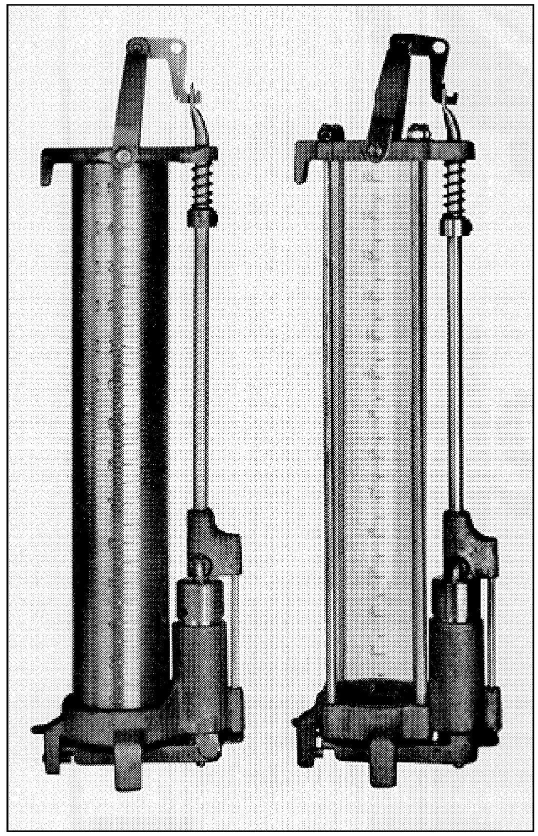


Figure 5. The Tulsa thief with brass and clear barrels, and a 12-inch trip rod.
(courtesy of W.L. Walker Company)

The second way to determine water level is by using a gauging paste such as Kolor Kut (Figure 6). This golden brown paste will retain its color in crude oil, but will turn a brilliant red when it comes into contact with water. It is applied to the line at an estimated spot for the water level, then the tank is gauged. The use of Kolor Kut is further discussed in Chapter 13.

Figure 6. Kolor Kut paste.
(courtesy of W.L. Walker Company)

B-3. Gauging Oil and the Grease Book.

Before the lease pumper gauges the tank, an approximate gauge should already be known. The pumper should know to the nearest ¼ inch how much oil there should be on any day based on the previous day's reading and the expected daily production.

The pumper should carry a daily gauge book or *grease book* that contains all gauge readings over a period of several months. This book is not the same as the larger and more extensive lease records book that is carried in the glove compartment. The daily gauge book is small enough to be kept in a pocket but is large enough to record gauges for four months to a year, depending upon how it is set up and how extensively it is used. Occasionally a pumper will carry a small pad while taking readings and then transfer the gauge readings to the grease book later. With this procedure the grease book remains clean. The setup and use of the grease book is reviewed more thoroughly in Chapter 19.

Gauging the stock tank. There are multiple techniques for gauging tanks. Some gaugers lower the plumb bob into the tank by unreeling the handle, being careful that the line never touches the edge of the thief hatch but stays in the center of the opening. Others drop it in and step back with the line almost horizontal as it is sliding over the edge of the thief hatch and into the tank. By using a light thumb pressure on the line, it slides very freely into the tank.

Regardless of the technique used, the line should be slowed down several inches before the plumb bob touches bottom. Then it should be lowered gently by hand until the plumb bob touches the bottom lightly. The line may need to be raised and lowered, or *spudded*, several times to work through sludge but without bouncing the plumb bob. If the plumb bob is bounced even slightly, the line will produce false readings. Oil will surge up the line, the plumb bob will lean to the side, and the line will show as much as ½ inch more oil than is in the tank.

The pumper must learn to gauge tanks accurately. If a tank is gauged ten times, the reading should never vary more than 1/8 of an inch between the highest and the lowest readings. However, the lease pumper's gauging procedures may result in slightly different readings than those of other gaugers, such as the one who purchases the oil.

As soon as the tank has been gauged, the pumper should review the previous day's gauge and calculate the production quantity. The number of barrels over or short should be noted immediately. If the accuracy of the gauge is suspect or if the difference is too great, the tank should be gauged again. Section 12-C discusses the action needed if the oil is long or short.

Gauging water levels. Even if the oil readings agree with what was expected, the gauger should check the water tank while at the tank battery, look at the gauge level in the sight glasses, and be sure that everything is functioning normally. Meter readings at the battery (such as the number of barrels of water to the disposal system) should be read and recorded.

Switching tanks and opening equalizer lines. Equalizer lines should always be opened well before they are needed. If the tank is available, the equalizer can be opened before a condition should cause the tank to overflow. It is embarrassing to wash oil from the side of a tank because of a miscalculation, and this also creates unnecessary problems for the company.

Alternate day gauging. When there are a large number of wells to gauge, production is marginal, and the leases are many miles apart, it may be more practical to gauge some of the tank batteries every other day. This allows more time to work on the lease and eliminates many miles of hard driving.

With a marginal lease it is occasionally feasible, when both management and the pumper agree, to split days off and not have a relief pumper. Some pumpers prefer this approach.

The Lease Pumper's Handbook

Chapter 12
Gauging and Analyzing Daily Production

Section C

ANALYZING DAILY PRODUCTION

When a stock tank is gauged (Figure 1), the anticipated production level may be detected, or the level may be long (more oil than expected) or short (less oil than expected). Usually if the production is short or long, the pumper's next action is to re-gauge the tank.

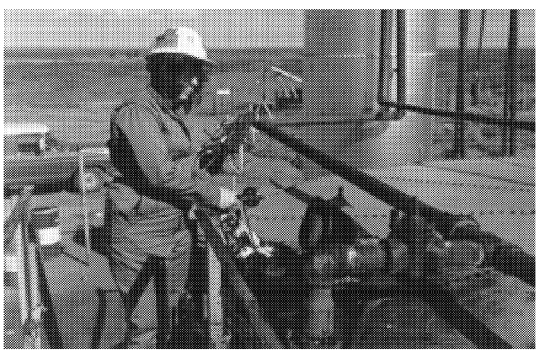


Figure 1. Gauging daily production of crude oil.

C-1. Problems with Short Production.

If the second gauge confirms that the tank is short, the pumper must investigate the reason for the loss. The four potential sites of loss are:

- At the tank battery.
- From a broken or plugged flow line.
- At the well surface.
- Downhole.

At the tank battery. Even if it is suspected that production was lost because a well failed to produce as scheduled or because of a problem downhole, the logical place to start is at the tank battery after re-gauging. This should only take a few minutes to check out. A visual inspection upon arrival at the property will have already confirmed that there are no leaks, so if the problem is at the battery, it must be in a vessel. Potential problems include:

- **Oil in the separator gas line.** There are many causes that may prevent separators from functioning correctly. If a float has broken off in the separator, the total emulsion may go down the gas line. This can be determined in seconds by observing the sight glass and feeling the action of the float to dump valve linkage or by force dumping the pneumatic valve control. A diaphragm control valve can develop a gas leak. Mud daubers (small wasps) can plug the vent holes in pneumatic valve breathing holes with mud if the holes do not have the correct screened fitting.
- **Oil is trapped in the heater/treater wash tank.** The oil level sight glass on the heater/treater should be checked and the gun barrel thiefed. If the oil dump line from these vessels plugs or an oil valve is closed, the accumulating oil will force water down the water disposal line until it empties all of the water from the vessel. The oil will then go into the disposal system or to the pit. Water accumulation

should be checked in both of these places. A glance at a functioning gauge glass will usually confirm or reject the possibility of a heater/treater problem. Sight glasses that are allowed to plug and become non-functional will cause problems in production analysis. They must be kept fully open and functioning correctly.

- **Paraffin.** Wax can accumulate at the oil/water interface level in the gun barrel and seal off at the edges. This seal prevents proper oil/water separation action and forces all liquid production out the water disposal line. A steamer or hot oiler and chemical treatment is usually required to melt the paraffin and force it into the produced oil tank. This is one of the many reasons that a gun barrel is periodically checked for performance and must have a satisfactory ladder or walkway access.

The water disposal system should be checked for excessive water accumulation. If water disposal is metered, a reading comparison from the past few days will reflect excessive water disposal. If these are not the source of the problem, other systems unique to the battery should be checked.

A flow line has broken or become plugged. These lines are normally inspected on a regular schedule and are rarely the source of the problem. However, to be thorough, they should be checked.

If the line is on the surface, it should be *walked*—that is, the pumper should walk along the line checking for leaks and plugged sections, occasionally tapping the line with a small hammer to locate plugs. The sound is more solid when it contains no gas. Lines under roadways become plugged occasionally. Use of conduit around the pipe can reduce this problem.

At the well surface. At the well, the problem can be on the surface or downhole. Since it is much easier to check surface equipment, troubleshooting should begin here. Surface problems at the well include:

- **A well was accidentally turned off.** This is a fairly common and simple mistake, especially among inexperienced pumpers. By producing the well for a short time and gauging late, much of the shortage can be made up the same day that it occurs.
- **Electrical failure.** Electrical problems are common. The pumping unit must be turned on to check for electrical problems. This repair can be as simple as pushing the reset button or replacing a fuse or as serious as changing out a motor. Fuse problems are often caused by using incorrectly rated fuses. Most automatic boxes can have more than one fuse. Occasionally, field mice and other animals can cause problems, such as chewed wiring, if the motor vents are not covered with hail screen.

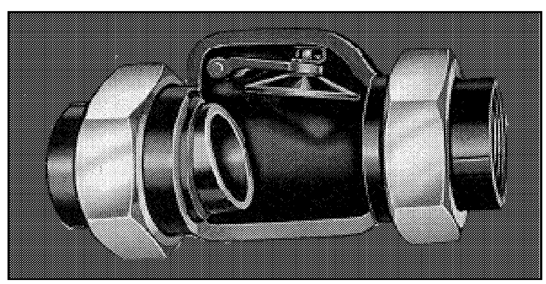


Figure 2. Forged steel Catawissa swing check valve.
(courtesy of Dandy Specialties, Inc.)

- **A casing check valve may have failed to close properly.** An example of a check valve is shown in Figure 2. If the casing check valve fails to close properly, the produced liquids may be circulating back to the bottom of the well through the annulus. If this occurs, the bleeder will have exceptionally good pump action, but the well will produce no oil to the tank battery. Often a simple cleaning of a check valve will correct the problem. To test the possibility of check valve failure, close the casing valve for two hours with the well pumping, then reopen it. If a casing check valve also fails at the tank battery, it is not unusual for the production from other wells to flow back and be lost back into the formation.

- **A leak in a casing check valve on the tubing will give a similar indication.** If the check valve is leaking, the lease pumper should re-gauge the stock tank for a production increase.
- **A valve accidentally left closed.** As the gas pressure builds up in the annular space and in the formation close to the well, the well will stop producing oil. This is most likely to happen when procedures have been done at the well that required valves to be closed, such as treating the well with chemicals that were circulated down the annular space.

When a closed valve is reopened, it should be done very slowly. The pressure may build up to several hundred pounds and this sudden surge to the tank battery can rupture an atmospheric tank. The valve should be slightly opened and allowed to bleed off for a period of time. Opening should be completed only after the pressure has bled off. A valve should never be placed to the wide open position suddenly.

Sometimes the failure will be the result of a combination of one or more of these problems.

Downhole. Some downhole problems that lead to a loss of production, such as a worn-out pump, parted rods, or a hole in the tubing, will require a well servicing job. Several other problems, however, can be solved from the surface without a pulling unit. Common problems include:

- **Pump valve not seating.** If the problem is in the pump, it may be determined by first opening the tubing bleeder valve while the unit is pumping. The pump may have trash under the standing or traveling ball. The pump should be lowered by raising the rod clamp above the pumping unit carrier bar and then started. This will allow the downhole pump to start bottoming out. With some wells this procedure may be necessary to stimulate the pump back into action. With wells on engines, pump tapping can be started by merely increasing the RPM if it is spaced to meet this need.
- **Gas lock.** Pumps are occasionally improperly serviced by supply companies. Common problems can include use of a barrel that is too long or a pull rod that is too short. The two valves are then too far apart when the pump is collapsed or pushed all the way in. This can result in gas being trapped between the valves. Even when the rods are lowered to make it tap, the only thing that will break the gas lock is to either wait until the casing fluid builds up enough hydrostatic pressure to override the problem (which may require several days) or to unseat the pump to lower the hydrostatic head inside the tubing. Neither of these is a good solution.
- **Salt bridges downhole** will cause a problem similar to closed valves with a resulting loss in production. To solve this problem, the lease pumper must drop a load of fresh water down the annulus. This is very dangerous as fresh water seals off some zones.

- **Plugged casing or tubing perforations can prevent oil from entering the well.** The casing can also fill become *sanded up*—that is, filled with sand from the production zone.
- **A worn or failed pump may lead to production losses.** Checking the lease record book may confirm this. The dates of the last several pump changes should be checked. Pumps will usually last a similar amount of time for a given well, so by checking how long the pump has been in use, the problem can be isolated as it begins to develop and before total failure occurs.
- **Tubing can split** due to a number of reasons. Sometimes a split in the tubing will seal as pressure is removed, only to open again when the tubing is pressurized, allowing fluids to escape through the split.

Some downhole problems, such as a worn pump or split tubing, may be indicated by a failure to develop pressure in the tubing. To check for this problem, the pump is run to place pressure on the tubing. The test is simple, but it requires common sense and caution. The proper method is as follows:

1. Place a pressure gauge in the pumping bleeder valve.
2. Close the tubing wing valve to the tank battery.
3. Turn the pumping unit for one revolution.
4. Turn the pumping unit off.
5. Check the gauge pressure.

   CAUTION: Never look the gauge directly in the face for safety reasons.

6. If no pressure develops, repeat the procedure.
7. After pressurizing the column, let it sit for several minutes to allow time to note pressure changes.

The bleeder valve and other surface connections may be standard pressure fittings, so extreme care should always be exercised when pressurizing a wellhead. The gas column in the tubing determines how quickly the pressure comes up. If the tubing contains a full column of liquid, the pressure will escalate rapidly. On shallow wells after pressure has been pumped up on the wellhead the rods will not fall, and the pumping unit bridle loses contact with the rod clamp.

If the unit does not develop pressure, the rod string may need to be lowered or other tests run. The problem should be reported to a supervisor before a well servicing company is called.

If the pump has good pump action but still does not produce fluid, a problem such as split tubing is likely.

Chapter 17 discusses downhole problems in detail.

C-2. Problems with Overproduction.

If the oil gauge is higher than expected, the pumper should be pessimistic. While there is a very remote possibility that a water flood project has caused an increase, it is much more likely that there is a production problem. For example, there may be a plugged water leg line in the wash tank or heater/treater or possibly a closed water valve. If thiefing a tank confirms that oil is being excessively produced, there is almost certainly a plugged water drain line causing water to rise in the wash tank or heater/treater, thus flushing excessive amounts of oil to the stock tanks. Problems such as this normally occur in three-stage vessels that utilize a water leg.

A quick check of the gauge glasses in the heater/treater, a Kolor Kut test on the gun barrel, and a quick look at the water disposal system will usually indicate the location of the problem in a few minutes.

The problem must be solved quickly or all water being produced from the wells will flow into the stock tank. The lease pumper should make sure that stock tanks have enough room so that excessive oil production cannot overflow onto the ground.

After the problem has been located and solved, the correct amount of oil and water will need to be circulated back through the heater/treater so the system can be re-balanced.

Determining if the overproduction is oil or water. A good pumper who takes care of the lease well should always know how much BS&W is in every tank. The last run ticket provides the reading as well as tests before sale of the oil. To determine if the overproduction is oil or water, the pumper should run a quick Kolor Kut test to determine the bottom condition, thief the bottom of the tank, or if in doubt do both. Both of these tests can be performed in less than 15 minutes.

If a heater/treater or gun barrel is at the site, the excess production will probably be oil, and the tank battery is entering an unbalanced situation that must be brought back into balance. The pumper should check all the sight glasses for level changes.

When the tank battery is still in balance. If all systems are known to be functioning normally, then the oil must have come from the formation. The common causes for wells to overproduce are as follows:

- **Increasing pumping unit time.** Pumping unit time can be increased and a small amount of oil can be gained for a few days, but production will return to the original level with the wells pumping longer. Pumping time costs money. However, if the pumper is overproducing the wells, cutting back the pumping time will cause a slight reduction in production for a few days. If the pumping time is sufficient, the wells should be produced efficiently in consideration of time.
- **A well has broken a gas lock.** When a pump breaks a gas lock, it will produce additional oil until the annular space has been emptied of liquid, then it will return to the original production level.

The Lease Pumper's Handbook

Chapter 12
Gauging and Analyzing Daily Production

Section D

UNITIZING THE RESERVOIR AND COMMINGLING PRODUCTION.

D-1. Satellite Tank Batteries.

A satellite tank battery is a sub-tank battery located between part of the wells and the main tank battery. Gas may be sold from a satellite tank battery and water may be removed and pumped into the water disposal system, but the oil is retained and piped to the main tank battery where it is combined with other oil produced from the lease. Satellite tank batteries are used on leases where wells are scattered over a large area to simplify operations and reduce line lengths.

Figure 1 illustrates a large satellite tank battery with the header located at the far right. Next is a line heater that prevents the regular separator from developing ice in the line during winter months. There are two vertical separators, one heater/treater for testing the wells, and a communication building that contains equipment to send a message to both the lease pumper and an answering service when problems occur. It also has the ability to shut in all the wells. In addition, it can be set up to automatically test the wells in a rotating manner.

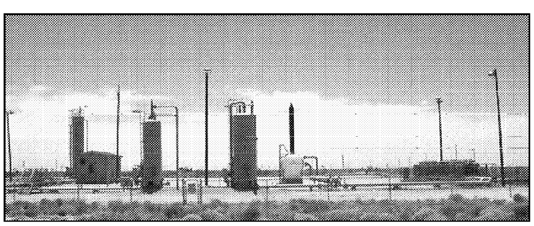


Figure 1. A large satellite tank battery with no stock tanks.

D-2. Problems and Solutions for Combined Flow Lines.

Production operations that flow the produced emulsion from two or more wells through one common flow line to the tank battery is the simplest form of a satellite arrangement. This saves the oil company the cost of purchasing and installing new long flow lines as well as future maintenance of the second or third line.

While the cost of a flow line can be saved, this arrangement presents new problems to the lease pumper. For example, how can a monthly production test on each well be obtained without shutting in each well for one day each month during testing? Even more important when producing marginal wells is the problem of testing combined emulsions. Until all oil and water in the flow line junction point of the two lines to the tank battery is produced, the combined emulsion is being tested. A large part of the test emulsion is still contained in the flow line when the test is over.

The individual well tester. The obvious answer to the testing problem is to move the well test to the well location site, rather than performing it at the tank battery. After selecting a convenient spot near the well or the edge of the location, a testing manifold can be installed. The junction point can be turned into a satellite tank battery. A typical tester is shown in Figure 2. The testing manifold is made by cutting the line and placing the following fittings into it in the order given:

- Tee
- 6-inch nipple
- Plug valve
- 6-inch nipple
- Second tee
- 6-inch nipple
- Union.

Figure 2. An individual well tester with a quarter-barrel dump used to test wells at the well location.

The tees are installed *running*, and in each tee a 6-inch nipple and a plug valve are installed, completing the test manifold. Optionally the two test valves can be left standing vertically or pointing to the side with all three valve stems pointing up. This is the most common position.

A trailer-mounted individual well tester can be brought to the well location. Once connected with satisfactory pressure-rated flexible hoses it is ready to test the well. The individual well tester will allow the pumper to separate the entering emulsion into gas and liquid, measure the amount of each, then allow them to recombine into the flow line to be produced to the tank battery. A sampler will periodically take a liquid sample. At the end of the test the liquid sample is blended, then two samples are removed and run through a shake-out machine or centrifuge to determine the percentages of oil and water in the produced fluid. This, along with a gas chart with appropriate information, completes the test.

Well tests at the satellite tank batteries. Occasionally, it is not satisfactory to move well testing to each individual well location, making it necessary to move the testing equipment to the junction point where lines come together. At this point a bypass header should be installed that connects all wells to a test separator. One well at a time should be diverted through the test separator for testing purposes. Occasionally, however, there are other needs, such as separating the water for water disposal or gas sales to the gas company.

This creates a recognizable satellite tank battery. It does not necessarily contain a flow splitter, but instead may contain heater/treaters, line heaters, water tanks, or other combinations of equipment. The rule of thumb is that the equipment is installed to meet the operator's needs. There will seldom be two identical satellite tank batteries.

Operation of satellite tank batteries. Common functions of a satellite tank battery include:

- Well testing
- Water separation for disposal
- Gas separation for sale or re-injection
- Pre-treatment of oil or water.

The operation of the satellite tank battery will be defined by the operator. Since the purpose and style vary widely, it is not possible to define every situation.

D-3. Unitizing Fields Under One Operator.

Whole books have been written explaining the need and processes for unitizing an oilfield. This section includes only some of the high points.

When a field is unitized, one operator, usually a major operator of the wells in the reservoir, will take over the operation of the reservoir and field for the life of the wells. This unitized field is a long-term operation.

Every well in the field is tested with approved witnesses observing every well test. These individual daily well tests record the ability of each well to produce gas, oil, and water. All of these figures are added together, and a percentage value of the unit for each well and operator is established.

The unitized field protects all well owners from formation abuse to their interests by those operators who produce their wells in a manner that benefit them only while causing damage and loss of production to others. It also allows beneficial enhanced recovery practices to begin and end as needed. Pressure maintenance can be implemented at higher elevations and there can be water flood at the lower sections.

D-4. Commingling Different Pay Zones.

When the operator has a small amount of production from two different pay zones, the rights to production are owned by the same individual or agency, and the two crudes are similar in gravity, it is possible to get a permit to produce them into a common tank battery or *commingle* the production together. This allows the oil to be sold more frequently and reduces the loss of the lighter ends into the atmosphere. It also eliminates the need to construct two separate tank batteries.

The operator is still responsible, however, for accounting for how much oil, gas, and water was produced from each of the two zones. Two separators or heater/treaters may be required as well as provisions to meter all of the fluids produced from each reservoir. The tank battery is usually identical to a tank battery designed to combine the production facilities from two different operators. This is reviewed in the next two sections.

D-5. Unitizing a Reservoir.

Unitized field operations occur only in fields where two or more operators have producing wells in the same pay zone. When a reservoir is large it may extend several miles in length and width. All wells may produce from similar distances above or below sea level, or the field may be on an incline and be much higher at one end than the other.

Problems in production that justify the need for unitization. Wells produce at different rates in the same field. If the reservoir is on an angle and is water driven, the operators on the higher level will produce at a high gas-to-oil ratio. In this situation, wells produce a large amount of gas and very little oil. Operators who have production in the center of the reservoir will produce a large amount of oil with very little gas. This lease has a low gas-to-oil ratio. The operators at the lower edge of the reservoir will produce less oil and more water.

Over time, every action of an operator will affect the other operators. If the operator on the upper areas produces a high rate of gas and very little oil, this will lower the pressure on the upper end and cause the oil and water at the lower zones to begin moving toward this area and upward. The operator in the middle will begin to lose reservoir pressure, and water will begin to migrate in. The operator whose wells are in the lower zone will be affected by all of the operators with wells in the upper and middle zones. The gas pressure will fall, oil production will decline, and water will increase.

The effects of unitizing. When the field or reservoir is unitized, one operator takes over the operation of all wells in that reservoir and operates them as an independent oil company. Usually the oil company with a larger investment and a higher capability for producing wells efficiently is selected as the operator. As part of the procedure for creating the unit, all wells are witness tested and their rate of production established. Several other factors are included, and each operator is guaranteed a share of the profits according to the value of the company's share of the unit. The practice of overproducing high-volume gas wells will be adjusted, and a pressure maintenance program will begin. The water will be reinjected in the lower zone. In the long run gross production may be increased, but the life of the field may be extended dramatically. The operating company will be allowed to recover all operating costs before profits are distributed.

D-6. Commingling Wells with Different Well Operators.

To develop the ability to survive in a tough oil market, operators search for methods to lower company costs. One method gaining in popularity is to combine some of the field operations to operate as one company. Figures 3 and 4 reflect how a commingled tank battery might look.

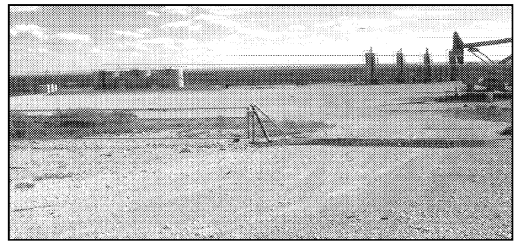


Figure 3. A commingled tank battery with two operators. The battery has three tanks, four heater/treaters, and three gas meter runs.

Figure 4. Two of the heater/treaters can be owned by the operators and the third reserved for treating oil in the tank battery. The fourth is used for well testing.

On the left side of Figure 3 are three gas meters and the stock tanks. On the right are four heater/treaters.

Each company in the scenario tank battery has its own heater/treater with the produced crude oil dumping to one common tank battery. Each company has its own sign nearby identifying company ownership. At the lower left of each heater/treater, a small metering separator has been installed to measure oil production before it is dumped into the common or joint venture stock tanks.

Figure 5 is a picture taken at the back of the heater/treaters, looking toward the stock tanks and three gas sales meters. Two are for the individual operators and the third is jointly owned as part of the tank battery. The circulating pump is located between the tank battery and the heater/treaters for convenience in treating the oil. It can also be set on automatic scheduling for continuous treatment.

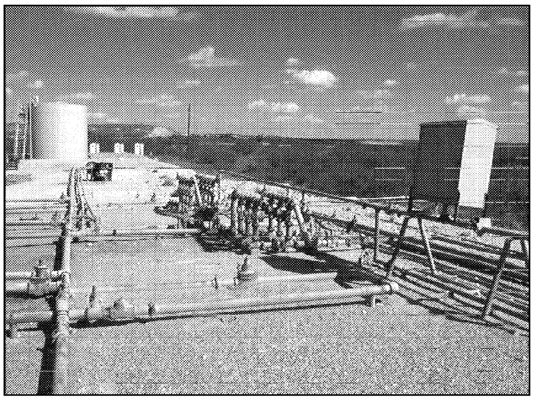


Figure 5. Each operator owns one header, and the closer line goes to the test heater/treater. The test gas meter is at right.

Also at the back of the heater/treaters are two company headers to direct the flow of oil from the wells toward the heater/treaters. The header has a second manifold that permits the wells to be directed toward the test heater/treater. The gas meter to the right measures the produced gas from the test heater/treater and is then directed back into the operator's gas system.

The small metering separator (Figure 6) is set at the base of the heater/treater and operates at the identical gas pressure. By using gas-operated motor valves, the metering separator can be alternately filled with oil, then dumped to the tank battery. It is recorded each time it is dumped. These gauges are read daily at approximately the same time to record how the wells are producing.

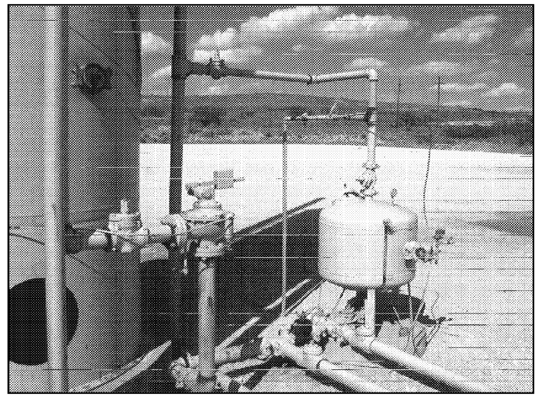


Figure 6. The small metering separator that measures the oil from the heater/treater before it is commingled in the tank battery.

D-7. Working for More than One Operator.

It is not unusual for a lease pumper to work for more than one operator. If the lease pumper is a contract pumper and is driving a personally owned vehicle, this should not create too great a problem, especially for one or two isolated nearby wells.

However, if the lease pumper is driving a company-owned pickup, consuming company-purchased fuel, and working an eight hour day, it would not be possible to contract pump other wells unless it was fully authorized and approved by the company that is supplying the vehicle and fuel. In this situation the payment check should go to the company and a special agreement for payment to the pumper for extra work time agreed upon.

There are so many possibilities of how a work agreement with the employer can be agreed upon that common sense must prevail to prevent problems from developing. If the pumper is working for a small company, a workable agreement may be possible. The company may even welcome the pumper establishing the agreement. The larger the company is, however, the more difficult it becomes to work for two operators. The employing company has enough work for the pumper to consume the entire workday, and it may not be possible to split time. Whether or not it is a gauge and telephone only situation or requires some physical work when it is indicated is another factor. Some work situations can consume considerable work time, and one job or the other may suffer for lack of attention when needed.

When considering accepting a second part-time job, the pumper should:

- Secure approval from the primary employer if needed.
- Not let regular work suffer because of the divided responsibilities.

The Lease Pumper's Handbook

Chapter 12
Gauging and Analyzing Daily Production

Section E

REPAIRS AND MAINTENANCE

E-1. Effects of Reduced Production.

The lease pumper is expected to continually maintain and repair everything mechanical in the field. For example, when there is a flat on the lease vehicle, the punctured tire is not automatically discarded. If it is repairable, it should be patched and expected to continue to give satisfactory performance for the life of the tire.

This is also true for the tank battery, pumping units, engines, equipment that has been pulled out of service, other materials stored in the pipe yard, and all equipment on the lease. All of the equipment is manufactured to be repairable, and the lease pumper must learn to maintain many systems. A lease with high oil production will have more funds available for contract and company repair personnel, but the company will still strive for maximum efficiency and production.

As production declines, so do the dollars available for maintenance and repair support. As production declines to marginal well level, it may approach the point where the operator will lose money if the company contracts out many repairs. In this situation, the lease pumper wears many hats, must be skilled at many lease maintenance tasks, and is a highly valued employee.

This does not imply that the job is more difficult but that job duties are more varied. As production declines, the entire lease slows down. Since less oil is produced there is more time available for treating. This added time requires less chemical per hundred barrels for treatment because there is additional circulation time to give more treating and settling time.

The tank battery is also easier to operate and maintain. Less automated equipment will be required on the lease. As formation pressure declines, the volume of gas produced may drop so low that gas is vented at the well casing valve, a vacuum may be pulled on the formation, and the tank battery may not produce enough gas to sell. The heater/treater may be switched to atmospheric operation rather than pressurized and during the warmer months act just as a three-stage separator. As these changes begin, the lease pumper's job description also changes to meet the lease needs.

E-2. A Reasonable Workload.

As lease income is reduced, the pumper will perform some duties that would normally be performed by other personnel when the income was greater. The lease operator, however, must limit the amount of physical effort lifting jobs that the lease pumper is expected to perform to a level that one person can safely perform.

The lease pumper must be skilled in a number of tasks and willingly perform lease tasks that are acceptable for one person to do. The lease pumper must also recognize that some jobs require two or more people to safely perform, and a single individual should not be required or expected to perform these alone. Some safety rules include the following:

- Use common sense in every task performed. **Never** take needless chances.
- Avoid lifting objects that are too heavy for one person.
- Safety comes first. Sometimes a task takes longer to do it safely. Take the safe way.
- The lease operator must always observe the same practices and insist that good field procedures always be followed.

E-3. At the Tank Battery.

The lease pumper is commonly expected to perform the following maintenance tasks:

- Repair small leaks on the sides of vessels. These are usually low on the vessels and repaired with patches and plugs. Always lower the level of the liquid in the vessel below the spot being repaired. Never try to patch a leak on the side when the oil level is above the leak.
- Clean oil spots on tanks as they are made. Keep everything as clean as possible.
- Cut weeds around walkways and automatic control boxes, especially where snakes are common.
- Do not allow bees to make hives in the equipment.
- Tighten small fittings when they seep oil. Always remove the pressure first.
- Lubricate plug valves as needed.
- Replace valve stem packing as needed.
- Adjust linkage on dump valves.
- Install leak clamps.
- Tighten bolts when bolted tanks leak.
- Clean and replace sight glasses.
- Paint repaired items that cannot be allowed to rust.
- Adjust temperature controls.
- Maintain automated equipment.

E-4. Leaks in Lines.

The lease pumper is usually expected to install leak clamps on flow lines when needed. Repairing leaks can be extremely dangerous, especially when working alone. Gas cannot be smelled after a few minutes or seconds, so lines should be repaired *after bleeding* the pressure off the line. No assistance is typically available to a lease pumper fixing leaks.

Upwind precautions when gas is present. A person should always be positioned upwind from a natural gas source. However, the breeze passing on both sides of a person creates a low pressure area in front. Gas is sucked towards the person's face. Standing a little to the right or left will break the vacuum effect and will reduce the amount of gas being sucked up into the face. When gauging a tank, the lease pumper should also stand with the wind directly at the back, facing the direction the windsock points (Figure 1) and turned slightly to one side so the wind will keep the gas out of the face.

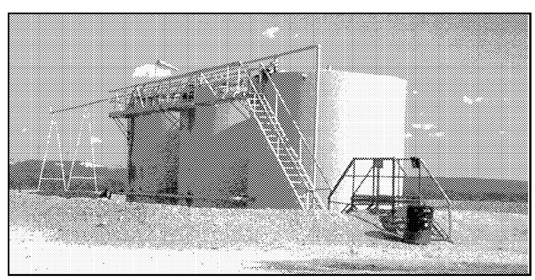


Figure 1. During maintenance, the lease pumper must remain aware of wind direction.

E-5. Pumping Unit and Wellhead Maintenance.

The lease pumper is always required to service pumping units. This includes lubricating bearings and maintaining gear oil levels. On small units the pumper may also be expected to perform the following tasks:

- Tighten belts and adjust as needed.
- Replace belts when needed.
- Lower rods to bump bottom and raise them back up to stimulate pumping.
- Pack stuffing boxes and adjust packing as needed.
- Replace fuses when they burn out.
- Maintain chemical pumps.
- Batch treat wells with chemical by dumping it down the annulus.

E-6. Automation Control Maintenance.

There are many actions that the lease pumper can take to keep automated equipment functioning correctly. The equipment manufacturer is usually very cooperative in supplying the needed literature to explain how a piece of equipment operates. Local supply companies can offer invaluable advice on where to acquire this information.

The functions of most unfamiliar items that need to be repaired can be understood after careful examination. Good field mechanics do this on a regular basis and perform a good job. The pumper should not hesitate to ask questions of other people. These tasks will become easier as experienced is gained.

The Lease Pumper's Handbook

CHAPTER 13

TESTING, TREATING, AND SELLING CRUDE OIL

- End of the month oil sales overload.

2. Selling Oil.
   - Requirements for a full transport load.
   - Selling split loads.
   - Communication with the gauger.
   - The note jar.
   - Witnessing the oil sale and the rejection notice.
3. Seals and Seal Accounting.
   - The run ticket.
4. Selling Oil by Use of the LACT Unit and Surge Tanks.
   - Hot oiling.

The Lease Pumper's Handbook

Chapter 13
Testing, Treating, and Selling Crude Oil

Section A

TESTING AND TREATING

There are several reasons why the lease pumper chemically treats crude oil systems. The pumper needs to understand chemical-related problems and how treatment can help alleviate the problem. Typical reasons for treatment include:

- Removing water from produced crude oil
- Treating produced water prior to re-injection
- Preserving casing and tubing from corrosion
- Reducing paraffin and asphalt accumulation
- Reducing scale accumulation
- Preventing gas sales lines from freezing

A-1. Treating Oil, Corrosion, and Scale.

The lease pumper stores chemicals on the lease that have been formulated to meet several treating needs. Chemicals are often delivered in 55-gallon drums. Because paper labels deteriorate over time, drums stored on the lease should be marked with a paint marking stick for future reference and identification. Recording procedures are included in Chapter 19, Record-Keeping.

The purposes for these chemicals include:

- Treating crude oil before sales
- Reducing corrosion damage
- Scale deposits and sand stabilization

Treating crude oil before sales. Most chemicals for treating crude oil are used to lower the BS&W content to an acceptable level prior to sale. There are several types of chemicals for treating oil, and chemical companies use different terminology to describe the same compound. The pumper must understand the purpose of each type, know when to use them, and always be as economical as possible when using them. Chemicals may be water-soluble, oil-soluble, or soluble in either.

Oil treating chemicals include:

- Oxygen scavenger
- Corrosion inhibitor
- Surfactant (a soap)
- Paraffin solvent (a thinner)
- Demulsifier
- Other chemicals according to need. Overuse of some chemicals can cause emulsion problems that require very expensive solutions. Some chemicals are used to solve problems created by overtreating. These are much more expensive than basic treating chemicals.

Reducing corrosion damage. Corrosion can be a big problem and can occur downhole by eating holes in either the tubing and casing or in surface facilities. Corrosion inhibitors prevent this.

Scale deposits and sand stabilization. Scale is treated as it enters the production system and in the formation before it can develop. Scale inhibitors must be matched to the conditions of the produced water.

A-2. Testing Crude Oil.

Long before a sellable amount of crude oil in the stock tank has accumulated, an important task is to test the oil to determine if the BS&W level is low enough to be accepted by the pipeline or truck transporting company gauger. The gauger will usually be more careful in analyzing the oil if the pumper witnesses gauging and testing procedures.

Eight inches of emulsion and thiefing the bottom. The BS&W or emulsion level accumulated on the bottom of the stock tank must be no more than what the local purchaser allows, typically 8 inches or less. The content of this heavy BS&W emulsion is usually a mixture of crude oil, salt water, paraffin, possibly a small amount of asphalt, formation sand, and a host of other compounds. This mixture is heavier than free crude oil so it falls to the bottom and may float on the water. Water in oil production is usually as salty as ocean water. The sand can be finer than bath powder and is, therefore, difficult to separate.

Crude oil weighs less than 8 pounds per gallon. Fresh water weighs 8.33 pounds per gallon. Produced salt water usually weighs more than 8.33 pounds per gallon and reaches a natural saturation point at about 9.6 pounds. This mixture is homogenized and blended together and is difficult to treat and separate. Free saltwater will migrate to the bottom. When the tank is thiefed, the stratifying of oil, BS&W, and free water becomes obvious.

This natural separation can occasionally be used to a distinct advantage when treating tank bottoms. If neglected, the bottom emulsion will become so heavy that the pumper will have to *spud* the plumb bob through it to gauge the tank.

Tagging bottom with the thief. When tagging bottom with the thief, the graduated trip rod must be set accurately. As the thief approaches bottom, it must move very slowly to prevent agitation that would result in a false reading. After tagging bottom, the thief should be lifted approximately one inch and then dropped sharply.

If the thief is lifted five or six inches vigorously and then dropped, BS&W will be agitated. The test will indicate a higher bottom than is actually present, as well as a greater BS&W percentage for the bottom shakeout. After excessive stirring of the bottom, an accurate reading may not be possible until sufficient time has been allowed for settling.

Checking the bottom. To check the bottom level, the lease pumper should follow this procedure:

1. Put on plastic gloves.
2. Lower the thief to the bottom of the tank.
3. Secure the sample.
4. Bring it back to the top.
5. Give it a side twitch after the top of the thief has cleared the oil to allow a small amount of oil to spill out.
6. When it stops dripping, lift the thief out of the tank with one hand and place a rag under the bottom of the thief with the other hand to keep the tank clean.
7. Slowly pour the oil out of the top of the thief across the palm of the other gloved hand. With close observation, it can

easily be seen when the oil thickens and turns to emulsion.

8. Hold the thief vertically again and look inside as well as outside. The level of the emulsion remaining in the thief can be easily read. This is the height of the tank bottom. The side of the thief is marked in inches.

As remaining emulsion is poured back into the tank, the point at which free water appears can also be determined.

1% or less BS&W and the centrifuge. BS&W contained in the crude must not exceed the maximum levels specified by the crude purchaser—usually less than 1%. To determine this, the lease pumper should use the following procedure:

1. Take one sample of crude oil from near the top.
2. Take a second sample approximately 10 or 12 inches above the bottom.
3. Place the two samples in a centrifuge and determine the amount of BS&W in each.
4. Add these two values together.
5. Divide by two.

This computation gives the average BS&W throughout the tank. Since the average is computed on a straight line and actual contamination is on a curved line, the oil purchaser has a small "shakeout" advantage.

To make the reading more accurate, another step can be added that involves taking a third sample from the center of the tank and dividing by three. Occasionally a tank will test as sellable by the three-sample method, while it would be rejected under the two-sample method.

There are several popular styles of centrifuges and three styles of tubes:

- 12.5 milliliter (ml)
- 100 ml pear-shaped
- 100 ml short cone-shaped.

Centrifuge tubes are expensive, so extreme care should be taken in handling them.

When oil is sold, the 100-ml tube is generally used to analyze the sample. The pear-shaped tube is more accurate when very low percentages of BS&W need to be measured.

The 12.5-ml size hand shakeout machine is commonly used and is satisfactory for estimates. A sturdy bracket should be made and fastened securely to the bed of the pickup to support the unit when in use. It is possible to fasten it to the tank battery steps or on a board, but the bracket is usually more workable. When properly maintained, the machine will last for years. Repair parts can be ordered from supply companies.

Oil temperature correction. It is more difficult to treat cold oil than warm oil. When slow moving oil is produced from the well, it will be approximately the temperature of the earth that it is coming through. Deep wells are hotter at the bottom than shallow wells, and as oil rises in the well and leaves the production zone, it becomes cooler. As oil cools, it does not flow as easily, and the viscosity becomes thicker, thus supporting more BS&W. A heater/treater may be needed to heat the oil to assist in separation, especially in winter. Flow lines in most sections of the country are left on top of the ground to absorb the heat from the sun in order to treat the BS&W out of the oil. If chemical is injected at the wellhead or at the bottom of the well through the annulus, the treating process may be easier. In winter the oil should be treated as quickly as possible before it becomes colder on the surface.

When the purchase price of crude oil is quoted, it must be at an exact temperature and gravity with no contamination to receive the posted price. The Scoop Master tank thermometer is an accurately computed device that contains a holding pocket to reduce temperature changes while it is being read. It is attached to the gauger's tray by a cord that allows it to be lowered into the middle of the tank of oil to obtain the exact temperature.

When oil is sold, the number of barrels is computed, then the temperature correction factor is applied. If the oil is cold, this factor will increase the number of barrels shown as sold. If the oil temperature is above the temperature at the quoted price, the number of barrels computed as sold will be reduced.

API gravity and the hydrometer. There are two methods for computing gravity. The specific gravity method compares the weight of oil to an identical volume of water at the same temperature. Under this system, pure water at 60° Fahrenheit represents a specific gravity of 1.000. A lighter liquid would have a value less than 1.000, while a liquid heavier than water would have a higher specific gravity.

The API gravity system sets the value of water at 60° Fahrenheit as 10. However, in the API method, a lighter liquid has a higher value. Oil will usually measure more than 15 but less than 50. Condensate will range above 50 into the 70s. As the number gets lower, the oil will be thicker, darker, and more difficult to treat. As the number gets higher, it will be thinner. As it approaches distillate, it may give the appearance of uncolored gasoline or kerosene. The higher the API gravity, the easier it is to treat. 16 gravity oil weighs approximately 8 pounds per gallon and 336 pounds per barrel. 50 gravity oil weighs 6.51 pounds per gallon and 273 pounds per barrel.

The API gravity of all oil sold is determined by the use of a hydrometer. In order to obtain the gravity of the oil, the following procedure is used:

1. Lower the thief to approximately the center of the tank.
2. Trip it closed.
3. Raise it up to where the support lip of the thief can be hung on the side of the hatch.
4. Gently lower the appropriate hydrometer into the oil and allow it to float until the temperature of the hydrometer adjusts to the temperature of the oil.

The hydrometer will have a range of 10-20 points. The hydrometer will float in the oil at the level of the gravity indicated at the top of the liquid.

The transport driver carries a set of 3 to 4 hydrometers in a case that will cover the range of gravity readings for all of the oil produced in the field, from distillate to a heavy gravity. Each gravity level has a value or reduction in the quoted price of the crude. This cost impact is one reason why the pumper must analyze the oil prior to the sale. The pumper must know the reading that the transport driver should indicate on the run ticket.

The Lease Pumper's Handbook

Chapter 13
Testing, Treating, and Selling Crude Oil

Section B

METHODS USED TO TREAT BS&W

B-1. Overview of Treating Methods.

Separation is the procedure whereby a mixed fluid of gas, oil, and water separates into these different components. Many factors influence the separation of water and oil, and often work at the same time with various degrees of success. Some of the more important factors include:

- Gravity
- Time
- Movement
- Chemicals
- Heat
- Electricity.

A knowledgeable pumper understands all factors and combinations of factors that result in a good pipeline oil separation with a minimum drain on time and expensive chemicals. As wells become marginal and production is from the final stripping of the reservoir, the oil can become much more emulsified and difficult to treat.

B-2. Gravity.

Gravity causes the separation of crude oil and water. Water will slowly separate from the crude oil from the time it is produced until it is sold. The water can be free water, which falls out rapidly, or it can be emulsified with oil, paraffin, and other elements and compounds, become very difficult to separate, and require a lot of time. This natural separation also occurs at an ever slower rate.

Gravity affects larger droplets of water more forcefully, causing them to sink to the bottom more rapidly. Smaller droplets fall slower than larger droplets. Crude oil is lighter than salt water, and gravity will cause the water to work toward the bottom. The smaller the droplet of water, the less the gravity pull and the harder it is to remove. If the heavier water can be broken loose from the oil and paraffin, then gravity will cause the water to work its way down through the liquid to the bottom of the vessel. Paraffin and other compounds form a strong surface tension around these droplets, and with low gravity oil the tension cannot be reduced without assistance by the use of time, movement, chemical, heat, electricity, or a combination of procedures.

Flash and slow water gravity separation in treating crude oil. To successfully treat crude oil and make it sellable, the pumper needs to consider what needs to be accomplished and the best way to proceed to achieve that goal. Two concepts to fully understand are flash separation and slow separation. If separation occurs within a few minutes, it is referred to as flash separation. Slow separation requires hours or days.

After these fluids have separated, they are usually removed from the vessels through different lines.

B-3. The Use of Time in Treating Oil.

It takes time to break the water out of the oil. Some produced water will separate so slowly that it would require far more time than is available, so action is taken to begin this process as soon as a last tank of oil is sold. If a pumper waits until a tank of oil is almost full before treatment, the ability to use time is lost.

Many decisions concerning time are governed by how much oil is produced and the treating problems anticipated. If oil is sold every few days from a tank battery and has treating problems, the pumper should begin treating the oil as soon as it is taken off the sales line. More chemicals than usual can be used because, with frequent sales, income is higher and funds are available.

If the wells are marginal producers, production is low, and there can be several weeks or even months between sales. The pumper will have a lot of time but not much chemical available because of the low income. The pumper will learn how to use time and movement and natural separation to an advantage.

B-4. Separating Crude Oil and BS&W by Movement.

Total separation is not feasible. As emulsion falls out, it accumulates near the bottom of the tank. The emulsion must be recirculated with crude oil from the stock tank back through the separation cycle to assist the process and keep tank bottoms clean.

Movement is the cheapest of all treating processes after time alone. If a small amount of oil is regularly circulated from the stock tank through the heater/treater or wash tank (gun barrel), this movement alone will treat much of the water out of the oil.

B-5. The Effects of Chemicals in Treating Crude Oil.

Chemicals are one of the most effective and common methods of treating water out of crude oil. An oil soluble surfactant can be added to the crude oil either at the wellhead or just ahead of the separator or first tank battery vessel. This oil soluble chemical is usually a form of soap that reduces the surface tension in paraffin and water droplets. This allows the water to separate by breaking apart from the hydrocarbons.

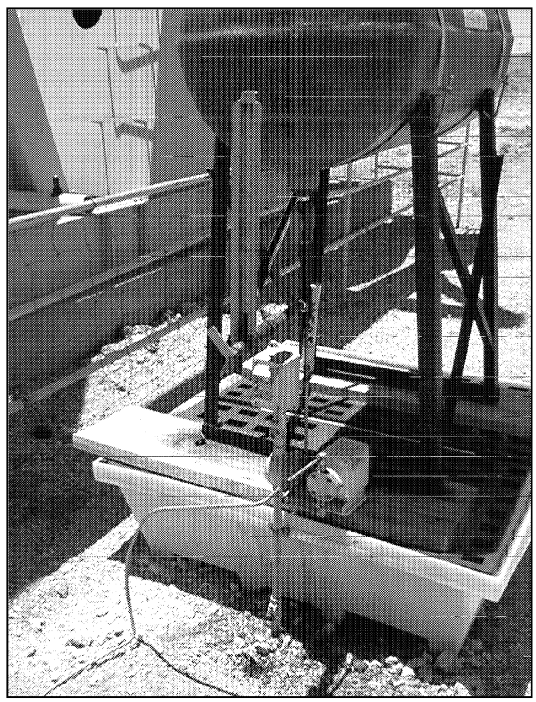


Figure 1. A chemical reservoir tank, electric pump, and lines for chemical injection at the wellhead. Note that chemical identification information has not yet been added.

Treating oil is just one of many reasons for using chemicals on the lease. The pumper should know the functions of all chemicals and how to apply them properly.

B-6. The Effects of Heat in Treating Crude Oil.

Heater/treaters (Figure 2) are used extensively to heat and treat crude oil. Heat is applied to the crude oil by both the sun and by burners in heater/treaters.

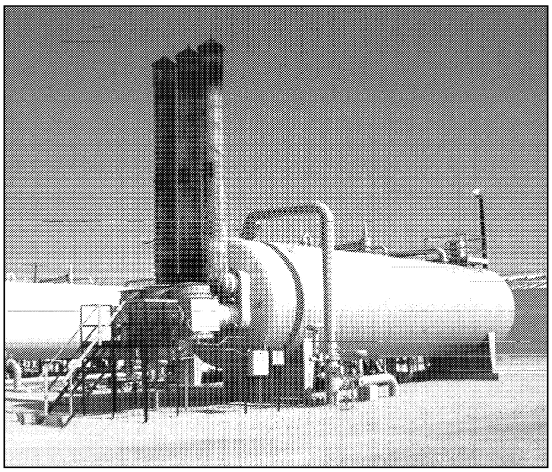


Figure 2. Chem-electric heater/treater for treating crude oil.

When possible, flow lines are left on the surface in order to take advantage of summer heat. During this time, heat is turned off and the vessel becomes a large three-stage separator.

As little heat as possible is used to treat oil. Some oil companies have set up an objective of eliminating all use of heat and fire boxes in treating oil. This is an extremely aggressive approach that will result in a dramatic reduction in lease gas consumption. However, technology to completely eliminate heating from the treating process is several years away.

B-7. Treating Oil by Chemical-Electrical Processes.

The electrical heater/treater is the most effective method for treating high volumes of crude oil. Because of the cost of electricity, this method is not practical for extremely low producing wells.

One chem-electric heater/treater will out-perform several standard vertical heater/treaters. Consequently, it is very popular where there are large volumes to treat as well as offshore where platform space is extremely expensive to build.

The Lease Pumper's Handbook

Chapter 13
Testing, Treating, and Selling Crude Oil

Section C

TREATING WITH CHEMICALS

C-1. Purposes of Treating Chemicals.

Many substances are produced along with oil and gas. Water, salt, paraffin, asphalt, iron, sulfur, and sand create many emulsions and compounds that become difficult to treat. These must be reduced to acceptable levels in order to sell oil and gas.

It can be confusing to the new lease pumper to dive right into terms such as demulsifiers, emulsion breakers, wetting agents, and other terminology. Instead, the explanations in this chapter will begin by describing the end objective of treating oil, the basic problem that needs to be solved, and how these goals can be reached.

The use of detergents to remove water. The primary agent used to reduce surface tension of oil and water droplets is a soap-like compound called a *surfactant***.** The surfactant can be both water- and oil-soluble. It is used to reduce the surface tension and viscosity of heavy crudes and can assist in removing iron sulfide. Detergents are often used in chemical treatments of oil to remove water. Also, they reduce the surface tension in emulsions to allow small droplets to form into larger ones that can then be separated by gravity.

Use of solvents for paraffin. Paraffin solvents are used to thin paraffin and lower viscosity. These can be used downhole to prevent paraffin from clinging to the inside of the tubing, and in the tank battery to thin paraffin and reduce surface tension. It has a high penetrating capability similar to *casing head gasoline* or *drip* that condenses in gas transmission pipelines. Casing head gasoline can be very volatile or explosive. It can be used everywhere oil is treated and is usually not as expensive as surfactant-based chemicals.

Bottom breakers for tank bottom emulsions. Bottom breakers are chemicals that are used to reduce the viscosity of the emulsions that accumulate on the bottoms of tanks. They are the most expensive of the common oil treating chemicals. A five-gallon container will usually cost more than $100 and may need to be specially blended for unique site problems.

Other treating chemicals and mixtures are available but are also usually directed toward solving these three problems.

C-2. Introduction to Chemical Injectors, Styles, and Operation.

Several styles of chemical injectors or chemical pumps are pictured in this chapter. Appendix E gives an overview of mechanical, electrical, and pneumatic chemical pumps and special treating equipment.

It is desirable to begin treatment as early as possible. As a rule, it is too expensive to begin the treatment in the formation. Treating for sand and scale production may possibly begin in the formation, but treating for BS&W in crude oil usually begins at the perforations where it enters the well, the Christmas tree or pumping wellhead, or the tank battery. Accurate injection records should be kept by the lease pumper, and when chemicals are added, consumption should be calculated regularly.

Treating oil at the tubing perforations or downhole. Figure 1 illustrates a typical installation where the objective is to treat oil before it reaches the surface. Oil is injected into the casing on the side of the wellhead opposite the casing valve that allows formation gas to be produced into the flow line.

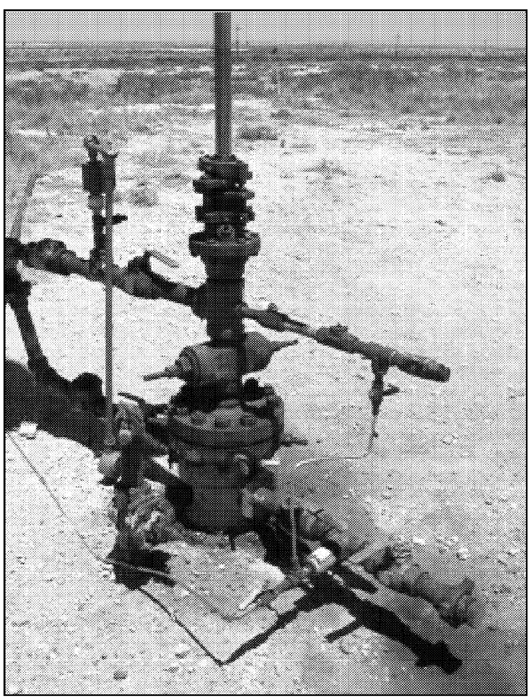


Figure 1. Chemical injection to treat oil at the perforations at the bottom of the well.

A small stainless steel bypass line from the bleeder opening of the pumping tee allows a small stream of circulating fluid to be injected with the chemicals. This increases the total volume of fluid and reduces the time required for the chemicals to reach bottom.

A check valve is installed near the pumping tee to prevent the chemical from being diverted directly into the flow line. With a valve at each end, it is simple to isolate the line for repair purposes. By connecting another chemical line that contains a valve to bypass the circulating line, the injection of chemical can be diverted directly onto the flow line without going downhole.

The mechanical pump shown in Figure 2 can be installed on the base of the pumping unit and connected with a small rope or cable, eliminating the need for electricity. One pump can inject paraffin solvent downhole to prevent paraffin buildup on the sucker rod string. The second container can inject oil treating chemicals either downhole or directly into the flow line.

Figure 2. Mechanical chemical pump with a sash cord connection to the walking beam. It has a weight to move it down and is the safest method for operation.

Note that the wellhead also has provisions whereby the well can be *batch treated* down the casing. The wellhead contains a pressure control that shuts in the well if the flow line pressure builds up above the setting level. A small blowout preventer allows pressure to be shut in while the upper polished rod packing and pressure packing are replaced.

The advantage of injecting the chemical at the well is that the oil is treated while being pushed toward the tank battery and the chemicals are blended into the mixture. The disadvantage of injecting at the well is that when the well is down, even during a normal cycle, the tank battery is not receiving the chemicals needed for blending with other wells. It is too expensive to install and maintain chemical pumps at every well.

There have been many injuries to arms and legs during the downstroke of mechanical pumps when construction reinforcement rods were used to operate the arm. The use of rope or small cable eliminates this hazard.

Injecting chemicals at the tank battery. The typical placement of chemical injector pumps at the tank battery is after the header where all wells come together but before the first vessel (Figure 3). This is just ahead of the separator or before the first vessel, whether it is pressure or atmospheric.

Producing sellable crude oil. Tank bottoms should be kept clean. This is a cardinal rule to follow when pumping a lease. Most tank batteries have a minimum of two tanks. As soon as one tank of oil is sold, the remaining oil from that tank should be pumped through the treating facilities and into the second tank. There will always be almost a foot of oil. Also, this oil is pumped through the treating facility. Occasionally there will only be one stock tank. If so, simply hook up the portable pump (Figure 4) and pump it from the bottom back into the same tank. This will assist in keeping the oil clean and sellable.

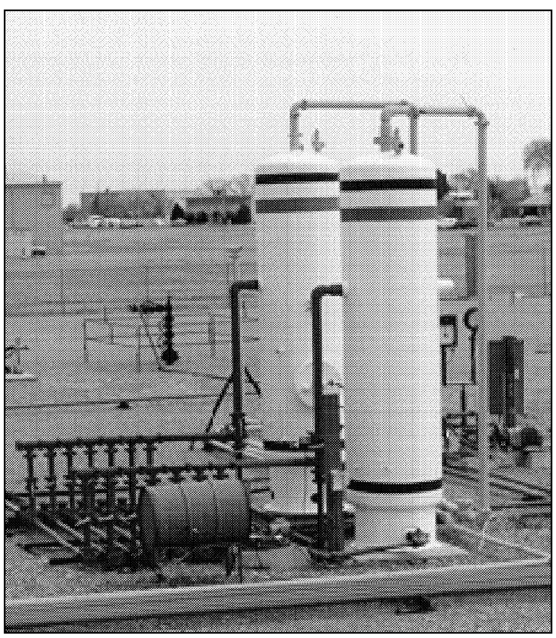


Figure 3. Injecting chemicals at the tank battery.

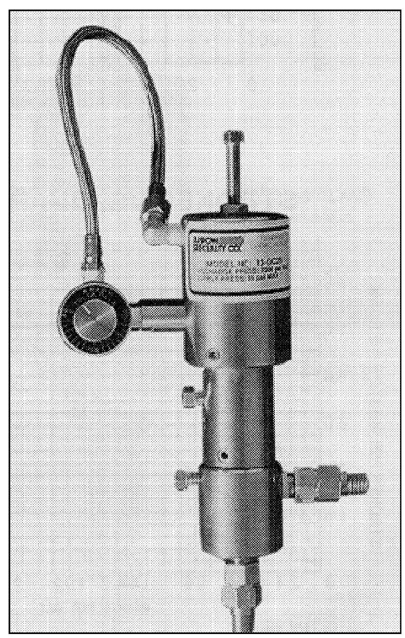


Figure 4. A portable chemical pump.
(courtesy of Arrow Specialty Co.)

The employer must be willing to cooperate with the pumper by providing a few suitable tools necessary to treat the oil. When treating equipment is acquired, it must be designed to perform the task. The pumper should sit down with the employer as needed to secure workable equipment to do a good job.

Since the pumper works alone, if a portable circulating pump is used, it must be light enough to transport conveniently. The portable circulating pump is small. If it is not trailer-mounted, the centrifugal pump is bolted directly to the motor and not skid-mounted. Otherwise, it is too heavy for one person to handle.

Batch treatment while circulating. When circulating oil for treatment, chemicals may need to be added while the tank is still circulating. One easy solution to adding chemicals slowly is to use a container such as an empty gallon plastic container that has a small drip hole punched in the bottom. This should be set in the thief hatch opening and chemical poured into it while the oil is being circulated. It will take fifteen minutes or so for the chemical to drip in for a good treating blend.

Some operators use a bottle of butane and a 50-foot air hose to roll the tank. The air line to the bottle is connected with it sitting on the ground. The end of the hose is weighted and carried up the ladder. The end is then lowered into the tank until it reaches bottom. The drip container is placed in the hatch and the bottle turned on to a low setting. Other problems on the lease can be tended to while the tank is being rolled and treated by the butane mixing the chemical with the tank bottom. Some lease operators use dry ice instead of butane for this procedure.

C-3. Special Treating Processes.

Cleaning tank bottoms. Tanks occasionally accumulate an emulsion that must be removed. When this occurs, the manway plate may have to be removed from the back of the tank and the tank cleaned. A small depression may be dug and lined and a vacuum truck called. The vacuum truck has a diaphragm-operated pump with flapper check valves and can pump almost anything from the tank

The hot oiler. Occasionally, the tank of oil may develop so much paraffin and such a large volume of water that it does not react to normal treating procedures. Often this occurs during the colder winter months. In this case, a hot oiler truck (Figure 5) must be called.

Figure 5. The hot oiler can heat oil as well as produce super hot steam for steam treating.

The hot oiler will load 20 or more barrels of oil on the truck from the tank battery into its oil tank. The oil is heated and pumped back into the tank through a flexible high-pressure metal hose to the battery. It is then pumped through a line that extends down through the thief hatch to the bottom of the tank.

As the oil is heated and pumped back into the tank, it will raise the temperature of the tank high enough that the paraffin will melt and become fluid again. Water will then fall to the bottom.

It normally will take a hot oiler several hours to complete this heating and rolling procedure. Upon completion, the free water is pumped off. As soon as the temperature of the oil falls to an acceptable level, the oil is sold.

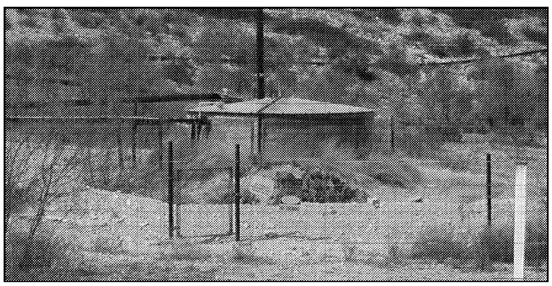


Figure 6. A slop tank used in treating very difficult-to-treat oil.

The slop tank. When treating problems recur at a tank battery, some companies solve the problem by installing a slop tank (Figure 6). This is a potentially invaluable tank that has become popular in areas where the use of lined pits is limited, and where a tank habitually develops high bottoms.

When the tank of oil has a high bottom that is difficult to treat, a few inches of the bottom is pumped off into the slop tank to make the tank sellable. As soon as the oil is sold, the bottom is pumped back through the treating facilities and into the tank of oil being filled. When the tank is filled, and the high bottom occurs again, the procedure is repeated.

Other systems, such as the rolling system, may also be installed to combat treating problems.

The Lease Pumper's Handbook

Chapter 13
Testing, Treating, and Selling Crude Oil

Section D

SELLING CRUDE OIL

D-1. Preparing to Sell the Oil.

Preparing to sell a tank of oil requires substantially more work than the actual sale itself. If the gauger thinks the pumper is careless in preparing the tank for the sale and the oil must frequently be rejected, the gauger will be more inclined to refuse the oil. A turndown should be a rare event. Some leases have very difficult treating problems. Every lease has its own treating characteristics.

Turndowns are bad for both the pumper and the transport gauger. The gauger must always have a back-up load to pick up in event of a turndown. However, this alternate load may be many miles away, causing the gauger to haul one less load that day. His company and possibly the gauger will make less money.

The three conditions that must usually be met for acceptance are:

- A full load is available.
- The bottom is a minimum of 4 inches below the outlet connection.
- The BS&W throughout averages 1% or less.

End of the month oil sales overload. If a tank of oil is almost full and the end of the month is approaching, the tank should be sold. This will allow the employer to receive his payment for the oil a month earlier than if the pumper waited until next month. Most employers appreciate the pumper selling all oil possible this month. However, all pumpers in your area will also think the same thing. As the end of the month approaches, the gauger or purchaser is flooded with requests and not all can be honored. Tank runs should be reasonably scheduled in advance with your purchaser to prevent this problem. Full tanks normally carry a priority over almost full tanks with your gauger at the end of the month.

D-2. Selling Oil

Requirements for a full transport load. Crude oil purchasers usually require the accumulation of a full truckload (Figure 1) or tank full of oil before purchase. The two reasons for this requirement are safety and cost.

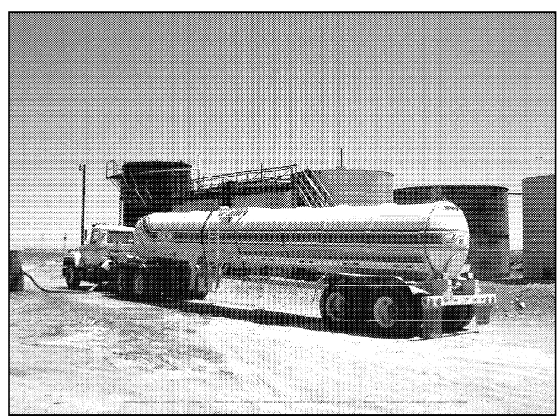


Figure 1. Selling oil by truck transport.

- **Safety.** It is difficult to transport a partial load of liquid safely. When the transport turns a corner, oil will climb up the wall of the tank and with excessive speed can turn the truck and trailer over. When the transport goes up or down inclines, the liquid rushes back and forward with a powerful force. Although the trailer tank is built with baffles to help withstand these forces, the safe trailer is a full one.
- **Cost** It costs the same amount to haul or pump into a pipeline regardless of whether the tank is full or not. It is a matter of economics to require a full load before purchasing it.

Selling split loads. It is difficult to sell less than a full load of oil. However, most purchasers will accommodate emergencies such as a hole in the tank or problems with a vessel. Possibly there is another tank nearby that will allow the transport to be fully loaded. Occasionally when there is a partial load of condensate and the weather is hot, the evaporation will equal and even exceed the production. The lease pumper must recognize such problems and search for reasonable solutions.

Communication with the gauger. Each area may have a different method of communicating to the gauger that there is a load of oil ready for sale. Some oil transported by pipeline still uses a visual cueing system of metal markers at the tank battery. As gaugers make their rounds, they put the oil on line when they drive by.

These days, however, requests are usually called in by radio or telephone. Regardless of the system used, adequate notice should be given to the gauger.

The note jar. Every tank battery should have a note jar (Figure 2). This can be as simple as a pint or quart clear glass jar with two holes punched in the lid. The lid is wired to the outside of the tank walkway steps, creating an efficient mailbox. When the gauger puts a tank on the transport line, a note is usually put in the jar with the top reading. After the tank of oil is sold, a copy of the run ticket is left in the jar if the pumper is not present. Different companies have different policies regarding the witnessing of gauges and selling oil.

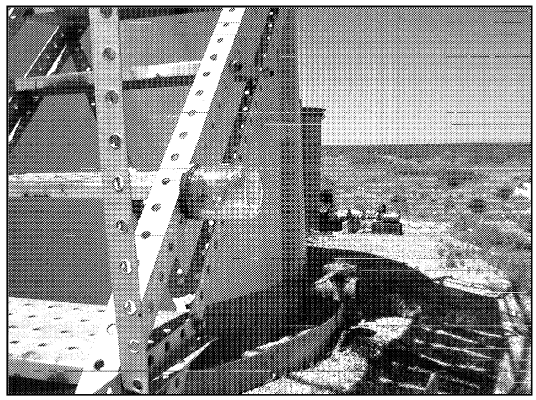


Figure 2. Glass jar for pumper-to-gauger communications when selling oil.

Witnessing the oil sale and the rejection notice. When the gauger rejects the tank of oil for purchase, a rejection notice on a printed form is placed in the tank battery note jar, and a copy possibly turned in to the purchasing company. The form will list reasons the load was unacceptable, date, pumping company name, lease and tank number.

Some companies require the pumper to witness every step of the purchase or rejection. Even if not required, it is still a good practice. Sometimes it is necessary for top gauges to match. If the ambient temperature is warmer than the tank of oil, the gauged volume will increase. If it is lower, the gauged volume will decrease. This is a normal situation. If the pumper last gauged yesterday, the level will almost certainly always be slightly different today.

D-3. Seals and Seal Accounting.

There are two types of seals in common use (Figure 3). The most commonly used type for years has been a flat, narrow metal style that must be pushed through a dart in order to be installed correctly.

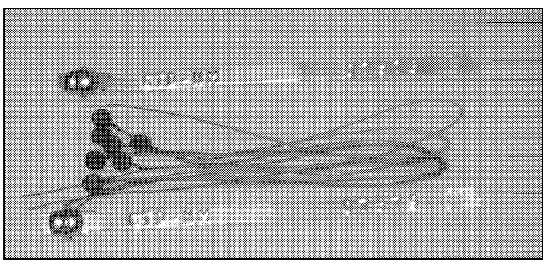


Figure 3. Two styles of tank seals.

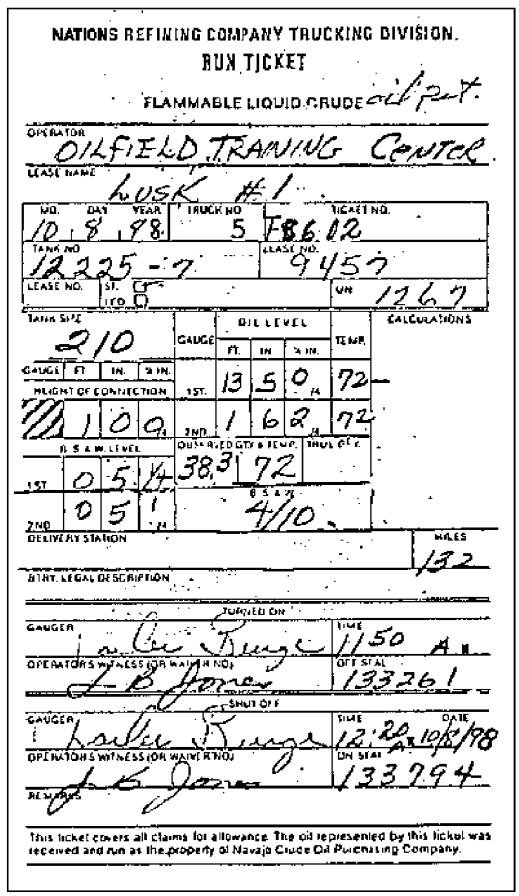
The second style is a soft wire that has a lead head. The wire is run through a small hole, then doubled back and run through it again. The wires are pulled tight, and the lead is crimped to hold it in place. The wire must be cut in order to remove the handle or open the valve.

When a tank of oil is sold by transport or by pipe line, the seal on the sales line valve on the front of the tank must be cut, removed, and the number on the seal recorded. At the end of the sale a new seal is placed through the dart, and the valve is resealed until the next sale. These seals are put on the tank by the purchasing company and usually have the name of the company imprinted in raised letters on the seal. The seal must be cut in order to remove it.

If this seal must be removed for any reason, the owner of the seal should be notified. If the oil is sold by transport, the regulations for cutting the seal may not be critical. If the oil is sold by pipeline, a witness from the pipeline company may need to be present for removal and replacement of the seal.

If the oil is sold by transport, the seal on the sales line valve will possibly be the only seal used. If the oil is sold by pipeline, the valve may be open from six hours to two days, so before the sales line valve is opened, the drain line on the back and the inlet valve must be sealed. These seals must remain in place until after the sales line valve has been closed and the seal replaced.

The run ticket. The run ticket (Figure 4) is proof of an oil sale, listing the purchaser, date of the purchase, seller, method of transportation, lease location, lease name, tank battery, and other information.



NATIONS REFINING COMPANY TRUCKING DIVISION.
RUN TICKET
FLAMMABLE LIQUID CRUDE oil Pet.

OPERATOR: OILFIELD TRANING CENTER
LEASE NAME: LUSK #1
MO. 10 DAY 8 YEAR 98 | TRUCK NO 5 | TICKET NO. F86 12
TANK NO 12225-7 | LEASE NO. 9457
LEASE NO. | ST. / FED. | UN 1267
TANK SIZE 210

GAUGE	OIL LEVEL FT.	IN.	¼ IN.	TEMP.
1ST.	13	5	0	72
2ND.	1	6	2	72

HEIGHT OF CONNECTION: 1 0 0
B S & W LEVEL: 1ST 0 5 ¼; 2ND 0 5 1
OBSERVED GTY & TEMP. 38.3 72 | THUL GTY.
B S & W 4/10
CALCULATIONS
DELIVERY STATION | MILES 132
STRT. LEGAL DESCRIPTION

TURNED ON
GAUGER: [signature] | TIME 1150 A.
OPERATORS WITNESS (OR WAIVER NO): L B Jones | OFF SEAL 133261

SHUT OFF
GAUGER: Leslie Burge | TIME 12:20 A. | DATE 10/8/98
OPERATORS WITNESS (OR WAIVER NO): L B Jones | ON SEAL 133794
REMARKS

This ticket covers all claims for allowance. The oil represented by this ticket was received and run as the property of Navajo Crude Oil Purchasing Company.

Figure 4. A run ticket.

The tank number at the battery is usually assigned by the oil purchasing company. Tank numbers are in order from left to right when facing the tank battery. If the numbers are not in sequence, this usually implies that a tank has been replaced or has had a problem that required the capacity to be re-strapped.

The run ticket illustrated in Figure 4 shows that the tank had a capacity of 210 barrels, and the 15-foot tank contained 13 feet, 5 and no quarter inches. Since the bottom of the equalizer would be at about the 14 foot level, the tank was within 6 inches of maximum capacity.

The 4-inch pipeline connection is 1 foot high, and the oil was pulled down to 1 foot, 6 and 2/4 inches. To pull the oil down to this level, the transport driver would have had to slow the pump suction down at about the two foot level, then keep lowering the suction speed to prevent air from being sucked in. It would take too long to lower the level using this procedure.

The BS&W level was 5¼ inches and was 2½ inches below the maximum allowed level. The observed gravity of 38.3 is below 40 gravity, so there may have been a small price reduction for lower gravity. The BS&W level throughout the tank was 4/10 of one percent, well below the 1% allowed. The observed temperature on the thermometer was 72° F. The temperature on the hydrometer was also 72°. There would be a small volume adjustment for temperature correction.

The truck drove 132 miles round trip to haul the oil, and it took from 11:50 until 12:20, or 30 minutes to load the oil. This is a long distance to travel if the oil must be rejected. There are 533 numbers difference in the number of the seal that was removed and the number of the one replaced. This is a marginally producing well.

A check for payment will be made the following month. Typically, the royalty owed to the mineral rights owner will be mailed directly to this owner and the operator's share will be mailed to the operator.

D-4. Selling Oil by Use of the LACT Unit and Surge Tanks.

The best method for selling crude oil is by use of the lease automatic custody transfer (LACT) unit (Figures 5 and 6).

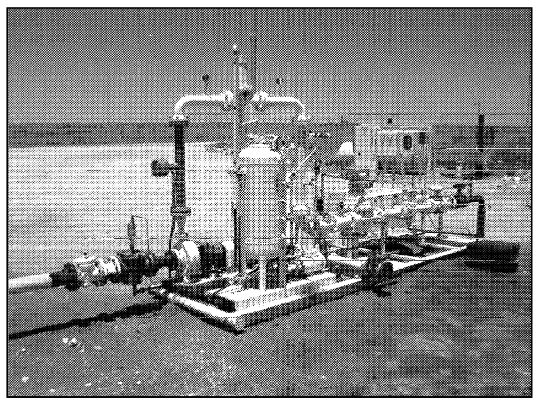


Figure 5. The LACT Unit. Oil travels left to right through this system. The control panel is visible in the background.

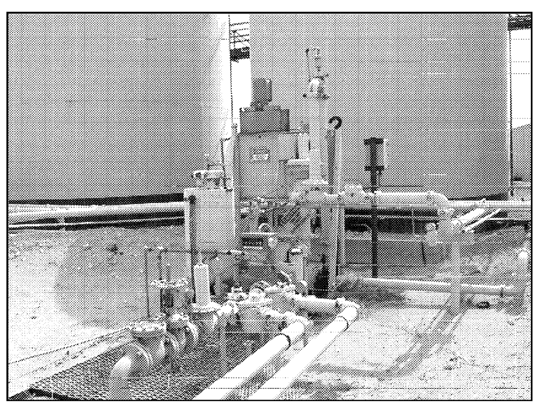


Figure 6. A picture of a second LACT unit. The two lines in the foreground are for the prover loop.

Oil can be produced to the LACT unit by use of the oil line that comes over the top of the tank, and the LACT sales line is left open at all times. As oil is produced into the stock tank, it rises and a level controller turns on an electric motor in the LACT unit. As the oil is sold and the level of oil lowers, the level controller turns the LACT unit off. The stock tank will act as a surge tank to achieve this objective. The first component of the LACT unit is a liquid transfer pump. The purpose of this pump is to place the fluid under approximately 30 pounds of pressure. This reduces the amount of gas that may break out while the oil is in the LACT unit and allows a positive displacement meter to operate accurately. The last component before the pipeline company's system is a backpressure valve to maintain this pressure.

As the oil travels up through the riser, the BS&W percentage is constantly monitored. The BS&W monitor controls a diverter valve. As the oil moves across the top of the riser, it passes through a screen and air eliminator. As it moves across and downward, a sample of oil is diverted into the sampler tank for BS&W analysis. BS&W is never monitored on a horizontal line because the liquids separate and stratify.

As the liquid return horizontal, it passes through a three-way diverter valve. If the oil is not sellable, it is diverted back through the treating facilities. If it is pipeline grade oil, it will continue through the positive displacement meter, the prover manifold, and the backpressure valve. At this point it is now owned by the pipeline company.

The prover loop determines the accuracy of the positive displacement meter. As pumps wear, they usually pump more fluid than is indicated on the meter reading. After the meter is tested, a correction factor is given to the lease operator and the oil purchaser. The reading is always close to 1.0000. A typical reading might be 0.998 or 1.0015.

The gauger and the pumper will periodically meet at the LACT unit and blend the oil in a sample container and work a sample. They will then empty the sampler tank back into the sales line and read the meter. These figures, along with the temperature correction and correction meter number, will determine the oil sales since the last average to be computed.

Hot oiling. It may become necessary to call for a *hot oiler*, a truck mounted with a propane heater to treat the oil. Cold oil is pulled from the tank bottom, heated, then put back into the tank. This thins the oil, melts paraffin back into a liquid state, and allows water to fall out. Chemicals can be added to assist in reducing surface tension on the droplets of water. Oil movement also assists in this treating.

Hot oil is more difficult and dangerous to pump because of the change in viscosity and the danger of ignition of vapors coming off the heated oil. Some truck transport companies may not purchase the oil after hot oiling until it has cooled to less than 100° F. It is to the advantage of the production company to sell the crude oil as quickly as possible after hot oiling in order to sell more paraffin and remove it from the system so that it cannot congeal and cause problems again in the tank.

The Lease Pumper's Handbook

CHAPTER 14

WELL TESTING

The Lease Pumper's Handbook

Chapter 14
Well Testing

Section A

INTRODUCTION TO WELL TESTS

A-1. Introduction to Well Testing.

There are many reasons for testing a well, and several distinct types of well tests. Because of the wide variety of problems that may be encountered, well tests may have slightly different purposes and names. This is understandable because of unitized reservoirs and dozens of variations in enhanced recovery.

Many people in charge of testing wells will also develop their own terminology for determining what to call a particular test. Even after hearing what the company supervisor calls the test, it may have little meaning to others until the test procedure and the purpose of the test is described in detail. However, this book uses the most widely accepted names for testing wells.

Unless wells are tested at regular intervals, the lease operator cannot determine how oil comes from each well and which have production problems. Other reasons are just as important. Economic gain is always important, but if the lease enters the enhanced recovery phase with water flood or secondary recovery practices, analyzing well tests is the primary method of determining the success or failure of an enhanced recovery process. Since artificially occurring forces in the formation such as secondary and tertiary recovery can increase the amount of oil recovered from a reservoir, well tests trace the success and failure of enhanced recovery.

A-2. Pre-Test Preparation.

To accurately test a well, the lease pumper must prepare the well for testing. There are two ways of preparing the well for a test—either produce it every day normally or shut it in one day before the test. The pumper must know what type of test is to be taken and do the best possible job of preparing the well for the test. For some tests, the bottom hole shut-in pressure prior to performing the test may be needed.

Shutting the well in. In flowing wells, some tests require that the well build up to its maximum wellhead pressure. When a well is to be tested from a shut-in condition, the casing and master tubing valves are closed so that no gas, oil, or water is produced. After closing the valves, noise should not be detected from the wellhead. If noise can be heard, this indicates that a valve is leaking and, until an additional valve is closed or the valve has been repaired or replaced, an accurate test cannot be made. As with pumping wells, when a circulating line has been run from the tubing to the casing so that inhibitors or chemicals can be injected at the wellhead, the circulating line valve must also be closed.

Twenty-four hours is the standard amount of pre-test shut-in time. Different wells, however, may be tested after a longer or shorter shut-in period. If the formation pay section is composed of coarse sandstone with a high porosity, 16 hours may provide enough time for the wellhead pressure to build to its maximum pressure so that the test may begin. If the formation is composed of tight shale (clay compressed into rock) and has a lower porosity, it may require more than one day for the well to build up to maximum pressure. Experience will teach the pumper how much shut in time is necessary to allow the pressure to build up in each well to its maximum level before testing can begin.

The pressure will build up rather rapidly when the well is first shut in but will slow down over time. The longer it is shut in, the slower will be the rate of pressure increase until it levels off at the maximum pressure.

Normalizing production by producing the well before testing. *Normalizing* a well means that the well must produce its normal average amount of oil, water, and gas each day for several days prior to testing. If a well has been purposely shut in for one or more days, turning it back on may produce far more oil than if it had been producing normally.

As an example, the first day a well returns to production, it may produce 125% of a normal day's production. The second day, it may produce 112% of a day's production. On the third day it may produce 105% production, and on the fourth day, it may be almost back to 100% of normal production. After three days, it may have made up 42% of one day's production. Each well produces differently from every other well.

Many factors influence whether a pumping well is producing a normal amount of oil and gas or if it is developing a problem. Experience will give the lease pumper additional causes. These same reasons will also factor into the problems encountered when testing a well.

A-3. Preparing the Tank Battery for Testing a Well.

Care must be taken in preparing the tank battery to receive and measure the produced fluids. The valves in the lines must be turned to the correct positions to direct the produced oil to a stock tank where it can be measured, the gas metered before entering the gas sales system, and the free water measured through a liquid measuring device or by other methods.

In a large tank battery, the well to be tested will be switched manually or automatically into the test separator (Figure 1). The gas is measured and recorded on a chart or in a computerized recorder, and the oil and water is directed to a metering heater/treater. The oil is directed to the oil holding tank. The water is also measured then directed into the water disposal system.

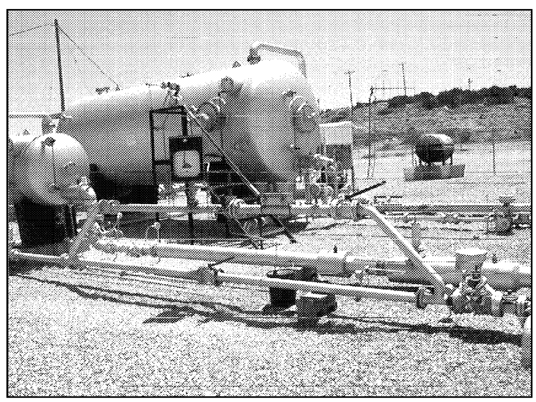


Figure 1. A test separator.

In small, low production tank batteries, oil and water may be diverted through the test separator, and all of the liquid produced into the same tank. Before the test begins, the total liquid in the tank is gauged, and the exact amount of liquid in the tank determined. The second step is to thief the tank and determine the oil/water interface level. A shakeout of the oil may also be taken to determine the suspended BS&W percentage. If needed, the API gravity and temperature will be taken. The number of barrels of oil and water in the tank is computed.

At the end of the test, the new fluid level is gauged and recorded and thiefed in the same manner as the first time. The total volume of oil and water in the tank is computed again and, by simple subtraction, the amount of oil and water produced is easily calculated. The acquired water can be circulated out of the tank into the disposal system. This assists in cleaning the bottom of the tank.

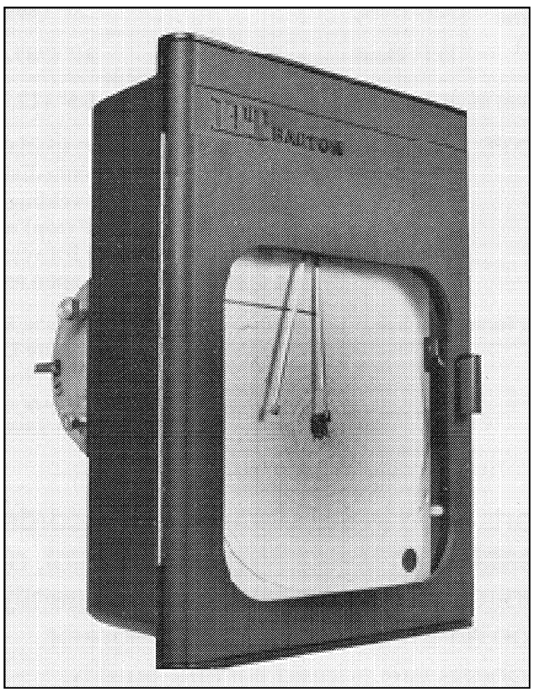


Figure 2. A differential, static, and temperature gas recorder.
(courtesy of ITT Barton)

The natural gas must also be measured. By turning to the prior well test information in the lease records book before the test is started, the correct gas meter orifice plate can be selected, and the gas system set up for the test (Figure 2). The ink pens on the chart should be moved lightly at the beginning to ensure that they are feeding ink and the correct time of day when the test begins is indicated on the chart. Some pressure recorders are computerized and do not have a paper chart.

A-4. Four Basic Well Tests.

The general purpose for conducting a well test is usually defined within the name of the test. While requirements may differ, the four basic tests, along with preparation and purposes are:

Potential test.
- Requires a 24 hour shut-in period prior to testing.
- Is performed on new wells and wells that have been worked over.
- Purpose: To determine the maximum 24-hour potential capability of a well to produce oil, gas, and water.

Daily test.
- Requires normalizing prior to testing.
- Is performed one time every month on a continuing schedule for the life of the well.
- Purpose: To determine how much fluid the well is producing daily within a month without affecting the well's ability to continue to produce fluids.

Productivity test.
- Requires normalizing prior to testing.
- Evaluates the well in various modes and cycles of operation.
- Purpose: To determine the best way to produce the most hydrocarbons with the least damage to the well's ability.

Gas/oil ratio test.

- Requires a 24 hour shut-in period prior to testing.
- Reveals when wells produce too much gas, which prematurely lowers reservoir pressure and affects all wells in the reservoir.
- Purpose: To determine how many cubic feet of gas is produced per barrel of oil.

A-5. Typical Test Information.

Every test will require that the amounts of oil and water produced be recorded. Gas production is recorded except for producing stripper wells where casing valves are open to the atmosphere. Wellhead pressures of tubing and casing are recorded on all flowing wells.

Lease information (typical for all tests.)

- Company name (may already be on form)
- Field
- Lease name
- Number of well to be tested
- Date test started
- Completion date
- Type of test
- Method of producing well or type of lift
- Conditions before test (shut-in or producing)
- Hours produced
- Oil produced
- Free water produced
- Total fluid produced
- Gas produced
- Temperature of gas
- Oil BS&W content of produced oil
- Gravity of oil
- Temperature of oil
- Gas/oil ratio
- Comments

Well information.

- Method of production (flowing, plunger lift, gas lift, etc.)
- Tubing shut-in pressure before test
- Tubing pressure at end of test
- Casing shut-in pressure before test
- Casing pressure at end of test
- Packer information (if used)
- Choke description and setting for test
- Well reaction to flowing
- Appropriate flow artificial lift assistance
- Flow cycle information
- Other information as needed

Pumping well information.

- Stroke length
- Strokes per minute
- Pump bore size
- Flow line pressure
- Casing pressure if appropriate
- Pumping cycles
- Special pumping information

Tank battery information.

- Lines switched correctly
- Initial tank gauges or meters read and tank number recorded
- Tank size
- Oil and water levels in test tank determined
- Gas line size
- Correct orifice plate installed.
- New gas chart placed on meter
- Other appropriate preparation
- Vessel pressure and temperature recorded as needed
- Comments

Special data.

- Intermittent data
- Interval data
- Injection time and pressure

- Power fluid injected and description
- Special lift information
- Meter readings

Almost all information gathered in testing any well is common to all tests of that well. Some of the information recorded is critical to some tests because of the varying purposes of the tests. Prior test information, used as a reference only, will save time in setting up the test.

Chapter 14
Well Testing

Section B

STANDARD TESTS

B-1. The Reservoir and Drive Mechanisms.

The reservoir can be thought of as a portable sprayer such as might be used to spray fertilizer or weed-killer. Once the sprayer has been pumped up, air is pushing against the fluid in the tank. Squeezing the handle allows the air to push the liquid out to create the spray. Until the trigger is squeezed, the fluid stays in the tank even though it is under pressure. The tank is like the reservoir, holding fluid under pressure. Drilling into the reservoir is like creating a spray tube and the valves in the well are like the trigger on the sprayer, allowing controlled releases of the fluid in the tank. Various types of forces—either natural or artificial—may force the oil out of the well. However, like the sprayer, when that force declines to the point that it cannot force the oil to the surface, then the well will stop producing just as the sprayer will not spray until it has been recharged with air.

The reservoir can have pressure applied to it just as the sprayer can be recharged. One type of pressure is that exerted by water that is trapped in the oil-bearing formation or in surrounding formation. As the oil is removed from the reservoir, water migrates into the reservoir to replace the oil and forces more oil out of the reservoir. This is an example of *water drive*. As the oil is produced out of the formation, the perforations must be moved upward to continue producing oil. Unless this is performed, the well will change to water production only. The water may be a natural part of the formation or it may be pumped into the formation to enhance production.

Some formations are completely saturated with liquid with natural gas contained within the liquid. When a new well is produced, the natural gas will break out of the oil as it is being produced. After a certain amount of oil has been produced, the formation will then begin to have free natural gas breaking out that will begin to work its way to the top of the reservoir. This is an example of *solution-gas drive*.

In some cases, the top of the reservoir is filled with natural gas with oil pooled at the lower part of the reservoir. The operator must drill deep enough so that the casing perforations are in the oil-bearing zone. This is an illustration of *gas cap drive***.**

A fourth type of formation has almost no pressure, except for the weight of the oil itself. Perforations must continue to be lowered toward the bottom of the hole to continue to produce oil. This is an example of a *gravity drainage reservoir***.**

The type of reservoir drive is important to well production, the method utilized, and the rate of depletion. In the geology of the well, the type of structure is important. The type of drive can also greatly influence well testing.

B-2. Potential Tests.

The potential test is performed on a well that has very recently been drilled or worked over. The primary purpose of this test is to determine how much oil, water, and gas this well will produce in 24 hours. To prepare for this test the well is usually shut in for 24 hours before the test begins, and the test is usually run for 24 hours.

Another factor determined by the new well potential is the pay-off factor. The potential helps determine if it will be profitable to drill other wells and, if it was a worked-over well, it will assist in determining whether it would be profitable to work over additional wells.

Purposes of the new well potential test. If the well is new, information gained from this test is important to the company. Some questions that it should help answer are:

- Will the regulating agencies place an allowable on the well to regulate production?
- Is this a profitable well? Will the well pay out?
- Should offset wells be drilled? Would they be commercially feasible?
- Should casing be run?
- What size tank battery should be built? Where should it be located in order to be convenient to receive flow lines from these additional wells?
- If it is a commercially viable well, how large is the estimated reservoir? How much oil and/or gas will it produce in the future?
- Should a pipeline be built to it when selling oil or should the oil be hauled by transport?
- Does it produce enough natural gas to be commercial? How many wells should be drilled to justify building a gas line?
- How much water is being produced? What should be done with it?

Purposes for conducting a potential test after working over an existing well. Some of the important questions answered by conducting a potential test after working over an existing well are as follows:

- Did the workover solve the production problems or achieve the goals of the workover?
- Did the well produce more hydrocarbons than it did before it was worked over, or was production restored to anticipated levels?
- Was excessive water production successfully plugged off by theworkover?
- Will the workover ever pay out and make a profit?
- Should the same or similar type of workover be performed to other wells in the same reservoir?

Potential testing conclusions. The potential test is used to analyze new well performance and to solve problems in maintaining and enhancing production from existing wells. It covers such a broad spectrum, it can be easily understood why special names may be attached to particular facets of it.

B-3. Daily Production Tests.

After a well has been normalized, a daily production test may be performed. This test indicates how much oil, gas, and water is normally produced by the well.

The daily production test is performed once each month on every well owned by the company. The results of these tests are posted in a permanently maintained record book with a sheet for each well. For each year, the company will have 12 postings on the sheet for an individual well. If possible, the ledger paper should be wide enough that each monthly record only occupies one line. The lease pumper should also maintain appropriate records in the **lease records book.** (See Chapter 19.)

In preparation for conducting the monthly *daily production* test, the well must be normalized. This means that the well must be produced during this period of time without serious problems. As the test is performed, the well will be producing its normal production for the full 24-hour period. Since the average well is produced at its maximum capacity every day, and daily allowable may be set higher than the well can possibly produce, the well is already being produced at its maximum capacity during the test.

As these tests are posted in the record books, a very important collection of reference information is accumulated. At a glance, it can be seen if the well is producing normally or if production is falling excessively each month and problems are beginning to develop. After a new pump is run, production will probably increase because of the improved efficiency of the pump. As the pump begins to wear, the pumping unit may need to be run longer or stimulated in some other manner to maintain the production average.

Without a properly maintained lease records book, the pumper is basically operating by guesswork in performing the testing and daily duties. The operator is not in a verifiable position to reach precise reasons for lowered production, and part of the ability to know when there is a problem is lost until perhaps there is a production failure. The pumper should be able to alert the supervisor about a lease problem, rather than vice versa.

With a one-well tank battery, the company may make a monthly production average and discontinue the monthly daily production test. The problem with this system is that it does not give an accurate picture of how much production was lost during the month because of downtime caused by pump failure, equipment failure, unexpected problems, and other reasons that may be corrected. The pumper should still pick a convenient day and continue to perform the test. This will reveal how much production was lost during the month due to problems. This is valuable information when asking the supervisor for problem solving work or expenditures to improve production.

The advantages of conducting a daily test each month include the following:

- Identifies failingdownhole pumps.
- Indicates problems caused by a closed casing valve on a pumping well.
- Identifies a gas locked pump.
- Alerts the pumper to increasing flow line pressures on pumping wells. As a flow line plugs, it will cause a corresponding production drop due to increased formation backpressure.
- Reveals leaking flow lines.
- Reveals casing and gas anchor perforation plugging.
- Reflects salt bridging in cyclic producing wells.
- Indicates tubing leaks.
- Indicates time clock problems.

B-4. Productivity Tests.

This series of tests is performed as needed or upon request to help determine the best way to produce a well. Basic productivity tests should be conducted by the lease pumper on a periodic basis to help maintain or improve production. This procedure takes several days or weeks with many adjustments to production time to gather adequate information.

The best results in conducting productivity tests may be achieved by having an echometer and dynamometer available where draw-down rates and fill times can be accurately established and pump action carefully calculated and observed. This method requires valuable equipment and somewhat specialized training that may not be available. Some pumpers, however, are very proficient at this analysis with no special equipment—just experience and an understanding of what is happening downhole. When conducting productivity tests, it helps to understand what type of drive exists in the formation.

To begin a productivity test of a pumping well, the casing should be pumped empty of liquid in the bottom of the well. At this point, the pumping unit should be shut in. By running an echo analysis every fifteen to thirty minutes, the fill rate of liquid entering the casing in the bottom of the well can be established. The longer the pumper waits, the more bottom hole pressure the well develops, and the slower the liquid enters. After sufficient liquid has accumulated, the pumping unit should be placed back in operation, and an echo analysis run every fifteen minutes or so to establish the draw down rate. This rate depends upon pump efficiency, size of tubing and pump, strokes per minute, and other factors.

Many people work for smaller companies that do not have echo analysis or dynamometer equipment available, and the lease owner will not be receptive to the expense of hiring this service. Their reasoning is that wells were produced for many decades before these pieces of equipment were designed and improved to the level that it has been developed today.

Even for companies that own this equipment, it may take a few days or longer before the lease can be tested. The pumper may not be able to wait days or weeks to analyze problems and take action that will continue and possibly enhance production.

Some of the productivity tests that can be performed without instruments include:

- Experimenting with well time controls to enhance production.
- Making changes slowly. It may take several days to a week before the effect of the changes settles back down to normal.

Some alternative methods of obtaining this information include the following:

- How to recognize some changes without instruments.
- Some wells running intermittently will produce more oil than if they run continuously.
- With many wells, rods can be lightly gripped with two fingers and so that the pump pounding the liquid can actually be felt. The pumper will also know if the pump is tapping bottom.
- With many wells the pumper can also feel when the pump is pumping well.
- By lightly touching the rods with a damp finger, the temperature changes will tell the pumper when it is pumping (cool rod), and when it is pumping off (warm to hot rod).
- When the pumper opens a bleeder hose into a bucket to check pump action and to determine if the well has a problem, the release of pressure expands the gas, allowing the well to flow for a few strokes. Once true pump action is obtained, the pumper can determine if there are pump problems.

Some factors that will help the pumper in analysis of the production from a well are:

- History of the well. What is normal production?
- Scale and paraffin accumulation, especially in the well bore and perforation area.
- Type of formation and how tight it is.
- A large pump moves liquid quickly. Is this the best way?
- A small pump moves liquid slowly. Is this the best way?
- Type of drive.
- Type of reservoir.
- Frequency of pump repairs.
- Strokes per minute of the pumping unit.
- Setting of tubing perforations in relation to the casing perforations.
- Flow line backpressure against the formation.

B-5. Gas/Oil Ratio Tests.

These tests are performed as needed to determine the ratio of cubic feet of gas being produced to each barrel of oil.

The purpose for conducting the gas/oil ratio tests is for pumper use and to inform regulating agencies how many cubic feet of natural gas are being produced per barrel of oil. This amount of gas, multiplied by the number of barrels of oil produced, equals the total cubic feet of gas that is being removed from the reservoir daily.

In some reservoirs it is important to leave as much gas in the formation as long as possible or even to return it to the formation until the oil has been depleted. Then the gas will be produced and sold. This can become important because when the natural gas supply in the reservoir is exhausted, no force remains to push crude oil toward the well.

When reservoir pressure is depleted, the pumper must re-inject another force into the reservoir to replace it to stimulate production or plug the wells. Without this gas movement and pressure, oil will no longer be produced.

Most reservoirs are large enough that many different operators own the wells that produce hydrocarbons from one. If the reservoir slopes upward, one operator may have several wells in the higher gas zone. The offset operator's wells, being higher up in the reservoir, only produce gas or gas with very little oil. This operator produces all of the gas possible out of the reservoir, while others produce very little gas. Production from the first operator's wells, in time, will begin to slow down for lack of a pressure maintenance program. If the whole reservoir is water drive, these wells will be the first ones to turn to water.

If gas had remained in the reservoir longer, the pumper would have produced more oil for several years longer. One set of wells may be progressively harmed by premature over-production of gas by other operators. Low gas production limits are good. Gas allowables are enforced to protect the wells to permit maximum hydrocarbon recovery.

Gas/oil ratio tests are necessary and enforced to extend the life of an oil field. This results in a higher hydrocarbon recovery, which is good for the industry, the mineral right owner, and the country. One of the best solutions is to unitize the field under one operator so long-range planning and good production practices may be possible.

B-6. Quick and Short-Term Special Purpose Tests.

The pumper should learn the many ways that abbreviated tests can be performed that determine which wells are not producing according to schedule. Sometimes the solution to returning the well to service is as simple as bumping bottom for a few minutes. This troubleshooting ability should be acquired by the lease pumper because these talents are used almost daily when producing marginal wells.

Bucket and barrel tests. In a situation where there are a large number of pumping wells producing into the same tank battery, the tank is gauged in the morning with one or more wells are off. The pumper must make an effort to determine which wells are off. To perform a full daily test might require two weeks or more, so quick testing procedures need to be performed.

Part of the problem in performing a bucket test through the bleeder is that when the valve is opened the flow line pressure is removed. When this backpressure is removed, the gas in the column of oil begins breaking out and expanding, giving a false reading of new oil being produced. A small backpressure valve that screws into the bleeder valve opening will prevent the loss of backpressure and give a more accurate reading.

The pumper needs to become proficient at performing bucket and barrel tests in order to isolate problem wells very quickly.

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Chapter 14
Well Testing

Section C

SPECIAL TESTS

C-1. Well Logs and Surveys.

As a well is drilled, many special logs are run to determine information concerning the commercial viability of a well. These include both open hole and cased logs, cement bond logs, directional surveys, and tracer surveys. It would consume too much space to review each of these in this manual.

Special production tests and surveys, however, are run on flowing wells to gather specific information. Two of the most common tests performed on flowing wells are pressure and temperature surveys. There can be many special reasons for running these tests, but this manual will discuss the procedures and general purposes only.

C-2. Pressure Surveys.

Pressure surveys are run for several reasons. One purpose is to project the producing life of the field. As the test instrument (Figure 1) is lowered into the hole, the altitude above sea level is a factor in locating at what depths below the surface the pressures must be taken.

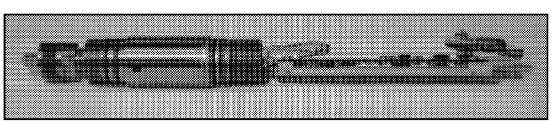

Figure 1. A quartz pressure gauge.
(courtesy of GRC Amerada Gauges)

To obtain the needed pressures, the instrument is mounted on the wellhead in a short lubricator, similar in appearance to a swabbing lubricator, and the instrument is run into the hole on a solid wire line (slickline) or by a logging truck. The master gate is opened and the instrument is lowered into the well according to the instructions from the production company office.

As the pressure recording instrument is lowered into the hole, it is stopped at specific points for a few minutes in order to obtain a straight reference line.

Pressure surveys are run on most flowing wells every six to twelve months. The pumper is notified as to when the well is to be shut in for this test and when it will be run. This will allow the pumper to be present at the test and to place the well back into service at the conclusion of the test. In preparation for this test the well is shut in long enough to record the maximum bottom hole pressure.

C-3. Temperature Surveys.

Temperature surveys are an excellent tool to help determine if there are casing leaks. A temperature recording instrument is lowered slowly on a small solid wire line to the bottom of the hole. The procedures for running this test are identical to the procedures for obtaining well pressures. At specific depths, the instrument is stopped for a short interval to give a series of reference points. At most casing leaks, gas will expand as it leaves the casing to enter a lower pressure area. This expansion creates a drop in temperature, indicating a possible leak.

C-4. Other Well Tests.

Several other procedures may be performed to check well conditions. A couple of the more common include:

Caliper surveys. A caliper survey tool is run on an electric line. After it reaches the desired depth, steel fingers are released to drag on the inside surface of the casing as it is slowly retrieved. Each finger draws a line on the chart, and every time a pitted spot is encountered, the arm goes farther out, resulting in a spike on the chart.

As the survey tool goes through a collar, all of the fingers or bows go out to provide reference marks to identify which joints are pitted and how deep each pit is. Caliper surveys are run in wells where the tubing may be damaged by corrosion. They give a good reference as to when the tubing is reaching the limit of its dependable life and of the condition of each joint of tubing.

Running scrapers. When a packer or other large tool is planned to be run in the casing with a diameter that is only slightly smaller than the casing, a tool is run that will scrape the inside of the casing to avoid the risk of sticking the tool in the hole. By running a scraper into the hole and retrieving it before running the packer, the pumper can reduce the possibility of problems.

There are many other testing tools that are utilized in production operations that the pumper will encounter over time.

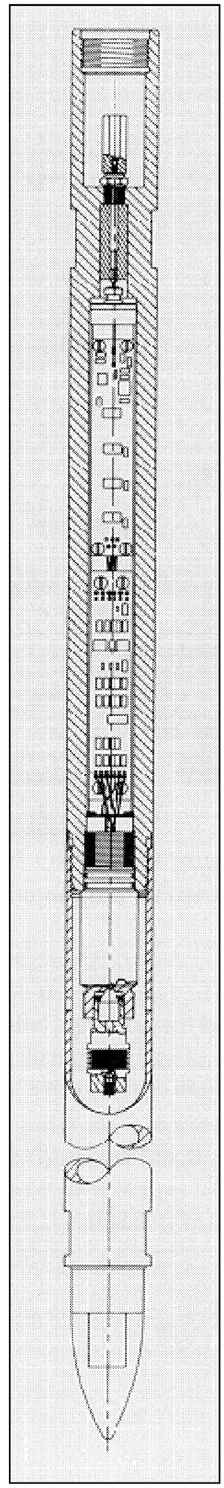

Figure 2. Cross-section of the quartz crystal pressure gauge.
(courtesy of GRC Amerada Gauges)

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Chapter 14
Well Testing

Section D

GAUGES AND GAUGE CALIBRATION

D-1. Quality of Pressure Gauges.

Pressure gauges are available in many different sizes, price ranges, and styles (Figure 1). They can vary from very cheap to very expensive. The most important considerations when purchasing a new gauge are what level of accuracy is needed, how much vibration and shock the gauge be subjected to, and what will be done with the reading after it is obtained.

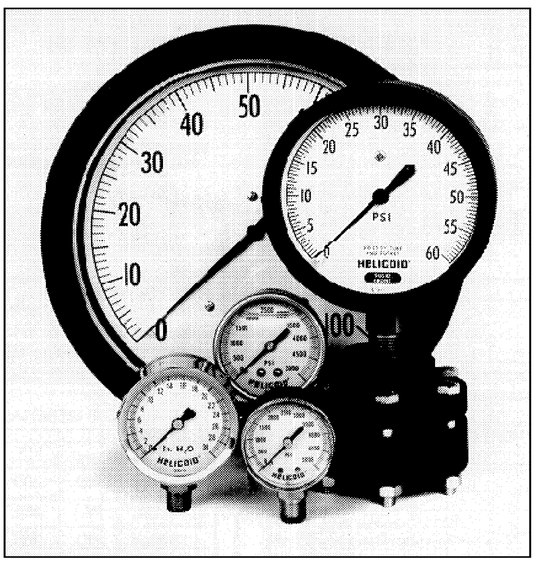

Figure 1. Typical gauge assortment.
(courtesy of Helicoid Instruments)

Simply glancing at a gauge when it is in service to determine the approximate pressure on a line is not particularly critical. Even inexpensive gauges can provide an approximation. However, more accurate and, thus, expensive gauges are required for. well tests where pressure will be reviewed closely to determine if the reservoir has had any pressure drop in the past year and accurately know how many pounds of pressure are involved. This is an instance when the pumper should use the most accurate gauge available—a test gauge that can be calibrated. If a pressure gauge is subjected to pounding by a high-pressure pump, such as a triplex, where the hand of the gauge fluctuates rapidly back and forth, an adjustable vibration dampener can be installed ahead of it to reduce the shock and extend the life of the gauge.

D-2. Gauge Construction.

Historically, the most common style of gauges in the oil fields had a bourdon tube on the inside to transmit the pressure to the hand. The second style is operated by exerting pressure against a spring.

The bourdon tube (Figure 2) is a long, curved, flat tube that extends about two-thirds to three-fourths of the distance on the inside of the gauge. It has a pivot point in the center of the gauge for attaching the hand, and the end of the bourdon tube is connected to the pivot with a lever. The inside of the tube is shorter than the outside and, as pressure is applied to the inside, the tube moves to the outside at the end. This action moves the hand of the gauge in a ratio to the amount of pressure applied.

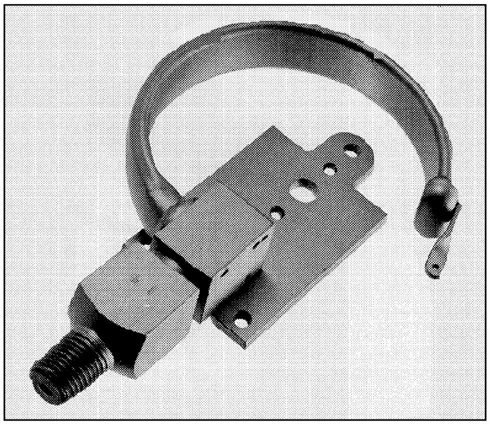

Figure 2. A bourdon tube.
(courtesy of Helicoid Instruments)

D-3. Safety Gauges.

When working with high pressure, the pumper should use a gauge with safety provisions and possibly improved glass in the face. A good quality safety gauge will have a rubber plug mounted in the back that can blow out if the tube should rupture. Also, safety glasses should be worn when opening a gauge to eliminate the possibility of blowing broken glass into the face and eyes. The pumper should stand slightly to one side, never directly in front of a gauge when opening it.

Liquid-filled gauges. The liquid-filled gauge is a sealed gauge filled with transparent liquid behind the glass or plastic face. Corrosion and oxidation cause serious damage to a gauge that is not sealed. Gauges that are not liquid filled may become hard to read and inaccurate with time.

D-4. Adjustable Test Gauges.

The pressure gauge used for testing a well is usually a test gauge (Figure 3). This is simply a better quality of gauge that can be calibrated for accuracy.

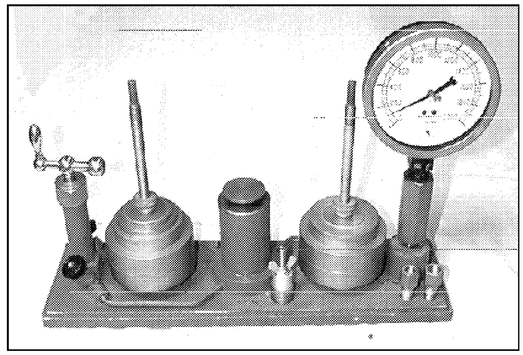

Figure 3. Gauge and dead weight tester.

Test gauges have an adjustment screw on the face, side, or back. By pressurizing the gauge to a specific known pressure with a dead weight tester, the adjustment screw can be used to correct any error in the reading. Economy gauges do not have calibration or adjustment capabilities.

Most pumpers carry their test gauges wrapped in a clean soft cloth stored safely in the vehicle. This will be in a specific section of the tool box or even in the glove compartment. It may be necessary to have the gauge re-calibrated by the factory or a laboratory occasionally if the pressure on the test must be exact. The cam and roller geared gauge is a good test gauge because of its proven long life and accuracy.

When purchasing new gauges, it is best to select a gauge with a pressure range where the hand turns to an approximately vertical position or the center of the measurable pressure range. They are usually more dependable when they are correctly selected.

D-5. Calibrating Gauges and the Dead Weight Tester.

Figure 3 illustrates a gauge tester. To operate the dead weight tester and calibrate the gauge, the procedure on the next page should be followed:

1. Remove the tester cover and loosen the plug that is screwed in where the gauge is mounted on the right side.
2. On the left, close the back black valve.
3. Open the front valve and crank the handle upward. This pulls hydraulic fluid from the center reservoir to the space under the plunger of the crank.
4. Close the front valve and open the back one.
5. Crank the handle downward so that fluid begins to move to the center pedestal stem.
6. Remove the right-hand plug and, when it fills with oil, tighten the gauge into place.
7. Place the correct amount of weight on the center pedestal as the left-hand screw is screwed down so that the weights are lifted to the correct height, and the gauge is then visually checked for accuracy.
8. Use a screwdriver to adjust the hand on the gauge.

Testing the pressure of the well directly. A high-pressure hose several feet long with a small diameter is available that will permit connection directly from the dead weight tester to the wellhead. Pressure of the tubing or casing can then be accurately determined directly from the tester without using a gauge in the system. In situations where extremely accurate pressure measurements are needed, this is an accurate method.

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CHAPTER 15

ENHANCING OIL RECOVERY

- Inert gas injection.

3. Chemical Processes.
   - Surfactant-polymer injection.
   - Polymer flooding.
   - Caustic or alkaline flooding.
4. Thermal Processes.
   - Steam stimulation.
   - Steam and hot water injection.
   - In-situ combustion.

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Chapter 15
Enhancing Oil Recovery

Section A

ENHANCED RECOVERY

A-1. Introduction to Enhanced Recovery.

The primary function of the lease pumper is to produce the most possible oil and gas at the lowest effective lifting cost. This purpose governs most of the pumper's daily activities. To this end, the pumper must learn how each individual well has produced in the past and study each independently to maintain and enhance recovery.

When the drilling industry was young in the United States, kerosene for lamps was big business. Gasoline was in low demand because the automobile industry was just beginning. The first oil wells were shallow and were produced as hard as possible to achieve the most production in the shortest possible time. These same objectives still apply to some degree today, but the pumper must learn how to extend the producing life of the well better than in the past through enhanced recovery practices.

In the past, natural gas in the reservoir was depleted very rapidly, and the wells went dry in some fields after producing less than 15% of the available crude oil. When gas was depleted in the formation, pressure was gone, and the oil stopped flowing to the well bore. The field had played out.

As a better understanding of what was happening downhole became known and better production methods came to be practiced, the percentage of available crude oil recovered steadily increased. Today, with good enhanced recovery practices, more than 60% of the available oil in a reservoir can be recovered. In some fields, even a higher percentage can be recovered. This still leaves a huge amount of oil waiting in the formations for tomorrow's enhanced recovery technology.

Names have been attached to the reservoir stripping processes to give meaning to the various stages of controlled depletion. New names or different meanings to the same process keep appearing in print with various writers, but this chapter will adhere to the older, more common terminology.

A-2. Enhanced Recovery Terminology.

The first step to understanding enhanced recovery is to review a few basic terms and to understand their meanings and implications.

- **Enhanced recovery.** This is an umbrella term that includes all recovery processes. The word *enhanced* in general means good, better, or improved recovery practices and does not identify the procedure used or the level of success achieved.
- **Flood.** The use of the word *flood* in describing an enhanced recovery practice indicates that the recovery force is

injected in one well and must be recovered from a different well after it has been pushed across the reservoir. With flood there are issues with controlling injection volumes, studying injection patterns, slugging volumes or applying alternating forces, controlling fluid channeling, and trying to achieve the best possible sweep efficiency.

- **First-stage or primary recovery**. This begins with the completion of a new well. It includes all forms of naturally flowing and artificial lift systems that produce fluids from the well bore to the tank battery. It can be a flowing well, have a pumping unit, plunger lift, gas lift, hydraulic lift, electrical submersible lift, or any other lift system. First-stage recovery also includes many forms of good well completion, treating, and stimulation practices that are performed on most wells to achieve optimum production.
- **Secondary recovery.** This term almost always refers to simple water flood or reservoir pressure maintenance through gas injection. Either is added as a continuous force to the formation outside the perforations. The force must go out through the casing perforations into the formation, be pushed through the formation, and produced back through a different well.
- **Tertiary or third-stage recovery.** To be referred to as tertiary or third-stage recovery, two or more forces are added to the formation, such as steam (heat and water), carbon dioxide and gas, water and chemicals, and slugging practices (the alternate injection of two types of fluids). This may or may not be a final recovery technique. Slugging is common in tertiary recovery, and one of the two forces is usually water.

A-3. Technology Keeps Changing.

With each year that passes, new technology makes some commonly used field procedures obsolete or less desirable. At the same time, these new procedures cost money to implement and may be too expensive to be practical for low producing, stripper, or marginally producing wells.

Some things, however, always remain constant. Gas still rises to the top and water falls to bottom, leaving oil in the middle. Consequently, the pumper can still understand what is happening regardless of the systems or methods that are introduced. The pumper must also keep up with how these innovative procedures work and when they need to be added to the wells.

A-4. Not All of Yesterday's Procedures Will Become Obsolete.

With the invention of the rotary drilling bit before 1920 and the jackknife rotary rig in the 1930s, the cable tool rig was declared obsolete. However, for the foreseeable future, a few cable tool rigs are still searching for oil. Cable tool water well drilling units are still being manufactured and operated. The cable tool rig remains an economical unit for drilling shallow wells.

Present-day drilling procedures will be replaced with techniques that permit wells to be drilled in much less time, to greater depths, and with more accuracy, resulting in greater production than is possible today.

Yet, many of the procedures common in today's oilfields will still be recognized and used far into the future. The skill developed by the lease pumper in understanding what may have caused a shortfall in oil production and how to restore production will continue to be important to the oil producer and to the welfare of the lease.

The Lease Pumper's Handbook

Chapter 15
Enhancing Oil Recovery

Section B

PRIMARY RECOVERY

B-1. Primary or First-Stage Recovery.

During the past 100 years, many innovative methods have been used to enhance first-stage recovery. Although no additional force is added into the formation on a continuing basis, many enhancing workover jobs involve procedures that are extended deep into the reservoir—such as fracing, chemical treating, and, more recently, horizontal drilling. Outstanding primary recovery or well treatment practices that continue to enhance recovery include:

Production allowables and productivity testing. Placing allowables (production limits) on some wells by company or regulating agencies can significantly extend the life of the wells and greatly increase long-range recovery. When several companies are producing from the same reservoir, oil companies may request regulations that limit production to protect their wells from offset operators who may abuse the reservoir through overproduction.

Through productivity testing on a scheduled basis, wells can conserve gas pressure and produce more oil for a longer period of time. The goal is to reduce gas production while stimulating oil production. Conation of water and gas can be reduced and controlled if the lease pumper understands what causes these problems and how to avoid damaging the wells.

Sand and acid fracing. Fracturing or *fracing* methods are techniques used to made the formation more porous. Sand fracing stimulates wells by using sand to prop open a formation. Acid fracing uses acids and other chemicals to etch openings in tight formations. These treatments continue to be popular and contribute to increased recovery in tight formations with low porosity.

Other fracing procedures such as the use of heat and pressure are also gaining in popularity. Newer technology includes the addition of tracers while fracing to control reservoir damage.

Stabilizing formation sand and scale. These two enhanced recovery procedures continue to be improved through research and technology. Sand and scale in the formation are stabilized by pumping chemicals into the reservoir. This produces more fluids with fewer problems. Important considerations in these procedures are location and relationship of casing and tubing perforations, as well as sand screens and gravel packing.

Echometer, dynamometer, gas lift, plunger lift, and other well analysis and automation control systems. During recent years, great strides have been made in many methods of automating producing wells with computer-controlled systems that obtain maximum production, lower lifting costs, and identify well problems as soon as they occur. These systems continuously analyze production, control well production, and make changes in production time. They also print out a daily well analysis report detailing well problems.

Hydrotesting, tracer surveys, well logging, and other surveys. These procedures can provide information that is valuable in deciding what types of enhancements may be effective.

Moving the casing perforations up or down the hole. When a well extends many feet into the reservoir, perforations need to be moved up or down the casing in order to restore production. This need is determined by the type and shape of the formation, how the well was originally completed, and the type of drive in the reservoir. Some strata also have impervious layers within the reservoir that separate sections that produce at different rates. The location of tubing perforations in relation to casing perforations also dramatically affects the production from each well.

Changing lift systems. During the life of a well, the lift system may need to be changed several times as performance changes. For example, a well may have flowed when first drilled, then later placed on gas lift, followed by mechanical lift, hydraulic lift, back to mechanical lift, and finally had a beam gas compressor added. Selecting the type of artificial lift is always a best-guess decision.

The number of activities that may enhance production from the wells requires the lease pumper and the lease operator to continuously study all wells to enhance production and make surface and wellbore changes to meet changing reservoir conditions. When the production of a well dramatically falls, sometimes it is very difficult to analyze the root cause of the problem and decide what corrective action must be performed. Many analysis methods are available and it is always a difficult choice to select the best methods for finding the answers. Many times wells are plugged too early in their producing life because the lease operator never identified the true problem that caused the loss of production and workover procedures did not solve the problem. This can occur even with outstanding operators.

B-2. Production Stimulation Through Horizontal Drilling.

The greatest technology advancement in drilling procedures in recent years has been the development of the equipment and techniques used in horizontal drilling. The controlled ability to deviate drilling from a vertical direction to a controlled horizontal direction has revolutionized the industry.

Along with the development of these techniques came the innovation of a drill bit and mud motor assembly with a slight bend in the middle. The next development was efficiency in tracking and orienting the mud motor; so the rig could continue to drill with the drill string not rotating while the bit was turned by the mud motor.

By turning the drill string, the bit drilled straight ahead with a wobble, but with stable motion and not greatly increasing the hole size. With the pipe standing still and the mud motor turning, the direction being drilled can be corrected or changed with orientation control.

With these improved techniques, a rig can drill down near the reservoir, turn horizontal in the oil producing zone, then drill for more than a mile in the pay zone. This drill and completion technique exposes so much open reservoir hole that it will increase production from the new well many times over previous drilling methods.

Many older wells are also being worked over using this technique. After workover, many wells produce more oil than when they were originally drilled. The success of horizontal drilling has been phenomenal, and the procedure continues to be improved. The ability and skill of the horizontal drilling specialist supervising this procedure and the correct interpretation of well logs greatly affects the success or failure of these production enhancement objectives.

B-3. Beam Gas Compressors.

The movement of gas in the reservoir stops when the pressure of reservoir gas is equal to the weight of the fluid column and the resistance in the flow line and tank battery. Production of oil falls to zero. It becomes necessary to either plug and abandon the well or find another solution that will restore enough production to extend the producing life of the well.

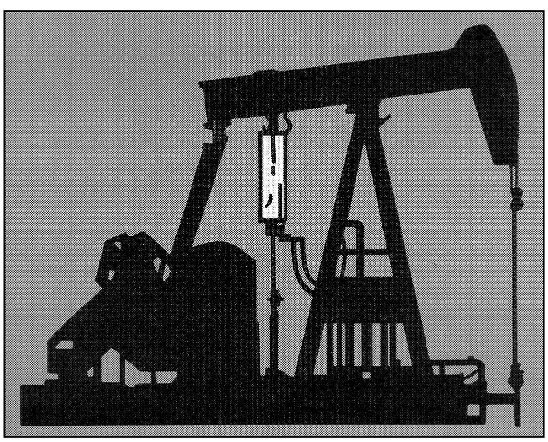

Figure 1. A typical beam gas compressor. *(courtesy of Permian Production Equipment, Inc.)*

One option available is to install a *beam gas compressor* (Figure 1). The design of a beam gas compressor allows it to pull gas from the casing and reservoir, compress it, and inject it into the flow line downstream from the flow line check valve. This can remove backpressure from the formation and allow fluids to migrate to the wellbore again.

The pumping unit supplies power to operate the compression cylinder. Many stripper wells have increased their daily production 300% or more with this system. This increase in income can pay for the equipment on many wells in just a few months. The compressor cylinder compresses gas on both the up and the down strokes with no lost motion. Operation of a beam gas compressor is shown in Figure 2.

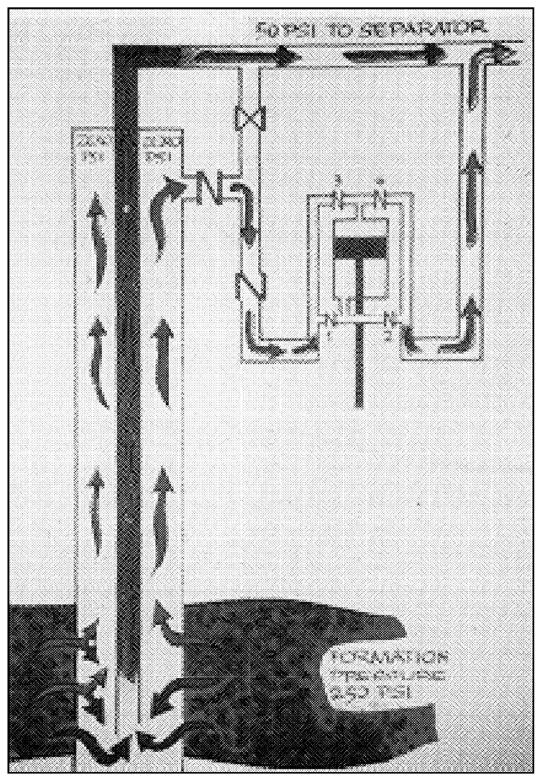

Figure 2. Beam gas compressor operation. *(courtesy of Permian Production Equipment, Inc.)*

B-4. Venting Casing Gas at the Wellhead.

When the volume of gas being produced from the well has been reduced to *trace* levels, another method to stimulate oil production may be used. This is to open the casing valve to the atmosphere and allow the casing pressure at the surface to fall to zero.

Although this volume of gas is extremely small, this production procedure will remove backpressure from the casing and formation and allow it to begin producing again.

When venting the gas at the wellhead by barely opening the casing valve, oxygen can enter the top of the casing and can contribute to oxygen corrosion. To reduce oxygen corrosion, some operators install a ball and seat standing valve from a downhole pump placed vertically in the casing opening. The weight of the ball seals out oxygen and only a few ounces of pressure remains on the casing.

A hose from the tubing bleeder valve into a swage in the casing valve will allow the pumper to visually check well performance easily. The produced liquids are bled back into the casing, which is coated with oil as it falls back to the bottom of the hole. This oil coating can also assist in preventing oxidation.

Since implementation of this procedure involves merely opening a casing valve, it is a popular way to extend well life.

B-5. Perforation Orientation.

Perforation orientation includes two areas that affect the well's ability to produce crude oil. The first is a review of the location of perforations in the formation. The second is to determine if oil production can be stimulated by closing off these perforations and moving them either up or down the hole.

Raising casing perforations. When wells are completed in water-drive reservoirs that are many feet thick, perforations may be placed above the water/oil interface level but below the gas zone. Eventually, the water table in the reservoir rises, and water production from the well increases. Perforations then need to be cemented off, and the well re-perforated at a higher level. This will restore part of the oil production, lower the water production, and extend the life of the well.

Lowering casing perforations. With a well produced in a gas-drive reservoir, the oil level will lower in the formation and the well will begin to produce more gas and less oil.

Overproducing gas from the well can result in several undesirable results. The first is caused by bleeding off the formation gas. This continued lowering of the gas pressure results in a like reduction in oil production. The second condition that it sets up is to allow water to rise in the reservoir if it is also water drive.

By cementing off top perforations and re-perforating lower perforations, oil production may again increase and gas production may be reduced. Before perforations are lowered, a plunger lift may need to be installed or a pressure maintenance program implemented to slow down gas loss.

Tubing/casing orientation. One of the procedures that must be determined by the lease operator is deciding where tubing perforations will be placed in relation to casing perforations. They can be placed above, even with, or below casing perforations.

Different companies have different reasons for deciding where they orient the tubing perforations in relation to the casing perforations. This orientation not only affects the amount of fluid that will be produced, but it also maintains a fluid or gas blanket on the formation and a small pressure against the formation. It also to a small degree affects paraffin and scale problems that may be encountered in the perforation area and the tubing.

B-6. Innovative Procedures.

The skill needed to produce marginal wells demands a close study of what is occurring to the wells, an understanding of how the wells were completed, what changes will be required in the future to maintain profitable production, a keen understanding of when these changes must be made, and having the desire to study and try to continuously enhance production.

One of the most important requirements in lease production enhancement is controlled by the lease pumper. This person must develop a deep understanding of production, make good decisions daily, and work consistently at the job. The pumper should keep the following factors in mind:

- Type of reservoir.
- Flow at each well. Is it increasing?
- Does the efficiency of the chemicals need to be retested?
- What are offset operators doing to stimulate production?
- A large pump moves liquid quickly. Is this the best way?
- A small pump moves liquid slowly. Is this the best way?
- Frequency of pump repairs.
- Setting of tubing perforations in relation to the casing perforations.
- Flow line backpressure against the formation.
- Should the type of mechanical lift be changed?
- How long has it been since the last productivity test?
- Pumping unit strokes per minute.
- Pumping unit stroke length.
- Causes for down times.
- Changes in production profiles.

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Section C

SECONDARY RECOVERY

C-1. Secondary Recovery.

In simple terms, secondary recovery is the addition of basic water flood or gas flood (i.e., pressure maintenance) as a continuous force. Secondary recovery methods should be introduced very early in the life of a field while the income and profits from the wells are high enough to pay for the additional equipment and installation costs.

As noted in the following sections, there are many problems with water and gas as drive mechanisms. Nevertheless, they both contribute greatly to enhanced recovery. They can double the amount of oil produced from the reservoir during the life of the wells.

Water flood is the term used to describe the increase in oil recovery by injecting water into an oil-producing reservoir. When gas is injected, it is not referred to as gas flood, but instead is referred to as *pressure maintenance.*

The term *injection well* is a general term that means that either water or gas is injected into a well.

Water disposal is a term used when water does not enter an oil-producing zone.

C-2. Water Injection and Water Flood.

In the early years of experimenting with enhanced recovery, water flood was introduced. This secondary recovery practice solved a major problem of well operation. It provided a way to dispose of undesirable water without the water being used to stabilize firewalls around tank batteries, control vegetation growth, and water lease roads. At the same time, the water raised production of the available oil in the reservoir.

Water flood remains a keystone to many methods of enhanced recovery. It is an excellent second-stage recovery technique and is also a major factor in slugging and blending and extends deeply into many tertiary recovery procedures throughout the producing life of the reservoir.

One problem with water flood is that it is difficult to push water through the formation as a vertical wall—that is, the water will spread out in the formation rather than move through it evenly. Gravity pulls the leading edge of the water down and causes it to move downward as it progresses through the reservoir. It can travel under the oil and leave a large amount of oil behind.

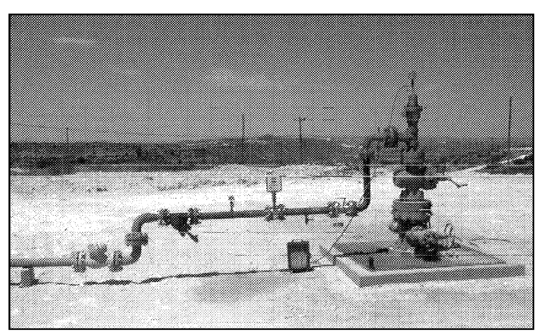

Figure 1. Wellhead set up for water injection.

Nevertheless, water continues to be one of the best enhanced recovery tools available. Water flood should be carefully designed and properly installed because it will probably be in place for the life of the well or until equipment needs major changes.

C-3. Preparing a Well for Water Injection.

Downhole preparation. When preparing an injection well, the casing must be tested for leaks, a packer added near the casing perforations to seal the annulus space, and the space filled with a packer fluid to protect it from corrosion. This process must receive formal approval before it can be placed in operation and must be witnessed by regulating agencies when installed.

Pressure in the annulus is checked regularly to determine that the casing or tubing has no leaks and that the injection pressure in the tubing is not excessive.

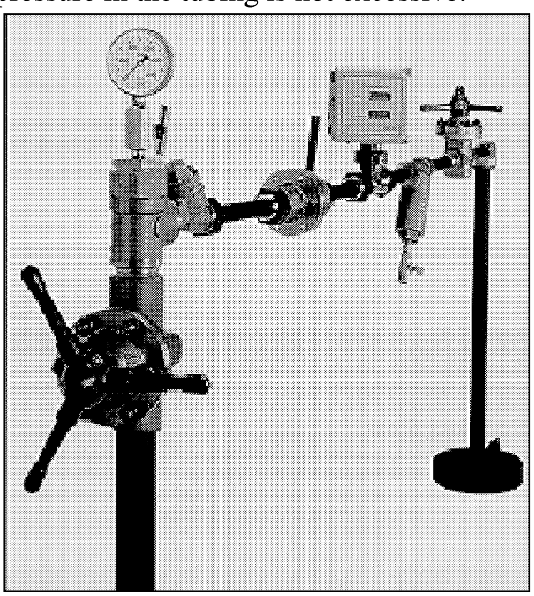

Figure 2. A wing valve used for water injection.
(courtesy of Baker SPD, a Baker Oil Tools company)

Wellhead preparation. When preparing the wellhead for water injection, the pumper will typically have a full opening master gate on the tubing. The wing assembly, as pictured in Figure 2, includes a valve, a solids screen, volume meter, throttling valve to regulate volume, a pressure gauge, and a check valve to prevent fluid loss from the injection well in the event of a line breaking.

C-4. Operating the Water Flood System and Typical Problems.

Some water injection systems require a collection system to gather all water from several tank batteries. This may involve large water holding tanks, filters, a high-volume injection pump with water distribution lines to each well, and choke valves. Other low-pressure, small-volume, one-injection well systems can be very simple in design and operation (Figure 3).

A problem that may occur is oil accumulation in the water disposal system. This can be solved by installing a skimmer tank immediately ahead of the pump. The skimmer tank is a simplified wash tank or gun barrel. Oil enters the tank, is recovered, and is pumped back into the oil production system. Water below this level is injected.

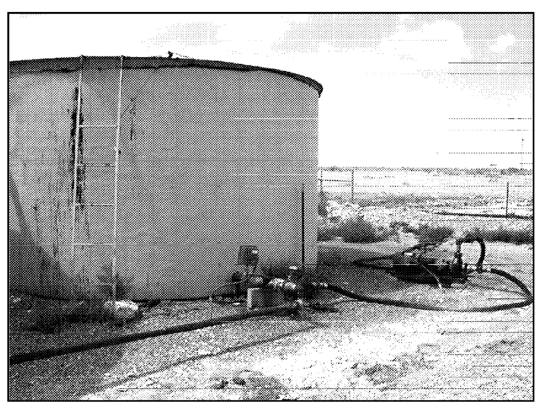

Figure 3. Low-volume, low pressure water disposal and injection system.

Intermittent Operation. Automating the water flood system for a basic automated injection system is a very simple procedure when simply injecting water that is produced on the lease. A simple hydrostatically controlled on/off switch arrangement to control the injection pump is all that is needed (Figure 4). If the system is small and the tank will not run over if the system should fail to function properly during the 16-hour period that the pumper is off the site, no backup system is required.

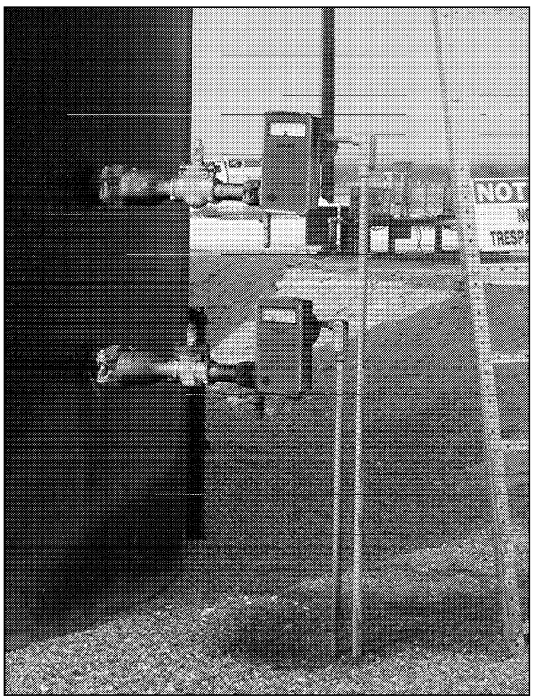

Figure 4. Automatic controls to allow intermittent operation of the water disposal system. Note that a second set of controls is provided as a safety backup.

If a larger volume is produced, a second higher level control is satisfactory to give a fluid level backup system. Normally, the lower control will start the system as the water level accumulates to a set height and turn it off when it is pumped down to a lower level. If the system should fail, the water level in the tank will build up, and the upper control will engage as a system safety on/off pump control switch. This switch will periodically need to be operated to verify that it will function if needed.

C-5. Gas Injection and Pressure Maintenance.

The re-injection of produced gas into the formation for reservoir pressure maintenance also plays a large role in secondary recovery.

Gas injection wells are in operation where it is essential that all or part of the produced gas be re-injected for pressure maintenance. As gas is collected from the tank batteries, it needs to be dried sufficiently either through a gas plant or through a gas scrubber to remove enough distillate or condensate to allow it to be re-compressed for injection.

The gas injection well is prepared in a manner similar to a water injection well. In addition, it will usually have a safety valve installed in the tubing string near the surface to protect the well from blowout if the surface injection line should break.

An example of a gas injection well for pressure maintenance is shown in Figure 5. Note that in this variety, injection gas comes from either side if the unit. This well has a downhole safety valve.

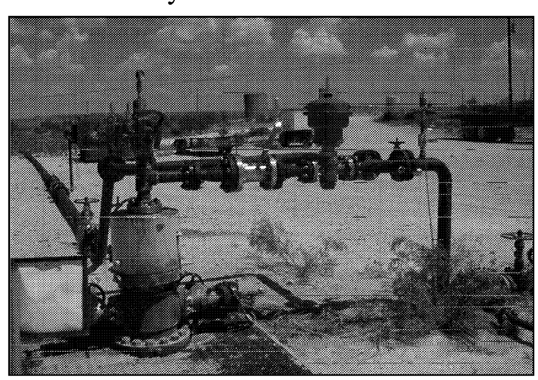

Figure 5. Gas injection well for secondary stage recovery pressure maintenance.

The first problem encountered with the gas injection recovery method is that although the gas was injected as a wall, it is very light. Consequently, as it travels through the formation, it migrates to the upper areas of the reservoir, travels over the heavier liquids (including the crude oil), and leaves very large pockets of oil behind.

The second problem encountered is that being lighter than oil, the gas will have a tendency to *finger*—that is, break into smaller streams—and channel to the recovery well, bypassing much of the oil and reducing the sweep efficiency.

The third problem is that it is difficult for the injected gas to recombine with the oil remaining in the formation. It can even make the remaining oil heavier and harder to move.

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Enhancing Oil Recovery

Section D

TERTIARY RECOVERY

D-1. Introduction to Tertiary Recovery.

Third-stage—tertiary—recovery is usually implemented and introduced slowly during water flood or pressure maintenance programs. However, in some reservoirs it is implemented soon after the first well is drilled. As with secondary recovery, tertiary methods should be introduced very early in the life of a field while income and profits can justify the additional equipment and installation expenses.

Although the term may not be used consistently throughout the industry, tertiary recovery, as used here, means that two or more forces are added to the formation. This can include water and heat for steam, water and carbon dioxide (CO_2) slugged alternately into the reservoir, polymers, or many other systems. Three of the more common processes that will be encountered are miscible displacement, chemical, and thermal. Variations for each are listed below.

Miscible displacement processes
- Miscible hydrocarbon processes
- CO_2 injection
- Inert gas injection

Chemical processes
- Surfactant-polymer injection
- Polymer flooding
- Caustic flooding

Thermal processes
- Steam stimulation
- Steam flooding
- Hot water injection
- In-situ combustion (fire flood)

Some of the goals in enhanced recovery within the reservoir include:

- Lowering interfacial tension to allow the oil to be recovered.
- Wettability change of the formation rock from oil-wet to water-wet.
- Wettability change from water-wet to oil-wet.
- Emulsification and entrapment.
- Solubilizing the rigid films at the point of the oil-water interface.

D-2. Miscible Displacement Processes.

Miscible hydrocarbon displacement. Miscible displacement processes involve the introduction of a fluid or solvent into the reservoir that will completely mix with reservoir oil and release the forces that cause the retention of oil in the rock matrix. This allows the solvent-oil mixture to be swept to the producing well. Some of these fluids or solvents are:

- Alcohol
- Refined hydrocarbons
- Condensed hydrocarbon gasses

- CO_2
- Liquefied petroleum gasses
- Exhaust gasses

Fluids or solvents that mix with the oil in the reservoir can be very expensive and cost many times the value of the recovered oil. After the slug of fluids or solvents is injected, alternate slugs of cheaper water or gas are used to make the process profitable by receiving maximum benefits.

There are three different miscible hydrocarbon displacement processes for improving recovery:

- Miscible slug process
- Enriched gas process
- High-pressure lean gas process

The use of inert miscible gas injection is increasing, and projects of this type are expected to continue to expand. They may potentially be used to recover a high percentage of the enhanced recovery reserves in the United States

CO_2 injection. This process involves pumping carbon dioxide into injection wells and, after sweeping it through the reservoir, recovering the natural gas and CO_2 from nearby wells. The CO_2 is separated from the natural gas and re-injected many times.

Combining CO_2 with heavy oils is difficult. Temperature, pressure, and oil composition conditions are difficult for carbon dioxide to obtain. Even if it does not fully combine, however, it will function as a solution gas drive. CO_2 is soluble in both oil and gas and causes fluids to swell. This is far more efficient than the injection of LPG and natural gas.

There are, however, some disadvantages to CO_2 injection. Since it thins the emulsion, it may cause early breakthrough to the producing wells, reducing sweep efficiency, and allowing large pockets of heavy crude to be bypassed and left in the formation. Water may be alternately slugged into the formation to reduce this fingering. It also dramatically increases the volume of CO_2-saturated water that is produced.

When CO_2 combines with water, it forms highly corrosive carbonic acid. Wellheads are usually prepared by installing stainless steel seals, bolts, and other trim to combat the problem.

Initial projects indicate that CO_2 flood might result in as much as 40% of the total oil recovered.

Inert gas injection. Inert gas injection procedures are very similar to injecting lean or dry natural gas. Although the scope of nitrogen (N_2) injection projects indicates that a higher pressure is needed to get ideal mixing action, inert gas is exposed to crude oil many times as it is swept through the formation and will result in an increase in production. Inert gas injection appears to be ideal for a limited number of reservoirs.

D-3. Chemical Processes.

Chemical flood processes are not used extensively and account for less than 1% of total tertiary recovery. This is because the processes are characterized by high cost, complex technology, and high risk.

Surfactant-polymer injection. This is a two- step process. The first step is injection of a surfactant slug. A surfactant is a wetting agent that breaks the surface tension between substances. The second step is the injection of a polymer mobility buffer. The surfactant slug may also be referred to as *micellar solution*, *micro-emulsion*, *soluble oil*, or *swollen micelle*. The purpose of the surfactants is to lower interfacial tension and to displace oil that cannot be displaced by water alone. The purpose of the polymer is to provide mobility control for a more piston-like displacement.

This system has not been totally satisfactory because of the adsorption of surfactants on the reservoir rock, slug breakdown, and the lowering of the ability to mobilize oil.

Polymer flooding. Polymers are substances with large molecules. When mixed with water, polymers increase the viscosity of the water, thus enhancing sweep efficiency.

There are two classes of polymers used in oil recovery:

- Polyacrylamides
- Polysaccharrides

Polyacrylamides are generally used in concentrations of 50-1000 parts per million. The use of polyacrylamides decreases the mobility of the injected fluid by decreasing the permeability of the reservoir rock.

A polysaccharride reduces the mobility of the injected fluid by increasing the viscosity of the fluid with very low levels of permeability reduction occurring in the reservoir rock. Although this results in a complex flow behavior, the viscosities of these fluids are significantly higher than water and result in a significant increase in long-range production.

Caustic or alkaline flooding. Caustic or alkaline flooding is a process wherein the alkalinity of injected water is raised to improve recovery beyond basic waterflooding. Water with a pH of 7 is considered neutral. As the pH value of a substance decreases toward 1, the substance is more acidic. As the numbers increase from 8 to the maximum of 14, the substance is more alkaline. A level of 12-13 approaches the maximum level of alkalinity practical for this process.

Caustic flooding is an economical option, because the cost of caustic chemicals is low compared to other tertiary enhancement systems. The final production gained is less, but the cost can be substantially cheaper, thus resulting in a higher income.

D-4. Thermal Processes.

Steam stimulation. Steam stimulation is a general term used when steam is injected into a well, then produced back out through the same well. This method is also referred to as *cyclic steam injection*, *steam soak*, or *huff and puff*.

With this process, up to 1,000 barrels of water per day are super-heated and injected into the well. Steam injection is continued for 10-30 days, then the well is shut in for a soak period of 1-4 weeks. During this shut-in period, heat dissipates into the reservoir. This thins or reduces the viscosity of the heavy crude oil, expands the volume of the oil causing fluid movement, and allows it to be pushed through the reservoir more easily.

The well is returned to production and produced until it has again slowed down to the level that the process of steam injection needs to begin again. After much of the reservoir oil has been recovered from the wells, then the cyclic steam flood may be converted to steam injection. The steam is injected into one well, and the resulting fluids are produced from other nearby wells. Steam flood in some reservoirs has resulted in a dramatic increase in production stimulation.

Steam and hot water injection. Steam injection continues to grow in importance in enhanced recovery. Steam injection accounts for approximately 20% of enhanced recovery processes. Steam flood wells are drilled on an approximate five-acre spacing and require a reservoir depth of approximately ten or more feet. Steam flood is most effective in wells no deeper than 5,000 feet.

Steam flood acts in a similar manner as water flood in relation to injection and producing well arrangements. The obvious advantage is crude oil expansion. It continues to expand as the pressure drops, and a water bank develops as the steam condenses.

Hot water injection is effective to some degree but, because of heat loss, it is not as effective as steam flood and can result in fingering and loss of sweep efficiency.

In-situ combustion. *In-situ* means "in place" and in-situ combustion indicates that a fire will be ignited within the formation. By injecting compressed air into the injection well this fire is driven across the reservoir. The heat generated by the fire will reduce the viscosity of the oil leading to a drop in pressure, which will allow the oil to expand, resulting in movement and possibly increased production.

There are two different in-situ combustion processes. In the first, **forward combustion**, the fire is ignited in the formation near the air injection well, and with continuing air injection the fire and produced oil is driven toward nearby producing wells.

The second process is referred to as *reverse combustion*. In this process, fire is ignited in the formation near the air injection well, and after fire has been driven for a predetermined distance from the injection well air injection is switched to the nearby producing wells. The fire will burn toward those wells, while oil production direction is reversed and produced through the initial air injection well.

The in-situ method is not always cost effective. Because of the large amount of heat left behind from forward combustion, several other methods other than the dry combustion described above are being developed. These are referred to as *wet* and *partially wet combustion*.

The Lease Pumper's Handbook

CHAPTER 16

CORROSION, SCALE, AND CATHODIC PROTECTION

The Lease Pumper's Handbook

Chapter 16
Corrosion, Scale, and Cathodic Protection

Section A

CORROSION AND SCALE

The purpose of this chapter is to assist the lease pumper in understanding corrosion and how to reduce the damage it causes in wells and surface facilities. In addition, this chapter provides a basic overview of scale and scale control for wells that produce a lot of water. Examples of corrosion and scale problems are shown in Figures 1 and 2.

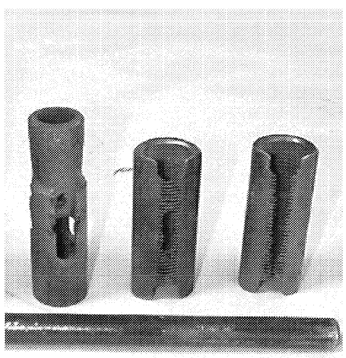

Figure 1. Note corrosion on left item, a downhole pump part, and a parted rod.

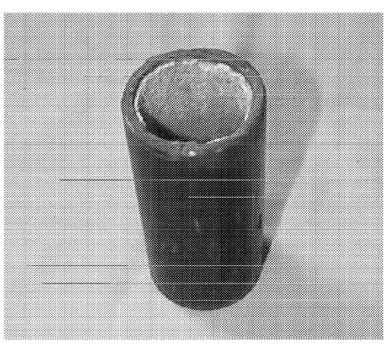

Figure 2. Scale in a cut-out section of tubing showing how it is deposited inside the unprotected pipe.

A-1. Introduction to Corrosion.

Corrosion is a general term for a reaction between a metal and its environment that causes the metal to breakdown. While there are many types of corrosion, they all involve either a chemical reaction or an electrochemical reaction. In chemical reactions, chemicals in the environment react with the metal to create different chemicals. Thus, atoms or molecules of the metal combine with other atoms or molecules that contact the metal to form different, generally weaker, materials. Rust is an example of this type of corrosion.

In electrochemical corrosion, the environment around the metal results in the creation of an electrical current, which is simply a flow of electrons. The metal corrodes by giving up electrons to create the electrical flow.

The oil field environment is filled with metal pipes and other components that often exposed to chemicals that can cause corrosion, especially when the metal and chemicals are in a solution such as downhole fluids. The pumper must understand how to reduce corrosive damage to the metal in wells, flow lines, tank batteries, and equipment.

There are four general types of corrosion of concern in the oil field. These involve three chemicals of concern and electrochemical corrosion. The types of corrosion include:

- Carbon dioxide (sweet corrosion)
- Hydrogen dioxide (sour corrosion)
- Oxygen corrosion (oxidation)
- Electrochemical corrosion

A-2. Carbon Dioxide Corrosion.

Carbon dioxide (CO_2) is a corrosive compound found in natural gas, crude oil, condensate, and produced water. CO_2 corrosion, or *sweet corrosion*, is common in the oil fields in southern Oklahoma, New Mexico, the Permian Basin of Texas, and the Continental Shelf along the Gulf of Mexico because of the high CO_2 content of the crude from these areas. Special refineries capable of refining high CO_2 crude oil are expensive to build and maintain. Most of these refineries in the U.S. are clustered in the Gulf Coast area. Much of the crude oil from Alaska must be refined in this area because it also contains a large amount of CO_2.

CO_2 is composed of one atom of carbon with two atoms of oxygen. When combined with water (H_2O), carbon dioxide produces carbonic acid (H_2CO_2). Carbonic acid causes a reduction in the pH of water and results in corrosion when it comes in contact with steel. When iron (Fe) combines with carbonic acid, it produces iron carbonate ($FeCO_2$). Iron carbonate is not as strong as the refined iron or steel used to make the well components.

The damage caused by sweet corrosion in oil wells usually results in pitted sucker rods and the formation of hairline cracks. Corrosion *test coupons* can be inserted into the lines to indicate the level of iron removal and other corrosive conditions. Caliper surveys can also be used to determine the extent of tubing damage. Chemical injection, alloys, and protective coatings are used to combat the problem.

A-3. Hydrogen Sulfide Corrosion.

Hydrogen sulfide (H_2S) occurs in approximately 40% of all wells. The amount of H_2S appears to increase as the well grows older. H_2S combines with water to form sulfuric acid (H_2SO_4), a strongly corrosive acid. Corrosion due to H_2SO_4 is often referred to as *sour corrosion*. Since hydrogen sulfide combines easily with water, damage to stock tanks below water levels can be severe.

Solutions to sour corrosion problems are similar to those for sweet corrosion. This includes the use of chemicals, alloys, and coatings to combat the problem and reduce the damage. Circulating chemical down the annulus is a common practice to treat downhole problems.

When sufficient amounts of H_2S are produced with the emulsion, the pumper must wear a gas mask when gauging or *working oil*—that is, testing oil at the thief hatch to determine if it is ready for sale (Figure 3).

Figure 3. Where H2S gas is present, sour corrosion is likely and breathing apparatus is required.

A-4. Oxygen Corrosion.

Oxygen corrosion or *oxidation* is the most common form of corrosion. On steel and iron, oxidation typically takes the form of rust. Painting the tank battery and other surface equipment to eliminate this contact is basic oxygen corrosion protection.

Oxygen corrosion begins when equipment makes contact with the atmosphere and moisture. Under these conditions, the iron and oxygen react with each other to form ferric oxide (Fe_2O_3), which is commonly referred to as rust. Oxidation can also occur with other metals, including aluminum. Although the compounds formed will be different, the results are the same in that the metal is weakened, usually undergoing embrittlement in which the metal becomes brittle. Oxidation can also accelerate the damage from sweet corrosion.

An oil blanket is often deliberately maintained on produced water to block the atmospheric oxygen from contacting the water. A system that prevents the atmosphere from making contact with the produced water is referred to as a *closed system*. A system that allows the air to contact the produced water is referred to as an *open system*. Stripper wells are often produced with the casing valve open to the atmosphere, which promotes downhole corrosion. Water flood can also inject oxygen into the formation, promoting oxidation. Open systems are sometimes preferred because the formation of rust can actually help to protect against some forms of corrosion, such as electrochemical corrosion described later.

A-5. Electrochemical Corrosion.

There are two common types of electrochemical corrosion. One is the result of electrical current leaking into the environment. Electrical current may be planned to power electrical equipment or it may be generated accidentally, such as the static electricity produced by the wind blowing. Corrosion can occurs wherever the electrical current leaks into the environment. For example, poor grounding may allow stray current to enter a pipe. When the current reaches a wet area, the current may flow from the pipe. Electrochemical corrosion is likely to occur at that point.

The second type of electrochemical corrosion is more common. It occurs when metal in water, such as downhole parts or pipe laid in moist soils, becomes part of an electrical cell. Such a cell is essentially an acid battery and will be formed just about any time two different types of metals are placed in an acidic solution. Electrons from one metal will flow to the other metal. This results in the metal that gives up electrons being eaten away and the other metal building up a brittle coating. The metal that gives up electrons and corrodes away is referred to as the *anode*, and the metal that collects electrons is called the *cathode*.

Techniques that are implemented to slow down or eliminate electrochemical corrosion are referred to as *cathodic protection*. In cathodic protection, the flow of electrical current is altered to prevent the metal to be protected from serving as an anode.

A-6. Problems with Scale.

Scale, or *gyp*, is carried with water in a solution and migrates toward the well bore. Problems with scale can begin as it approaches the matrix or well bore area. It can plug the formation, casing, and tubing perforations; make tubing in the hole stick; fill tubing to the point that the pump cannot be pulled without stripping; and plug flow lines. At the tank battery it can fill lines and vessels and accumulate in the bottom as a solid. Scale can accelerate electrochemical damage by acting as a cathode to the steel, resulting in deep pitting.

Stopping scale in the formation and chemical treatment. The first place to solve problems with scale is in the formation. Chemicals are available that can be blended with water and pumped into the formation to stabilize the scale and highly reduce its accumulation in the system. It may be necessary to acidize the wells periodically to clean up the immediate reservoir area and to reopen the casing perforations. Special small materials that are water- or oil-soluble can be blended into the fracing compounds to control the process and increase the efficiency of the treatment.

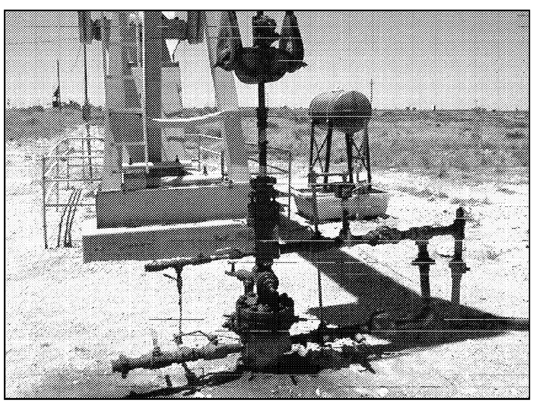

Figure 4. The chemical tank (background) and the pump and injection tee (left of wellhead) are used to combat scale with chemicals.

Protective coatings. Special coatings can be applied to reduce the ability of scale to cling to the inside of the tubing. With flowing wells, this coating may be applied like paint. On pumping wells the rod action would damage the coating. Consequently, special chemicals can be circulated down the casing that are produced back up through the tubing to protect perforations, tubing, and the downstream flow line and tank battery. This treatment can be a continuous or periodic batch treatment.

Scale removal. When systems are permitted to fill with scale, it may be necessary to disassemble, clean, and rebuild of the system. A good and efficient scale control program must be maintained.

Scale can be reduced and removed by slow and expensive chemical processes. Scale accumulation in tubing can also be scraped or drilled out. In vessels, it may require the removal of the manway plates, entering the vessel with the proper safety equipment, and physically shoveling the accumulation out.

Problems with scale caused by construction practices. Good construction practices should always be followed to prevent building systems that trap scale and cause unexpected problems. As an example, the line from the wellhead to the tank battery should not contain any 90-degree bends. Even an ell in the line may not be satisfactory. Pipe can be bent or slow curves installed to eliminate any scale traps between the well and the tank battery.

A-7. Other Types of Corrosion

Many environmental factors can influence the effects of corrosion. The chemical content of the soil and the production fluid, the climate, the materials used for well components, and other factors have an effect. The presence of microorganisms can accelerate corrosion, and microbiological corrosion in which organisms eat the materials or chemically transform them is also common.

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Chapter 16
Corrosion, Scale, and Cathodic Protection

Section B

CORROSION PROTECTION

B-1. How to Prevent Corrosion Damage.

To stop corrosion, the pumper must make changes in the environment that prevent the chemical reactions and electrical currents that cause corrosion. Since corrosion affects virtually all equipment on the lease, a wide-reaching prevention program is necessary. Good corrosion prevention begins on the first day of the first installation with the drilling of well number one and continues on all equipment at the most affordable level.

This is emphasized because the cost of drilling the well, installing the necessary surface equipment, and constructing facilities must be invested while the well produces enough oil to support the recovery of this expense. As wells become marginal producers, income from production may barely cover lifting costs alone. Funds are rarely available for expensive methods of corrosion protection.

There are many methods of protection, and no one system is used exclusively anywhere. The pumper should become familiar with all protective methods in order to make logical decisions. These include chemical, mechanical, and electrical methods such as:

- Rust
- Oxidation
- Painting
- Inside coating and lining
- Oiling
- Insulating flanges
- Sacrificial anodes
- Applied electrical current
- Conduits
- Fiberglass components
- Galvanized bolted tanks
- Stainless steel and metal plating
- Plastic flow lines
- Mechanical barriers

Rust. While rust is often considered destructive, it can be a natural first level of protection for ferrous (iron-containing) metals. The rust itself can protect the outside of a flow line while the produced crude oil partially protects it on the inside.

When equipment is first constructed and installed, unpainted metal rapidly oxidizes. As the rust ages, it gets heavier, a scale is formed, and the corrosion rate slows down. In the dry southwest where rainfall is low and the ground surface stays dry, surface flow lines are seldom painted or treated because rust rarely gets severe enough to cause leaks. Many unpainted lines are still in service after more than fifty years.

Oxidation. Oxidation is also a natural first level of protection on non-ferrous (containing no iron) metals. Oxidation on copper, aluminum, and other non-ferrous metals provides protection similar to rust on iron. Aluminum has not been popular in oil fields except for use as temporary water lines to drilling rigs. When some types of oilfield acids contact aluminum, extensive damage can occur in a short period of time.

Painting. Most equipment in tank batteries, especially welded tanks and lines, is painted immediately after construction to prevent corrosion. Galvanized, stainless steel, nickel-plated, and other corrosion-resistant materials do not normally require painting. However, galvanized pipe is not suitable for carrying petroleum products.

Inside coating and linings. Coating lines on the inside is popular for protection against some types of corrosion, especially in downhole tubing. Linings may also be used in some lines and vessels. Another level of natural protection inside the lines and vessels comes from naturally produced compounds such as the crude oil itself and, in some instances, scale. Scale is the buildup of minerals that can be dissolved in groundwater and deposited on tubing and casing.

Oiling the outside. At one time, crude and other oils were sprayed on pipe and equipment that was put in storage for extended periods of time. A good heavy oil with a small paraffin content will spray easily, protect nearly as well as paint, and last for several years. Non-corrosive oil also provides significant protection to the inside. This practice is less common today due to environmental concerns.

Insulating flanges. Insulating flanges are used extensively to prevent electrical current flow. With steel lines, an insulated flange union can be placed above ground level at each end of a line, near the well, and near the tank battery. This acts as a buffer to block static and stray electricity.

Sacrificial anodes. Sacrificial anodes are often installed in liquid holding vessels. For example, by installing two to four sacrificial anodes in a heater/treater near the firebox and below the water line, a path is provided for electricity to travel from the anode to the cathode, protecting the vessel. Thus, the anode provides the electrons for current flow rather than the part being protected. The anode is “sacrificed” and must be periodically replaced as it corrodes away.

Electrical current. Electrical current can be imposed in selected areas to protect the outside of a downhole casing. Shallow cathodic protection wells can be drilled near operating wells and, by use of a sacrificial anode in these holes, small amounts of current (milliampere range) can be directed to the wells and removed at the wellhead to greatly reduce casing material loss and prevent casing leaks.

Figure 1. A cathodic protection well.

Conduits. Conduits are used extensively where lines must pass under roads to protect them from moisture. Vents are also installed to allow leaking fluids to escape.

Fiberglass. Initially, fiberglass was used inside tanks to extend their life. Now tanks made entirely of fiberglass are available. These are widely accepted in water disposal and chemical injection systems, and their use continues to expand for holding crude oil.

Galvanized bolted tanks. Galvanized bolted tanks are not subject to corrosion and were standard for years. Many are still common in the field.

Stainless steel and metal plating. Stainless steel bolts, seal rings, gaskets, and small tubing have replaced more corrosive parts that fail due to embrittlement and metal fatigue. Nickel plating is also highly used.

Plastic flow lines. In recent years, plastics such as polyethylene, polyvinyl chloride (PVC), and other synthetics are replacing steel and rubber in corrosive situations.

Chemical protection. Chemicals still offer protection in casings and other hard-to-reach areas. These chemicals are constantly being improved and are very effective.

Mechanical barriers. Mechanical methods can effectively stop some equipment corrosion problems. One method is to remove oil- or water-saturated soil from contacting lines or equipment. Also, insulating materials such as gravel and tarred felt under tanks will allow air to circulate and greatly extend their lives. Tarring and wrapping underground black metal lines prevents water and chemicals in the soil from contacting the lines. This method is often used to protect pipe in wet areas. Finally, a simple downhole pump ball and seat can stop oxygen from entering open annulus valves, yet allow gas to escape.

B-2. Locating Corrosion Damage Downhole.

Corrosion downhole at the well has caused production problems since the first wells were drilled. Corrosion can create holes in the casing and cause formation leaks in upper zones. This can also allow oil to flow out the surface pipe valve and overflow the cellar. The hole in the casing can even be in an offset well rather than one from which hydrocarbons are escaping. The surface valve cannot be closed in this situation because it may force the oil and gas to break into the upper freshwater zone, compounding the problem.

Temperature surveys are conducted periodically on flowing wells to check for holes in the casing. The expansion of the escaping fluids at the leak creates a cold spot that can be detected by the survey.

Another method of locating holes in casing is to run a *casing survey*. Gas pressure can be injected into the annular space with the well shut in, depressing the liquids back down to the casing perforations where the pressure chart will level off to a straight line. As the gas injection is stopped and the well sits pressurized for a 24-hour period, the pressure should remain constant on the chart. If it falls, there is a hole in the casing.

B-3. Protecting the Casing Long String.

Protecting the inside of the casing string that is cemented through or to the oil producing zone can be important in corrosive wells. Protection can be achieved by periodically scheduling the application of a chemical protective inhibitor blanket on the surface of the pipe all the way down the hole by batch injecting the chemical into the annular space. A carrying agent, such as several barrels of crude oil or water, may need to be mixed with the chemical to give it sufficient volume to allow the inhibitor to quickly flow by gravity to the bottom of the well without channeling or streaking on the way down. This results in 100% coverage.

Preventing electrochemical corrosion of the outside of the casing requires a different approach. Since the string of pipe is cemented as it passes through the impervious cap and is bolted at the wellhead, the only opening into it is the surface valve on the wellhead. Drilling mud is usually caked around the outside of the casing from the surface down, so corrosion-inhibiting liquids cannot be injected at the surface and be expected to coat the outside of the pipe. The solution is to block or stop the electrochemical process, which is caused by oxygen and acid.

The use of insulating flange unions. Insulated flange unions (Figure 2) are installed at the well and the tank battery to prevent the flow of electrical current into the well through the casing. When electricity flows into the casing, metal is removed at the point where it leaves the well. These points act as anodes. By preventing the flow of electricity into the well, the amount of iron lost will be reduced.

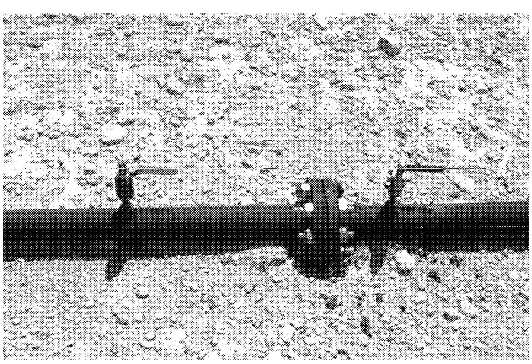

Figure 2. An insulated flange union that is installed near the well. The valve is used to periodically record line pressure.

The use of sacrificial anodes. The ideal solution is to drill another shallow hole nearby and install a series of sacrificial anodes. Lines are run to the surface and connected through a control panel to a power line. A controlled electrical current is run through the sacrificial anode from this special well. The current runs through the earth and enters the well casing and comes up through the casing. This turns the casing anode into a cathode and corrosion stops. A protective scale will even develop on the outside of the casing at this point, offering additional protection.

B-4. Corrosion Protection at the Tank Battery.

Corrosion protection at the tank battery begins before the tank battery is constructed. As the tank battery is constructed, appropriate steps of the construction are directed toward corrosion protection.

Tank battery elevation and ground protection. The tank battery location is elevated several inches above the surrounding area. Dirt is bladed up to give it a slight elevation above the surrounding terrain. A side taper is added that will allow rainwater to run off. Several cubic yards of crushed rock are placed under the vessels so air can circulate under them to evaporate any water that might be present. This rock is then covered with a double layer of 120-pound roofing felt to further insulate the tank from the rock.

The pressurized vessels are set on concrete bases to keep them level and support the weight of the vessel, fluid, and lines. Crushed rock may then be spread over the open ground to control vegetation growth, which may trap moisture and promote corrosion from organisms.

Lines protection. When lines are laid, areas with heavy vegetation and standing water should be avoided. Coated and wrapped pipe or elevated lines offer some protection when these areas cannot be avoided. Many styles of insulated unions are available for use near the well and also just before the flow lines enter the tank battery to reduce electrochemical corrosion in the line.

Protecting vessels on the inside. Paint is always used at the tank battery as the first method of protecting vessels. A second method is to protect the inside of the vessel with special epoxy-type paint and fiberglass liners. The method selected to protect the vessel on the inside will depend upon what corrosive agents are contained in the produced crude oil.

Fiberglass vessels and PVC water lines have also reduced some corrosion problems. Improved fiberglass vessels (Figure 3) are becoming more common as new batteries are built and vessels replaced. Low-pressure water injection systems are being constructed with plastic and PVC.

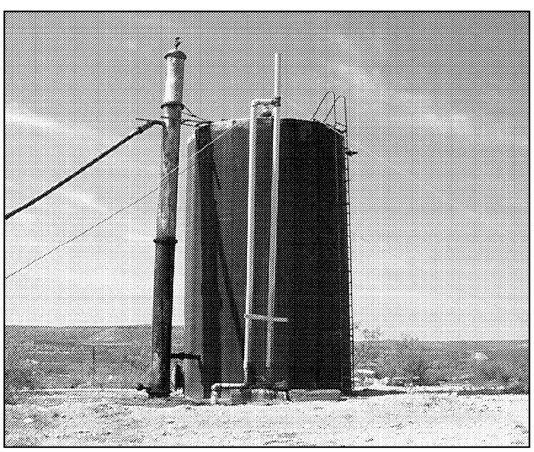

Figure 3. Fiberglass gun barrel or wash tank with PVC water leg to reduce problems from line corrosion.

Another method is to protect the vessel with chemicals. These may be injected at the tank battery, but the most logical place to inject them is down the casing annulus to protect the full system.

Sacrificial anodes are widely used in heater/treaters (Figure 4). These anodes must be replaced as they corrode in order to provide continual protection of the vessel. The anode is inserted into the vessel in the lower water area, and a ground wire is attached from the anode to the firebox flange. Here, current is diverted into the line system to protect the bottom section of the heater/treater from pitting. Oil-saturated dirt is removed from around the steel lines and clean sand put back into its place. This stops the formation of galvanic cells which cause line leaks.

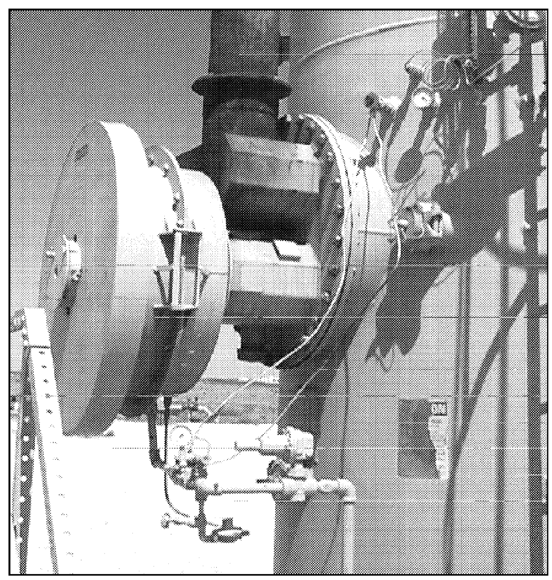

Figure 4. Heater/treater firebox view with two sacrificial anodes visible, one to the right and the second directly below the fire tube flange.

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CHAPTER 17

WELL SERVICING AND WORKOVER

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Chapter 17
Well Servicing and Workover

Section A

WELL SERVICING

A-1. Introduction to Well Servicing.

Some wells are plugged and abandoned too early because the people responsible for maintaining the well did not recognize or understand why it stopped producing and did not know how to restore production.

In order to keep wells producing oil and gas, the pumper must understand the problems that can occur and how production can be restored. Any problems that occur downhole must be correctly identified and repaired. This means that rods and tubing must be occasionally pulled.

The pumper must understand what well servicing equipment is available, how it functions, what problems may be occurring in the reservoir, and what must be done to restore production.

A-2. Styles of Well Servicing and Workover Units.

There are three styles of basic well servicing units based on their mast or pole design. All three are manufactured today, although the two smaller models have a limited market. The smaller pole units are available with one or two drums, while the larger mast unit has two drums.

Single-pole units. Single-pole units are used to service shallow wells. Since the well servicing unit has one pole, the rods and tubing are laid down on a rack. The unit can be operated with only an operator and a floor person, although for most wells it is better to have a third helper.

The unit has as many as eight guy lines, four for the lower section, and four for the upper section to be guyed after extending the upper section. After folding the pole mast up on most single-pole units, the two front load supporting guy lines must be fastened before the upper mast pole can be telescoped up. For safety and when the wind is blowing, it is better to guy all four lower lines before telescoping.

The mast can be telescoped to several different heights, according to what job is planned. Since most rods are 25 feet long, for a rod job only the mast can be lower than for a service job that involves tubing, which can exceed 32 feet. The higher pin level will allow tubing and 30-foot rods to be pulled. When telescoped to maximum height, rods can be pulled in doubles and laid on racks.

These units are still popular with operators who have many shallow wells and do their own service work.

Double-pole units. The double-pole unit is more efficient than the single-pole, because rods can be hung in the derrick in doubles, and the tubing can stand in singles. It still allows the option of laying the rods down in singles or doubles and the tubing in singles. When pulling rods, the box can break on either side, so the rods must go back into the hole in the same order from which they were broken out.

When pulling tubing, the collar is used to support and lift the string, so the connection must always be broken out of the top of the collar. When possible, the tubing should also be run back in the well in the reverse order of being removed. More thread leaks will be encountered when the joints are jumbled in random order each time they are pulled. Thread lubricant should always be applied when running the pipe back into the hole. Cards are available from rod suppliers to show how tight the rods should be made up.

The double-pole unit support truck is not much larger than the one for the single mast unit. With two poles braced together, however, it can pull medium depth wells, allowing many operators to pull most of their own wells. This unit can also perform light workover duties and can be operated with a three- or a four-person crew.

Mast style units. Figure 1 illustrates a mast style well servicing unit. This unit is capable of pulling standard 25-foot rods in triples and tubing in doubles. Fiberglass rods are 37½ feet long and can be pulled in doubles. Since the rods are racked by a person on the derrick, they can be pulled very rapidly. For deeper wells, the work is almost always performed with the mast style units.

Single- and double-drum well servicing units. A well servicing unit may have one or two drums. If it has a single drum, operators usually just pull rods and tubing or swab, although it can be used both ways by swapping the lines. A double-drum unit contains a swab line for swabbing, cutting scale and paraffin, pulling standing valves, running impression blocks, setting and removing downhole tools, as well as other functions.

The single- and double-pole units may have one or two drums. The larger standard mast type unit has two.

A-3. Roading the Well Servicing Unit to the Lease.

Driving the well servicing unit to the lease can present several road hazards. The service rig is heavy and slow moving. It is usually followed by a crew truck pulling a tool security trailer. The drivers should talk about safety and observe good road practices.

The crew truck should trail the servicing rig at a comfortable distance so that vehicles needing to pass will have enough room to pass each the truck and rig separately.

When the road rises, especially on a rough lease road, extra separation must be allowed. If the driver of the well servicing unit misses a gear or if the engine should die, the well servicing unit may roll backward down the slope. This can present exceptional risk to the crew truck occupants.

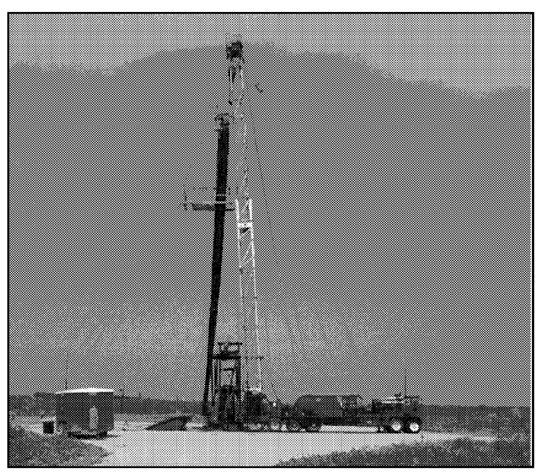

Figure 1. A typical telescoping mast type pulling unit.

A-4. Approaching the Well.

When backing the unit up to the well, a person should stand in front of the unit on the driver's side so that signals can be seen easily by the driver. Another person at the back of the rig should watch the pumping unit and the pulling unit and signal instructions to be relayed to the driver by the person in front of the rig. The pumping unit must be turned off with the horse head in a position where it cannot be hit by the pulling unit or poles, and the pumping unit brake should be set. A *sill* or 6" x 8" wood block approximately two feet long should be placed on the ground so that the unit will back up against it and cannot strike the pumping unit or wellhead in event the driver's foot slips off the brake. The unit should be set the correct distance from the wellhead and be square with the anchors and leveled with the leg screws. This allows the blocks to hang directly over the hole.

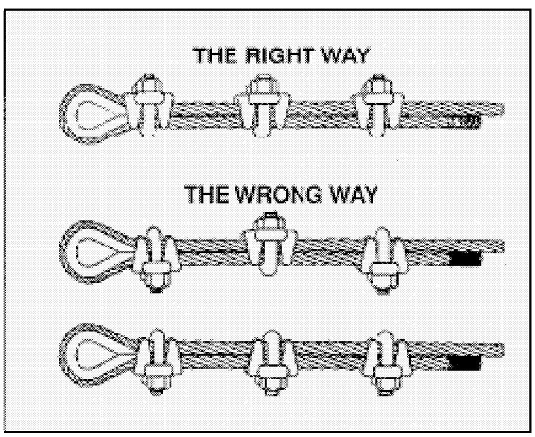

Figure 2. Guying the pulling unit.
(courtesy of Williamsport Wirerope Works, Inc.)

A-5. Setting Up the Well Servicing Unit.

When setting up the double mast unit, there are usually only six guy lines. Two of these are pre-set in length and reach from the top front of the lower section to the headache rack that supports the mast when it is folded down. After the lower mast has been set up and these two guys are tight, the upper section is telescoped up and the remaining four guy lines attached to the anchors.

The correct method of guying a pulling unit is shown in Figure 2.

A-6. Well Records.

There are five records or pieces of information that the person in charge of the well servicing operation should have available. These are:

- **Casing information.** This sheet lists the distance from the wellhead to the top of the perforations, the number of perforation shots and arrangement, the distance that they cover, and the cased hole distance from the bottom perforation to the bottom of the open casing.
- **Tubing tally sheet.** This is an itemized listing of the tubing hanger, pup joints, joints of pipe, safety joint, packer, hold-down, seating nipple, perforated joint, mud anchor, and bull plug in exact order and length from the tubing head to the bottom of the string. This sheet will also provide the grade of the tubing, if the joints are measured with the thread off or overall, the average length of the full joints of pipe, and a listing of all other equipment in the hole. Additional information may also be listed.
- **Complete packer or holddown description.** This sheet will list all special equipment such as packers, holddowns, and safety joints in the hole. These should be identified by

manufacturer, year of manufacture, metal content, brand, style, model, description, and instructions on how to release and latch this equipment during workover operations. Enough information about the downhole equipment should be available that all questions on pulling and servicing are answered.

- **Rod tally sheet.** This identifies the size and length of every rod in the hole, including the polished rod, pony rods, sucker rods, safety joint, pump, and gas anchor. Rods should be identified by brand and described with instructions on how to release any safety joint in the hole. If the well has a tapered string, the number of rods in each size should be included.
- **Complete pump description.** If the pump must be replaced or fished out of the hole, a complete description of it should be on file.

A more complete description of the importance of this information and illustrations of the downhole well records that should be maintained in the field record book are in Chapter 19. The pumper should be familiar with these important records.

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Chapter 17
Well Servicing and Workover

Section B

PULLING THE ROD STRING AND PUMP

B-1. Rod String Records.

When performing well servicing work, it is important to have access to the latest well records, including the last pulling record that shows what is currently in the hole.

An illustration of a pipe tally is shown in Figure 1.

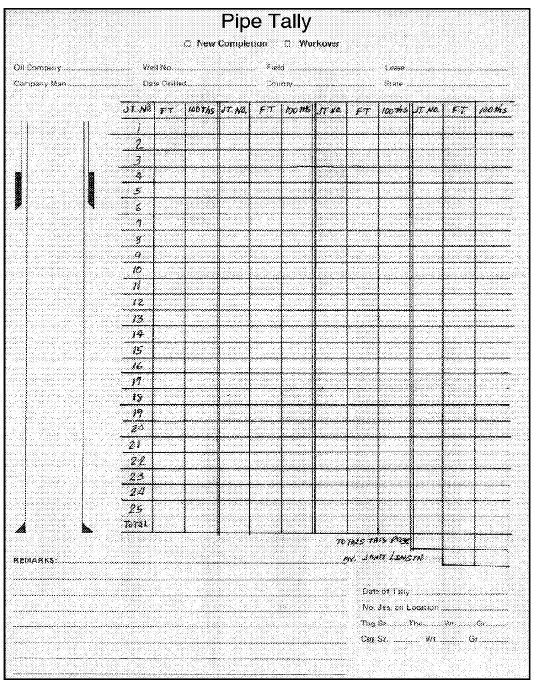

Figure 1. A tubing record and a rod record must be maintained on every well.

B-2. The Strength of the Rod String.

If the well is 2,000 feet deep or less, all equipment made to go downhole will meet the strength requirements of the installation. Little attention is given to tensile strength. If the well is 10,000 feet deep, rods and tubing capable of supporting a 10,000-foot string with a satisfactory operation and safety margin must be used. Satisfactory records of the API tensile strength must be maintained and must include the API rating of every rod in the hole.

Companies that manufacture sucker rods use API designations such as C, D, and K to identify the quality of the rod, including tensile strength and corrosion resistance. This letter is also stamped on the flat side of the pin. Class C rods are used in light to medium applications, and D is used in medium- and high-tensile strength applications. An example of an API Class D sucker rod is shown in Figure 2.

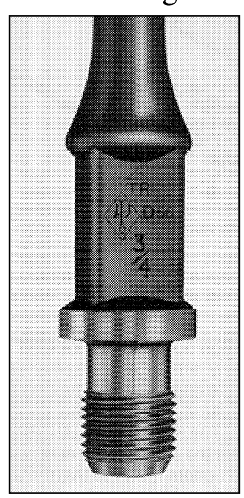

Figure 2. API Class D sucker rod.
(courtesy of Trico Industries, Inc.)

When a string of rods or tubing has been exposed to severe service and the well begins to have excessive problems such as parting rods or breaks, a new or better quality string will be run in the well. The used string will usually be downgraded one step and re-used in a well that requires a lower tensile strength since they should never be graded back to their original level of service.

When these used rods are transported to the storage yard, they should be stored and recorded with their lower rating. Common sense must be used when placing them back in service. The lease pumper should accept the inventory classification record, not the stamped designation. Thus, when purchasing used rods or tubing, the lease pumper should make sure that the downgrade practice has been followed.

B-3. Straight and Tapered Rod Strings.

The API has guidelines for identifying the rod system in the well. Rod diameter measurements are in fractions of an inch, with numbers assigned based on eighths of an inch. The table below shows the numbering system. The first line shows a rod with a one-half inch diameter body. Since one-half inch contains four one-eighth increments, this rod is designated with a 4 and is referred to as a *number four rod*. Number four rods will work in a water well, but are not usually found in the oil field.

½ = 4 1/8"-increments, or a # 4 string.
5/8 = 5 1/8"-increments, or #5.
3/4 = 6 1/8"-increments, or #6.
7/8 = 7 1/8"-increments, or #7.
8/8 = 1 inch or 8 1/8"-increments, or #8.
9/8 = 1-1/8 inch or 9 1/8"-increments, or #9.
10/8 = 1¼ inch or 10 1/8"-increments, or #10.

With this method of identification, it is easy to represent the rod string with just a few numbers even if it is a tapered string. Rod string identification numbers are as follows:

API Rod	Rod Dia.	API Rod	Rod Dia.
44	= All ½"	86	= 1", 7/8", ¾"
54	= 5/8", ½"	87	= 1", 7/8"
55	= All 5/8"	88	= All 1"
64	= ¾", 5/8", ½	96	= 1-1/8", 1", 7/8", ¾'
65	= ¾", 5/8"	97	= 1-1/8", 1", 7/8
66	= All ¾"	98	= 1-1/8", 1"
75	= 7/8, ¾, 5/8"	99	= All 1-1/8"
76	= 7/8", ¾"	107	= 1¼", 1-1/8, 1", 7/8"
77	= All 7/8"	108	= 1¼", 1-1/8", 1"
85	= 1", 7/8", ¾", 5/8"	109	= 1¼", 1-1/8"

Figure 3 illustrates a method of identifying the rod quality to be used at a well site.

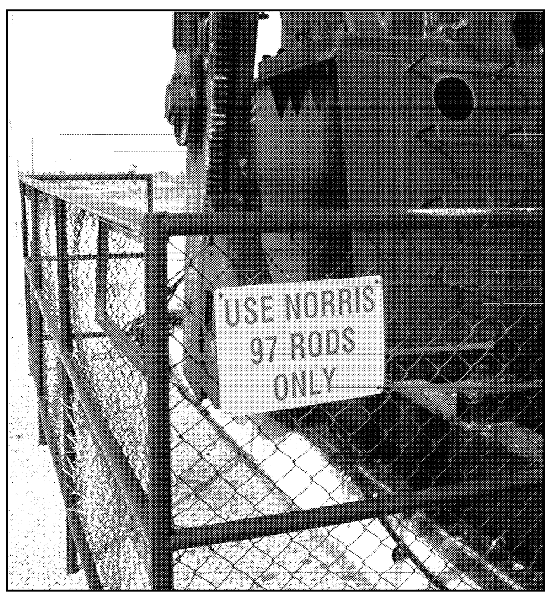

Figure 3. Sign at well specifying rod quality.

Some rod strings are tapered. Tapered rod strings do not actually use tapered rods. In this context, *tapered* means that top of the string has larger rods and that smaller rods are used in lower portions of the string. When going in the hole, a selected number of the smallest rods are run immediately after the pump is set in the hole. A change-over coupling is then added and the next larger size is run. A selected number of this size is run, and, if a third size is used, a second change-over coupling is added so that the next larger size can be run. There are several advantages to this approach:

- It lowers the string weight and, thus, reduces the weight load.
- A smaller gearbox or pumping unit can be used.
- The horsepower or electrical energy needed is reduced.

This is a common practice in deeper wells. The tensile strength, stretch, strokes per minute, and other parameters are limiting factors and must be considered when designing tapered strings. When designing tapered strings, the pumper should always consult with qualified engineers who understand sucker rod installations

B-4. Pulling and Running Rod Strings.

Some lease pumpers with small oil companies may be in charge of well servicing when the owner is not present. At other companies, the lease pumper is not only in charge but runs the well servicing unit or physically assists as a member of the crew. With larger companies, the pumper may only be a spectator who must return the well to service after the job is completed.

When pulling and running rod strings, always handle rods in a manner that will run them back into the hole in the same order that they were pulled. The use of a rod elevator (Figure 4) is recommended. Since the boxes are allowed to break at either side on some rigs, this saves problems with double or no boxes when running them back in the hole.

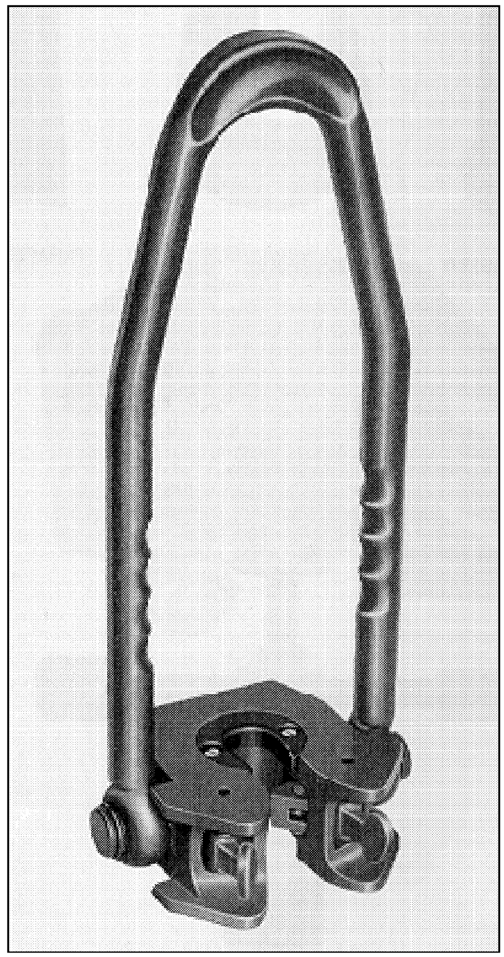

Figure 4. A rod elevator.
(courtesy of Trico Industries)

When making up rods, always use the correct make-up procedures. This includes using proper tools, such as special hand wrenches (Figure 5). The rods can be damaged by over-tightening just as easily as not being tightened enough. Make-up charts are available and should be followed.

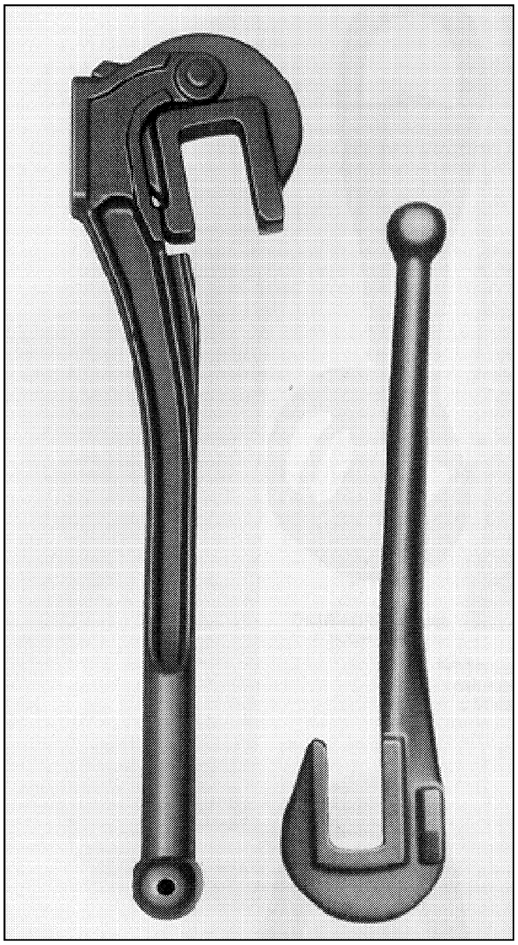

Figure 5. Typical hand rod wrenches.
(courtesy of Trico Industries)

When laying rods down on a rack, care should be taken at all times to prevent damaging or kinking the rods. Extreme care must be used when picking up the pump; sometimes a center bridle support must be used.

Power rod tongs. Many companies prefer that their rods be made up with power tongs. When correctly used, the rods are made up exactly to manufacturer's specifications. The correct torque should be used to prevent stretching the neck of the pin, which can cause the rod to break under load.

Pulling stuck pumps. Rods are normally pulled through the use of a rod hook (Figure 6). Normally, the rods will come out without excessive problems. However, sometimes the rods will bind or a pump will get stuck.

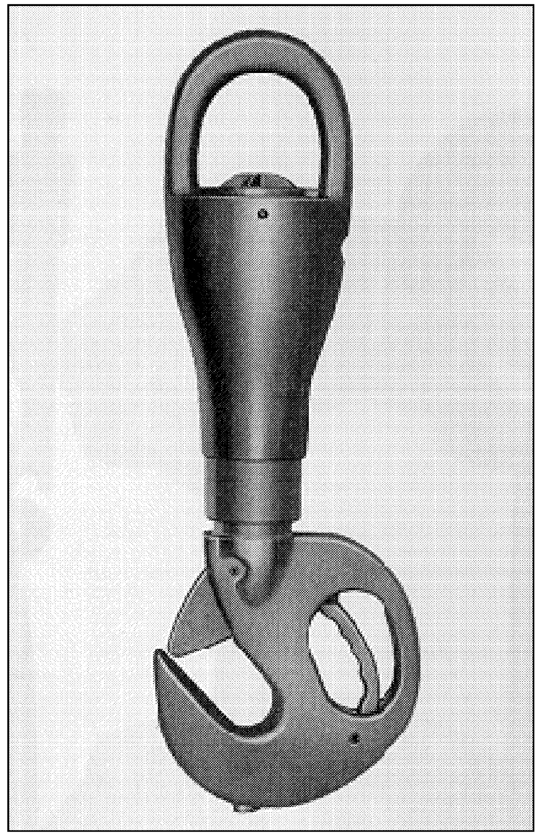

Figure 6. A snap-in spring lift rod hook.
(courtesy of Trico Industries)

One of the most difficult decisions the lease pumper may have to make occurs when a pump refuses to be pulled out of the seating nipple. If the rods are new, they hang in an even row at the bottom in the derrick. The bottom pins line up. When pulling tension on the rods, the rods always stretch as the operator pulls a tension. If pulled too hard, their ability to return to the original length can be exceeded. The stretch is permanent. When these rods are hung in the derrick, it is obvious to everyone that they have been stretched. If the supervisor has placed the pumper in charge of overseeing the well servicing operation, the pumper has to decide whether the maximum recommendation on the weight indicator has been reached.

There are several options if a pump is stuck. The operator could be allowed to pull more tension but at the risk of stretching the rods beyond their ability to return to the original length. Alternately, the pumper could begin a stripping job, which means stripping out the rods and tubing and extending the pulling time and cost. If there is a safety joint in the rod string, the pumper may decide to disconnect the rod string at this point, and pull the rods and tubing separately.

For wells that develop pump sticking problems, many options are available that do not involve stretching the rods or having oil spilled on the location. A supervisor should be contacted for a final solution before risking damaging the rod string or beginning a more expensive stripping job.

B-5. Running the Rod String into the Hole.

If the pumper oversees running the rod string into the hole, a careful listing should be made as everything goes in. Even for a pump change, there may be differences in pump length. As the rod string is run in, the following should be listed:

- **Gas anchor.** Many production people recommend that the gas anchor be long enough to contain 1½ times the capacity of the pump. When very little bottom hole space is available, the gas anchor may be as short as six inches and contain many small holes along the sides and bottom. The pumper must know company policy and must know how long the tubing mud anchor is to make the gas anchor length decision.
- **Downhole pump.** When changing out a worn pump, the pump is taken out of the hole, laid beside the replacement pump, and the bottom of the no-go sections are lined up. If the new pump is eight inches longer than the one being replaced, the clamp on the polished rod will need to be lowered approximately eight inches, so that the pump will have the same spacing. This can be determined by comparing the pumps. Occasionally, the differences in pump lengths will necessitate removal or addition of a pony rod, or exchanging one length for another of a different length. The length of the stroke should be compared and noted on the replacement pump record. A complete description of the new pump needs to be entered in the record. This information will be essential if the pump needs to be fished out of the hole.
- **Pony rods and the pump record.** The first pony rod installed is the lift pony rod between the downhole pump and the rod string. It is listed in this position. New and rebuilt pumps are delivered with a description tag. This is always sent to the office attached to the rod tally sheet. If no changes are made in rods or tubing and the pumps are identical, no new tally sheets are necessary and the tag is simply attached to a sheet of paper giving the date and a brief explanation of where it was installed.
- **Safety release tool.** A safety release tool is next installed if one is to be used. Release instructions should be noted in the report.

- **Rod string.** The number of rods run needs to be counted and entered into the record. If it is a tapered string, the number of each size should be listed separately. Although a length is given, permanent rod stretch may change the length of the string by many feet.
- **Pony rods.** Additional pony rods are used just before the polished rod is reattached as needed to space out the well. Pony rods are available in two-foot lengths from two to twelve feet. Other special lengths may be encountered.
- **Polished rod and lift pony rod.** The polished rod is installed last, and the lift pony on the top may be left in position or removed. If it is removed, a coupling needs to be left on the polished rod to protect the threads (Figure 7).

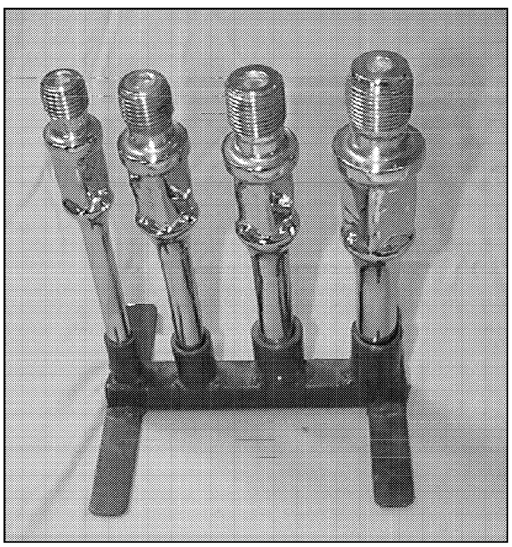

Figure 7. The threads of polished rods need to be protected if the lift pony is removed. Shown from left are 5/8-, 3/4-, 7/8-, and 1-inch rods.

- **Polished rod liner.** If used, a polished rod liner is placed over the polished rod. It needs to be at a minimum of 2-3 feet longer than the stroke length. This allows the rods to be lifted a small distance without pulling the liner out of the stuffing box and also allows a wick-type lubricator to be added. The longer the stroke of the pumping unit, the more polished rod liner is needed below the stuffing box to be able to pick up the string. It also needs to be long enough that the stroke length of the pumping unit can be extended.

After the rod job is finished. Before the rod record is sent to the office, a second copy is made. On this report, the listing order is reversed. This final sheet has rods listed in correct order from the top down, just as they are in the hole, and will be retrieved the next time that the well is pulled. This sheet will be forwarded to the office. A copy of this record is entered in the lease pumper's lease record book for future use.

Returning the well to service involves much more than just turning on a switch. Close attention must be given to the well when the fluid reaches the stuffing box so that packing tension may be adjusted, the polished rod liner checked for leaks, all valves opened to the battery, and all equipment set properly.

B-6. Fishing Parted Rod Strings.

Fishing parted rods is often required when the rod string has corrosion and pitting. The break usually occurs in the rod but can occur anywhere along the string. When fishing, rods are pulled, one additional rod and the fishing tool are added, and all are sent back down the well to "catch the fish." If the pump unseats and starts out, the brake is adjusted as needed to prevent grabbing or bouncing action of the well servicing unit brake when they are applied. Jarring may cause the overshot to release and drop the fished rods, possibly corkscrewing all of the dropped rods and parting the tubing.

Pulling tubing after dropping a rod string requires special considerations to prevent stripping parted tubing from over the rod string and leaving a loose rod string in the casing. These are especially hard to fish.

When fishing parted rods, the pumper will need proper fishing tools. One of the typical fishing tools is illustrated in Figure 8. There are several other styles that may be needed. There are several styles of rod boxes, and these may require special considerations. If the pumper's company owns its own fishing tools, they should be kept well greased and in a waterproof storage location. Appendix A addresses typical fishing problems.

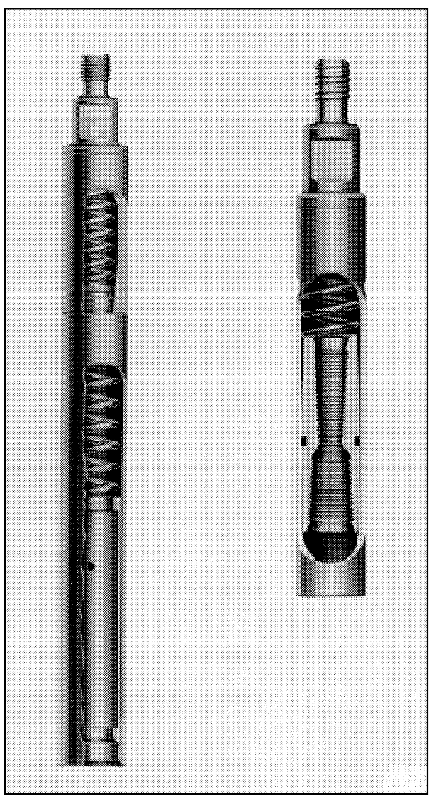

Figure 8. Typical sucker rod fishing tool.
(courtesy of Trico Industries)

B-7. Fiberglass Rods.

Fiberglass rods have become widely accepted because their quality has dramatically improved over the years. Fiberglass rods are usually 37½ feet long, so instead of pulling rods in triples on a telescoping well servicing unit as with steel rods, the lease pumper pulls them in doubles.

When installing fiberglass rods, a part of the string requires steel rods at the bottom to hold the string in a constant tension condition. These steel rods are installed immediately above the pump. This prevents the fiberglass rods from being operated in a compression mode.

Since fiberglass rods weigh one-third the weight of steel, a smaller gearbox can be placed on the pumping unit.

With the use of fiberglass rods, the travel length of the pump is dramatically increased and the weight of the rod string is decreased.

When laying fiberglass rods down or picking them up during a well servicing job, the lease pumper should always *tail* the rods by carrying them in or out rather than letting them drag or scrape on the rack.

If fiberglass rods are used, the lease pumper should obtain from the manufacturer or supplier a booklet of instructions for care and handling of fiberglass sucker rods.

Fiberglass rods are stored and handled much like steel rods, although a few special considerations should be taken. Fiberglass rods should be stored inside a warehouse, under a roof, and/or covered to prevent *fiber bloom* from occurring while they are in storage. While in storage for three months or longer, these rods should be shielded against ultraviolet rays by storing them inside or with a protective tarp.

The rods should never be thrown or dragged. When they are lifted, they need be tailed in. Wooden sills are less damaging than steel. When nicked, rod damage is permanent and the joint may need to be replaced. If a rod is cross threaded, a tap and die (Figure 9) should be run, the threads lubricated, and the joint screwed back together correctly.

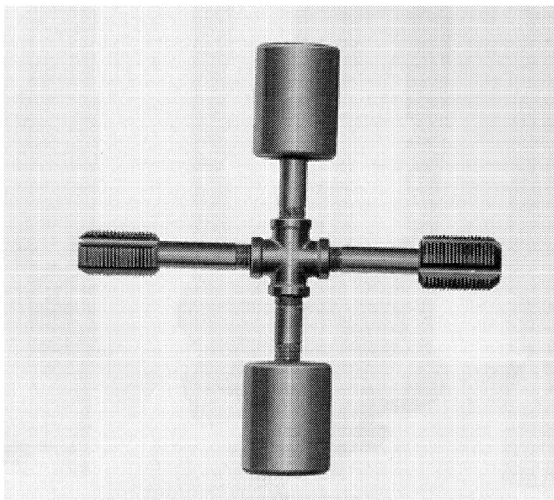

Figure 9. A tap and die for two rod sizes.

B-8. Downhole Pump Problems.

The most common reason for well servicing is to replace the pump because of valve wear or because the barrel and plunger clearance has worn excessively. This will occur on a fairly regular schedule and, by referring to the pump replacement record, the next service job can almost be predicted.

By studying the pump failure and understanding why each one failed, the pumper can occasionally make small changes such as using a better adapted metallic content or changing the pump arrangement. This may extend the life of the pump dramatically. Occasionally, double valving a pump may extend its life.

The shop doing pump repairs must also perform them accurately each time. Many repair shops may not be the most appropriate one for a job. They may not know the correct repair procedures or may not have the proper parts for servicing. For example, if a replacement barrel has been used that is too long it can place additional space between the two valves and promote gas locking. Sometimes when a pump is repaired on a "while-you-wait" basis, substitutions may be made for the correct replacement repair parts. This can cause shorter pump life. These types of repairs should be avoided.

The pumper should always search for ways to reduce the necessity of pulling rods and try to lower lifting costs. This section contains only a small sampling of the information that is needed about rods and pump repairs.

The Lease Pumper's Handbook

Chapter 17
Well Servicing and Workover

Section C

THE TUBING STRING

C-1. Tubing and Casing Perforation.

The relationship of casing perforations to tubing perforations is important to the performance of the well, whether it is a flowing well or produced by artificial lift. The lease operator must know if the tubing perforations are above or below the casing perforations or at the same level (Figure 1). This can be critical as to how much oil the well produces and the problems encountered.

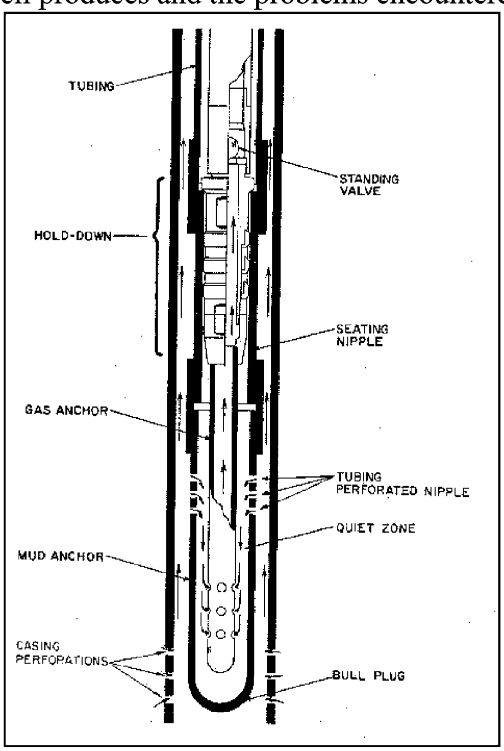

Figure 1. Relationship of well perforations.
(courtesy of Harbison Fisher)

For wells that produce a lot of scale, production personnel operate under different philosophies. One school of thought is that the higher the tubing perforations can be raised above the casing perforations and still achieve a satisfactory daily production, the less the scale will break out of the water in the tubing and flow line. Some companies raise the tubing perforations a few feet above the casing perforations, while other companies move them much higher.

Some operators maintain that if tubing perforations are placed even with or lower than the casing perforations, the reduction in reservoir pressure will increase daily production, resulting in increased income to solve the additional production problems.

Other companies place the tubing perforations below the casing perforations even if it results in a tubing arrangement where the tubing has no mud anchor. A shop-made two-foot perforated joint is used. The joint is closed on bottom and has dozens of ½-inch holes drilled into it. A collar is used to screw it directly under the seating nipple. This reduces the length of the pump gas anchor to one foot or less. Companies favoring this method maintain that it gives the highest daily average production.

The most typical tubing arrangement is to place the tubing perforations a few feet above the casing perforations. This maintains a small amount of liquid against the formation, instead of having a drained or dry matrix area at the bottom of the hole.

The lease pumper should know the company preferences, and a supervisor is usually able to provide this information.

C-2. Selection of Tubing Quality.

Tubing is available in many different wall thicknesses and qualities of metal. Typical tubing ratings include:

- **H-40.** This is the most economical tubing and is used on wells that are not very deep.
- **J-55.** Most medium depth wells use this tubing. It will be found in wells up to approximately 7,000 feet deep.
- **C-75.** This tubing is not quite as common but gives dependable service where pipe better than J-55 is required.
- **N-80.** This pipe gives very good service in wells to approximately 12,000 feet or more in depth.
- **P-105.** This is an example of the heavier duty pipe needed for wells that are drilled deeper, where high gas pressures are encountered.
- **Additional tubing ratings.** Additional classifications go from x-heavy line pipe on the lower end to 110, 125, 140, 150, and 155 on the upper end. With wells exceeding 20,000 feet, special pipe has been developed.

C-3. Tubing Lengths and Threads.

Tubing is an extruded seamless pipe that is sold in random lengths from 28-40 feet (Figure 2). It is measured with a hundredth of a foot tape. By joint selection, a string of pipe can be made up to any specific length. Pup joints are available in two-foot increments up to twelve feet long. A mark may be stamped on the outside a few feet from the end to show its quality rating. The stamping may be a simple H, J, C, N, or P. On used tubing, this stamped number may be located after cleaning with a wire brush.

Threads may be round or V-shaped, with 8 round serving as the standard thread today. Round threads are hot rolled into the metal and are much stronger than the older V-thread style. Changeover couplings are available when different threads are encountered.

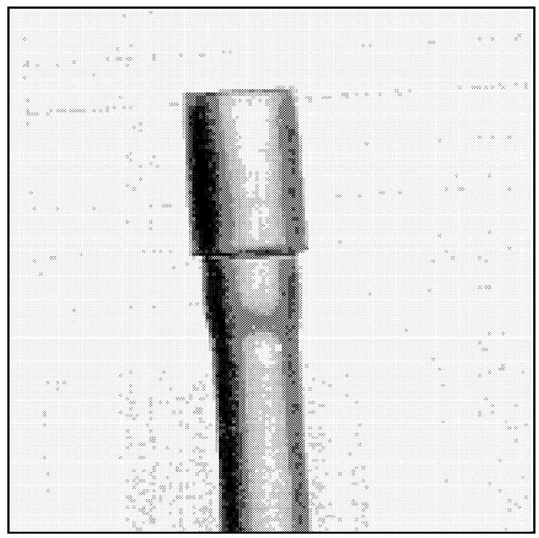

Figure 2. The end of a joint of tubing showing the upset end and the tubing collar.

C-4. Measuring Line Pipe and Tubing Diameter.

New oilfield workers sometimes have trouble understanding the sizes of pipe and should memorize the following two rules:

- Line pipe is measured by inside diameter because it is associated with production volume.
- Tubing is measured by outside diameter because this is the inside diameter of lifting tools needed to run tubing into the hole.

Pipe used on the surface for flow lines and for constructing tank batteries is usually referred to simply as *line pipe* and is always measured by *inside* diameter. For example, 2" line pipe has an inside diameter of 2".

On the other hand, 2-3/8" tubing has an inside diameter of 2", and an outside diameter of 2-3/8". When 2-3/8" tubing is used for flow lines or other high- or low-pressure applications on the surface, many companies will refer to the pipe as 2" line pipe in their records. This does not create a problem when joints are measured. Common sense will dictate if it is tubing being used on the surface because line pipe for oil fields is usually 25 feet in length and tubing is longer.

Line pipe and tubing comparison.

- 2-3/8 inch tubing is 2 inch line pipe.
- 2-7/8 inch tubing is 2½ inch line pipe.
- 3½ inch tubing is 3 inch line pipe.
- 4½ inch tubing is 4 inch line pipe.

Smaller tubing is also available with an inside diameter of ¾", 1", 1¼", and 1½", as well as streamlined special sizes. Other special sizes are reviewed in Appendix D.

C-5. Pulling and Running Tubing.

During tubing make-up, care must be taken that the correct power is applied. If the joint is made up too loose, it may leak, and, if too tight, it expands the coupling and damages the threads. When standing the pipe in the derrick, care must be taken to prevent damaging the threads.

Dropping rabbits through tubing. When running new or replacement tubing into a well, a *rabbit* is always dropped through the joint to be sure that it is fully open. A standing valve containing the no-go section can be used for this. This will identify scaled or out-of-round joints, because the rabbit will hang up and fail to fall through the joint. It is preferable to identify the problem before the joint is run into the hole.

Tubing is usually broken out and made up with hydraulic tubing tongs. For some work, mechanical tools such as *crummies* are used and are available on well servicing units.

The advantages to hydraulic tongs over hand tools are obvious. The desired torque can be dialed into the tongs' power settings and additional or less power is available on demand. Correct pressure when running pipe is an assurance that threads will not be damaged on make-up.

C-6. Identifying and Recording the Tubing String Components.

The mud anchor. The mud anchor is the first joint run in the hole. It is usually a full joint with a tubing bull plug on bottom. When the tubing is pulled, this joint will usually contain several feet of sediment, formation, or drilling mud and will be emptied. The mud anchor also protects the gas anchor on the rod pump.

Pipe length measurements. By joint selection, a string of pipe or group of joints can be made up to a specific length. This is especially important when spacing gas lift valves or adjusting the total string length.

Perforated nipple. The perforated nipple may be two, four, six, or more feet long and is a pup joint with many rows of approximately ½-inch holes drilled through all four sides. Special combination mud anchor/perforated joints may be shop-made. The coupling or collar that connects each joint of the tubing string together must be of equal or better quality than the tubing.

Seating nipples. A seating nipple is a short joint of upset thickness tubing that has a tapered opening at either end to allow the pump to seat into it and seal the opening between the pump and the tubing.

Seating nipples are only long enough to seat the pump as long as the seat will hold. For cup-type seating pumps, it is less than one foot long. A longer seating nipple is available that is long enough to be reversible. If the seating surface becomes scratched or damaged, it can be turned upside down and a new seat is available. Mechanical-type seating nipples may not be reversible.

Packers, holddowns and safety joints. Records must contain specific information about special equipment that may have been installed such as packers, holddowns, and safety joints. This may be brand, model, serial number, method of how to set the tool, and how to release and remove it. For example, if a 25-year-old tool is removed, fished, run, or re-dressed, records are needed that must supply identifying information

The tubing string. Tubing is a random length string of pipe with each joint measuring from 28-40 feet long. When measured, the tally sheet must indicate if it is measured overall or with the 1½ inches of thread left off. This changes the measurement of the string length by 15 feet per 100 joints. The third and most accurate method of measurement is taken when pipe is hanging from the elevators, measuring from the top of the collar to top of the next collar with the slips removed. This gives the installation length.

When loading the string from the storage yard, some companies measure the pipe overall, including thread, but remove the thread measurement when running it into the hole for perforation correlation reasons.

If the string has problems and is being removed after many years, the pumper needs to know exactly what comes next and have an exact description. For this reason, pipe is always run back into the hole in the same order that it was removed.

Pup joints. When all of the full-length joints that can be run are made up, the final tubing spacers added are pup joints. Pup joints are available in two foot increments from 2-12 feet long. One and one-half foot as well as three-foot joints may be available. As many pup joints as necessary will be added until tubing perforations are at the correct depth in relation to casing perforations.

Wellhead hangers. The final item added in the tubing string is either the tubing hanger or the slips, according to the wellhead style. Another final act is to set the packer or latch onto the tubing holddown to prevent tubing breathing. It may also be necessary to pull a tension on the tubing.

C-7. Typical Tubing Problems.

Typical tubing string problems include split collars, holes caused by corrosion, and split tubing (Figure 3). With such problems, a well may stop producing fluid, even while showing good pump action from the bleeder.

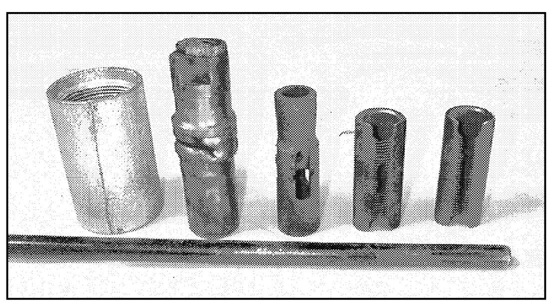

Figure 3. A split collar, damaged brass pump part, corrosion damage, and two worn sucker rod boxes.

Leaks or production problems can also be confirmed by placing a pressure gauge in the bleeder valve, closing the wing valve, and pumping against a closed-in system. This procedure needs to be coordinated with two people, with one standing at the electrical switch or clutch and the other observing the gauge. This procedure can also clear debris out of a pump valve. For safety reasons, the lease pumper should never stand directly in front of a gauge when it is being pressurized.

Split collars and holes in tubing. These problems usually result in no production at the bleeder and are relatively easy to locate. A typical solution is to mix a small amount of tracer material such as aluminum paint in five gallons of diesel fuel or kerosene, and pour it down the tubing. As the well is pulled, the leaking joint can be identified by observing the tracer material or aluminum paint on the outside. After identifying and replacing the leaking joint, the pipe is run back into the hole, and the well placed back into production. Normally only one hole will be found.

Standing valves. A standing valve can be dropped into the tubing to seat in the pump seating nipple in situations where the hole in the tubing is difficult to locate. The hole is filled with fluid, pressure applied at the surface, and the tubing pulled. When fluid is reached or the tracer fluid is observed, it should be possible to locate the hole or split joint.

After the problem has been solved, the standing valve can be retrieved with the sand line and an overshot, then the pipe can be run back into the hole and the well placed back into production. A good standing valve such as the one shown in Figure 3 will allow the pumper to release the fluid weight before having to unseat it. This reduces the pressure needed to unseat it.

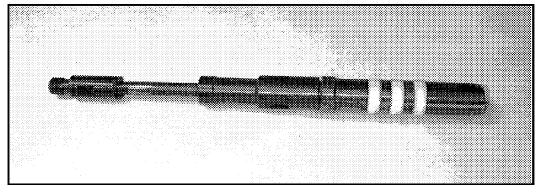

Figure 4. A 3-cup standing valve from Harbison Fischer.

Split tubing and hydrotesting. Occasionally a split joint of tubing can be very difficult to locate. Oil may or may not be produced. The bleeder valve may show good production, but no liquid travels to the tank battery. A standard pumping flow line pressure check at the bleeder valve can confirm the possibility of a split joint. If monthly flow line pressures are not taken and recorded, the pumper cannot know what the pressure should be. Consequently, there is no basis of reference to identify a problem in this manner.

When all other methods of locating the tubing leak fails, one option remains. The tubing can be hydrotested. When hydrotesting, the full tubing string may be pulled and two joints tested at a time under high pressure as the tubing is run back into the hole. A special two-person crew and a specially equipped truck are brought to the lease. Three sucker rods are used to rig up the 75-foot long tool. As each "double" of tubing is dropped into the hole, it is pressure tested. The tool is pulled up each time, so is just below the slips while testing. It is considered too dangerous to the safety of the floor crew to test above the slips.

Many other methods may be used when trying to solve problems of poor production.

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Chapter 17
Well Servicing and Workover

Section D

WIRE LINE OPERATIONS

D-1. Five Uses for Wire Lines in Servicing Wells.

There are many styles of wire line available for use in the oilfields. The wire used is generally either solid wire or wire rope. There are five major purposes for wire lines around well servicing units.

Surface uses:
- Guying the pulling unit
- Line from drum to blocks

Downhole uses:
- Sand lines
- Solid wire lines
- Electric lines

D-2. Wire Rope.

Wire rope consists of strands of solid wire braided in specific patterns around a core to create various shapes (Figure 1). These parts of a wire rope are shown in Figure 2.

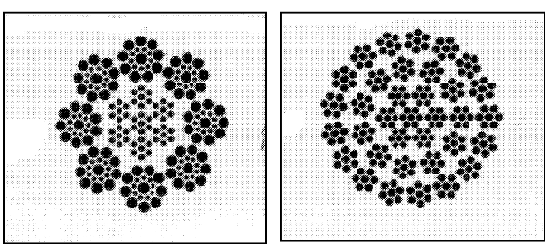

Figure 1. Typical shapes of wire rope.
(*courtesy of Williamsport Wirerope Works, Inc.*)

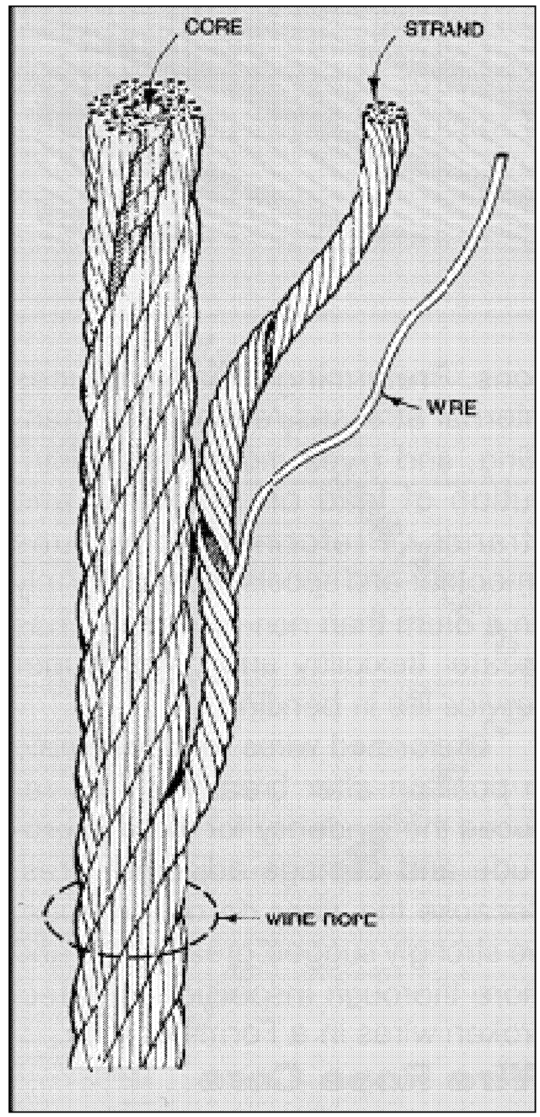

Figure 2. Parts of a wire rope.
(*courtesy of Williamsport Wirerope Works, Inc.*)

Wire lines are available in right- and left-hand lay or twist (Figure 3).

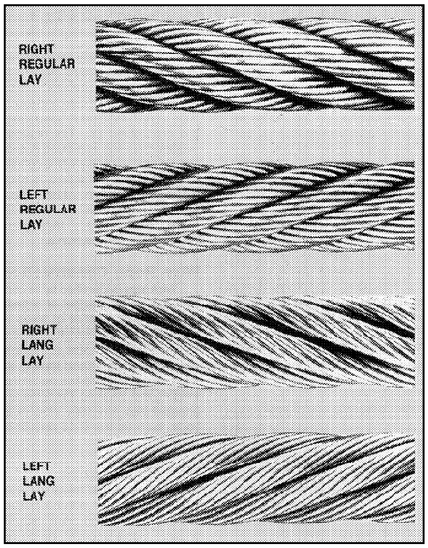

Figure 3. Several types of wire rope lay. (*courtesy of Williamsport Wirerope Works, Inc.*)

The correct method of measuring lines is shown in Figure 4. This is important when selecting wire rope accessories such as clamps, blocks, and sheaves.

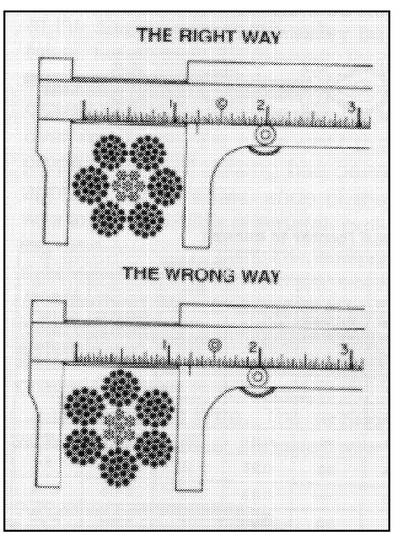

Figure 4. Methods of measuring lines. (*courtesy of Williamsport Wirerope Works, Inc.*)

As illustrated in Figure 5, wire ropes can be damaged. Extreme care must be used to prevent damage to the lines. Guy, sand, and all other lines must be protected. The lines should always be inspected prior to use.

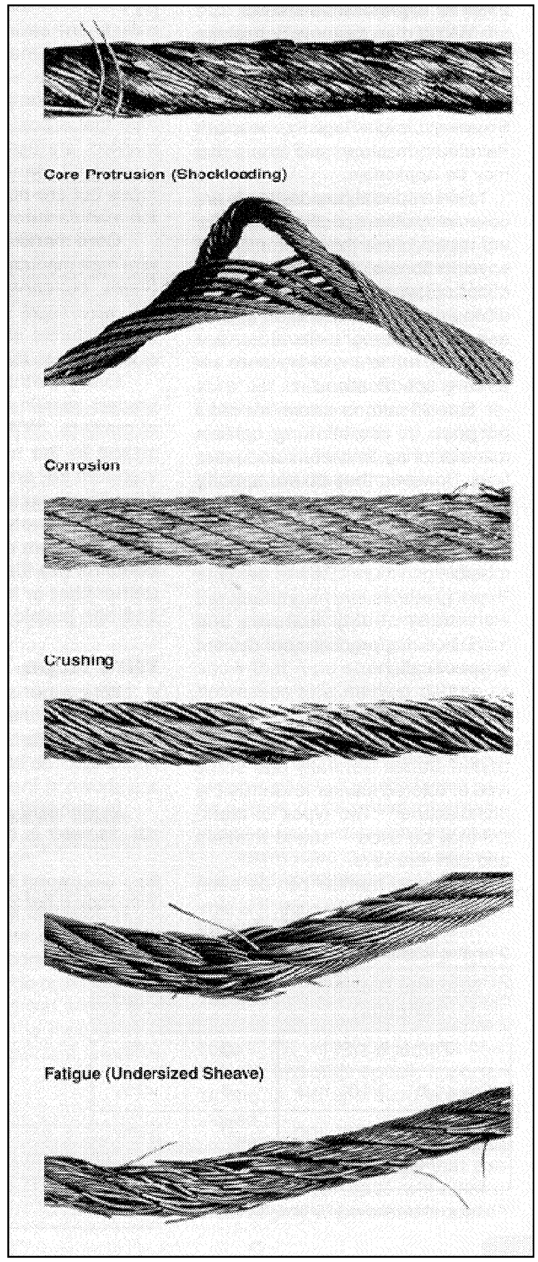

Figure 5. Typical wire rope problems. (*courtesy of Williamsport Wirerope Works, Inc.*)

D-3. Functions of Guy Lines.

Wire rope used for guy lines is usually right-hand regular lay. This line is available in many sizes but is smaller than the lines used on the drum. When purchasing guy lines, and the pumper should buy line that will not break under load and should check with the manufacturer to select the correct line and core.

D-4. Functions of Line from Drum to Blocks.

The draw works line used to drill an oil well is different from the lines used on a well servicing unit. The wire rope used for well servicing is rotation-resistant so that the elevators will remain in the same position while traveling up through the derrick, especially when using a single line. The lines are designed to be used on the surface. When purchasing a new line, the pumper will need 500-800 feet or more in order to lower tubing blocks from the crown to the floor. A reserve amount needs to be stored behind the drum divider so that 20 or more feet can be periodically cut off according to the ton-mile schedule. This will extend the life of the line.

D-5. Sand Lines.

Sand lines are placed on the second drum of the pulling unit or on the drum closer to the cab. Many downhole services are performed by the well servicing crew using the sand line, so it must be long enough to reach the bottom of the hole. Some typical well servicing crew services are:

- **Swabbing fluids.** This operation involves dropping a swab down the hole and lifting fluid out to a vessel to remove it from the tubing to a holding tank. When completing a new well, fracing, or performing other operations, swabbing is necessary to clean up the well bore and matrix area. A satisfactory lubricator with the proper valves and accessories is needed.
- **Bailing sand.** As fluids are produced, sand may migrate from the formation and settle in the bottom of the hole. A sand bailer may be lowered to the bottom of the hole when the tubing is pulled on some wells and the sand bailed.
- **Cutting paraffin and scale.** The well servicing crew may cut paraffin and scale with the sand line with special tools (Figure 6).

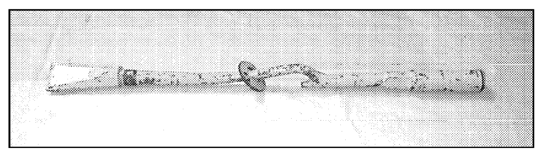

Figure 6. One style of paraffin scraper.

- **Running impression blocks.** Another function of the sand line is to run an impression block. When a *fish* or loose object in the hole is lost, the pumper must go fishing to try to retrieve it. When fishing, it is often desirable to run an impression tool in and set it down on the lost item in order to know how to grab hold of the object. A standard or hard impression block is a flat-bottomed tool made of lead. It resembles a flat-bottomed drill bit from a distance.
- **Running scrapers.** Before running a packer into the hole, the well servicing crew generally runs a scraper slightly larger than the packer to remove any scale or paraffin. This also checks for collapsed casing.

- **Pulling standing valves.** If problems are encountered while checking for or locating tubing leaks, a standing valve can be dropped into the hole and the tubing filled with water. As the tubing is pulled, the water level will drop to the level of the hole. When that point is reached, the leaking joint is replaced. The sand line can be run in the hole to retrieve the standing valve without having to pull the remaining joints.

D-6. Solid Wire Lines.

The solid wire line is a single strand of wire. It is run into wells to perform special tests and functions. Several sizes of wire are available, according the depth of the well and job to be performed. These jobs are generally tests or valve placement using a downhole tool usually referred to as a *bomb*.

Temperature surveys are run primarily to detect casing (or tubing) leaks, although they serve other needs as well. Temperature surveys are run each six months to one year to test for leaks in flowing wells. The leak will be detected by a temperature drop or decrease due to the expansion of the escaping gas.

Pressure surveys are run on a yearly schedule to determine pressure drop and remaining reservoir fluids. By taking the pressure drop and comparing it to the previous year's reading, the remaining fluids in the reservoir and the remaining life of the well can be projected. This is also an important factor in regulating the effectiveness of gas injection and reservoir pressure maintenance. For flowing wells the date when artificial lift may become desirable is projected and funds to install it can be scheduled.

Directional surveys can also be conducted with a wire line while drilling a well. A clock in the survey bomb is set for a pre-determined time and the tool is lowered into the hole. After the appropriate time has lapsed, the clock will trigger the direction impression on a small bull's eye disk, rotate the disk 180 degrees, make a second impression, and retrieve the tool.

Solid wire lines are used to **run and retrieve special tools**, such as gas lift valves in wells with side pocket mandrels. The wire line machine is used to change gas lift valves, scrape paraffin and scale, and perform several other functions. There are several other uses for the small solid line such as running, perforating, and retrieving blind plugs.

D-7. Electric Lines.

Electric lines are used for many purposes in oil wells. When a well is being drilled, open hole survey logs are run to evaluate formations that are being drilled to determine if hydrocarbons encountered have enough volume to make a commercial well. After the casing has been run, cased hole logs can also be conducted. When the casing is cemented, this is usually followed with a cement bond log.

In production operations electric logs are run for many purposes. All wells are perforated by use of electric lines. They are also used for measuring depth, conducting temperature and pressure surveys, measuring pressure drop during fracing operations, running tracer surveys, and many other purposes.

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Chapter 17
Well Servicing and Workover

Section E

WELL WORKOVER

E-1. Well Workover Operations.

When a well has a problem more serious than changing out a pump, repairing a hole in the tubing, fishing a parted rod, or other basic well service need, it is referred to as *well workover*. This section highlights a few of the well problems and necessary workover procedures that may be encountered.

Killing flowing wells and blowout preventers. In most cases when a flowing well is to be worked over, the well must be *killed* before service can begin. This is usually done with a transport truck similar to the truck that hauls oil or water. Wells can be killed with oil, formation water, or treated water. Water is used when it will not damage the formation. After the kill fluid has been injected and until the injected fluid exerts more downward pressure than bottom hole pressure, the well will sometimes go on vacuum. Water is injected until the desired amount has reached bottom. At some point, all fluid movement stops. The well is dead and can be worked on.

With flowing wells, the injected fluid slowly dissipates into the formation, and the well begins to flow again after a period of time. This means the volume of kill fluid injected is proportional to the work being performed. The pumper must not only begin the work, but must always be prepared to close the well back in if it begins to come back to life or flow.

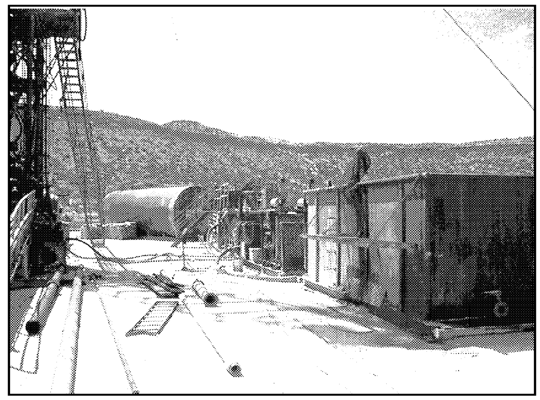

Figure 1. Specialized equipment for well workover, including a water tank, hydraulic power for rotating head, mud pump, and mud pit.

If a blowout preventer or *BOP* is to be installed, the crew needs to be prepared for a quick transfer in removing the Christmas tree and the BOP installation.

If water is injected as a killing fluid, potassium chloride may need to be mixed with the water to prevent formation hydration. This is especially true if any shale is present in the reservoir. Enough water is injected to kill the well for the needed time before it may disperse in the formation and allow the well to begin flowing again. Swabbing will remove the load water to speed up the process.

Blowout preventers. A typical blowout preventer used for workover will usually consist of two sections. The upper section contains rams that fit around the pipe if it should become necessary to close them. The lower section contains blind rams that can be closed if necessary whenever the pipe is out of the hole. This will permit control of the well if it should begin to flow while the pipe is in the hole or if it is out or on the bank.

E-2. Stuck Pipe.

Stuck pipe can be caused from several problems, such as salt bridges, scale deposits, and sand accumulating in the bottom of the hole. The pumper does not usually know that the tubing is stuck until tension is pulled on the tubing and it cannot be moved.

Salt bridges. Salt bridges can occur on a pumping well whenever it pumps many cycles a day and the water being produced is extremely salty.

While the well is off between pumping cycles, the salt water rises in the casing, and when pumping, water is pumped down to a level near the tubing perforations. Each time this is done, a thin layer of salt may adhere to tubing and casing walls. Since this occurs thousands of times, these thin layers build up until salt bridges the area between the tubing and the casing. If this area bridges completely, gas cannot be released to the tank battery, and the pressure near the well bore increases to formation pressure. Oil production will fall dramatically and eventually cease.

To solve this problem, fresh water may be dropped down the casing annulus at scheduled intervals to dissolve the salt, reduce the buildup, and prevent bridging.

Scale deposits. Scale is carried into the annular space dissolved in water. It is deposited on the walls of the casing and tubing much in the same way as salt. As pressure and temperature are lowered on the water, the suspended scale breaks out. This scale can bridge the tubing in the hole as well as stick the pump and reduce the size of the tubing to make it too small to be removed. The tubing may need to be pulled out of the hole, laid on a rack, and reamed or drilled out.

With flowing wells a special coating on the tubing can reduce scale buildup. With pumping wells it may become necessary to circulate a scale-reducing chemical down the annulus. This may be done periodically through batch treatment or pumped into the annular space daily.

Sand control. Sand can be periodically bailed from the well or the well may be gravel packed. Screened perforated joints may also be installed to filter out the sand. If sand is a problem, a maintenance program will need to be developed to meet the needs of the lease.

E-3. Drilling with Tubing.

On some leases, it may be necessary to drill out scale in the bottom of the hole periodically. The tubing in the well can be utilized as drill pipe by the use of a rotating head and a power swivel. Some operators perform this service to their wells as needed to restore production.

E-4. Stripping Wells.

Stripping a well is a process of pulling the rods and tubing simultaneously. This begins by breaking the rod string out by setting the string down, engaging the pump clutch or notches, and turning the rods to the left. After many rounds of turning, the rods will break at some point. Rod tongs or a wheel may be used for this purpose. The part of the rod string that breaks loose is removed. Tubing is pulled until the rods are reached, and the procedure repeated until all of the rods and tubing has been stripped out or removed.

All downhole pumps have a clutch or engaging notch built into them for this purpose. With most pumps, there is a clutch on the bottom only, so the rod string must be lowered until this off-set notch assembly engages. The rods to the left can be turned to break them out. Other pumps have a clutch assembly on both the bottom and top, so the rod string may be lifted to engage it and break the rods loose. The location can be determined in a few minutes by raising or lowering the rod string and turning it until it engages.

Problems are encountered by losing oil through spilling it on the ground, lighter oils *heading* (flowing up out of the tubing) and flowing, and even blowing out and covering the rig and location with oil, causing environmental damage and a major equipment clean-up. Special equipment and procedures such as swabbing can be used to prevent this contamination.

Safety joints can be installed in the rod and tubing string to unlatch and pull most of the string easily. This procedure presents special problems such as the tubing safety device turning loose while trying to unlatch the rod safety device.

When stripping a well, some lease pumpers attempt to turn the rod and casing string by using a rod wrench with an extension or ***cheater***. This is a dangerous practice and should not be attempted.

E-5. Fishing Tubing.

When fishing a loose string of tubing in the hole, there may be problems latching onto the broken part that is in the hole. To determine the problem, an impression block is run. It may be necessary to design and make a special fishing tool for catching the fish.

Running impression blocks. When an impression block is run, the type of block to be used must be selected. Rental blocks are usually made of a soft lead, but a softer material may be needed to get a deeper impression. This are made of tar.

Hard impression blocks. When running a lead impression, the tool is lowered into the hole by running it onto the tubing string. The amount of pressure applied and the manner of obtaining the impression depends on the weight of the tubing string being lowered. The lighter the string, the faster it is lowered to strike the fish to obtain the impression. After examining the impression, a decision is made as to the best method of fishing.

The soft impression block. A soft impression block is usually a shop-made tool. A hole is drilled in the neck of a swage, then roofing tar is poured into it with a short crown. After lowering it into the hole on three or four joints of tubing, the sand line is attached. It can be run to bottom quickly, and very little pressure is necessary to receive a deep impression.

Fishing tools. There are many types of fishing tools that can be rented for fishing. A spear works well for a jagged opening, and an overshot with a milling surface can be used to catch a round fish. When the fish is too far to one side, a shop-formed offset finger can be made to wrap around the fish by turning the pipe. The local tool rental company also has fishing specialists available to supervise special fishing jobs.

E-6. Fracing/Hydraulic Fracturing Wells.

There is an abundance of new technology available for use when stimulating wells through a fracturing process. This requires applying enough hydraulic pressure to the rock formation to split the rock, then pumping sand into the fracture, propping the fracture open to allow oil and gas to flow to the well bore.

Several fluids are used to carry the treatment to the formation when fracing wells. The easily available fluids are lease water, fresh treated water, and crude oil. Several petroleum-based fluids are also used.

Sand frac is a common procedure using natural and manufactured agents. The formation is fractured and spread open, and several sizes of a special sand are pumped in as a propping agent. Rock salt, which is water soluble, and moth balls, which are oil soluble, may be added to block receptive passages during the fracing process to extend the fracture deeper into the formation and improve the final results.

With acid fracing, an acid is pumped into the hole under high pressure to open the rock and etch rock away to permanently open the formation. A time neutralizer is added to make the acid safe to produce back after the job has been completed.

Other special fracs may be performed such as an explosive heat frac. The explosion will back flush the formation toward the reservoir. The heat is especially effective in shallow, low bottom hole temperature wells where tars, paraffins, and other firm petroleum products plug the formation and cut off production. A water blanket is added above the charge to add weight and force the heat into the formation.

E-7. Pulling and Running Tubing Under Pressure.

By using two sets of blowout preventers with a space nipple in between, a well can be worked over without killing the well. It is also possible to work over a well while it is producing.

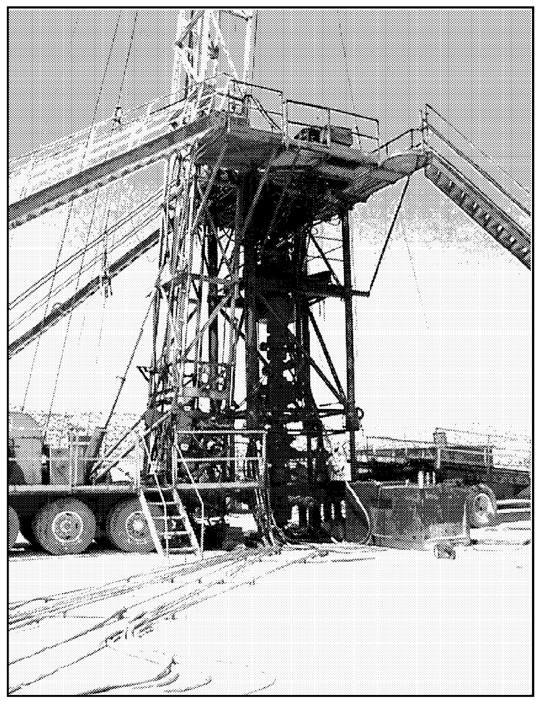

Figure 2. A well workover rig with a double blowout stack so that workover can be performed while the well is still under pressure and even while it is producing oil and gas.

The Lease Pumper's Handbook

CHAPTER 18

GAS WELLS

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Chapter 18
Gas Wells

Section A

INTRODUCTION TO NATURAL GAS WELLS

Many people will casually refer to all the wells in a field as ***oil wells***. When it is necessary to specify exactly what type of hydrocarbons are being produced from a designated well, the designations may become ***oil well*** or ***gas well***.

A-1. Understanding the Gas Well.

The typical production from a gas well is primarily natural gas, often accompanied by liquid hydrocarbons and water. The hydrocarbon liquid is usually referred to as ***condensate*** or ***distillate***.

- **Condensate** implies that the liquid was already in a vapor form, and only one step is required—**condensing**—to change the fluid from a gas to a liquid. The condensing may have occurred as the vapor was leaving the formation, as it flowed up the tubing, as it passed through the processing equipment, or even as it traveled through the gas transmission pipeline. The condensed liquid may be as clear as tap water.
- **Distillate** implies that a two-step process occurs where the liquid is transformed from a liquid state to a vapor, then condensed back to a liquid form. This is a common purifying process that results in the production of a crude or casing head gasoline that contains little or no oil.

A-2. Wellheads and Christmas Trees.

A typical medium- to low-volume gas well has a double master gate and a safety valve next to the wing gate. The wellhead valves are often referred to as **gate valves**, which is often referred to merely as a *gate*. The upper master gate is always used when it becomes necessary to shut in the well. The lower one is in reserve so that if the upper valve fails, the lower one can be closed to make it possible to safely close the well in to repair the upper valve. A gas well may or may not have a packer installed, depending on how the tubing string is installed.

A-3. Reservoir Characteristics of Gas Wells and Gas Production.

A gas well is any well that produces a lot of gas and very little oil. The oil is usually a very light crude with a high viscosity or API gravity rating—that is, the weight of the crude as compared to the weight of a similar volume of water. An oil well usually produces a heavier crude with a lower viscosity and produces a higher percentage of oil versus gas. The gas produced from an oil well may be low or high volume, depending on the placement of the well in the reservoir and where the well is drilled.

Condensate may leave the formation as a liquid or as a gas. If it leaves the formation as a gas, it may begin condensing to a liquid as it travels up the hole and the pressure and temperature decrease. The fluid falling back down the hole can affect production dramatically. Gaseous condensate with a lower hydrocarbon content may remain a gas. Plunger lift is widely used to assist in moving these liquids to the surface.

A-4. Producing the Gas Well.

Production in gas wells is measured in cubic feet. A well may be capable of producing less than a hundred thousand cubic feet of gas a day or have a potential of over one hundred million cubic feet a day. Each well is different in volume of production, pressures, condensate, and water production. The support equipment will change according to need.

In most cases, gas from the well is delivered to a transportation pipeline operated by a gas purchasing company. The gas purchasing company will accept gas as long as a market is available. In the event of oversupply or in emergency situations, the gas purchasing company representative may close the well in as needed. Occasionally a gas well may be shut in for an extended period of time. This seldom occurs with an oil well or the gas produced in conjunction with producing oil. Thus, producing natural gas as a by-product along with crude oil is a more stable product sales market.

A-5. The Wellhead and Safety Devices.

A typical medium- to low-volume gas well as pictured in Figure 1 has a double master gate and a safety valve next to the wing gate. The upper master gate is always used when it becomes necessary to shut in the well. The lower one is in reserve so that if the upper valve fails, the lower one can be closed to make it possible to safely close the well in to repair the upper valve. A gas well may or may not have a packer installed, depending on how the tubing string is installed.

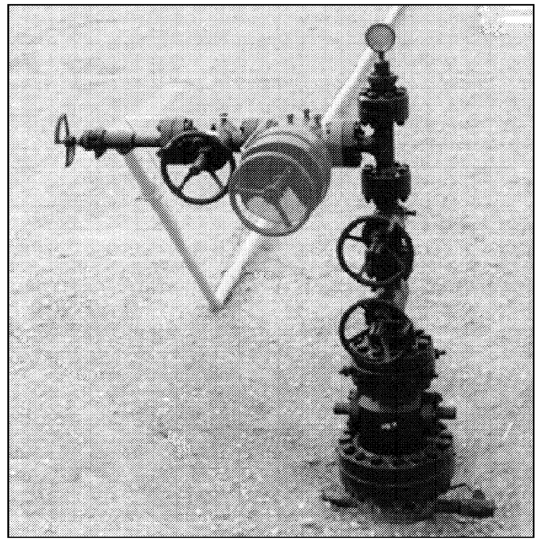

Figure 1. A gas well with a dual or double master gate valve, safety valve, wing valve, and variable choke.

A gas well may have two types of safety shut-in controls. Each serves a different purpose, although the results can be similar in that both systems shut the well in.

The tubing safety valve. The safety valve installed downhole in the tubing will shut in the well in the event the line should break and a large volume of gas is being discharged. This safety valve is checked on a regular schedule to ensure that it will close in the event of an emergency. A wireline company sets, services, and retrieves these valves. Many companies do not install the downhole safety valve for medium- and low-volume wells. A hydraulically opened valve can be installed such that the well automatically shuts in whenever this pressure is reduced. This system has been used extensively offshore, even for flowing wells.

The surface safety valve. The surface safety valve signal to shut in the well is usually controlled at the high-pressure separator. A hi-lo valve with hi-lo pilot and bypass will shut the well in on either high or low pressure of the sales line. A small stainless steel tube leads from the safety valve on the Christmas tree to the control valve at the separator.

The picture of the gas wellhead in Figure 1 shows the surface safety valve. Both Figure 2 and Figure 3 show the same type of control.

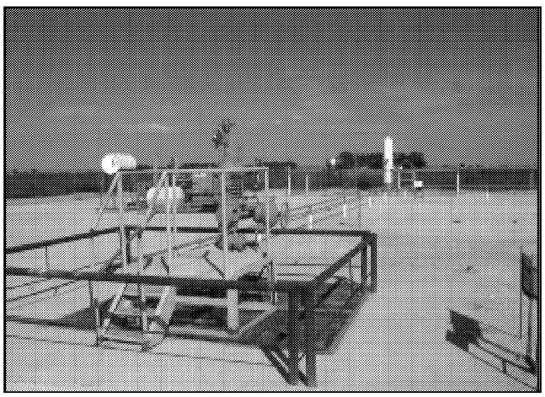

Figure 2. A small gas well with a three-phase separator and compressor in the background.

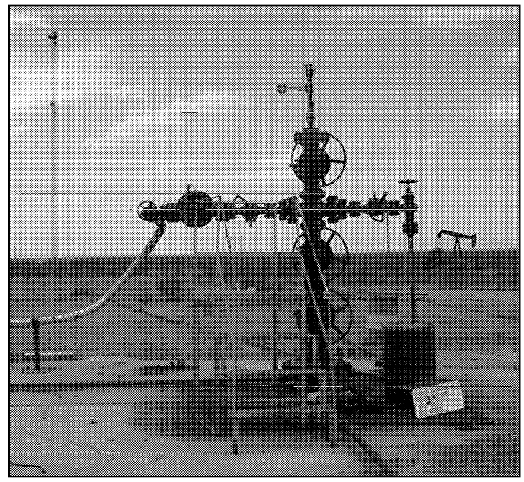

Figure 3. A high-volume gas well.

The gas well shown in Figure 4 has no safety valves or even dual master gates. It has been completed like any typical flowing well. This indicates very low production.

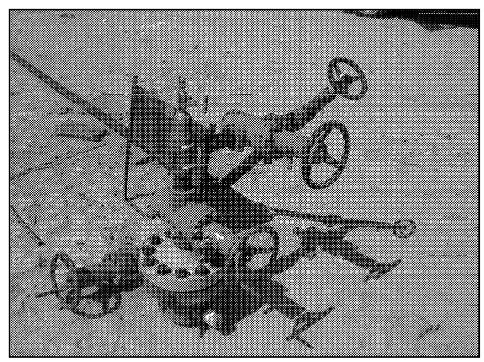

Figure 4. A low-volume gas well.

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Chapter 18
Gas Wells

Section B

FLUID SEPARATION

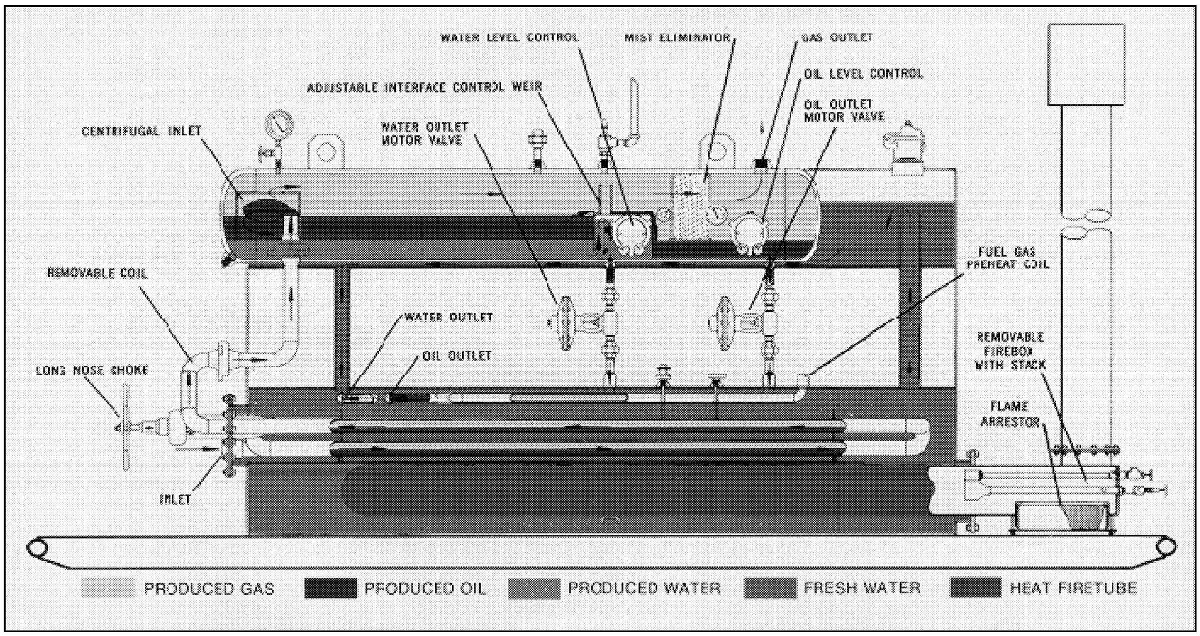

Figure 1. A high-pressure gas well separator that keeps the choke valve from freezing.

B-1. High-Pressure Gas Well Separators.

Several styles of separators are manufactured for use on gas wells. All of these separators operate at high pressure. A low-pressure oil separator is designed to operate on 100 pounds or less of gauge pressure. The gas well separator is usually designed to operate at 1,000 pounds pressure or more, with a test pressure of approximately 2,000 pounds.

To achieve this pressure, the diameter of the vessel is small, usually 24 inches or less, with a much heavier wall thickness. For safety, the sight glasses also use much heavier construction. The separator can always be identified instantly, just by observing the liquid level sight glass.

B-2. Three-Phase, High-Pressure Separation and Indirect Heating.

When the gas well has a very high pressure and the gas contains water moisture, the gas expands quickly coming out of the choke, becomes very cold, and begins forming ice inside the gas lines. Soon, the ice fills the line for several feet past the choke, the well freezes, and production of gas ceases. After a period of time, the ice will melt, and the well will begin to flow again. After a short time, the line freezes again. To solve this problem, a heated water bath unit was designed. This system is illustrated in Figure 1.

This unit has a heated container. The firebox heats the water, and then the water heats the gas and choke valve. The gas enters the water chamber, makes several loops back and forth, then goes through the choke. This hot gas keeps the ice melted at the choke and allows the well to produce. The produced gas then moves up, travels horizontally through the three-stage separator, and on to the dehydration unit for final clean-up and drying.

The fluids in the gas—the oil and water—are processed through the high-pressure separator. The water falls to the bottom is removed through the water outlet motor valve. It then flows to the water disposal storage tank. The oil flows over the water disposal unit and travels through the oil outlet motor valve to the distillate storage tank.

As water is lost by evaporation out of the atmospheric heat chamber, makeup water can be poured back in through the top of the hydrocarbon separation unit. When it has been determined that too much distillate is being sent down the gas line, a small low-pressure flash separator unit can be added to the unit to separate more distillate. It can increase distillate production.

B-3. Vertical Separators That Do Not Require Heat.

The vertical high-pressure separator pictured in Figure 2 is a three-phase design. The inlet line from the well enters the separator on the left side. The gas goes up through the center of the top and is directed to the dehydration unit. The two round float controls that are at the right front of the vessel regulate the height of the liquids in the vessel.

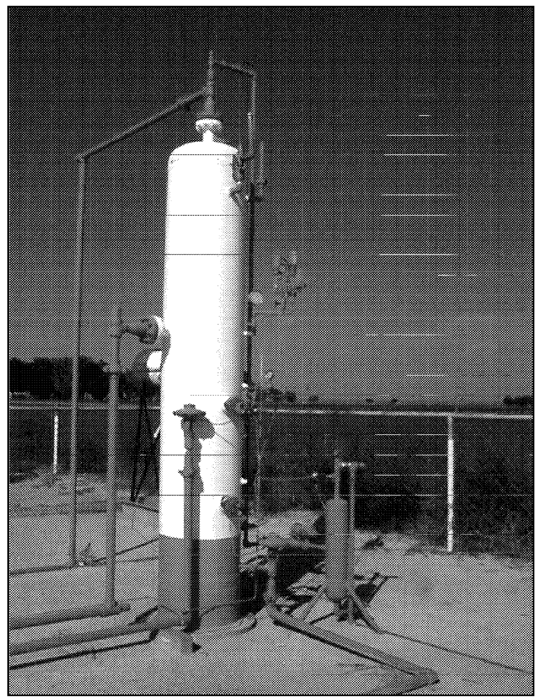

Figure 2. A high-pressure, three-phase separator.

The upper indiscriminate float controls the condensate level in the vessel. The pneumatic diaphragm control valve on the left front of the vessel dumps this liquid to the oil stock tank in the tank battery. The lower float control has a discriminate float inside the lower part of the vessel and dumps the water out through the pneumatic diaphragm control valve at the lower right side of the picture. These controls can be more easily identified in the close-up photograph in Figure 3.

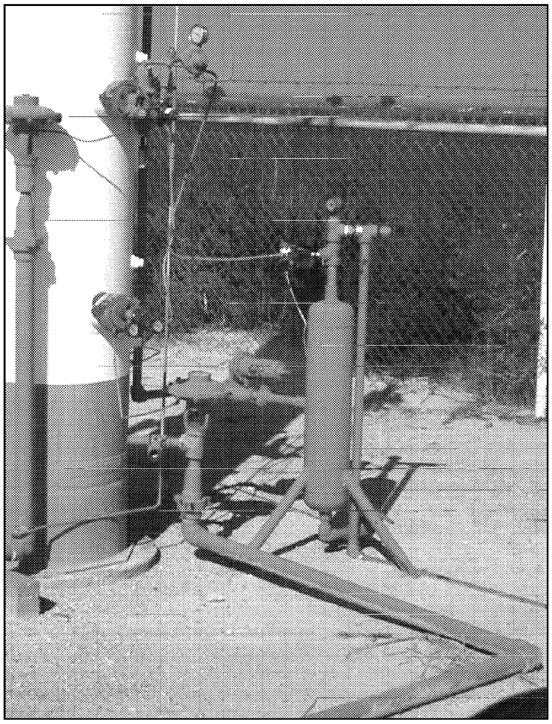

Figure 3. A closer view of the pneumatic condensate and water dump valves and a shop-made gas scrubber from Figure 2.

A high-pressure 1-inch line and regulator directs gas to the shop-made gas scrubber that sits on the ground at the right side of the picture. This scrubber removes any final liquids ahead of the pneumatic controls. Safety valves and rupture discs are also mounted on the upper right side.

The basic system for a small gas well that produces only trace amounts of liquid includes a small separator, a water holding tank, and a gas meter (Figure 4). This along with the well completes the total gas well system.

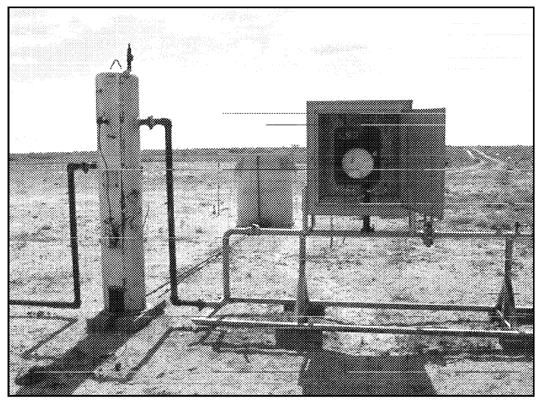

Figure 4. A basic gas well system for low gas volume and little fluid production.

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Chapter 18
Gas Wells

Section C

GAS DEHYDRATION

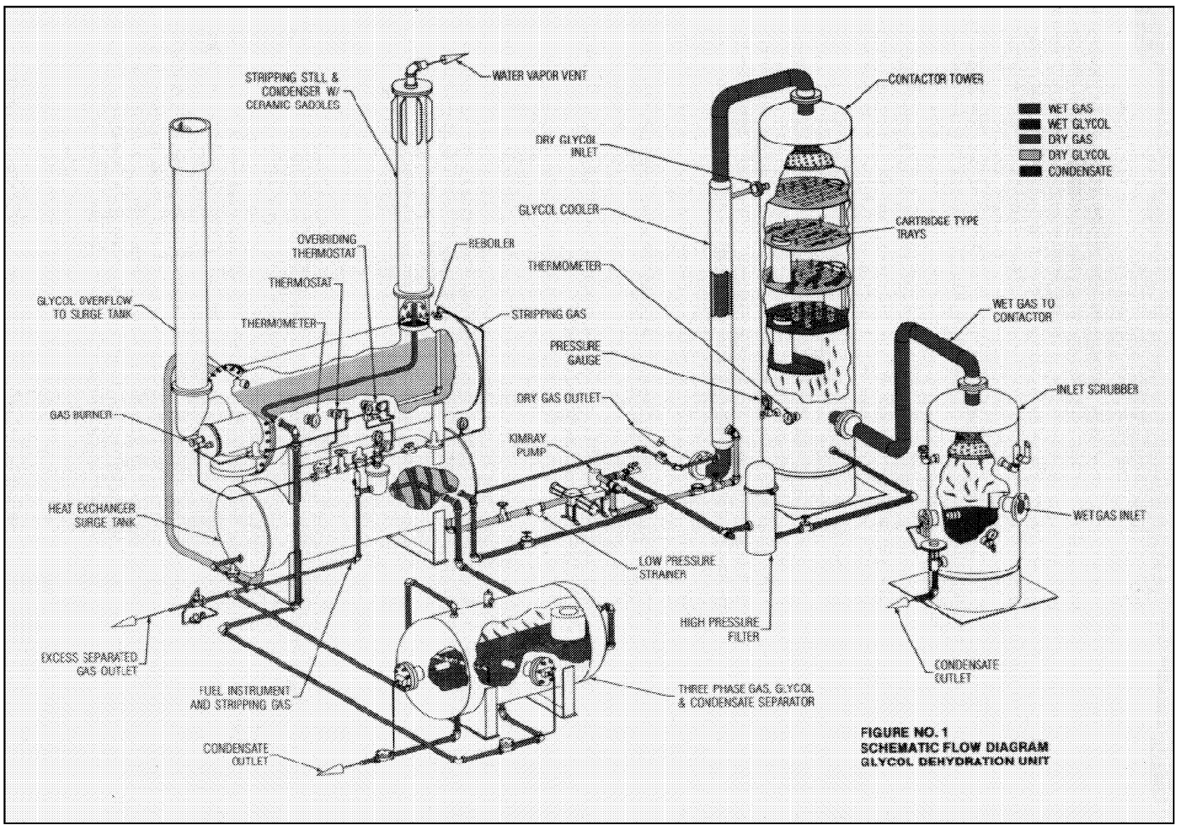

Figure 1. An glycol dehydration unit.

C-1. Gas Dehydration.

Gas, as it leaves the separator, will probably be saturated with distillate and water vapor. Gas in this condition is referred to as *wet* or *rich* gas. The purpose of the dehydration unit (Figure 1) is to reduce the level of the water and distillate remaining in the gas. After these vapors have been removed, it is referred to as *dry* or *lean* gas. The field glycol dehydration unit has other popular names such as the *stack pack* or *thermo pack*. As the gas leaves the dehydrator, it will still contain some moisture and distillate, but it will have a lower *dewpoint*, the temperature at which the gas will form condensation.

C-2. Operating the Dehydration Unit.

The dehydrator is part of the separator unit (Figure 2) and may use either ethylene glycol or tri-ethylene. In the following paragraphs, glycol is referred to but the same principles apply to a system using tri-ethylene.

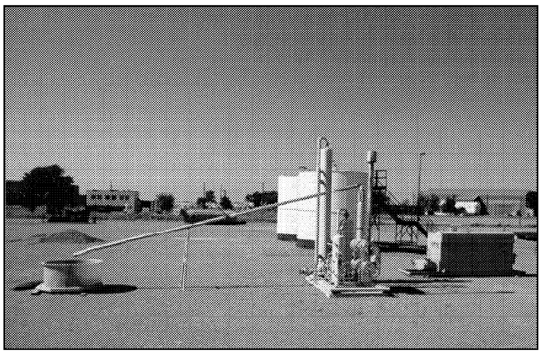

Figure 2. A separator unit with dehydration unit, a knee tub, and the water and distillate tank battery.

The inlet scrubber. The two-phase inlet scrubber (Figure 3) is the first vessel in the dehydration unit that the wet gas enters. The wet gas is divided into drier gas and liquid. The gas is diverted into a circular action, passes up through a stainless steel wire mesh mist extractor, then flows on toward the contact tower. The condensate (and water) that is stripped out of the gas is dumped to the distillate stock tank.

The contact tower. The contact tower (Figure 3) is the vessel that is designed to dry the gas. The gas enters the contact tower near the bottom through a chimney tray. The gas works its way up through bubble-type trays filled with ethylene glycol, which has a natural attraction to water. The glycol absorbs the water contained in the gas, and the gas passes up and out the top of the tower.

Figure 3. Note the inlet scrubber and contact tower in this view of a dehydration unit.

As the gas returns to ground level through the down-comer line, it passes through the glycol-gas heat exchanger where the outgoing gas cools the glycol coming into the contactor. The dry gas leaves the dehydration unit to be compressed and measured as it leaves the location.

The glycol pump. Glycol is pumped into the contact tower by a dual-purpose pump (such as the Kimray glycol energy exchange pump), which moves glycol up through the cooler or heat exchanger and into the top of the contact tower. The glycol trickles down through the contact trays where it collects water and condensate and flows to the bottom of the contact tower.

The dual-action pumps. The dual-action glycol pump pulls the wet glycol out of the bottom of the contact tower through a high-pressure strainer, where it is pumped along with a little gas through the bottom section of the reboiler.

The heat exchanger surge tank. The wet glycol is circulated through the heat exchanger surge tank and into a three-phase gas, glycol, and condensate separator.

The three-phase gas, glycol, and condensate separator. As the fluid enters the end of the three-phase separator, the fluid stratifies into three layers. The gas comes to the top and fuels the reboiler and supplies it with stripper gas.

The second layer formed is the condensate, which is controlled by an indiscriminate float. The float directs the fluid into a tank for distillate and condensate at the tank battery. The water-laden glycol is directed toward the reboiler for water removal.

The reboiler. The purpose of the reboiler is to boil off the water that was removed from the contact tower but leave the glycol. This is done by raising the temperature to a level that will cause the water to evaporate but which is below the boiling point of glycol.

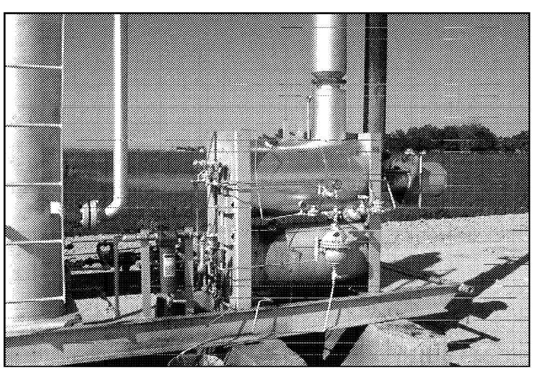

Figure 4. A small reboiler.

The reboiler operates at a temperature of approximately 350° F. If the reboiler has a back-up temperature control, this second control is set 20° higher. Water boils at 212° F, but, if it is under pressure or contains any contaminants, it requires more heat. Glycol boils at a temperature higher than this temperature setting.

The water vapor rises in the stripping still and condenser. It trickles down an angled pipe and is collected in a foot tub (Figure 5). This tube has to be insulated to prevent the water from freezing in cold weather.

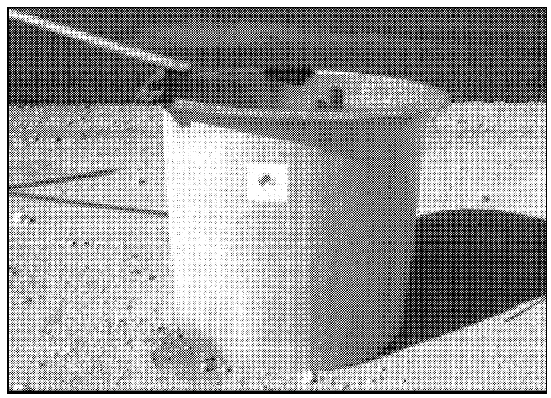

Figure 5. A water collection tub.

The water collects in these short, small volume tanks, and vacuum trucks come by periodically to remove the accumulated water to prevent overflow.

C-3. Tank Batteries for Gas Wells.

Tank batteries for gas wells, as a rule, are less imposing than tank batteries for oil wells. Most gas wells will produce distillate and water. Distillate has such a high API gravity that these two fluids flash separate almost instantly. Since they separate usually in a matter of seconds, no treating vessels are necessary. This means that there is no need for heater/treaters, gun barrels, free water knockouts, or flow splitters.

There are, however, a host of support vessels and equipment designed just to take care of the needs of gas wells. The tank battery for a gas well (Figure 6) is basically just like any other tank battery with one exception. Condensate has a very high gravity and acts as a penetrating liquid so that seep leaks that lose a small amount of liquid may develop unless the fittings are made up properly. With time, the installation becomes stained and looks bad. Because the produced fluids will be a little different from each well, the vessels to be considered in new construction are the two- and three-phase separator, the condensate storage tank, the water disposal tank, and possibly a chemical injector.

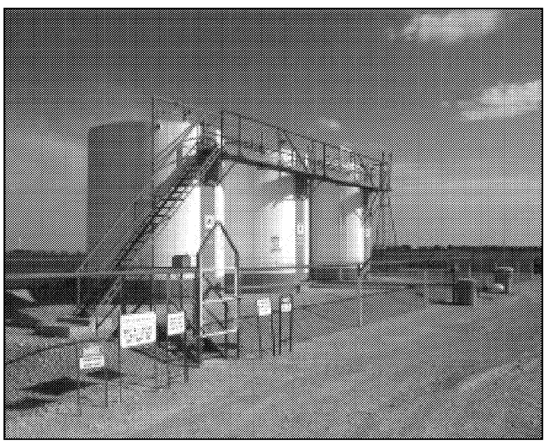

Figure 6. A gas well tank battery. Note the two loading lines—one for condensate and one for water.

The dehydration unit has either one or two small separators that produce condensate, according to how much is contained in the gas. The small tank shown in Figure 7 was set up just to serve the needs of a dehydration unit because for fire safety, the tank battery was a long distance away.

Because of the high gravity of the distillate in the tank battery, the tank vent valve is of considerable importance. Evaporation out of this vessel can be so great that in the heat of summer, the evaporation can be several barrels a day. A higher back pressure may be required, and if smaller loads or split loads are sold, income from the distillate may be dramatically increased. Careful accounting and measurement will indicate the lease needs in sales of liquids.

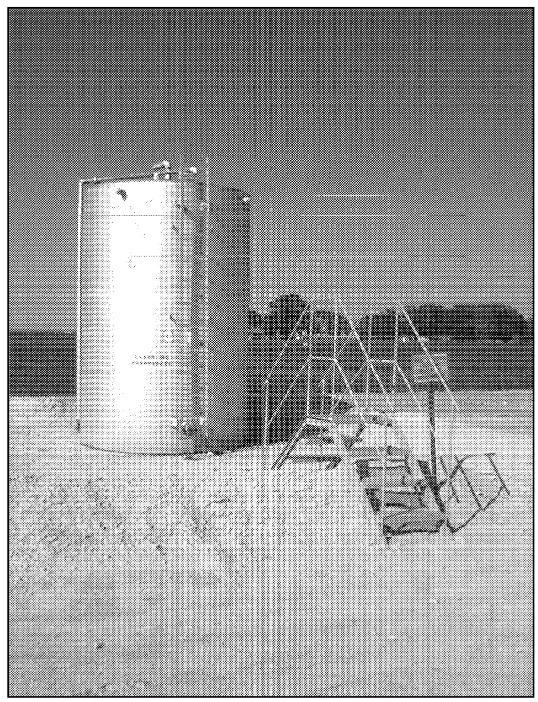

Figure 7. A small tank used to store condensates.

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Chapter 18
Gas Wells

Section D

GAS COMPRESSION AND SALES

D-1. Natural Gas Compression.

In some systems, natural gas has to be compressed to a high pressure to be transported by pipeline across the country. If pressure at the location needs to be more than 500 pounds, compression is required. As this pressure falls due to line resistance and the line volume increases as other wells are added to the gathering system, other compressors are installed.

The gas compressor will have a series of automatic controls that shut it in in the event of problems such as a loss of pressure indicating a line break, a high buildup of pressure indicating a plugged or frozen line, or a low supply pressure. If an engine is utilized in compressing the gas, a series of engine safety switches will also be installed.

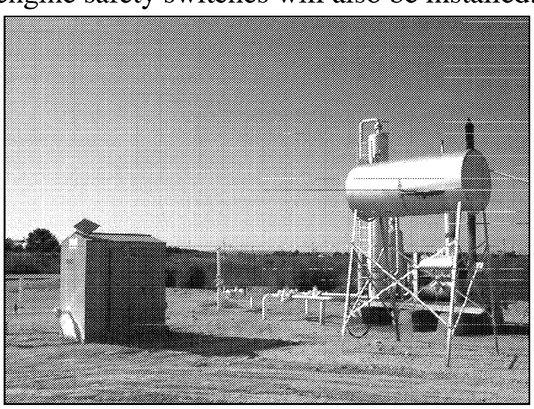

Figure 1. At this site, the gas measurement meter is protected against weather in a building.

D-2. Natural Gas Measurement.

A gas meter is installed on the location a short distance after the compressor to measure the amount of gas sold (Figure 1). The production company owns the gas as it comes out of the well and through the three-phase hydrocarbon separation unit.

As the gas leaves the production unit, it is usually owned by the gas company. This means the gas purchasing company also owns the dehydration unit and the compressor. In this event, the gas company will also own the small vessel that stores condensate that has been separated from the dehydration unit and is responsible for emptying the knee tub as needed.

The gas reservoir must be large enough and have sufficient pressure to make it a commercially profitable investment. The factor that governs who owns what is how much gas does the well produce. For low producers, the production company may not only own everything, but the company may be required to lay the line at their expense to connect to the natural gas gathering system. The gas from the wells is sold by contract, and the conditions of that contract are agreed upon by both parties.

A gas meter is installed a short distance from the compressor to measure the amount of natural gas sold. This may be a simple chart meter or a more complex one with a solar panel and radio communication with the gas company (Figure 2).

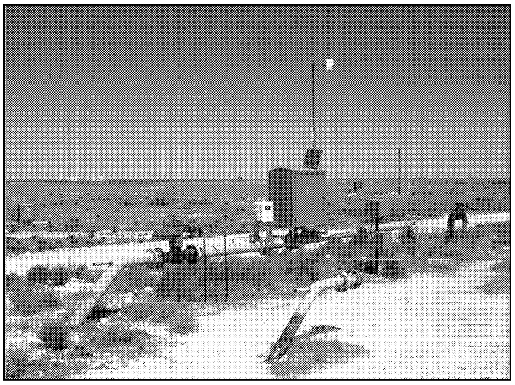

Figure 2. A gas meter powered by a solar panel. Readings are sent to the gas company via radio.

D-3. Testing Gas Wells.

Several methods are used in testing gas wells. One of the simplest tests is to shut the well in for a specified length of time and record the shut-in pressure. After this has been done, the well is returned to service. The purpose is to determine reservoir pressures remaining to project remaining reservoir volumes as well as projecting when a gas compressor may be required.

A second method of testing is to begin from a shut-in condition and flow the gas well where a specific backpressure curve is maintained to determine correct choke settings and to determine condensate (or distillate) and/or water production at various flow rates. Some tests are performed to meet regulation requirements and to set allowables.

In preparing to test the well, the pumper may need to flow the well vigorously enough to clean up the well bore prior to shutting it in. Wells that stabilize bottom hole pressure slowly may need to be shut in up to four days prior to the test. The equipment used to measure the volume is basically the same as with oil production wells but in some situations will handle a larger volume of gas.

Abbreviations commonly used in measuring gas flow are:

BCPMM	Barrels of condensate per million cubic feet of gas
BHP	Bottom hole pressure
CF	Cubic feet
CFM	Cubic feet per minute
MCF	1,000 cubic feet
MMCF	1,000,000 cubic feet
MMCFD	Million cubic feet per day
MSCF	1,000 standard cubic feet

D-4. Pipelines and Pipeline Problems.

As the gas goes down the pipeline, the amount of water and condensate remaining in the gas is of great concern to the pipeline company. As the fluid condenses back into a liquid state, it has to be pushed along with the gas or it will accumulate in low spots and result in back pressure while the gas is trying to push it over the next rise. The water will also freeze in winter time, and between the water, distillates, and other contaminants, a jelly-like substance called *hydrates* forms in the line and results in line restrictions.

When a mist of water accompanies the distillate and condenses back to a liquid, it contains little or no salt so it freezes easily, at around 32° Fahrenheit or 0° centigrade. This causes the lines to freeze on the inside and chokes off production. Appropriate production techniques must be adapted to overcome this problem. The well will begin to freeze and flow in cycles, and in the winter it may just stay frozen.

In Figure 3, the chemical tank near the gas compressor injects methanol, an antifreeze, into the line. This antifreeze, trickling into the line, assists in keeping the water from freezing and blocking the line.

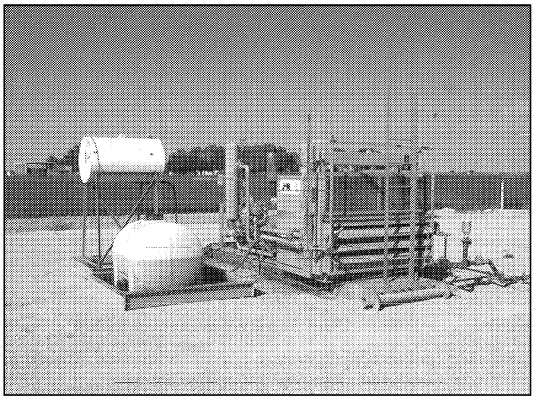

Figure 3. A gas compressor with a methanol injection tank.

The removal of liquids from pipelines. The problem of liquid, popularly called *drip*, being pushed down the line still exists. This liquid must be removed. Liquid collection tanks (Figure 4) are installed in low areas where this drip accumulates. In the past, these containers were often referred to as *drip pots.* This condensate is very volatile, unpredictable, and good safety practices must be used to handle it. With oxygen and a spark, it is very explosive and requires training to be able to handle it safely.

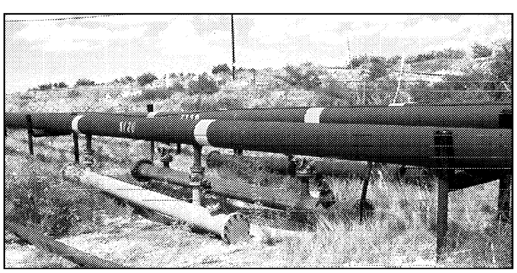

Figure 4. Gas lines in a collection system with drain lines to condensate tanks or *drip pots*.

D-5. Treating and Drying Natural Gas.

Before natural gas can be transported long distances across the country for consumption in other areas, all liquids must be removed. In addition to the petroleum condensates, which can be compared to gasoline, the butane and propane must also be removed. Special natural gas processing plants (Figure 5) are constructed in many locations in a large gas field to be able to process the gas.

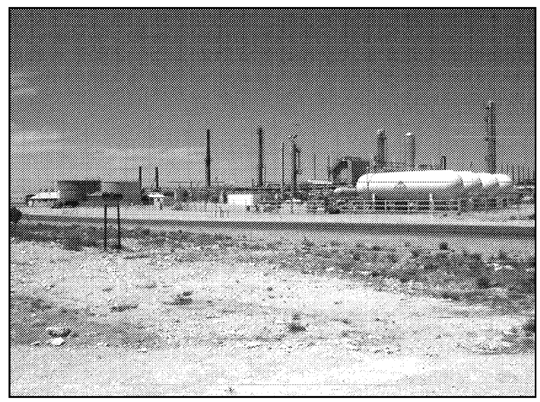

Figure 5. A plant for drying gas and processing natural gas.

D-6. Transporting Natural Gas Long Distances.

Before natural gas can be transported, it must be dried and all liquids removed. Natural gas is a very clean burning fuel and can be marketed in many ways. It supplies steam power for operating electrical generating plants, manufacturing plants, and the petro-chemical industry. It can be compressed and marketed for short-distance travel as *CNG, compressed natural gas.* Marketing natural gas in this form is becoming more popular across the country. Some city bus companies and service companies are converting to this system. It can be reduced even further into *LNG, or* *liquefied natural gas.* New Zealand has been using LNG for long distance travel automobiles for some time. It is gaining in popularity. China used *ANG, atmospheric pressure natural gas,* for city buses many years ago. The large gas bladders attached to the top were as large as the buses.

Cross-country gas lines. Cross-country gas lines are large and transport gas all across the country. Compressor stations along the line boost pressure for continuous flow. When problems occur in the line, the line is large enough to act as a surge chamber, or reserve supply, so that minor interruptions do not affect the end-user. The pipeline companies do a good job in supplying gas with little or no interruptions.

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Chapter 18
Producing Natural Gas Wells

Section E

NATURAL GAS SYSTEMS

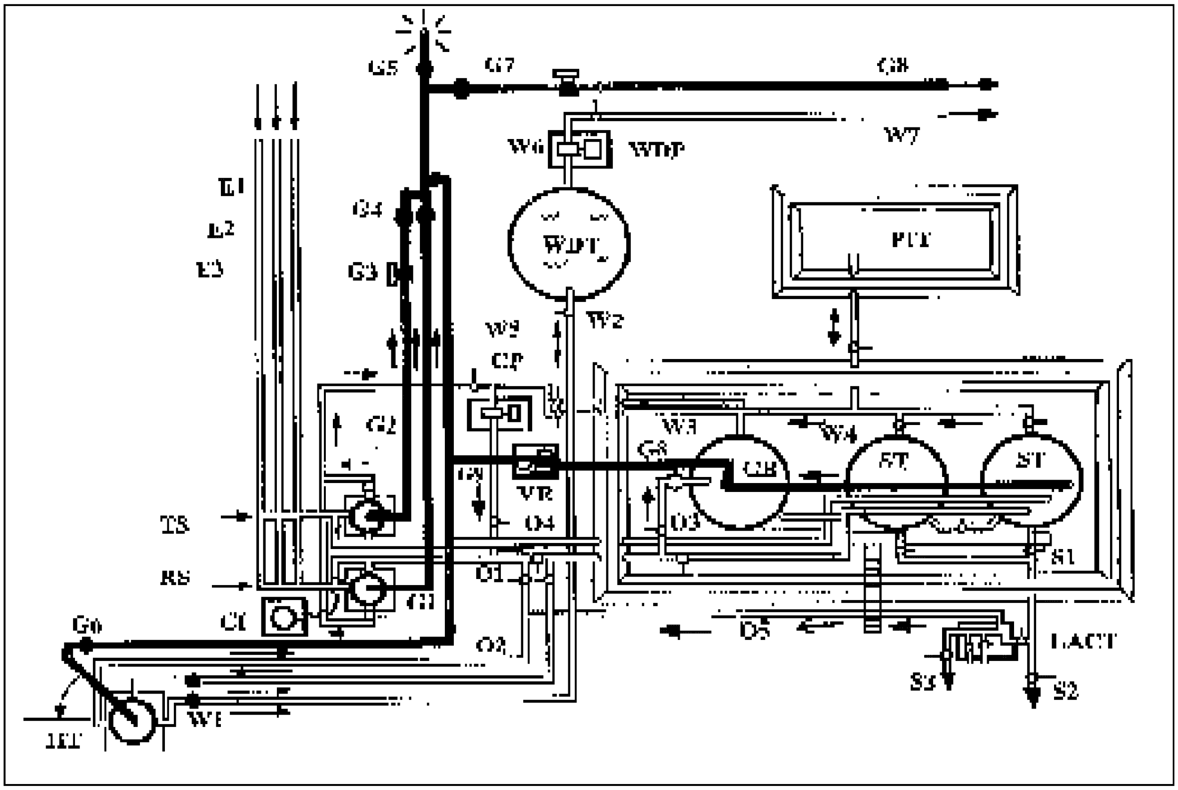

Figure 1. The high and low pressure gas system is indicated by the letter *G*.

E-1. The High-Pressure Gas Line System.

The natural gas system at the tank battery (Figure 1) begins in the first vessel that the produced fluid enters and where the natural gas is separated. The high-pressure gas system is really not *high* pressure, especially when considering the truly high pressure of bottom hole and wellhead pressures. High pressure is just the separator pressure, which may vary from as low as 20 pounds to as much as 50 pounds. When producing stripper wells, the well pressure has usually been depleted. It is usually producing with the assistance of a mechanical pumping unit and makes a low volume of gas. The casing valve may even be open to the atmosphere. As the downhole pump pumps fluid, however, enough gas will usually break out of the oil so that a separator pressure can be maintained as needed.

E-2. Controlling the Pressure in the Separators and the Heater/Treater.

Controlling the pressure in pressurized vessels is usually done by using a diaphragm-controlled automatic backpressure valve (Figure 2). These valves have a spring, bolt, and nut arrangement on top for easy adjustment. Since fluid can only flow from a higher to a lower pressured vessel, the separator must carry a higher pressure than the heater/treater. In turn the atmospheric vessels have the lowest pressure in the system, which is just a few ounces. Fluid will flow from one atmospheric vessel to another by line height or pump.

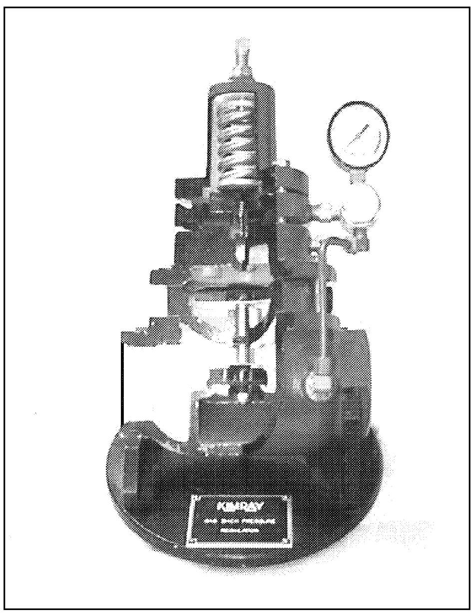

Figure 2. An automatic backpressure gas valve.
(courtesy of Kimray, Inc.)

E-3. The Well Testing Gas Measurement System.

All wells are normally tested one time per month. The well will be tested through a separator, heater/treater, or by producing directly to a stock tank, according to emulsion content. Figure 3 shows a gas testing system that requires a gas chart, a gas meter, and an orifice plate holder installed in the gas line.

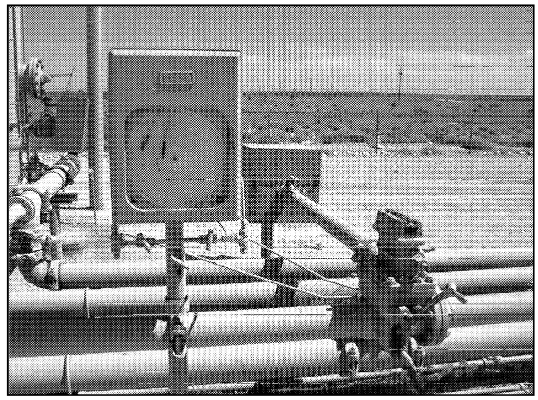

Figure 3. A gas test system that includes a gas meter with chart recorder.

E-4. The Gas High Pressure Gathering System.

As indicated in Figure 1, the heater/treater will have a backpressure valve located near the vessel. Each of the two separators will also have its own backpressure valve installed in the lines just before they join together. The backpressure valves are identified on the chart by a round black dot on the gas line drawing.

Each of the three vessels will have a gas pressure that is appropriate for that vessel. The heater/treater will have a lower pressure than the separator to permit the fluid to flow from the separator to the heater/treater.

E-5. The Low Pressure Gas Line System and the Vapor Recovery Unit.

Each of the atmospheric vessels will have a gas line coming out of the center of the top of each vessel. Even though the gas in the system flows through the line to a vapor recovery unit, a safety release must be provided. One design has two A-frame support stands, and the end of the pipe turns up for about 1 foot. On the end of this connection, a one-ounce backpressure valve (Figure 4) is attached. This permits the gas to escape in the event the pressure inside the vessel exceeds the safety vent setting. The ounce pressure rating is usually indicated in raised letters on the side of the fitting.

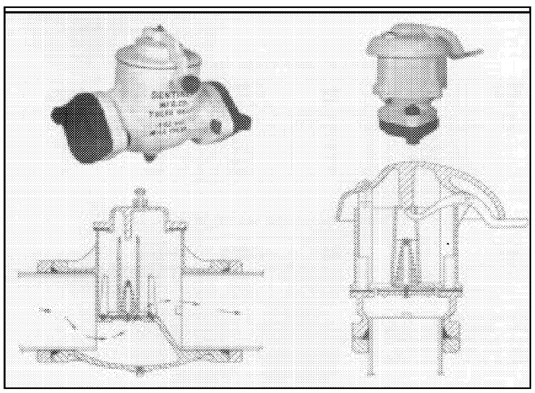

Figure 4. Horizontal and vertical one-once backpressure valves for atmospheric vessels.
(courtesy of Sivalls, Inc.)

The vapor recovery unit. The **vapor recovery unit** is placed in a location between the atmospheric vessels and the high pressure gas system. The tank battery can be tested for gas loss due to gas entering the atmosphere to evaluate the value of the vapor recovery unit.

The higher the API gravity of the crude oil and the higher the temperature of the crude oil, the higher the vapor loss. Even with low gravity oil, a heater/treater used to treat the oil increases the vapor loss. When the tank battery is located in a community, regulations may require the installation of a vapor recovery unit.

The vapor recovery system (Figure 5) is a skid-mounted unit that contains several components. When the gas enters the unit, it passes through a final liquid recovery unit to remove any distillate that may be condensing out of the gas. This vessel is important, because the gas is going to be compressed to a pressure greater than the separator pressure so that it can be re-injected into the high pressure gas system.

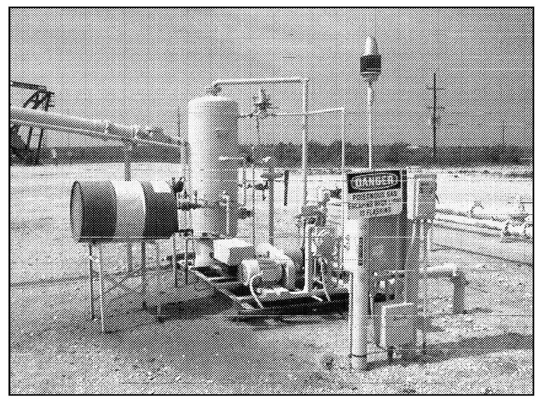

Figure 5. A vapor recovery unit.

The compressor is a gas compressor and cannot handle any significant amount of liquid. If the vessel should fill up with liquid and this liquid spill over into the compressor, the unit could be damaged. An automatic control will send the accumulated liquid back to the stock tank, or it will have to be performed mechanically by the lease pumper. Either way, the pumper will periodically check the liquid level in the vessel.

Gas can be very dry, and most gas compressors require lubrication to prevent metal galling and the resulting mechanical problems.

E-6. The Flare and the Gas Sales System.

All of the gas systems come together into one system before leaving the tank battery.

This includes the separators, heater/treaters, and the vapor recovery line from the low pressure atmospheric vessel collection system.

The gas company will install a backpressure control valve, a gas measurement meter, and a check valve in their system just outside the fence of the tank battery. As an illustration, consider a tank battery gas system having separator pressures of 30 and 35 pounds. The heater/treater has a pressure of 25 pounds. This means the system is operating with pressures of 25, 30, and 35 pounds. The flare vent pressure may have to be set at 50 pounds.

The gas company may set their gas line pressure at 15 pounds. This pressure is lower than the lowest vessel operating pressure, so everything will operate as normal. The gas company will have an area compressor that steps the gas pressure up to more than 500 pounds so it will move down their line at a rapid rate, providing room for the gas and that of other operators.

If the gas company has a slowdown accepting gas, and the line pressure builds up to 45 pounds, the system will still continue to function, but the backpressure on the pumping wells will slow down production dramatically. The tank battery will appear to be operating normally, but the system will be encountering production problems. If the pressure in the gas company line builds up to 55 pounds, all of the gas production is being vented to the flare (Figure 6), and this may require shutting in the wells temporarily.

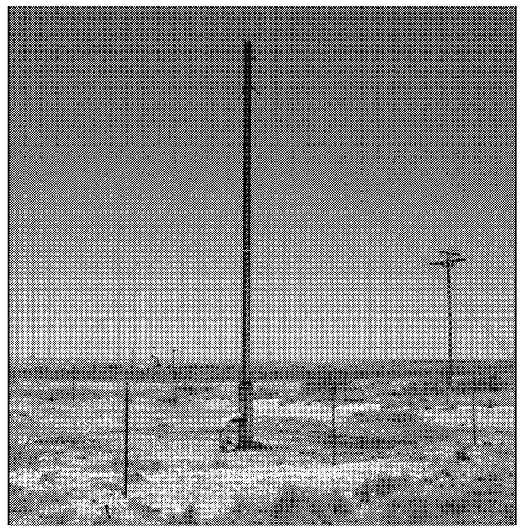

Figure 6. A gas vent and protective pit.

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9. Time Sheets for Work Performed.
    - Company employees.
    - Contract labor.

D. MATERIALS RECORDS.

1. Materials Control.
    - Theft by Employees.
2. Controlled Lease Equipment Storage.
    - Location of a storage area.
    - Security fencing.
    - Weed and mud control.
3. Pipe Storage.
    - Pipe and rod storage areas and magnetic orientation.
    - Classifying used pipe.
    - Pipe rack design and numbering systems.
    - Pipe range.
    - Pipe collaring and condition.
    - Pipe separation and layering.
4. Storage of Other Materials.
    - Arrangement, pads, docks, and weather protection.
    - Junk and scrap designations.
    - Chemical and drum storage, content marking, and accounting.
    - Winterizing and deterioration control.
5. Joint Venture Inventory and Accounting.
6. Transfer Forms and Procedures.
    - Materials transferred out of storage.
    - Materials transferred into storage.
    - Materials being transferred from one lease to another.
7. Identification of All Chemicals Used or Stored on the Lease.
    - Identifying Chemicals and Marking Barrels.
8. End of the Month Chemical Inventory.
    - Measuring barrel content.

The Lease Pumper's Handbook

Chapter 19
Record-keeping

Section A

LEASE RECORDS

A-1. Advantages of Maintaining a Lease Records Book.

The lease records book is a small book that should be kept in the glove compartment or other convenient spot inside the cab of the lease pumper's vehicle. It is an essential tool used by outstanding pumpers that saves hours of work every month and reduces costly mistakes. If a lease records book is not maintained, the pumper will encounter numerous problems. Good pumpers become better when this book is set up and used.

The purpose of this section is to provide ideas and directions on what type of records can be important and how to set up a meaningful information and performance handbook. Special equipment on each lease will require that the pumper decide what information is important to know. Time and a reduction in errors are the big factors that will make the pumper aware of what records are or are not useful.

The information contained in the book may be rather basic for some leases and rather extensive for others. A sample of the questions the book can answer includes:

- What electrical fuses are used on the lease? What are their sizes, current ratings, and location?
- Is the pumping unit gear- or chain-drive?
- Which direction does the motor turn?
- What size plate is needed in the orifice meter to test each well?
- How many of each type and length of belt are needed?
- Can substitute belts be used? Will another size fit and, if yes, what length?
- How many sheave grooves are available for belts?
- What size, quality, and quantity of rod packing is needed?
- Was more oil per day produced this month or last? Three months ago? Six months ago?
- What type and weight oil is needed for each gearbox or other piece of equipment?
- What spark plugs are needed for different models of engines used on the lease? How many, what brand, and what model number are in the engines?

Extensive reasons can be given concerning the need for a lease records book and problems projected to justify having it. The best way to judge the convenience of having such a book is for the pumper to begin one. After using one and enjoying the benefits, the pumper will never choose to be without one again. It will very rapidly become a bible of lease operations information.

A-2. Setting up the Lease Records Book.

The lease records book is custom designed by the pumper and contains most of the important facts about the lease. For example, the pumper has the option of dividing the book into lease or individual well sections. Thus, no two lease records books are exactly alike, but the following are some general guidelines to use when setting up the book.

- It must be a binder with three or more rings in which pages can be removed, rearranged, added, or exchanged, as needed.
- Section or sheets with lease number tabs are convenient to divide it into specific areas and leases.
- Blank and lined page sheets are needed. The pumper should have a source for future paper insert needs. Full size 8½" x 11" paper is recommended.
- By using blank sheets, the pumper can design custom information pages, even if written by hand. Most duplicating machines will accept and print on the paper with holes that fit the notebook.

A-3. Setting up Standard Records.

The standard records that are kept are up to the lease pumper. The following arrangement is used by many pumpers:

- Communications Information.
- Pumping Well Records.
- Electric Motor, Control Box, and Engine Records.
- Materials Records.

As records needs are analyzed, the pumper can select what types of information may be most appropriate. If the company has a full-time mechanic, electrician, and maintenance crew, records needs may be less than for the lease pumper who does not have this extensive of support. As few records as possible should be set up, but, when in doubt, this book should be used to record odd information that may become very important to know at some future date.

A-4. The Daily Gauge or Grease Book.

The grease book is just as important as the lease records book and should be posted carefully every day, retained and stored for several years.

Questions will arise—next month or next year—and although a day's activities will fade in the pumper's mind, it will occasionally become important to obtain production figures or other information for a specific day.

Notes or records should be maintained as daily rounds are made. If books are filled out at a later time, the pumper may not accurately recall all of the information. Notes should be made about the equipment checked, oil and water gauged, meters read, wells tested, gas sold, and repairs made.

The book may be divided into sections, one for each lease. Some pumpers notch the top corner of the pages alternately by battery to make it easy to reference or make other adjustments so the book is easy to use. The stock tanks are listed in ascending numbers from left to right, and the last two letters can be used to identify them. This is usually enough information for identification. A line can be drawn across the page before work is begun each day and the date written in.

After gauges are posted each day, the next lines can be used for water volume if appropriate, engines started, any work done at the battery, etc. with brief notes stating what was performed. A daily record may contain the following information:

- Tank numbers and sizes.
- Posting today's gauges.
- Today's activities.

- Oil sold, treated, circulated, and chemical added.
- BS&W levels.
- Engine fluids added and any repairs.
- Well testing.
- Well status.
- Wells pulled or shut in.
- Meter readings.
- Servicing records and lease activities.
- Any other important activity.

Some pumpers prefer to record the date and gauges on the left side, and the activities that may need to be recalled on the right side.

At the end of the month or other convenient time, some records in the grease book will need to be transferred to the lease records book.

When any section in the grease book has been filled, it gets confusing to mix the information, so it is usually best to start a new book. The dates that this book was used should be included on the front if possible and the book stored for possible future reference.

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Chapter 19
Record-keeping

Section B

WELL RECORDS

B-1. Introduction to Well Records.

It is not the lease pumper's responsibility to record and maintain the company's permanent records. To be more successful, however, the pumper needs to understand lease records and recognize what is happening on the lease by examining these records and noting changes that may be occurring daily. By examining the production records being submitted, the company supervisor can assess part of the production changes that are occurring. However, the pumper can see these changes daily and should be able to bring them to the supervisor's attention.

To be able to make an educated analysis of what is occurring at the wells, the pumper can maintain the lease records book described in the previous section to assist in recognizing lease changes as they occur. Most field supervisors will support the pumper in this effort by providing information from permanent drilling and well records.

B-2. Lease Drilling Records.

The well drilling record is maintained for the life of the well. It not only records the completion and initial tests of the completed well, but it also contains information about the reservoir and future changes to the well that may extend its producing life.

The pumper does not need to see the complete drilling record, but a few items from it will provide an understanding of downhole pipe arrangements. Useful information about each well includes:

- The year it was drilled.
- Initial production of water, oil, and gas.
- Depth and size of casing.
- Depth from wellhead to perforations.
- Number of perforations and spread.
- How much open hole is in the well.
- The distance from the kelly bushing to the wellhead.

The casing size and perforation record is referenced every time a change is made in the tubing string to place temporary tubing perforations in the desired position in reference to the permanent casing perforations. The pumper also needs to know how many perforations were made and the distance from the top to the lowest perforation. Occasionally, more than one zone has been perforated. Other important information is included such as any open hole.

When re-completing the well, raising or lowering the casing perforations, or performing many other work-over procedures, this record is vital to the job.

B-3. Pumping Unit Information.

Pumping unit information may include:

- Manufacturer tag information.
- Direction of rotation.
- Service records and requirements.
- Belts, sheaves, shafts, keyways, and adjustments available.
- Stroke lengths, gear ratios, strokes per minute, etc.

B-4. Wellhead Records.

Wellhead records include only that information that the pumper needs to know about the wellhead. This includes only those items that can be seen on the wellhead. When the pumper has a wellhead problem, there is an immediate need to know such information. As an illustration, assume that the pumper has just pulled a well and does not have the correct pony rods to finalize the spacing of the rods. Every pumping well in the field usually has a lift pony rod on it, so what size are they and where are they located? If a well servicing crew is waiting to continue spacing the rods and charging for being on the lease, knowing where to find an appropriate pony rod may save the company a great deal of money. Data that the pumper may need to know include:

- Length of polished rods.
- Dimensions of the rod liner.
- Gasket sizes.
- Stuffing box information.
- Packing information.
- Polished rod clamp bolts—number, diameter, length, etc.
- Types of valves installed on the wellhead.
- Information about other components on the wellhead.

B-5. Casing Records.

Most companies require that rods and tubing be installed in a very specific manner. Tubing perforations must be a specific distance above, even with, or below casing perforations. The gas anchor must be a specific length. The pumper needs to learn how the company prefers these to be set before making decisions when supervising a well servicing crew pulling a well on one of the leases.

B-6. Tubing and Packer Information.

Every time a problem is encountered while pulling tubing or unseating or reseating a packer, this record needs to be available. It lists the quality of the tubing, a measurement of every joint in the string, the manufacturer, size and type of packer or holddown, instructions on how to unlatch or release it, how to place it back into service, and the distance from the wellhead to the tubing perforations.

The two records that the lease pumper should maintain about the tubing string are:

- A tubing tally and description sheet.
- A record of when the tubing string was pulled with a description of the problem and solution.

Tubing records must be exact. As the pumper runs pipe in the hole, the item going in first is listed first, then the second, and so forth. After the string has been run in the hole and the job has been completed, it is listed again by turning it around, because the last item that went in is on top and the final list is from the top down.

The thread of a joint of tubing is approximately 1½ inches long. The pumper may measure a joint over-all as it is run in the hole, measured without the thread for more accuracy, or actually lifted off the slips and measured from the top of one collar to the top of the next collar for total accuracy. Normally, just measuring it without threads is acceptable for most installations. If the pumper has 200 joints in the hole, and are measuring overall, perforations will be approximately thirty feet above what the tally shows less pipe stretch.

A sample pipe tally sheet is presented in Appendix A-129.

Packers and Holddowns. A packer or holddown may stay in a well for many years before it needs to be pulled. The well record needs to list the packer manufacturer, the type of packer, and setting and release instructions. When the pumper runs a new packer or makes a change in a well, this information must also be submitted to the company office so that this record can be updated and corrected.

Pulling Tension on the Tubing String. Deeper wells have a bottom holddown on the tubing string to stop any breathing of the tubing and the resulting wear on the pipe. A well over 10,000 feet deep may have more than 25,000 pounds of tension plus the weight of the tubing. This may exceed 100,000 pounds on the weight indicator as the tubing hanger seats. The pumper needs to know this before pulling the well.

B-7. Sucker Rods, Pump Design, and Service Records.

The records that the lease pumper may maintain on each pumping well are:

- A rod tally and description sheet.
- Complete description of the bottom hole pump.
- A record of each time the rod string was pulled for the past few years and a description of the problems and solutions.

These records are important when a problem occurs with the rod string or downhole pump. When a well is pulled, the length of the removed pump is compared to the length of the replacement pump. The length of the stroke can also be compared as well as the style of the pump. When the pump is laid down, pumps are placed side by side and visually verified. The replacement pump is bucket tested to verify its ability to pump before it is run into the hole.

When the pulling record is sent in from the field to the office, the pump description tag, which is attached to the replacement pump, should be attached to the materials transfer and repair sheets. It can be important for the lease pumper to be able to refer to the lease records book to determine how long the pump was in the hole and compare it to the last several pull dates. This gives instant insight into the success of pump repairs as well as possibly indicating why pumps are failing. Sometimes a minor change or upgrade in the pump design can double the length of time that it will last in the well without replacement, dramatically reducing downtime and pulling costs.

The lease pumper can make suggestions to the supervisor concerning questions or conclusions that can be observed with good lease performance information.

B-8. Current Rod Servicing Records.

The procedure for listing a rod string is similar to the procedure for listing tubing except for the full sucker rods. Since all of these are 25, 30, or 37½ feet, the pumper only needs to list the number in the hole. If rods have stretched, there can be many feet of stretch in each rod, so the length of the rod string will not correlate exactly with the length of the tubing string. While the rods are hanging in the derrick, however, the pumper can see at a glance the amount of stretch that has been pulled into the rods.

A rod listing may look as follows:

1.	16.23	Polished rod, 1"
2.	4.00	Pony rod. 3/4"
3.	8.00	Pony rod 3/4"
4.	4,200.00	168 25-foot sucker rods 3/4"
5.	16.34	Pump, 1-1/4, travel rod, bottom holddown.
6.	10.33	Gas anchor, 1"
	4,254.90	Total length

Past Rod Pulling Record. It is important that the lease pumper know the dates that the well has been pulled in the past. A pump will last similar lengths of time. If the pump normally lasts for two years, and it has failed after four months, the pumper should first suspect a problem other than the pump. The pulling record is very informative when production begins to decline. The problem may involve more than one well.

The listing sheet is simple to set up. The lease pumper need only take a lined sheet of paper and draw vertical lines and add headings. This sheet can be individual for each well or a lease record, listing all wells on one sheet. The information headings should be similar to the following:

Well Pulling Record.

Lease	Well#	Date	Rods Pulled	Tubing Pulled	Pump Changed	Pump Size	Pump Length	Remarks
Jones	3	2-17-01	X	No	Yes	1-1/8	12'4"	Barrel was worn out.
Jones	6	4-22-01	X	X	No	1-1/4	13'4"	Hole in tubing

B-9. Electrical Information.

Information regarding prime mover equipment should include electrical control boxes, fuses, motors, and engine maintenance information. All sections of the lease records book are important, but the electrical section is especially important if the pumper does not have much basic knowledge of electrical systems.

Control boxes and fuse information. The lease may use several types of electrical control boxes, but two are most common—— the simple arm action fuse box and the automated style containing the time clock, manual and automated controls, and appropriate safety and protective considerations.

Most lease pumpers do not work on automated control panels. However, they do affect the lease pumper in that the pumper may have to call out an electrician. If the pumper can supply the electrician with the manufacturer and number of the parts contained in the panel, the electrician can bring correct repair parts. This can save at least a day in repair time.

The following may need to be identified:

- Style.
- Fuse size, current handling capacity rating, and description.
- Transformer.
- Time clock or percentage timer.
- Manual motor reset starter.
- Overload relays.
- Temperature safety breakers.
- Lightning arrester.

Electrical motor information. When listing the information contained on the plate of the electric motor, the pumper needs to list everything available and take some measurements.

B-10. Other Well Record Information.

Engine information should include engine identification, servicing, repair, and accessory information. This can be included on one general sheet. The pumper may prefer to make a list showing a schedule for servicing.

Special workover records should describe the workover and report fishing or other problems. This includes problems such as drilling out scale, stuck pipe, or fracing a well. Some companies simply add some of this information as an update to appropriate parts of the well records.

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Section C

PETROLEUM PRODUCTION RECORDS

C-1. Production Record-keeping.

The lease pumper's primary job is to produce and sell the most possible oil and gas economically. In addition, the pumper has other responsibilities, such as not abusing the wells by producing them in a manner that will damage their integrity, pull in water, or conate the gas.

Each production company varies in their frequency and method of reporting, forms used, and lease responsibility. Usually, the smaller the company, the more responsibility the pumper carries. As production information is recorded and submitted, these records continually indicate field and production conditions. The pumper needs to become an expert in reading and understanding what these records mean and take appropriate action to meet these changing conditions.

In this age of personal computers and instant communication capabilities, methods of recording and entering lease records are rapidly changing. With some companies tank gauges are phoned in to the office as they are taken, and all accounting is computed in the office and posted instantly.

The lease pumper, however, is the person on the firing line. As a dedicated employee, the pumper must be instantly aware of whether the production is over, short, or just right as a tank is gauged. Since the pumper is at the operation, if action is needed it can begin immediately.

For this reason this section begins with older field procedures and typical pumper responsibilities. If production is all from marginally producing wells, chances are that many of the older procedures are still in use and have some appropriate content. Parts of these procedures are still relevant. In any event, the pumper should follow whatever part is applicable.

C-2. Typical Lease Operation Records.

Records regarding activities on the lease that the lease pumper makes may include:

- Daily and monthly oil production records for every lease tank battery.
- One daily production test record each month for every well on every lease listing all oil, gas, and water produced.
- A report of all oil and gas sold on the lease.
- A record of any oil hauled for special purposes, such as well chemical batch treatment, hot oiling, etc.
- A record of all produced water injected or transported off the lease.
- A record of the number of every seal removed and added.
- Records of every well problem and wells pulled.
- With some operators pipe tallies of any downhole changes and a transfer record of all material, pipe, or rod changes if the pumper oversees the well servicing.

- A materials transfer ticket for every piece of equipment or pipe that is moved and its new location on the lease.
- A monthly chemical record of opening and closing inventory for the month, as well as accounting for consumption and needs for the near future.
- A number reading for all meters on the leases.
- Any appropriate environmental records of spills or other problems.
- Time sheets for the pumper and any special labor that is under the pumper's supervision.
- Reports for any special projects.
- Vehicle mileage, repair, service, or fuel tickets.

C-3. Production Reports.

To report daily production, the lease pumper may use any of a variety of methods, including:

- By written reports for daily, seven-day, eight-day, or monthly production.
- By computerized systems.
- By telephone or radio.

Types of written oil production reports. The company may require the pumper to write a daily record of all oil produced at each tank battery. Once the *seven-day report* was the most common. Production reports were pulled every Monday morning and on the first day of the month. They represented a midnight gauge (taken at day gauging time), although the true gauge time was recorded.

With the seven-day report, as many as six sets of records can be reported each month. To reduce paperwork, the eight-day report became more common, and records were submitted four times a month, on the 1st, 9th, 17th, and 25th of every month. An example of an eight-day report is included at the end of this section. This is still a common method because with the radio and telephones, the pumper usually talks to the office immediately when urgent problems arise.

Gas production records. Gas production records, other than special tests, are recorded from the lease either on a chart or by computers. They require very little effort by the pumper. The pumper will, however, usually make a chart record when testing a well.

This record only requires 12 lines in the record book per tank battery to record a year of production. The pumper can use these figures to determine at a glance how well the lease performed compared to the prior month or year.

C-4. Important Production Records.

The lease pumper wants to know how current production compares to past periods of performance. Is the well making the same amount of production, falling off, or about the same? The pumper will need to know this each month for each tank battery and for every well. The pumper should tell the company when everything is going well, remaining constant, or declining. With a few simple records the pumper can make good judgments as to where problems may be beginning.

There are two places to keep up with the welfare of the lease—at the well and at the tank battery. Even if there is only one well going into the tank battery, the tank battery production figures are just as important as the well production figures.

Well Information. A well test record should be set up that indicates the daily production test for each well. A separate sheet should be used for each well to eliminate confusion when comparing the monthly production figures. This record should only occupy one line for each month, even if it means using the back of the first sheet and the front of the next page. Only one figure is needed for the month. This record can also be set up in column form if preferred. With the passage of time one page of records will extend for six months to two years into the past, depending on system selected, so as the record is read, it will tell the pumper a great deal of information about each well. Some of the information that needs to be posted includes:

Information Sheet Heading.
- Lease
- Well number
- Test time (24 hours)

Line Information.
- Date of test
- Pump cycles
- Total hours produced
- Total barrels per day (BPD)
- Barrels of oil
- Percentage oil
- Total barrels water
- Percent of water
- Wellhead shakeout
- Cubic feet of gas
- Gas/oil ratio
- Orifice plate size
- Temperature
- Well bleeder pressure or flowing pressures
- Separator pressure
- Other desired information
- Comments

Each pumper will need to adjust this list to the specific needs of the lease. Too much information is better than a short list. To make a good well production analysis, the information must be complete.

Single-Well Tank Batteries. When one well goes into one battery, a specific day of the month can be selected and declared a test day. The pumper will also average the daily production from the tank battery and show this as a daily test. In this event, the pumper will also need to project any downtime so that it is known how the average was derived.

C-5. Monthly Tank Battery Total Production Record.

At the end of each month, the pumper lists the total production of oil, water, and gas. By dividing these results by the number of days the well produced during the month, a daily average is computed. As a year of records is kept and daily averages compared, the pumper will get a good overview of production. This is the best guide to indicate how the wells are performing.

Problem analysis from monthly test data. Some questions that can be answered from the production information include:

- How did the lease do this month?
- Are any wells declining in production?
- Which wells need productivity tests?
- Which wells are having pump problems?
- Do any wells have a tubing problem?
- Is it time to treat and stimulate the reservoir?
- Which wells are developing higher wellhead pressure?
- Are higher casing pressures lowering production?

Depth			Ft.			Ft.		
	3	83	1	23	96	2	44	09
¼	4	25	¼	24	38	¼	44	51
½	4	67	½	24	80	½	44	93
¾	5	09	¾	25	22	¾	45	35
1	5	51	1	25	64	1	45	76
¼	5	93	¼	26	06	¼	46	18
½	6	35	½	26	47	½	46	60
¾	6	77	¾	26	89	¾	47	02
2	7	18	2	27	31	2	47	44
¼	7	60	¼	27	73	¼	47	86
½	8	02	½	28	15	½	48	28
¾	8	44	¾	28	57	¾	48	70
3	8	86	3	28	99	3	49	12
¼	9	28	¼	29	41	¼	49	54
½	9	70	½	29	83	½	49	96
¾	10	12	¾	30	25	¾	50	38
4	10	54	4	30	67	4	50	80
¼	10	96	¼	31	09	¼	51	22
½	11	38	½	31	51	½	51	64
¾	11	80	¾	31	93	¾	52	06
5	12	22	5	32	35	5	52	47
¼	12	64	¼	32	77	¼	52	89

Figure 1. A tank chart to convert gauge depths to volume of liquid. This chart is for a cone-bottomed tank and allows for 3.83 barrels in the cone.

If the pumper does not maintain and seriously compare daily production statistics, the most important information available to judge lease performance is being lost.

C-6. Records for Daily Use.

Some records are so valuable that they are referred to almost daily in working on the lease. Regardless of the method used to report the production of the past 24 hours, the lease pumper must understand what is happening on the lease, produce the most possible oil, and keep lifting costs as low as possible while still doing a good job. This is not possible without production references that can be checked quickly as needed. Some of these records are:

Yesterday's tank gauges. The grease book used to record today's activities will contain a record of yesterday's tank gauges, which will show production volume based on tank charts (Figure 1). Every day's oil and water production is rendered into feet and inches, so as soon as today's gauge is completed and recorded, the pumper can know how the lease did. Is it over, just right, or short? Corrective action may be needed. If this cannot be determined, the reference system needs to be improved.

The daily, seven-day, eight-day, or monthly production report. This is an important record for the production supervisor and company. It details how much oil was produced daily and lists all oil sales. This informs the company of how much income they will receive the following month for this period of time, shows results of well tests, itemizes all major lease problems during the reporting period, and details how much oil was over or short.

The lease pumper should double-check this report before sending it to the company to ensure that all math is accurate and all information easy to read.

Monthly tank battery production of oil, water, and gas, and daily averages. The lease records book will contain a monthly total of oil, water, and gas produced, a daily average, gas/oil ratios, and water/oil percentages. This record only consumes one line per month and provides a continuing pulse of how the lease is performing.

This simple record provides answers to questions such as:

- How much oil is being sold?
- How much water is injected or hauled?
- Are injection pressures changing?
- How much gas is being sold?
- How are production averages changing?
- Where are the problems?

Monthly individual well tests. Possibly the most valuable record that the lease pumper carries is the monthly well production test record. This is a test where the well has been normalized for several days and a 24-hour test performed. This test is performed one time each month on every well on the lease. It is just as important to carefully perform this test on batteries with one well as on a battery with several wells.

This record is important because it provides the pumper with a measuring tool on how the lease, wells, and pumps are doing. Needed information includes:

- How much tank room will be required to perform this test?
- What orifice plate will be required for the gas reading to stay on the chart?
- Is production falling, constant, or increasing? How much?
- Is the gas/oil/water ratio changing?
- Is the flow line pressure changing?

Chemical consumption records. The chemical consumption record for each month is important to maintain because it is an important part of the lifting cost per barrel. Because there is treated oil not yet sold, it is difficult to render into a cost per barrel from the records. It does, however, give the pumper an accurate record of daily consumption. By noting the barrels of oil produced each month, it is relatively accurate. The pumper should know how much chemical is being consumed per 100 barrels of oil treated.

C-7. Benefits of Production Records.

There are many benefits from maintaining production records. After maintaining these records for a few months, the pumper would never be without them. Some benefits are:

- Knowing how much oil and gas was lost during the month because of lease problems. This figure can also be projected into lost dollars, and the analysis of why it was lost may illustrate the importance of equipment maintenance and pinpoint special problems.
- Indicating wells that are beginning to have downhole problems such as pump wear.
- Assisting in determining when productivity tests should be conducted. They allow monthly analysis of well conditions.
- Indicating increased production from wells that have been worked over and the feasibility of working over other wells.
- Showing loss of production that occurs with time and natural depletion.

Benefits will change according to lease conditions.

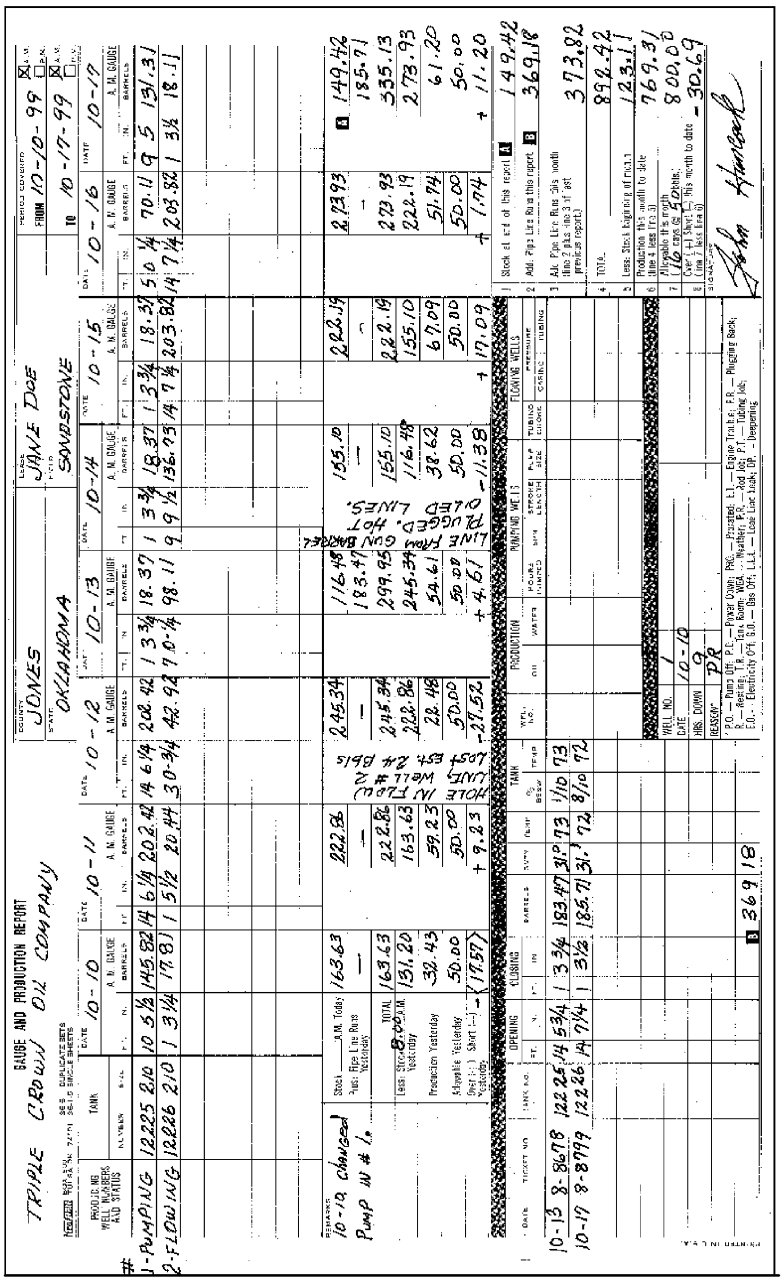
C-8. Supply Purchases.

The lease operator will have written or verbal policies concerning supply purchases. For larger operators where bids can periodically be taken and where case lot purchases are cheaper per item, the pumper should work closely with the lease supervisor when making purchases. Companies usually require advance approval for the purchase of higher quantities of supplies or some types of purchases, such as tool replacement.

C-9. Time Sheets for Work Performed.

Company employees. Time sheets for employees are usually required, even with a small company. This confirms that the pumper receives all pay earned and is a statement to the company confirming that the pumper worked the time submitted.

Contract labor. When the pumper is required to confirm the accuracy of work hours submitted by contract labor, the method of time-keeping should be discussed with the contract labor supervisor. It may be preferable to record work to the nearest 15-minute interval in order to be fair to both the contractor and the production company. The pumper must always be accurate in keeping these records to be fair with the employer as well as the contractor.



8-day production report to be completed by the lease pumper.

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Section D

MATERIALS RECORDS

D-1. Materials Control.

Keeping a record of every piece of equipment on the lease that has either been installed or is in reserve for future use is an important function within the petroleum industry. All of the varied items stored on the lease are usually referred to as *materials.* Maintaining accurate records of this material is a necessary part of the job. When equipment or supplies are needed, these records will indicate if it is on hand, can be moved from another location, or must be acquired.

As material is acquired, the tendency is to store it on the lease, even if the lease operator office is in a nearby town. If stored within city or town limits, material may be subject to additional property taxes. Being easily available to meet lease needs is also an important consideration.

Oilfield equipment is very expensive to purchase and transport and represents a large lease operator investment. The pumper will almost always have a certain amount of materials on hand available for immediate use. The lease pumper is often in charge of overseeing the storage and welfare of this equipment, and this means that the pumper has responsibility and accountability for everything on the lease. When equipment or materials are missing without the pumper's knowledge of where it went, the employer must be notified immediately.

Theft. Prevention of theft of oilfield pipe and equipment is an important part of the lease pumper's job. Lease equipment can be protected from theft or loss to a large degree by following good practices. The petroleum operator, because theft is such a common problem in the oil field, usually has a low tolerance for theft and will prosecute to the limit of the law.

Theft by employees. A large part of theft in the oilfields is a result of actions or permissiveness by the lease pumper. If anything is missing when needed, the pumper usually comes under close scrutiny by company management. Sometimes the pumper knows who may have stolen the missing items, even if the pumper is innocent. Suspicious activities or visitors on the lease should be noted and reported, and the pumper must never assume they have the owner's permission to remove anything from the lease without prior approval. The pumper should also discourage visits by people who are suspected of surveying the lease for what they can return after hours to steal.

D-2. Controlled Lease Equipment Storage.

Controlled lease security is common practice. Often equipment is temporarily left on a lease location, but for many reasons (such as the appearance of the lease) may be moved to one central area of controlled storage.

Some of the replacement equipment, repair parts, and supplies usually on hand on the lease are:

- Rods and tubing for well repairs.
- A small assortment of pony rods and tubing subs.
- Fuses.
- Electric motors.
- Steel and plastic pipe.
- Fittings and leak clamps
- Barrels of several types of chemical.
- Equipment that has been pulled out of service.
- Equipment waiting to be installed.
- Damaged and surplus equipment.
- Joint venture equipment.
- Walkways, ladders, and vessels.
- Junked equipment being retained for spare parts to repair similar equipment.
- Scrap equipment whose value is only in the weight of the material.
- A host of other repair and maintenance materials such as motors, vessels, and walkways.

Location of a storage area. The operator will usually secure landowner permission to use a small area as a controlled storage area. It may be an abandoned well site or require setting up a special controlled area or *yard*. Usually, the first thing considered is a security gate. It can be a simple locked gate across the road with cable wings extended to the sides, or a specially designed storage yard with a *Private Road* sign.

Security fencing. Security fencing—usually cyclone fencing—is the first step to setting up a secure storage area. Occasionally this secure area will also include a *dog house* for storage of materials needing weatherproof storage and a place to fill out production records. This fenced area should be large enough to allow trucks to enter, turn, load, and unload equipment.

Weed and mud control. Crushed rock or a similar material is usually placed on the location, especially on roads and on the equipment storage areas to reduce maintenance problems caused by vegetation growth and control of mud. The yard should be placed where maintenance will not become a burden.

D-3. Pipe Storage.

A minimum number of joints of pipe and sucker rods are stored on most locations for replacement purposes. Due to the cost of labor and short notice delivery requests, it is more practical to have a few joints available nearby to reduce downtime and hauling expenses. Major centralized storage areas may have more extensive stocks of materials for the area or several leases.

Pipe and rod storage areas and magnetic orientation. Many companies demand that their pipe be stored in alignment with the magnetic pull of the earth—that is, north and south. This may reduce crystallization from occurring while the pipe is in storage. Many commercial storage companies carefully align their pipe storage racks with this in mind.

Classifying used pipe. Pipe is classified by the composition of the steel and the depth that it may be run, such as H-40, J-55, and N-80. Although pipe is lightly stamped to show this classification, used pipe is usually lowered one rating number when it is moved to the storage area as used. As an illustration, J-55 pipe may be reclassified as H-40. This is normal practice just to be certain that the pipe will perform satisfactorily when returned to service. For this reason, the pumper must accept the pipe *book* or office classification, even if the number on the pipe indicates that it is of higher quality.

Pipe rack design and numbering systems. The pipe rack needs to be well designed and strong enough to support the amount of pipe to be stored. It needs to be high enough to allow for easy rolling of the pipe off or onto the rack and onto the truck trailer.

A sign on the rack identifies the rack and sometimes what is stored on it (Figure 1). This identification may also identify the number of joints, size, and quality.

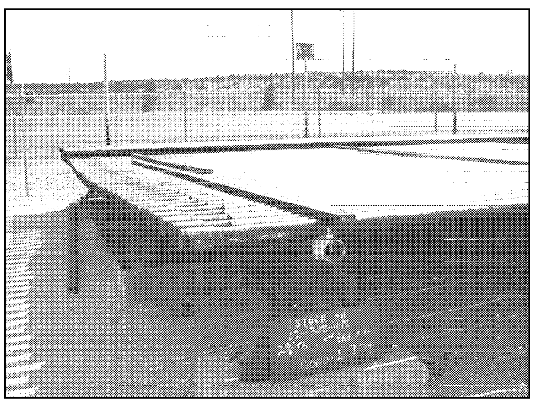

Figure 1. Pipe stored on site and labeled for location and classification.

Pipe range. Casing may also be identified by length. This length is usually on the storage record. The longer the joint, the fewer connections that have to be made up when running it. Range numbers include:

30 to 35 foot pipe is Range 1
35 to 40 foot pipe is Range 2
40 to 45 foot pipe is Range 3

Pipe collaring and condition. Pipe is always neatly aligned and collared when it is placed on the rack. The threads should be cleaned and lubricated and, if thread protectors are available, they are screwed onto the pipe.

Pipe separation and layering. When several layers of pipe or sucker rods are stored on a rack, lumber is used to separate the layers. This allows the pipe to be easily rolled and placed in neat order. The thickness of the lumber is selected according to the weight of the pipe. A scotch or block is nailed on the board, next to the pipe at the ends to prevent the joints from rolling off.

The stripping lumber that separates pipe layers is valuable company property. This material should be handled and stored with care because it will be used again and again when the next loads of pipe are hauled to the yard. Unauthorized removal of stripping material from the lease is theft.

D-4. Storage of Other Materials.

Crushed rock pads, as well as 8x10-inch sills, may be needed when storing heavy equipment. Equipment be stored leveled, balanced, and off the ground.

Arrangement, pads, docks, and weather protection. Some space should be available in the secure area for delicate equipment and supply storage where protection may be essential. Timber-covered pads may be needed for small equipment, and a truck height dock with a roof is of great value when off-the-ground storage is needed.

A plat or drawing of the storage area should be made, designating all areas by some numbering system. Pipe racks also need sub-numbering systems indicating east to west or another appropriate numbering system preference. Several sizes and classifications of pipe will occasionally be stored on the same rack, and the number count must be included on the working list. Unlisted materials seem to disappear.

Junk and scrap designations. When equipment has been pulled out of service, it may be classified as *junk* or *scrap*. Junk is valuable material because it has many parts that may be salvaged for re-use. When material is classified as scrap, it has been no longer usable, is not reparable, or has become obsolete. When selling these items by bid, junk brings a much higher price than scrap because much of it will be salvaged and re-sold. Many times a junked item is too valuable to sell because other similar units are running in the field, and salvage parts can be used to repair other equipment.

Materials going to junk or scrap usually have a weight estimate. When this scrap or junk is sold, the weights should basically agree with the amount shown on the records. Even scrap has a value.

Chemical and drum storage, content marking, and accounting. All 55-gallon drums should be stored in neat order and separated by content. Content and generally the date received should be identified by use of a paint marking.

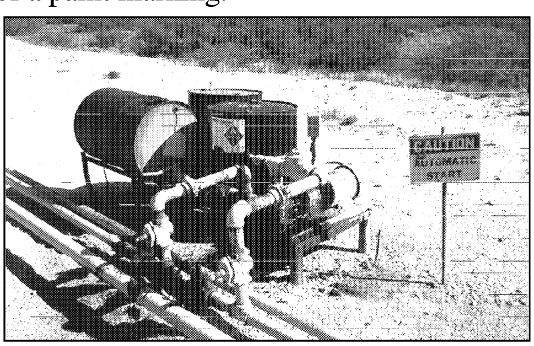

Figure 2. Chemicals should be properly stored and only kept if required.

The lease pumper should maintain a chemical inventory to know when the chemical supply on hand is low and more should be ordered.

Proper determination of the actual contents and correct disposition of abandoned barrels of chemical left on the lease can cost hundreds of dollars per barrel, so no chemical should be allowed to stay on the lease if it does not serve a purpose.

Winterizing and deterioration control. When engines and specialized equipment are moved into storage, they should be winterized—that is, the water removed and all openings sealed. When a piece of equipment is received, the pumper should make a notation on the to-do list and check it as early as possible for proper storage. Valves in engines can be damaged if rain is allowed to enter through an exhaust opening.

D-5. Joint Venture Inventory and Accounting.

Occasionally a lease is a part of a joint venture. This means that the lease has two or more owners, and all equipment and materials brought into storage are part of this project. They must not be mixed with the stock fully owned by the company. Some simple system, such as an X in front of all inventory numbers and stamped on the equipment, can identify it as joint venture equipment at a glance. This equipment is restricted and cannot be used without proper management approval.

D-6. Transfer Forms and Procedures.

As a project in the field begins, all materials that arrive on the location have been transferred and appropriate records placed in the lease operator's office. When materials such as pipe are shipped, a small extra amount is added to allow for changes and to prevent construction shortages. After the project has been completed, this extra material must be transferred into appropriate storage or to another location or project. These transfers are important, so information needs to be accurate and complete.

A typical type of transfer form is illustrated in Appendix A-11. When transferring pipe out of storage, a pipe tally sheet must accompany the transfer sheet. A typical pipe tally sheet is illustrated in Appendix A-12. Common sense must be used when filling out this form. It will not meet all needs, so if it does not contain the specifically needed information space, the pumper should use the back side of the form to write additional notes. The word *OVER* should be used on the front to indicate that more information is written on the back of the form.

The location of all pipe and equipment on the lease is listed on company records. Pipe is either in use as a part of an installation or is in storage. If it is in storage, the exact location should be noted on the materials transfer form. Except with pipe transfers, a separate form should be avoided because they can become separated. Some companies request a drawing on the back if it includes the laying of a pipeline.

Materials transferred out of storage. A *materials transfer* form is usually written every time material is transferred. Material includes all forms of pipe and equipment, but usually excludes supplies unless they are very expensive. Only the spaces that apply to that particular item are utilized. A simplified version without prices may be developed for field use.

When transferring pipe out of storage, more pipe than is needed is usually transferred, just to be sure enough is on location to complete the job. Whatever is left over must be accounted for after the job has been completed. A specific destination is included on the transfer, and some type of correspondence should be sent to the warehouse materials inventory person to indicate that the project has been completed.

Materials transferred into storage. When materials are transferred into storage (if the storage area is comprehensive), a notation must be made showing where it is stored. If pipe has been downgraded, this must be indicated on the transfer as it is unloaded. Identification marks may be needed. If the material is part of a joint venture, this must also be noted.

Materials being transferred from one lease to another. When material is being transferred from one lease to another, a full explanation may be needed. Occasionally, special notations must be made on the back explaining the project. The office personnel should not have to guess why the material was needed or for what it was used.

D-7. Identification of All Chemicals Used or Stored on the Lease.

The lease records book should have a record of every chemical used or stored on the lease. This is extremely important.

Identifying chemicals and marking barrels. Because barrel markings may fade, a paint stick should be used so that every barrel can be identified. Regulations require that the contents of every chemical barrel be identified before it can be properly disposed.

The identification and disposal can cost several hundred dollars for each barrel if its contents are not known.

Identification numbers on barrels should be a minimum of 1 inch high or larger and easily read. A number system can be adopted to specify chemical purpose such as O for treating oil, B for bottom breaker, S for paraffin solvent, F for stabilizing formations, P for cathodic protection, and so forth. Barrels should also be grouped according to content to aid in end of the month inventory and to know when to notify the office that supply is low. It may also be useful to identify the supplier.

Other information that must be noted includes the following:

- Date of purchase.
- Name of the chemical.
- Purpose of the chemical.
- Chemical mixing ration.
- Where used.
- How it is used.
- How often is it used.
- Storage life.
- Other pertinent information as needed.

When a service crew leaves the lease after performing contract services, all barrels should leave with them and nothing left behind for the pumper to handle.

D-8. End of the Month Chemical Inventory.

At the end of every month, the pumper should inventory the chemical on hand and compare those quantities to what is posted in the lease records book. At this time, a projection can be made of how much chemical was used and when more will be needed. It is easy enough to develop a chemical accounting system.

Measuring barrel content. As chemical on hand is inventoried, measuring the amount remaining in barrels is more difficult to transfer into a gallon accounting. A 55-gallon drum volume chart has been included in Appendix A-6 for convenience in making this estimate.

APPENDIX A

TOOLS AND RECORDS

The Lease Pumper's Handbook

Appendix A
Tools and Records

Section 1

API PUMP DESIGNATIONS

6.7.1 The basic types of pumps and letter designation covered by this specificiation are as follows:

Type of Pump	Letter Designation: Metal Plunger Pumps, Heavy-Wall Barrel	Metal Plunger Pumps, Thin-Wall Barrel	Soft-packed Plunger Pumps, Heavy-Wall Barrel	Soft-packed Plunger Pumps, 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	....	TP	....

6.7.2 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

- Total length of extensions, whole feet.
- Nominal plunger length, feet.
- Barrel length, feet.
- Type seating assembly; C — Cup type
  - M — Mechanical type
- Location of seating assembly; A — Top
  - B — Bottom
  - T — Bottom, traveling barrel
- Type 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 — 1¼ in. *(31.8 mm)*
  - 150 — 1½ in. *(38.1 mm)*
  - 175 — 1¾ in. *(44.5 mm)*
  - 178 — 1 25/32 in. *(45.2 mm)*
  - 200 — 2 in. *(50.8 mm)*
  - 225 — 2¼ in. *(57.2 mm)*
  - 250 — 2½ in. *(63.5 mm)*
  - 275 — 2¾ in. *(69.9 mm)*
- Tubing size;
  - 15 — 1.900 in. OD. *(48.3 mm)*
  - 20 — 2⅜ in. OD. *(60.3 mm)*
  - 25 — 2⅞ in. OD. *(73.0 mm)*
  - 30 — 3½ in. OD. *(88.9 mm)*

(courtesy of Harbison Fischer)

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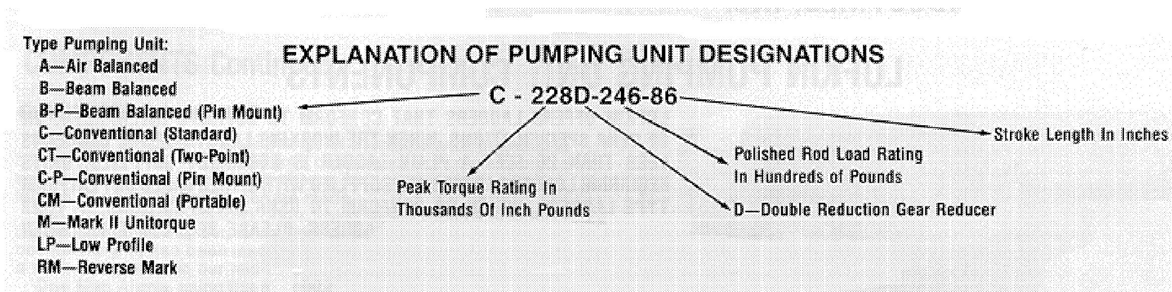
Appendix A
Tools and Records

Section 2

API SIZES OF PUMPING UNIT DESIGNATIONS



Pumping Unit Size Designations.

Pumping unit sizes and the load that can be suspended safely from the sucker rods are reduced to 5 designations that can be written on one line. A permanent metal plate is attached to the gearbox with these identifying numbers printed on them. These designations in order are:

1. Type of Pumping Unit.
   - A Air Balanced.
   - B Beam Balanced
   - B-P Beam Balanced (Pin Mount)
   - C Conventional (Standard)
   - CT Conventional (Two Point)
   - C-P Conventional (Pin Mounted)
   - C-M Conventional (Portable)
   - M Mark II Unitorque
   - LP Low Profile
   - RM Reverse Mark

2. Peak Torque Rating in Thousands of Inch Pounds.

3. D Double Reduction Gear Reducer.

4. Polished Rod Load Rating in Hundreds of Pounds.

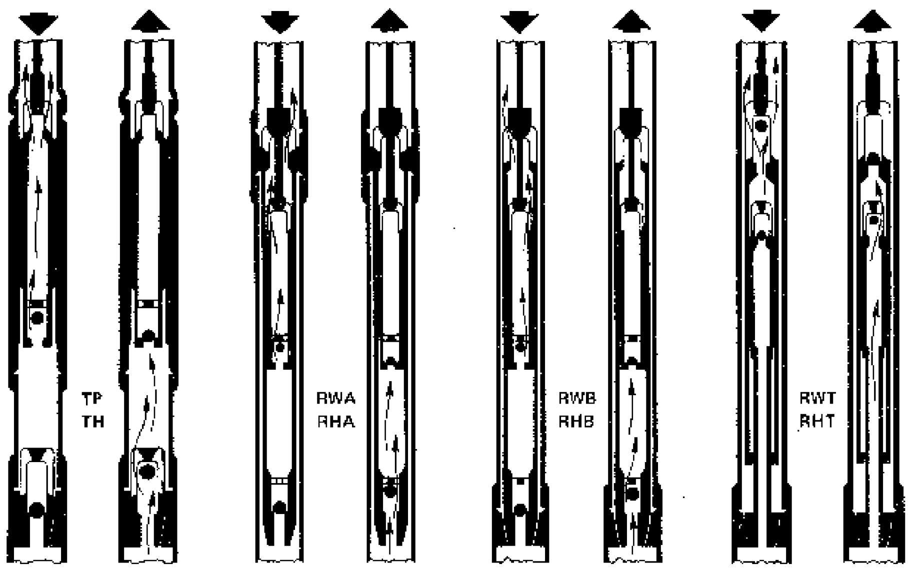
5. Stroke Length in Inches.

The Lease Pumper's Handbook

Appendix A
Tools and Records

Section 3

PUMP ABBREVIATIONS



PUMP TYPE ABBREVIATIONS

FULL BARREL	FULL BARREL HEAVY WALL	
TP	**TH**	Tubing type
RWA	**RHA**	Rod type, stationary barrel with top holddown
RWB	**RHB**	Rod type, stationary barrel with bottom holddown

LETTER DESIGNATION

1st Letter		
T	=	Tubing type, barrel run on tubing
R	=	Rod type, complete pump inserted into tubing on sucker rods
2nd Letter		
H	=	Heavy-wall barrel wherein wearing and sealing surface for plunger is integral with the barrel
W	=	Full barrel wherein wearing and sealing surface for plunger is integral with the barrel
3rd Letter		
A	=	Top holddown with reference to rod type stationary barrel pumps
B	=	Bottom holddown pertaining to rod type stationary barrel pumps
T	=	Traveling barrel rod type pump (bottom holddown)

(courtesy of Trico Industries, Inc.)

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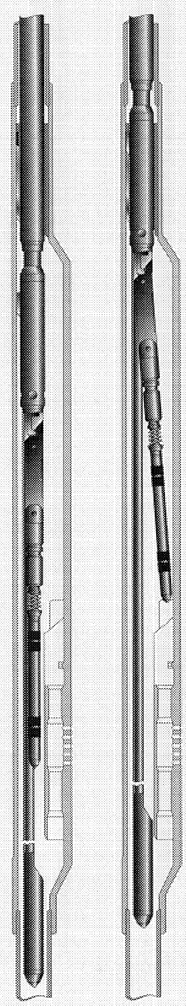
Appendix A
Tools and Records

Section 4

KICKOVER TOOLS FOR RUNNING GAS LIFT VALVES

Kickover Tool

Wireline Running and Pulling Procedure for All Camco Orienting Type Side Pocket Mandrels



1A 1B

Running Procedure

Introduction

The Camco kickover tool is run into the well using standard wireline methods. When the locating finger of the kickover tool contacts the stop in the orienting guide sleeve in the mandrel, the kick spring pivots the lower section of the kickover tool, the pulling tool or the running tool and valve into the kicked-over position. Correct installation is assured by the orienting guide sleeve in the mandrel. Once the wireline device is installed, a shear pin in the finger housing and release plunger assembly is sheared, permitting the kickover tool to be returned to the surface.

Figure 1A. In the running procedure, the valve, latch and kickover tool are made up onto the wireline tool string and lowered through the tubing until the kickover tool is below the selected mandrel.

Figure 1B. The kickover tool is raised slowly upward through the tubing until the finger on the kickover tool contacts the orienting sleeve slot and stops. Tension is pulled on the wireline until the tool releases and kicks over. The tools are then lowered until a loss of weight indicates that the kickover tool has located the side pocket of the mandrel.

Figure 1C. Downward jarring drives the valve and latch into the side pocket mandrel.

Figure 1D. Upward jarring shears a pin in the latch and releases the running tool from the valve and latch. The tool string can then be retrieved from the well.

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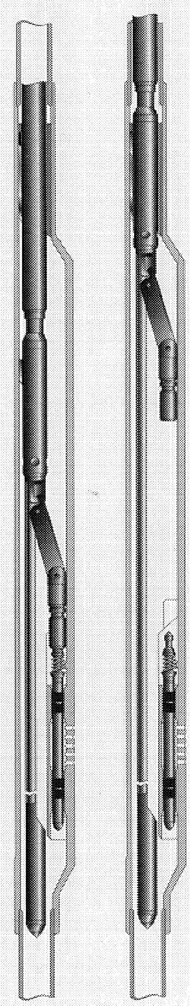
A CAMCO INTERNATIONAL COMPANY



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(courtesy of CAMCO Products and Services)

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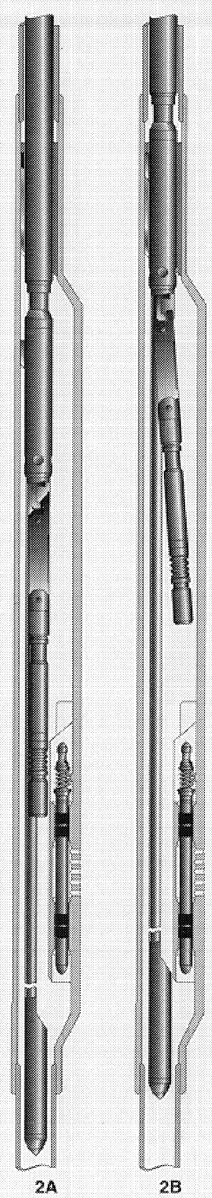
Appendix A
Tools and Records

Section 5
KICKOVER TOOL FOR PULLING GAS LIFT VALVES



Pulling Procedure

Introduction

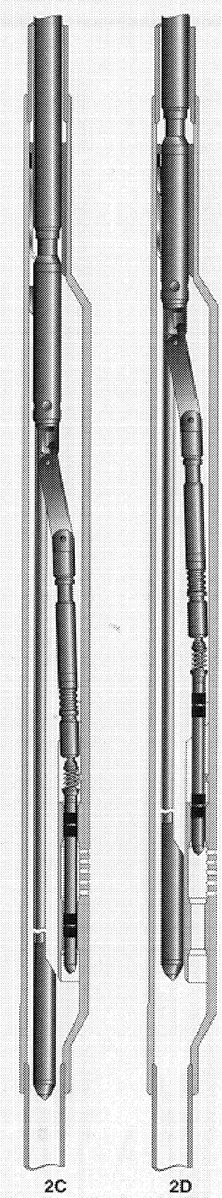
The Camco kickover tool is run into the well using standard wireline methods. When the locating finger of the kickover tool contacts the stop in the orienting guide sleeve in the mandrel, the kick spring pivots the lower section of the kickover tool, the pulling tool or the running tool and valve into the kicked-over position. Correct retrieval is assured by the orienting guide sleeve in the mandrel. Once the wireline device is retrieved, a shear pin in the finger housing and release plunger assembly is sheared, permitting the kickover tool to be returned to the surface.

Figure 2A. In the Pulling procedure, the kickover tool and pulling tool are made up onto the wireline tool and lowered through the tubing until the kickover tool is below the selected mandrel.

Figure 2B. The kickover tool is raised slowly upward through the tubing until the finger on the kickover tool contacts the orienting sleeve slot and stops. Tension is pulled on the wireline until the tool releases and kicks over. The tools are then lowered until a loss of weight indicates that the kickover tool has located the side pocket of the mandrel.

Figure 2C. Downward jarring securely connects the pulling tool to the latch.

Figure 2D. Upward jarring shears a pin in the latch and releases the valve from the mandrel. The tool string and valve can then be retrieved from the well.



(courtesy of CAMCO Products and Services)

The Lease Pumper's Handbook

Appendix A
Tools and Records

Section 6

55-GALLON DRUM MEASUREMENTS

Drum Horizontal Gallons	Drum Horizontal m^3	Measured Depth Inches	Measured Depth mm	Drum Vertical Gallons	Drum Vertical m^3
0.90	0.003	1	25	1.72	0.007
2.51	0.010	2	51	3.45	0.013
4.54	0.017	3	76	5.17	0.020
6.88	0.026	4	102	6.90	0.026
9.47	0.036	5	127	8.62	0.033
12.26	0.046	6	152	10.34	0.039
15.19	0.058	7	178	12.07	0.046
18.25	0.069	8	203	13.79	0.052
21.39	0.081	9	229	15.58	0.059
24.59	0.093	10	254	17.24	0.065
27.82	0.105	11	279	18.97	0.072
31.06	0.118	12	305	20.69	0.078
34.28	0.130	13	330	22.41	0.085
37.46	0.142	14	356	24.14	0.091
40.56	0.154	15	381	25.86	0.098
43.56	0.165	16	406	28.59	0.108
46.43	0.176	17	432	29.31	0.111
49.12	0.186	18	457	31.03	0.118
51.60	0.195	19	483	32.76	0.124
53.81	0.204	20	508	34.48	0.131
55.66	0.211	21	533	36.21	0.137
57.00	0.216	22	559	37.93	0.144
		23	584	39.65	0.150
		24	610	41.38	0.157
		25	635	43.10	0.163
		26	660	44.83	0.170
		27	685	46.55	0.176
		28	711	48.25	0.183
		29	737	50.00	0.189
		30	762	51.72	0.196
		31	787	53.45	0.202
		32	813	55.17	0.209
		33	838	56.89	0.215
		33.25	845	57.33	0.217

Calculations based on:

Drum height = 33.35 inches or 845 mm
Drum capacity = 57.325 gals. or 0.217 m^3

THE BARREL CHART

The barrel chart is handy for calculating how much chemical is on hand. This is especially important at the end of the month in determining how much chemical is on hand, what types, and whether a waiting period for delivery is required. Most chemicals used to treat crude oil, clean tank bottoms, treat injection water, inject as a casing preservative, treat scale accumulation, or other purposes on the lease are custom blended. If chemicals are not ordered until the supplies are deplete, the lease pumper may run out of required chemicals before they can be blended and delivered. This may result in a lot of difficult-to-treat crude oil accumulating.

The barrel chart allows the amount of chemical in a barrel to be computed whether the barrel is standing vertically or lying on its side. Although the chart is in 1 inch increments, it is easy to interpolate to the nearest quarter-inch if required. If a barrel is used for short time tests on wells, this chart is extremely useful.

The chemical record should be updated in the **lease information and performance handbook** every month. This gives the lease pumper an instant reference of monthly use of every chemical stocked, and consumption and restock dates are easily projected long in advance of running out. It also allows the computation of the amount of chemical consumed per hundred barrels of oil sold. These figures can help the lease pumper determine whether chemical consumption is appropriate for production needs and results.

The chemical records will also correctly identify the contents of every barrel of liquid held on the lease and the amount on hand. If the contents of a barrel are unknown, a company must pay to have the chemical analyzed and identified so that it can be disposed of properly to meet environmental regulations. If accurate records are kept, a great deal of money can be saved. Thus, the lease pumper should keep good records and never allow the lease to accumulate even one barrel of unknown liquids.

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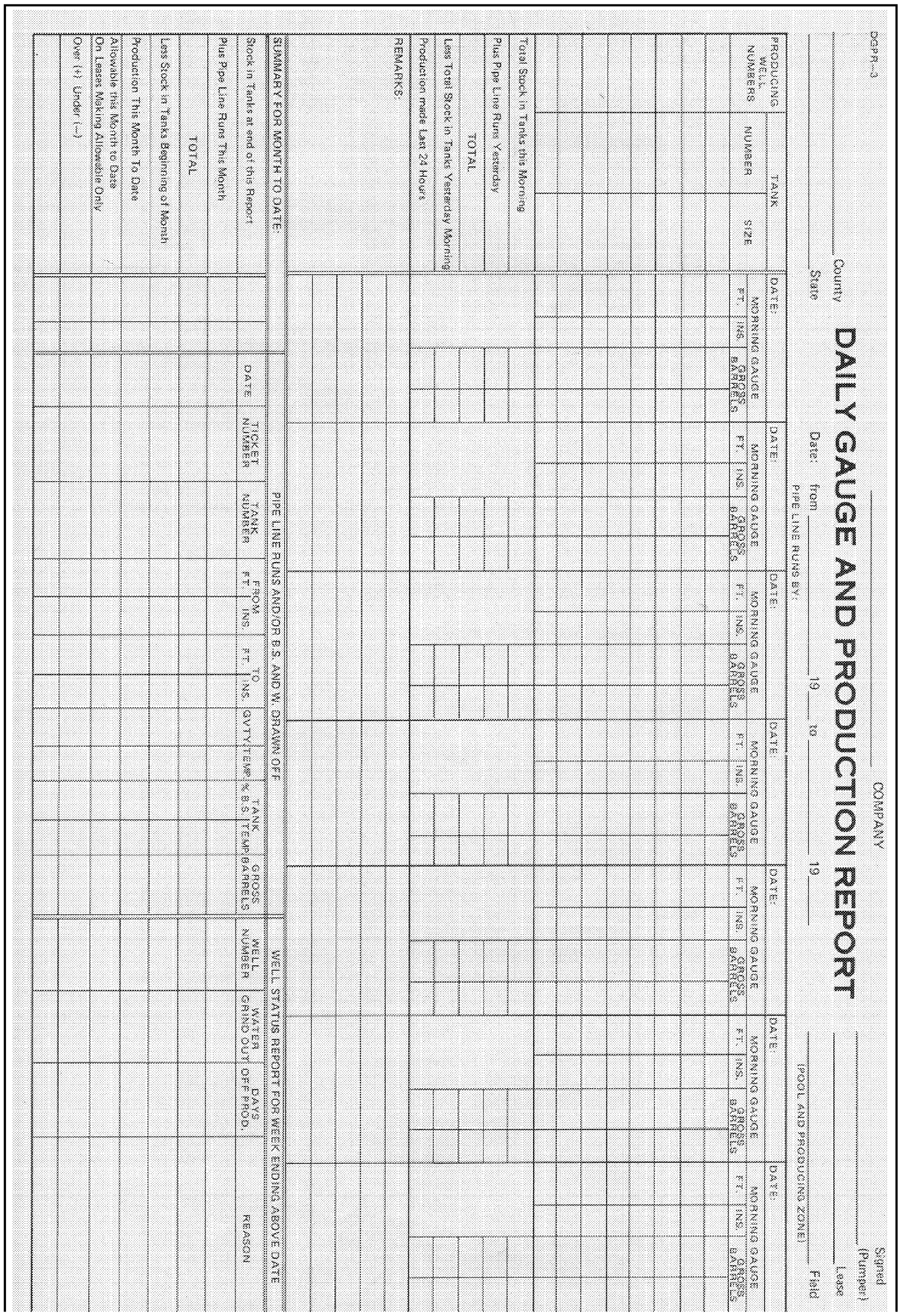
Section 7

THE 7-DAY DAILY GAUGE REPORT



DGPR—3

DAILY GAUGE AND PRODUCTION REPORT

_______ COMPANY

_______ County _______ State

Date: from _______ 19___ to _______ 19___

PIPE LINE RUNS BY: _______

_______ (POOL AND PRODUCING ZONE) _______ Field

_______ Lease

Signed (Pumper) _______

PRODUCING WELL NUMBERS	TANK NUMBER	TANK SIZE	DATE: MORNING GAUGE FT.	INS.	GROSS BARRELS	DATE: MORNING GAUGE FT.	INS.	GROSS BARRELS	DATE: MORNING GAUGE FT.	INS.	GROSS BARRELS	DATE: MORNING GAUGE FT.	INS.	GROSS BARRELS	DATE: MORNING GAUGE FT.	INS.	GROSS BARRELS	DATE: MORNING GAUGE FT.	INS.	GROSS BARRELS	DATE: MORNING GAUGE FT.	INS.	GROSS BARRELS
Total Stock in Tanks this Morning																							
Plus Pipe Line Runs Yesterday																							
TOTAL																							
Less Total Stock in Tanks Yesterday Morning																							
Production made Last 24 Hours																							

REMARKS:

SUMMARY FOR MONTH TO DATE:	
Stock in Tanks at end of this Report	
Plus Pipe Line Runs This Month	
TOTAL	
Less Stock in Tanks Beginning of Month	
Production This Month To Date	
Allowable this Month to Date On Leases Making Allowable Only	
Over (+) Under (—)	

PIPE LINE RUNS AND/OR B.S. AND W. DRAWN OFF

DATE	TICKET NUMBER	TANK NUMBER	FROM FT.	FROM INS.	TO FT.	TO INS.	GVTY	TEMP	% B.S.	TANK TEMP	GROSS BARRELS

WELL STATUS REPORT FOR WEEK ENDING ABOVE DATE

WELL NUMBER	WATER GRIND OUT	DAYS OFF PROD.	REASON

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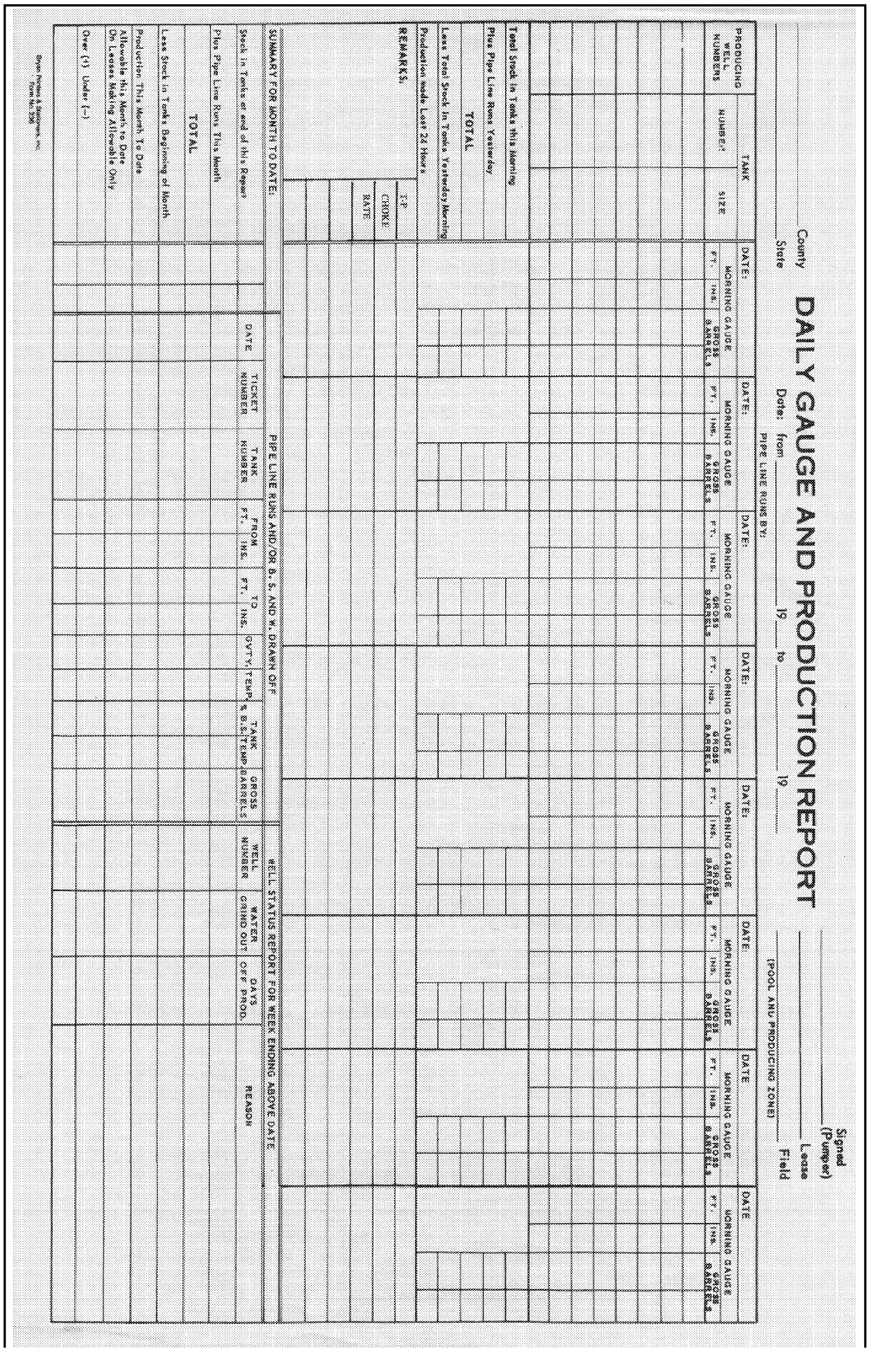
Section 8

THE 8-DAY DAILY GAUGE REPORT



DAILY GAUGE AND PRODUCTION REPORT

County ____ State ____ Date: from ____ 19__ to ____ 19__ PIPE LINE RUNS BY: ____ (POOL AND PRODUCING ZONE) ____ Signed ____ (Pumper) ____ Lease ____ Field

PRODUCING WELL NUMBERS | TANK NUMBER | SIZE | DATE: MORNING GAUGE FT. INS. GROSS BARRELS (eight columns)

Total Stock in Tanks this Morning
Plus Pipe Line Runs Yesterday
TOTAL
Less Total Stock in Tanks Yesterday Morning
Production made Last 24 Hours
REMARKS: T.P. CHOKE RATE

SUMMARY FOR MONTH TO DATE:
Stock in Tanks at end of this Report
Plus Pipe Line Runs This Month
TOTAL
Less Stock in Tanks Beginning of Month
Production This Month To Date
Allowable this Month to Date On Leases Making Allowable Only
Over (+) Under (–)

PIPE LINE RUNS AND/OR B.S. AND W. DRAWN OFF: DATE | TICKET NUMBER | TANK NUMBER | FROM FT. INS. | TO FT. INS. | GVTY. | TEMP. | TANK B.S. TEMP | GROSS BARRELS

WELL STATUS REPORT FOR WEEK ENDING ABOVE DATE: WELL NUMBER | WATER GRIND OUT | DAYS OFF PROD. | REASON

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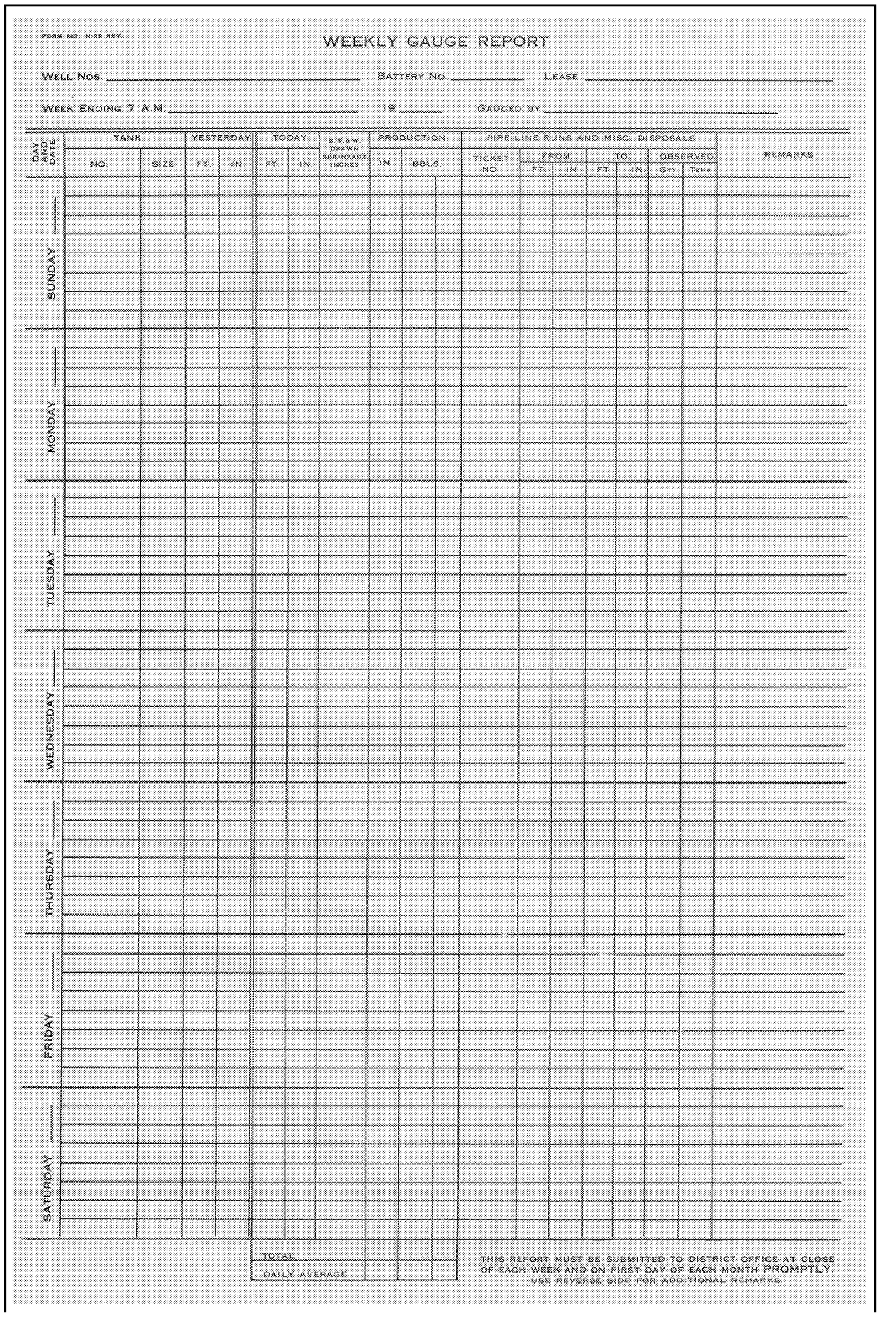
Section 9

THE WEEKLY GAUGE REPORT (VERTICAL)



FORM NO. N-38 REV.

WEEKLY GAUGE REPORT

WELL NOS. ______ BATTERY NO. ______ LEASE ______

WEEK ENDING 7 A.M. ______ 19 ______ GAUGED BY ______

DAY AND DATE	TANK		YESTERDAY		TODAY		B.S.&W. DRAWN SHRINKAGE INCHES	PRODUCTION		PIPE LINE RUNS AND MISC. DISPOSALS							REMARKS
	NO.	SIZE	FT.	IN.	FT.	IN.		IN	BBLS.	TICKET NO.	FROM FT.	FROM IN.	TO FT.	TO IN.	OBSERVED GTY	OBSERVED TEMP	
SUNDAY																	
MONDAY																	
TUESDAY																	
WEDNESDAY																	
THURSDAY																	
FRIDAY																	
SATURDAY																	

TOTAL

DAILY AVERAGE

THIS REPORT MUST BE SUBMITTED TO DISTRICT OFFICE AT CLOSE OF EACH WEEK AND ON FIRST DAY OF EACH MONTH PROMPTLY.
USE REVERSE SIDE FOR ADDITIONAL REMARKS.

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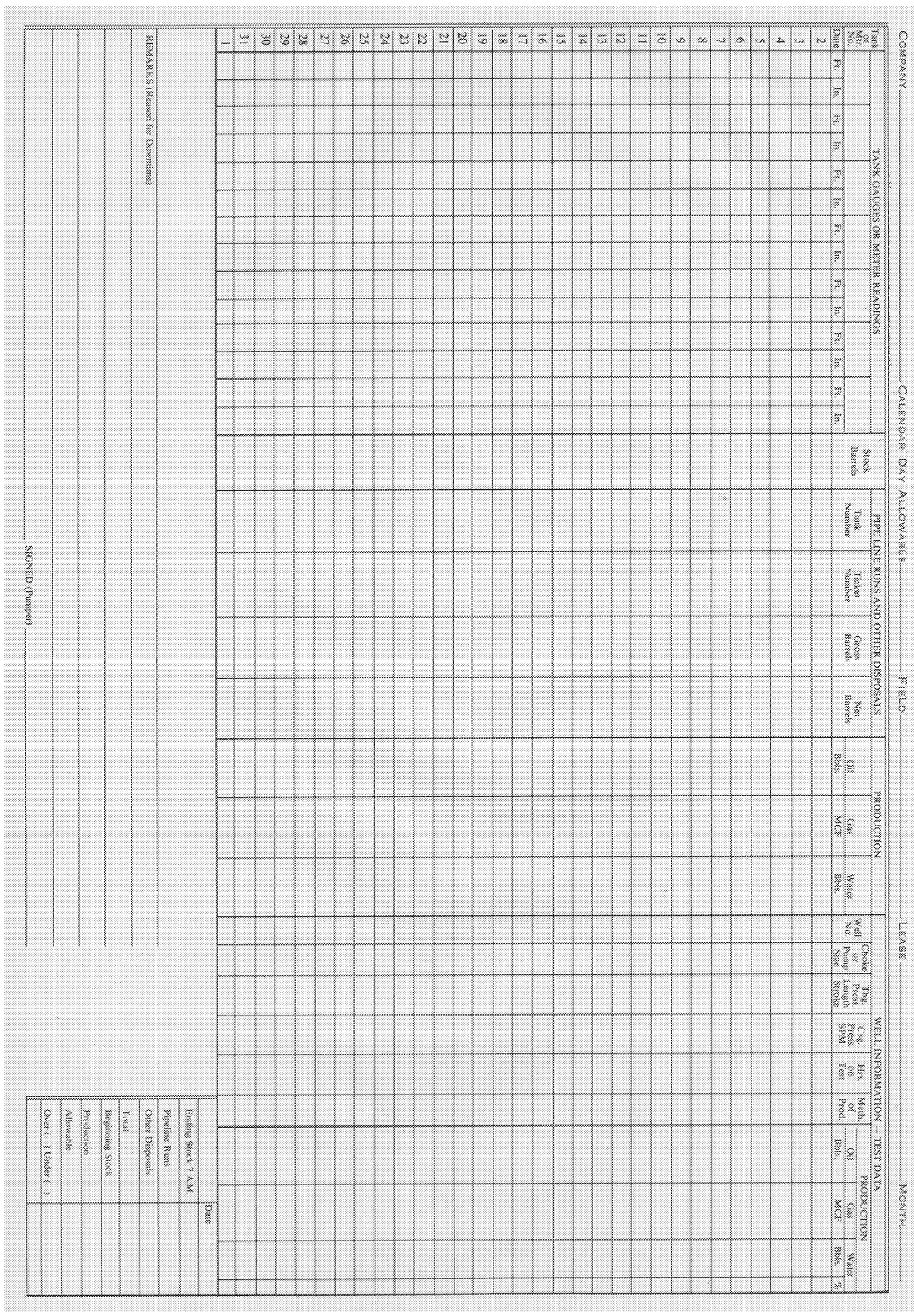
Appendix A
Tools and Records

Section 10

THE MONTHLY GAUGE REPORT


COMPANY
CALENDAR DAY ALLOWABLE
FIELD
LEASE
MONTH
Tank or Mtr. No.
Date
TANK GAUGES OR METER READINGS
Ft. In. Ft. In. Ft. In. Ft. In. Ft. In. Ft. In. Ft. In.
Stock Barrels
PIPE LINE RUNS AND OTHER DISPOSALS
Tank Number
Ticket Number
Gross Barrels
Net Barrels
PRODUCTION
Oil Bbls.
Gas MCF
Water Bbls.
WELL INFORMATION — TEST DATA
Well No.
Choke or Pump Size
Tbg. Press. Length Stroke
Csg. Press. SPM
Hrs. on Test
Meth. of Prod.
PRODUCTION
Oil Bbls.
Gas MCF
Water Bbls. %
2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 1
REMARKS (Reason for Downtime)
SIGNED (Pumper)
Date
Ending Stock 7 A.M.
Pipeline Runs
Other Disposals
Total
Beginning Stock
Production
Allowable
Over ( ) Under ( )

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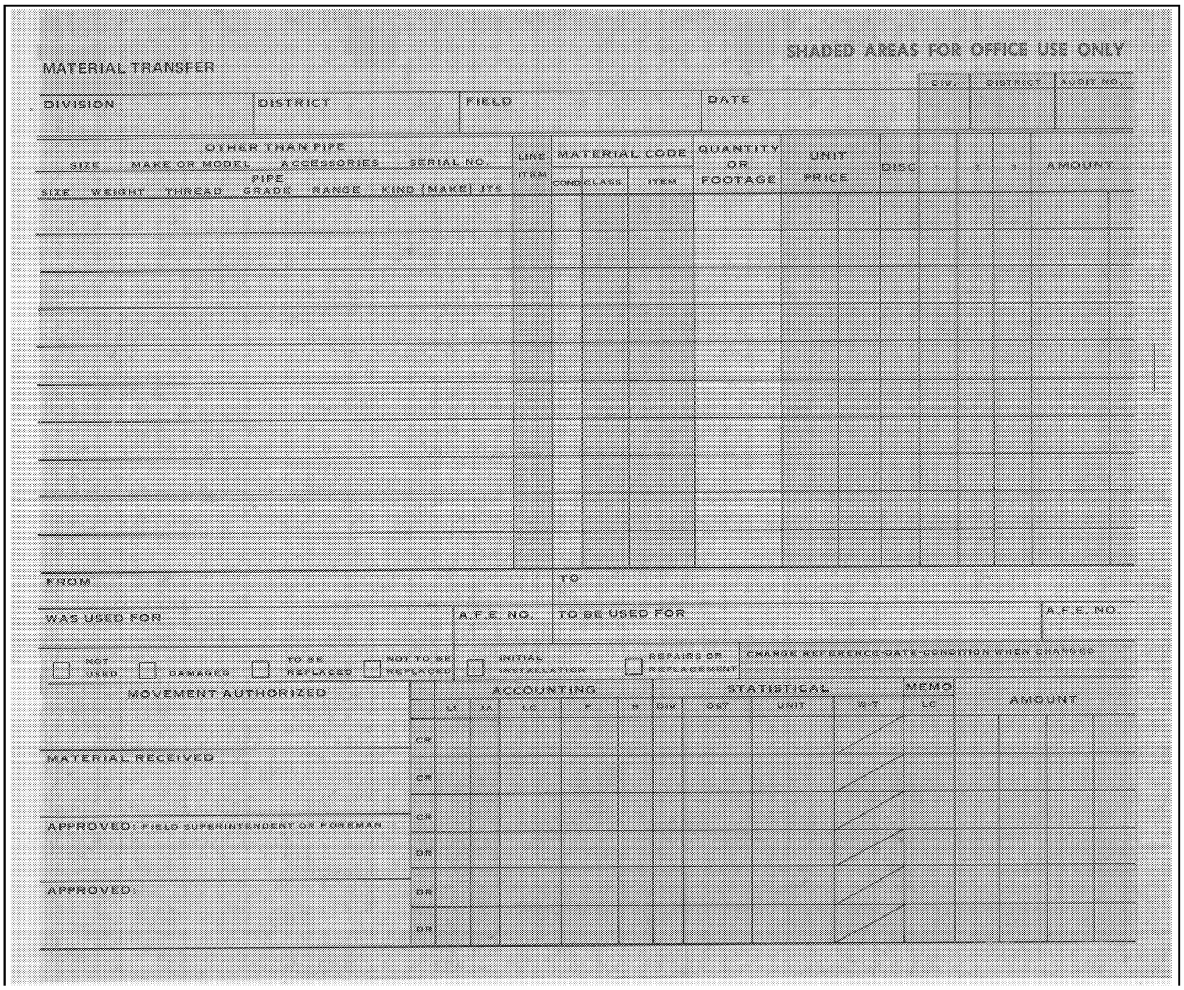
Tools and Records

Section 11

MATERIALS TRANSFER RECORD



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Section 12

PIPE TALLY SHEET

☐ New Completion ☐ Workover

Oil Company ________ Well No. ________ Field ________ Lease ________

Company Man ________ Date Drilled ________ County ________ State ________

JT. NO	FT	100THS	JT. NO.	FT	100THS	JT NO.	FT	100THS	JT. NO.	FT	100THS
1											
2											
3											
4											
5											
6											
7											
8											
9											
10											
11											
12											
13											
14											
15											
16											
17											
18											
19											
20											
21											
22											
23											
24											
25											
TOTAL											

TOTALS THIS PAGE ________

AV. JOINT LENGTH ________

REMARKS: ________

Date of Tally ________

No. Jts. on Location ________

Tbg. Sz. ____ Thd. ____ Wt. ____ Gr. ____

Csg. Sz. ____ Wt. ____ Gr. ____

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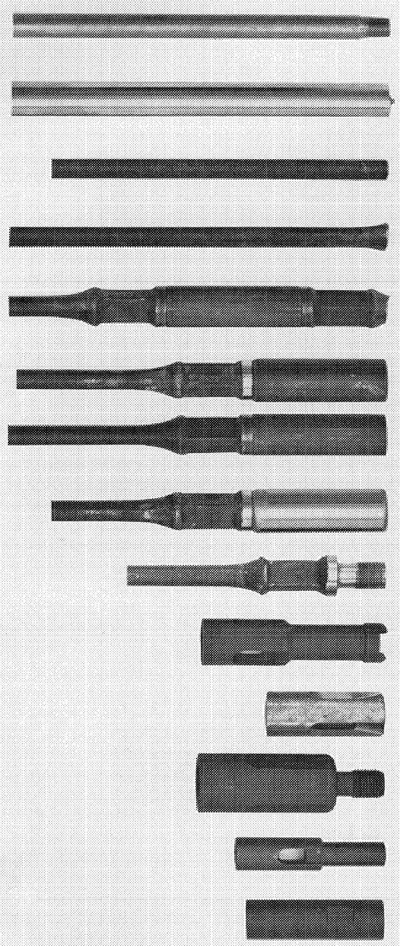
Section 13

FISHING RODS



	Broken Part	Use one of these tools; try it out above ground first.
1.	Valve Rod	Combination tools, Reversible slip tool, Little Giant.
2.	Polish Rod	Reversible slip tool, (will not work on hard-overlayed rods).
3.	Sucker Rod body break	Combination tools, Reversible slip tool, Little Giant.
4.	Sucker Rod bead break below joint	Reversible slip, Combination tools, Little Giant.
5.	Sucker Rod bead break on top of joint	Sleeve type tools, Mousetrap, (snap ring tool doesn't have a deep enough "throat" to catch the lower rod shoulder).
6., 7.	Sucker Rod pin break or coupling break	Combination tools, Reversible tool, Mousetrap. Tapered tap may be used if pin strips out (cut tap to fit).
8.	Pin break on hard overlay	Combination tools, Mousetrap. Tapered tap may be used if pin strips out (cut tap to fit).
9.	Sucker Rod Pin	Combination tools, Reversible slip.
10.	Fish neck on top of Pump's Rod Guide	Combination tools, Reversible slip, Tapered tap.
11.	Cage Standing valve	Tapered tap.
12.	Pin top Cage	Reversible slip type, Little Giant. This pin is short, so try one out above ground to be sure slips will reach.
13.	Top Plunger Cage	Reversible slip type, Tapered tap.
14.	Closed Cage	Tapered tap (cut-off to fit).

(courtesy of Trico Industries)

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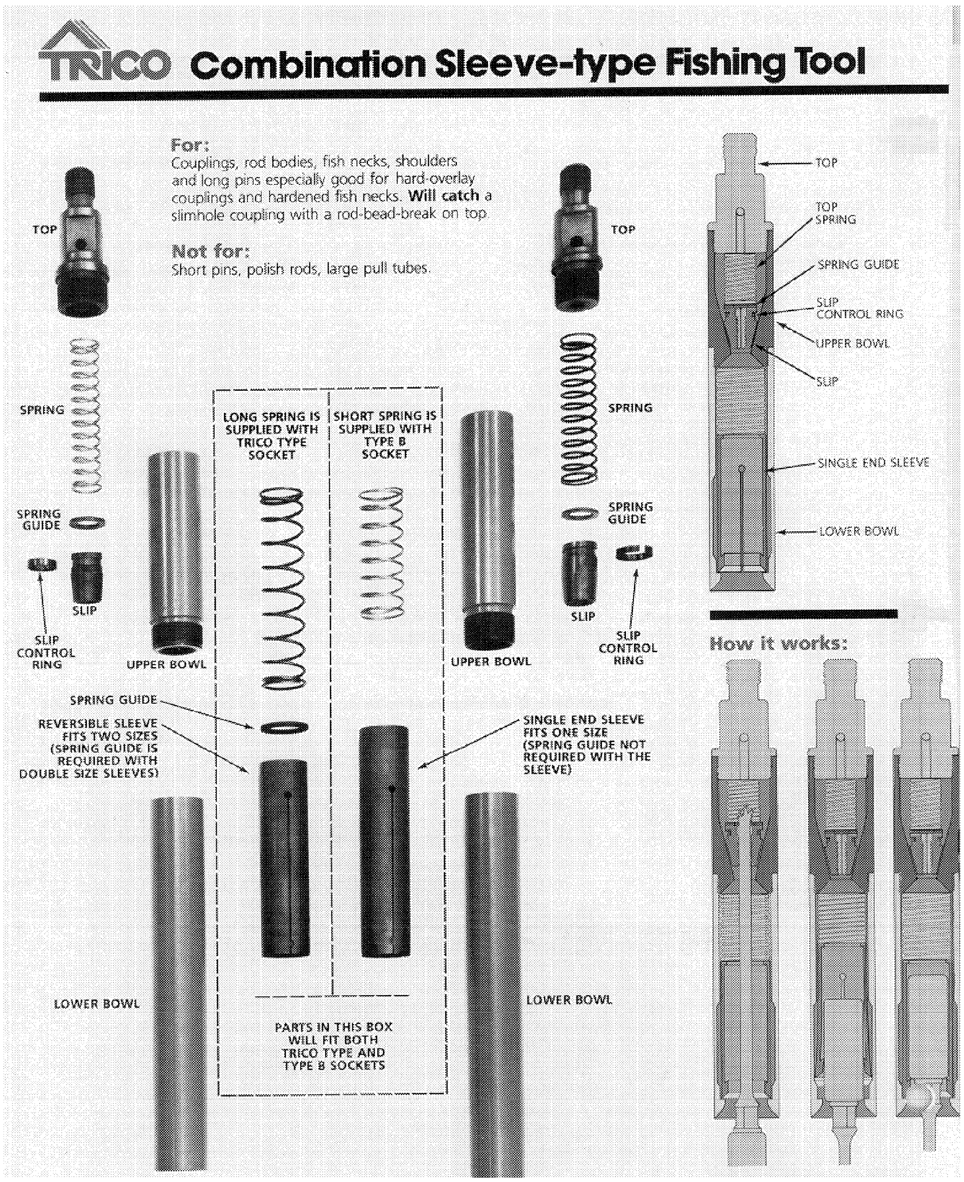
Section 14

ROD FISHING TOOLS



(courtesy of Trico Industries)

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Section 15

LEASE INFORMATION RECORD

LEASE INFORMATION

Name of Lease ______________________________
Location of Lease ______________________________
Well Number________________ Depth of Well______________ Date Drilled_____________

PUMPING UNIT INFORMATION

Date Installed______________
Manufacturer____________________________ Style of Unit____________________________
Size______________ Serial No.______________________ Direction of Rotation____________
Stroke Lengths Available_______________________________ Length in Use______________
Gear Ratio_________________________ Strokes Per Minute Now_______________________
Pumping Unit Sheave Diameter_______________ Number of Grooves_____________________
Belt Width _______________________ Number and Size of Belts________________________
Shaft Size____________________ Keyway_______________ Maximum Size ______________
Style of Pumping Unit Skid________________________ Style of Base____________________
Gearbox Oil________________ Capacity_____________ Bearing Grease__________________
Rod Lubricator Oil __________________________ Stuffing Box Lubrication_______________
Prime Mover_______________________________ Strokes Per Minute___________________
Remarks______________________________

BELT DRIVE INFORMATION

Number of Belts____________ Size____________ Length______________ Type___________
Belt Capacity: Prime Mover__________________ Pumping Unit_________________________
Sheave Description: Prime Mover: Diameter_________ Shaft Size________Keyway________
Pumping Unit: Diameter________ Shaft Size________ Keyway________
Prime Mover Adjustment Available (Inches)
Toward Unit_____________________ Away from Unit_________________________
How Will This Affect Belt Guard?______________________________

WELLHEAD INFORMATION

Lease______________________ Well No.____________________ Date Listed______________
Polished Rod: Thread Up___________ Thread Down____________ Length________________
Polished Rod Liner: I.D.______ O.D._____ Length_______________ Gasket Size___________
Lift Pony on Top of Polished Rod ______X______X_____________
Lubricator Brand ______________Pad Description________________ Oil Used_____________
Stuffing Box Brand.________________________I.D. of Packing___________________________
Packing Brand __________________Inserts Needed (Describe)___________________________
________________________ Packing Quality or Info._____________________________________
Polished Rod Clamp Bolts: How Many? ________ Diameter__________ Length_____________
Pumping Tee__________________________ Bleeder Valve _______________________________
Wing Valve___________________________ Wing Check Valve_____________________________
Casing Valve__________________________ Casing Check Valve __________________________
Other (Rotators, Misc.)____
____

CASING RECORDS

Depth from Wellhead to Perforations ____
Description of Perforations ____
Open Hole Below Perforations ____

PIPE AND TUBING

Type of Tubing. (Check One) H-40______ J-55______ C-75______ N-80_______ P-105______
Other (Describe) ____
Threads: 8 Round __________________________ Other than 8 Rd.________________________
Average Joint Length ___________________ Pipe Measured: Threads Off______ Overall______
Packer or Holddown. To Set____
To Release____ Tension Pulled____________Pounds

COMMENTS:

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MOTOR/ENGINE RECORDS

Electrical Motor Information

Manufacturer ____________________________ Type of Frame______________________________
Horsepower _____________________________ Volts Required______________________________
Amperage _______________________________ RPM _____________________________________
Shaft Diameter ___________________________Keyway___________________________________
Sheave Diameter____________________ Style___________________ Grooves_______________
Can Voltage Be Changed? (Yes/No)____________ If Yes, describe_________________________
____
Mounting Bracket: Width_______________________ Length______________________________

Engine Information

Field _____________________________ Lease__________________ Location _________________
Type of Installation____
Make of Engine____________________ Model_________________ Serial No._________________
Number of Cylinders________________ Rings__________________ Bearings _________________
Valve Clearances: Intake______________________ Exhaust_______________________________
Spark Plugs_______________________ Magneto _______________ Magneto Rotation_________
Coil ______________________________ Distributor ____________________________________
Carburetor____
Battery size________________________ Date Installed______________________________
Starter _____________________________ Generator___________________________________
Oil: Capacity_______________________ Brand__________________ Weight_________________
Oil Filter __________________________ Change Schedule______________________________
Radiator: Capacity_________________ Quarts Antifreeze________ Freeze point______________
Radiator Hose Sizes: Upper_________ Lower__________________ Water pump______________
Fan belt ___________________________ Clutch____
Shaft Diameter ______________________ Keyway_______________________________________
Sheave Style _______________________ Diameter_______________ Number of grooves________
Drive Belt Size and Length ____
Date Engine Was Installed______________________ Date Overhauled______________________
Gas Log and Scrubber Information ____
Maintenance Notes ____
____

APPENDIX B

PUMPING UNITS

The Lease Pumper's Handbook

Appendix B
Pumping Units

Section 1

TYPES AND STYLES OF MECHANICAL PUMPING UNITS

B1-1. Development of the Walking Beam Mechanical Pumping Unit.

Mechanical pumping units have undergone many advances since the early years when one central roundhouse station pumped many wells. During the mid-1920's, Lufkin Industries, Inc. made their first pumping unit. This wood beam unit began capturing part of the market that had been supplied by manufacturers of the round wooden wheel, the roundhouse model, and several other styles of units. The single counterweight gearbox with one pitman arm was first marketed in 1925 and was very efficient. The pump jack and workover mast were removed from the pumping unit shown in Figure 1 in the late 1980's, though the unit was still pumping every day. It has pumped several hundred thousand barrels of oil.

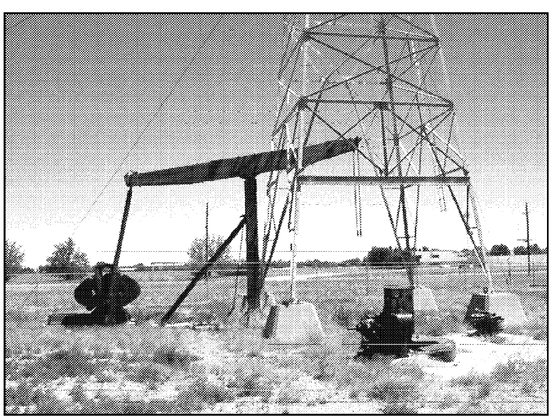

Figure 1. Lufkin pumping unit from the early 1920s.

A gear-driven pump jack powered by a flat belt was developed by Alamo Duplex. To move the pumping unit out of gear, the belt was shifted over to an idler gear. These became more popular for water wells than oil wells, because of their limited size. The unit pictured in Figure 2 was removed from service in the 1970's. Note that the wellhead and stuffing box were designed as part of the unit base.

Figure 2. The Alamo Duplex Geared Pumping Unit with flat belts.

Figure 3. The 1926 Lufkin Crank-Balanced Pumping Unit is still in service today with only slight modification.

The next pumping unit that Lufkin offered began manufacture on July 15, 1926, although it was 1931 before the design became popular. This unit with twin cranks and counterweights proved to be an ideal design (Figure 3). It was well balanced and even served as the stepping stone for development of the Mark series. After more than seventy years of service, this mechanical beam-balanced model, with only minor changes, is still available for purchase today.

B1-2. Styles of Pumping Units.

There are four basic styles of beam-balanced pumping units:

- **Conventional units.**
- **The Mark series units.**
- **Air-balanced units.**
- **Low-profile units.**

These styles are so common that three or four of them may be represented on a single lease.

B1-3. Conventional Units.

Conventional units are characterized by a Samson post in the middle of the walking beam. However, there are four major variations in conventional unit design. These include:

- Beam-balanced.
- Crank-balanced.
- Reverse Mark.
- Slant-hole.

Beam-balanced. This pumping unit gets its name from the fact that weights are added to the tail of the walking beam behind the tail bearing or equalizer bearing to counter balance the weight of the sucker rod string. Many manufacturers have sold variations of this design over the years, such as the small unit shown in Figure 4.

Figure 4. A small beam-balanced pumping unit.

It may be necessary to lift the cover of the gearbox to know the correct direction of rotation for this unit while it is in operation and to determine how to maintain it. Some will have herringbone gears that permit them to rotate in either direction. Others are chain driven, and some of these get lubrication only when they are rotated in the correct direction. Some operate with 50 weight motor oil in the gearbox, others require 90 weight gear oil, and some even require 120 weight oil for long life and proper performance. Holes are drilled in the flange of the walking beam to permit changing the stroke length. These units are generally used for shallow wells.

The standard beam-balanced pumping unit with counterweight balance and two pitman arms has been the workhorse of the industry since Lufkin put it on the market in 1926. Used primarily for medium to deep wells, it is still manufactured by several companies.

Crank-balanced. This unit has already been pictured in (Figure 3). The crank-balanced unit was the workhorse of the industry for more than fifty years without much competition. This unit is still popular today and continues to be sold.

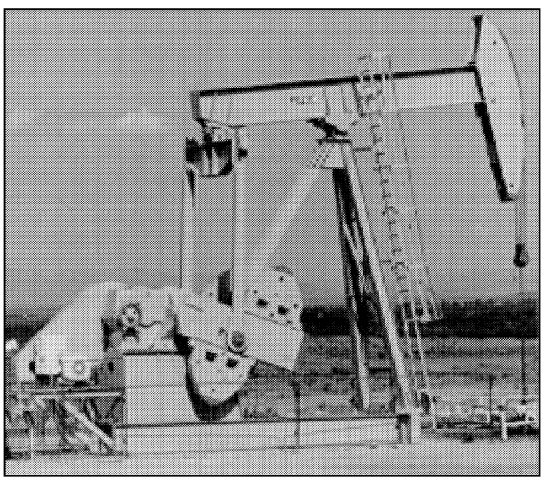

Figure 5. The Reverse Mark pumping unit.
(courtesy of Lufkin Industries, Inc.)

Reverse Mark model. A newer style of conventional unit being manufactured is the Reverse Mark unit. At a distance, it is difficult to distinguish it from the standard unit. However, note the differences in the pumping geometry apparent in Figure 5. These include the location of the saddle bearing in relation to the walking beam center and the off-center pitman arm pin hole. The improved performance of the Reverse Mark series results in a reduction in torque and power requirements. It can operate with a smaller reducer and prime mover.

Slant-hole model. To meet special needs, the slant-hole unit (Figure 6) was developed. These units can operate and pump wells at a deviation angle of 45 degrees. Slant-hole pumping units have a horse head that is much longer below the walking beam than a conventional head. As the unit makes a revolution, this longer head and other modifications cause the bridle to sweep forward with each stroke to provide the correct angle of 45 degrees.

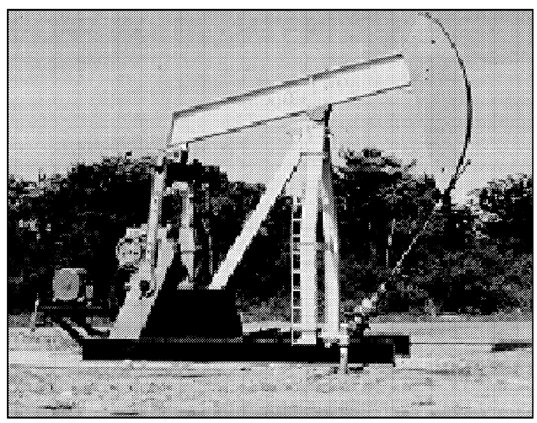

Figure 6. A slant-hole unit.
(courtesy of Lufkin Industries, Inc.)

B1-4. The Air-Balanced Pumping Unit.

The air-balanced unit has enjoyed a half century of service in the oil fields. Although it is not as common as the conventional and the mark series, in some areas it is extremely popular. Compressed air in a cylinder under the front of the walking beam is utilized to offset the weight of the column of rods and fluid in the well, eliminating the need for counterweights.

The air-balanced unit (Figure 7) is extremely desirable for deep, heavy pumping loads where the counterweight load needed to install a conventional unit would be prohibitive and a long stroke is desired. Another of the advantages of the air-balanced pumping unit is the accurate finger-tip control of the balance of the pumping load. This balance operates automatically.

The air-balanced unit has an air compressor mounted behind the gearbox for air makeup. To balance this unit the lease pumper merely disengages the clutch and observes where the walking beam stops. If it is horizontal, the unit is balanced. By turning a dial, the unit can be re-balanced in a few minutes. This is the only unit that offers this simple balancing feature for a massive pumping unit.

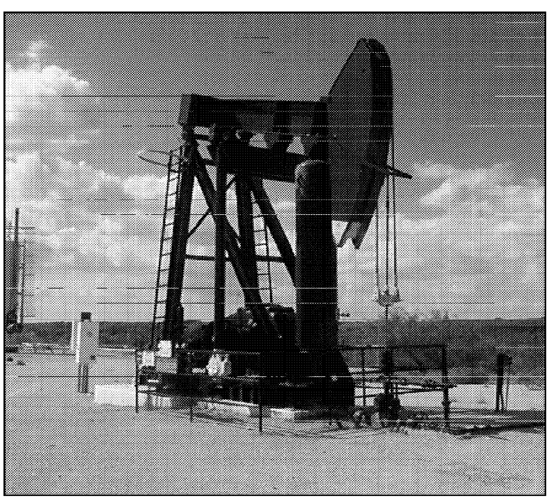

Figure 7. An air-balanced pumping unit.

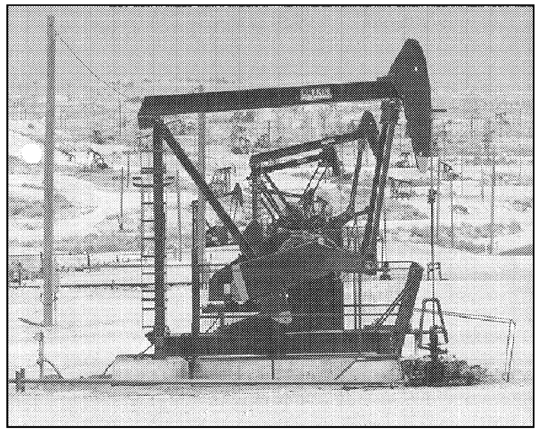

Figure 8. The Mark II Unitorque Pumping Unit.
(courtesy of Lufkin Industries, Inc.)

B1-5. Mark Unitorque Units.

The introduction of the Mark series pumping unit (Figure 8) by Lufkin Industries more than thirty years ago changed the trends in the pumping unit industry. This dramatically improved unit and its unique geometry revolutionized the design of mechanical pumping units everywhere. The Mark pumping unit design greatly improved pumping geometry and the efficiency of the pumping unit.

The Mark unit is lighter in weight, resulting in lowered materials and transportation costs. The unit requires just two lighter weight pads and is able to pump a deeper well. The dynamics of the unit also resulted in lowering horsepower requirements, lower lifting costs, lower peak loads, and longer rod life. For medium to deep wells, the Mark series is used in a large share of pumping unit installations.

B1-6. Low Profile Units.

Pumping units are located almost everywhere. This includes on farms and ranches, in cities, on golf courses, in orchards, and elsewhere. Some special application pumping units have been designed to reduce their intrusion on the vista and to prevent interference with other operations. For example, at one time pumping units in irrigated crop land were placed in holes to avoid interfering with sprinkler systems. With low profile units (Figure 9), giant sprinkling systems can operate and travel right over the pumping unit while watering crops. This installation may require the well to be completed with a lowered wellhead also to reduce the profile by lowering the base as much as possible. The low profile unit continues to be improved and fills a definite need in the industry.

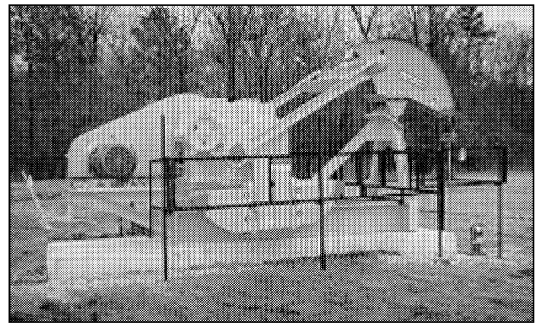

Figure 9. A low-profile pumping unit.
(courtesy of Lufkin Industries, Inc.)

B1-7. Other Styles of Pumping Units.

Many other styles of mechanical pumping units are available on the market, such as styles where the rods rotate. The sizes of the API recognized pumping units vary from the very small to the very large.

The Lease Pumper's Handbook

Appendix B
Pumping Units

Section 2

SELECTING AND SETTING UP PUMPING UNITS

B2-1. Selecting the Correct Pumping Unit Base.

When selecting a pumping unit, regardless of whether it is new or used, the first consideration is to choose an appropriate base. The base will generally be a metal skid or a pre-formed concrete structure. Bases are designed to meet many different conditions (Figure 1). For example, the type of prime mover is a critical factor. Multiple-cylinder engines require a different skid design than single-cylinder engines. If the prime mover is to be an electric motor, an elevated skid, built closer to the gearbox reduces the belt length and size of the belt guard. The shorter belt also gives much better service, lasts longer, and costs less.

A different concrete pad will be required for the shorter pumping units with elevated motors. If the pumping unit is to be set on the ground, with either compacted rock or sills, the steel base must be almost three times as wide as a pumping unit that is to be bolted down on a pre-formed concrete base.

Once a pumping unit is on the location and ready to install it, there are several important factors that must be considered, such as type of pumping unit skid base, selection of a good base for the crushed rock pad, and other factors. This section addresses many of these basic considerations.

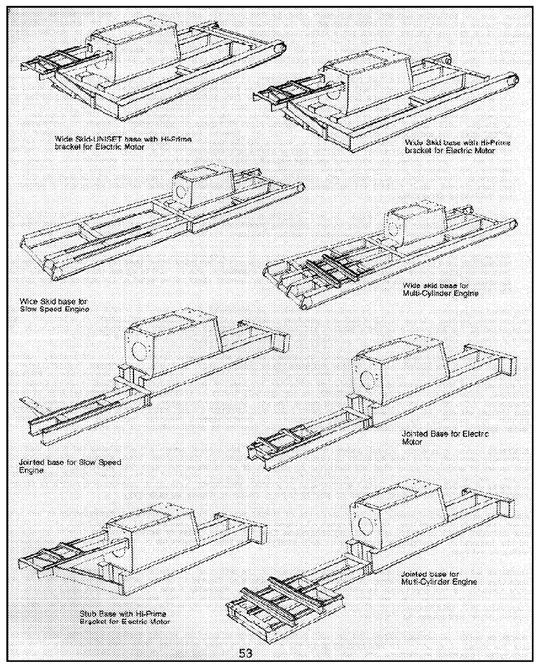

Figure 1. There are many styles of metal bases for different installation needs.
(courtesy of Lufkin Industries, Inc.)

B2-2. Height of the Base.

The pumping unit base must be high enough to allow sufficient distance for the necessary fittings between the horse head and the wellhead on the pump downstroke. To determine how high the base must be, the distance from the bottom of the pumping unit carrier bar on the downstroke to the top of the wellhead must be determined. With the riser nipple, the pumping tee, and the stuffing box installed, the height of wellhead above the ground must be measured. Many problems with base height result when these factors are not considered so that the surface pipe with the wellhead is set too high. This can cause the pumping unit to have to be placed on a high mound of crushed rock, pipe framed pumping unit stand, or concrete base. Occasionally, more than one base must be stacked on top of each other to solve this problem (Figure 2).

Figure 2. A pumping unit set on two concrete bases to allow for the height of the wellhead.

The depth of the well should also be considered. Shallow wells should have a lower wellhead than deep ones because the units are so small and low.

After determining the distance from the top of the stuffing box to the bottom of the carrier bar, 12 inches is subtracted to allow for the installation of a polished rod liner and possibly a rod lubricator, while providing room for a polished rod clamp. The remaining distance is the from the top of the polished rod liner to the bottom of the carrier bar on the downstroke.

B2-3. Preparing the Base.

There are three main factors to consider when installing a base for a pumping unit. These factors are :

- Earth stability and preparation.
- The type of skid on the pumping unit.
- Preparation of the base to receive the pumping unit.

Earth stability and preparation. Regardless of the style of base used, the pumping unit needs to be set on a firm bed of gravel. Once the height of the base has been determined, the area is covered with gravel or crushed rock and leveled. Some lease pumpers bury a straight 2x4 board in the center of the gravel for the full length of the base. This gives a satisfactory support for the level as the crew works the gravel to a flat surface. The level must also be turned across the pad to check side-to-side leveling to prevent the pumping unit from leaning to one side. After the gravel bed is level and the board removed, the space that the board occupied can be filled in with gravel by hand.

Type of skid base on the pumping unit. The style of pumping unit as well as the style of steel skid are important in deciding what pad and base design is used. Generally, pumping units with wide bases are placed on crushed rock pads with boards laid upon the pad. The boards extend beyond the width of the pumping unit skid base. In this way, the weight of the pumping unit is distributed over the length of the boards and, thus, spread over the crushed rock pad. When the boards are laid upon the rock pad, they are first leveled and stabilized—that is, sufficient rock is placed under and around the boards to keep them from shifting.

Pumping units that have narrow skids are generally placed on concrete bases—either pre-formed structures or poured-in-place concrete. This approach can also be used for units with wide skids. Pre-formed concrete bases are installed using techniques similar to the use of boards. In other words, the concrete blocks are placed on the crushed rock pad, leveled, and stabilized.

If the concrete is laid at the site, a smooth, level pad of concrete is poured (Figure 3). Often the pumping unit is bolted to the concrete base by means of bolts embedded in the concrete. The correct placement of the bolts can be made easier through the use of frames that help locate the bolt positions so that they line up with the holes in the skid of the pumping unit (Figure 4).

A pumping unit that uses a multiple-cylinder engine prime mover will usually be set on a full concrete base that may even be ell-shaped to allow for the engine.

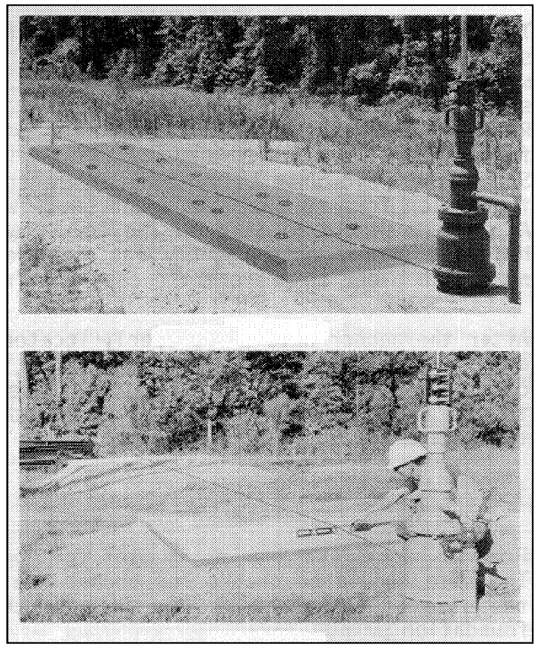

Figure 3. Laying out the concrete pad for a pumping unit.
(courtesy of Lufkin Industries, Inc.)

Preparing the base to receive the pumping unit. Before installing the base on the crushed rock pad, the pumping unit should be on hand and ready to install. Occasionally the steel base of the pumping unit must be modified before it can be mounted on the selected base. For example, mounting holes may be required to fit the bolts on the pre-formed concrete base.

Other factors that may need to be considered include the orientation of the pumping unit on the pad. For example, what is the best and safest way to get electricity to an electric motor prime mover? If an engine is used as a prime mover, the direction of the winter and summer wind should be considered so that the radiator of the engine can be positioned to take advantage of cooling in the summer and warming in the winter.

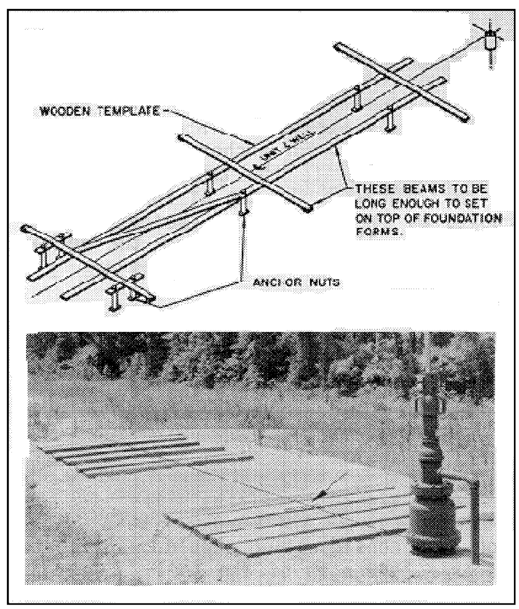

Figure 4. A frame can be used to assist in the placing anchor bolts in the correct locations for the pumping unit skid.
(courtesy of Lufkin Industries, Inc.)

B2-4. Centering the Horse Head Bridle Carrier Bar over the Hole.

Another item that should be carefully checked when installing the pumping unit is that the carrier bar is perfectly centered over the hole. When the rods hang perfectly centered in the stuffing box under load, the chances of a stuffing box leak are lessened and the need to buy packing is reduced. This also prevents polished rod and/or liner wear and metal-to-metal galling, scoring, and wear. Damaging the polished rod or liner due to unnecessary side wear or damage is expensive to repair and costly in packing replacement due to short working life. On a shallow well with a well-centered polished rod, a set of packing can last for several years and will not need to be tightened as often.

B2-5. Leveling the Pumping Unit.

Occasionally a pumping unit must be removed and the base re-leveled because of continuing problems with stuffing box leaks. Often this is caused by the pumping unit settling unevenly because of an unstable pad. The amount that the pumping unit is leaning can be easily determined by removing the packing from the stuffing box to check the centering of the polished rod in the stuffing box with the horse head at the top, at the center, and at the bottom of the stroke. This is a check that the lease pumper can easily make when a stuffing box begins to leak excessively. Occasionally a tilted pumping unit can be leveled by inserting shims between the pumping unit and the base. Otherwise, the base must be re-leveled to support the pumping unit evenly.

B2-6. Safety Grounding.

When a pumping unit has an electric motor as a prime mover, one of the possible dangers is electrical shock from a short. A grounding system should be installed on all electrically driven pumping units for personal protection. The system is made up of bare copper ground wires that connect appropriate areas of the wellhead, such as the electric motor, the control box, and the pumping unit. A clamp was formerly attached to one of the 2-inch casing nipples on the wellhead beside the casing valve. However, tests have shown that having the ground cable attached to the wellhead can cause galvanic corrosion that leads to tubing, casing, and rod corrosion. The accepted practice today utilizes a ground rod driven into the earth near the control panel.

The best method of preventing an electrical shock in the event of a short is to periodically check the electrical system to be sure the grounding system is intact. Generally, there are no problems maintaining the integrity of this system, except for the line that is attached to the wellhead, which is where the electricity is supposed to go in event of a problem. When the well is worked on, the ground line may be removed and not reattached at the end of the job. It can also be broken off just from workers walking on it at the wellhead. The lease pumper should check this clamp a minimum of every six months on every well.

B2-7. Selecting Guard Rails and Belt Guards.

Protective guards should be installed around all moving equipment. These devices not only protect workers around the unit, but they protect cows, horses, sheep, and wild animals from injury. Guard rails (Figure 5) should be selected to meet particular needs. To do so, adjustments may have to be made beyond the manufacturer's rails. These are designed primarily to protect people. Sheep fencing or other suitable protection may also be added according to need.

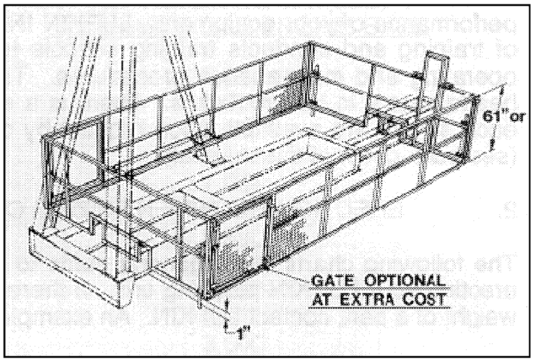

Figure 5. One style of guard rails.
(courtesy of Lufkin Industries, Inc.)

Counterweights on the Mark series pump move upward toward the wellhead and an appropriate guard should always be placed between the front of the pumping unit and the wellhead.

Occasionally it is desirable to put guard rails only around the counterweight movement area. For some pumping units, this is a satisfactory arrangement.

Belt Guards. Belt guards (Figure 6) offer a large margin of safety when working around a pumping unit. When making and installing a belt guard, care must be exercised in the construction to be sure that it agrees with available belt lengths.

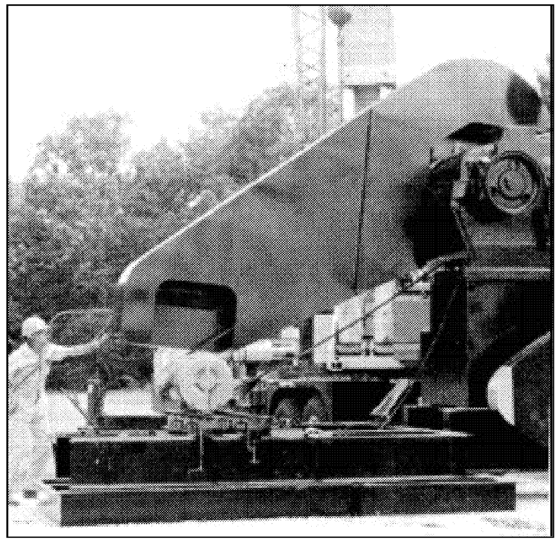

Figure 6. Belt guards installed on a large pumping unit.
(courtesy of Lufkin Industries, Inc.)

Appendix B
Pumping Units

Section 3

CHANGING PUMPING UNIT ADJUSTMENTS

There are many reasons for making changes in the design and adjustments of the mechanical pumping unit. Most of these changes in adjustments seek to achieve a more efficiently operating pumping unit, to change downhole pump action, to stimulate oil production, or to solve specific problems. Some of the common adjustments are:

- Changing the counterweight balance.
- Changing stroke length.
- Lowering and raising the rod string to stimulate gas locked or failing pumps.
- Changing the number of strokes per minute.
- Making changes such as belt length, motor size, dynamometer controls, etc.

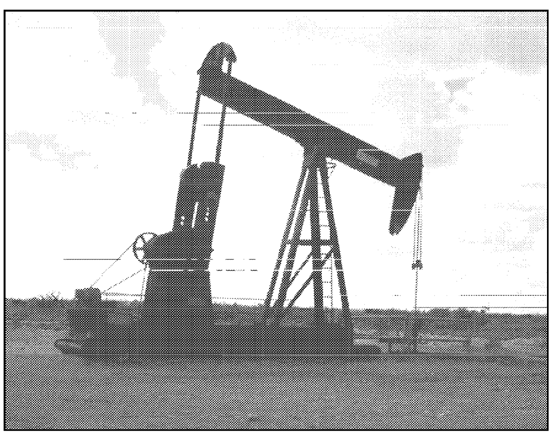

Figure 1. Because of a need to pump a large volume of water, this pumping unit is much larger than would normally be required.

Most of these changes are not typically performed by the lease pumper. Some require a crew and special equipment. Job descriptions vary, however, from lease to lease and with different lease operators. The lease pumper's duties also depend on the depth of the wells, pumping unit size, and daily work load. The purpose of this section is to give an overview of such procedures.

B3-1. Designing the Pumping Unit to Do the Job.

Regardless of the cause—natural water drive, water flood, etc.—the well may have to pump high volumes of water along with the oil. In Figure 1, an over-sized pumping unit has been installed on a shallow well to support production of the desired daily oil and water volume. The counterweights have been removed to achieve near balance of the rod load. This installation achieves the desired pumping goals, but it is not as satisfactory as a correctly designed pumping unit. The gearbox is oversized and may be operating at a higher RPM than is recommended by the manufacturer, which could lead to oil foaming and lubrication problems.

Pumping unit manufacturers will assemble and sell a long stroke unit with a reduced size gearbox designed to meet special needs. The requirement for custom-designed pumping units increased with the growing use of enhanced recovery. When pulling a pumping unit from storage to place it back into service, it may be necessary to check the manufacturer's production record to understand the design and capability of a pumping unit. As an illustration, Lufkin Industries, Inc. has a record of every unit that they have ever manufactured.

B3-2. Changing the Counterweight Position to Balance the Rod Load.

Counterweights are moved in or out on the crank as needed to balance the pumping load (Figure 2). The counterweights of the unit are adjusted along the crank arm to balance the weight of the rod string. The heavier the rod string, the farther out on the arm the weights must be. When moving these weights, it may be necessary to refer to the manufacturer's operation manual or hire an experienced service person to place the pitman arm in the correct position to perform this procedure, based on the power required to move them. There are several techniques used for balancing many older models.

Pumping unit weights are manufactured in several sizes to meet balancing needs. Thin, auxiliary weights can be added to the counterweight when it is not heavy enough.

When balancing counterweight loads on units that have electrical power, an ammeter should be used to monitor amperage on the upstroke and downstroke.

It has been customary through the years to balance the rod load with a slightly "rod heavy" attitude. This means that each time the unit stops pumping, the unit will stop on the downstroke and the polished rod in the hole. This has a tendency to keep the rod free of dirt and extends the life of the rod and packing.

The lease pumper should always check with the manufacturer's representative when making dramatic changes.

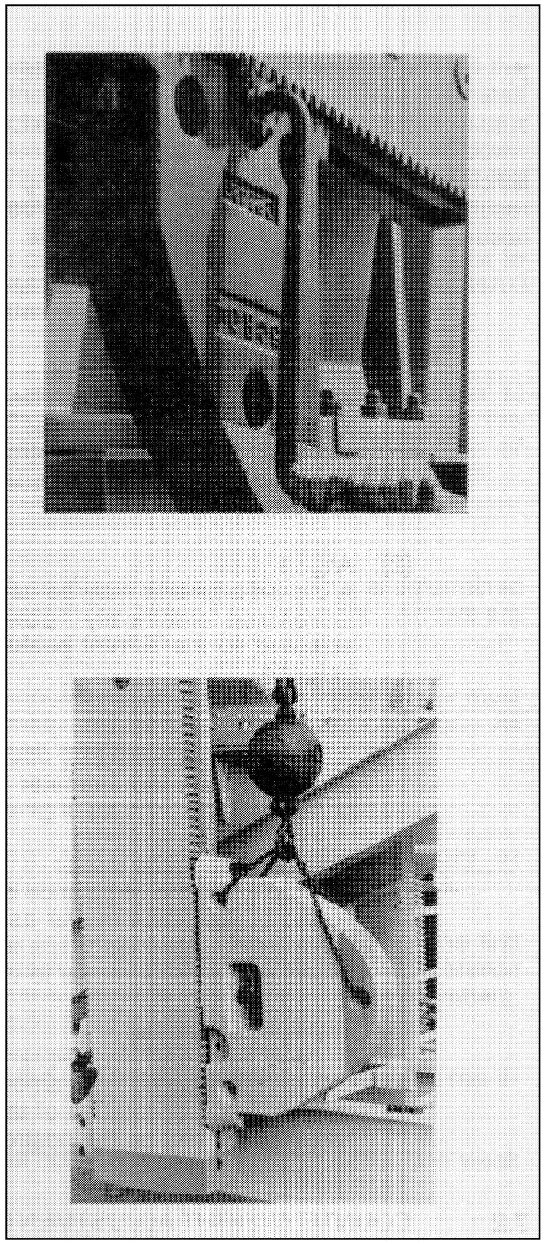

Figure 2. To balance some pumping units, the counterweights are repositioned.
(courtesy of Lufkin Industries, Inc.)

When weights are repositioned or removed from a pumping unit, the balance of the unit can suddenly shift with the weight of the rod string being applied to the end of the walking beam. This can cause a sudden and dangerous swing in the balance beam. To prevent this, most adjustment procedures require that the brake be chained to prevent the beam from moving (Figure 3).

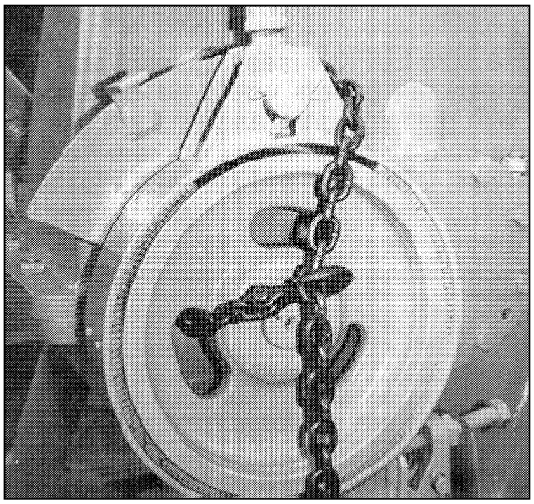

Figure 3. Correct procedure for chaining the brake.
(courtesy of Lufkin Industries, Inc.)

B3-3. Beam-Balanced Pumping Units.

For balancing beam-balanced pumping units, there are several styles of weights. Most weights are simply bolted onto the tail end of the walking beam. Some brands of units have limited adjustments, and others only have a means of adding or removing weights. Sometimes weights are added or removed by bolting them on. Others have racks that hold cast iron bars. The methods are not always obvious. If in doubt of the adjustment options or methods, the lease pumper should ask someone with appropriate experience.

B3-4. Changing Stroke Length.

The stroke length on most pumping units is adjustable. The crank arm generally has three holes in a line or in a triangular pattern so that moving the weights to a different hole will change the stroke length by several inches. Changing the stroke length on beam-balanced units is generally a matter of moving the walking beam and the U-bolts at the tail equalizer to a different set of holes. On some, the walking beam can also be moved on the Samson post also. When this is done, the unit may have to be realigned over the hole.

To change the stroke length on a crank and counterweight unit, the general procedure is:

1. To prepare the pumping unit for the change, move the counterweight to a position slightly below being straight across horizontally (Figure 4).

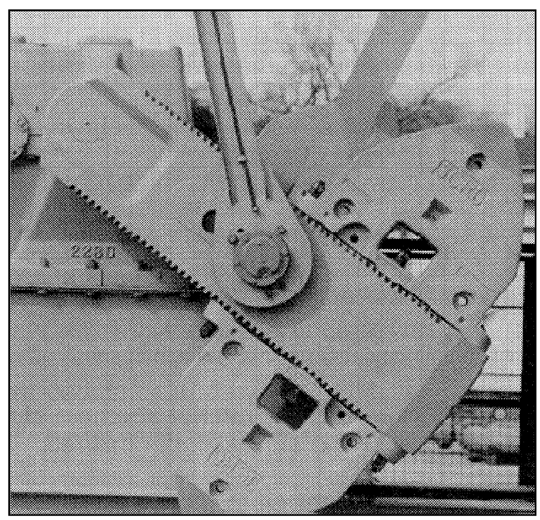

Figure 4. Changing the pumping unit stroke length.
(courtesy of Lufkin Industries, Inc.)

2. Remove the weight of the rod string from the carrier bar.
3. Lower the polished rod liner until it is sitting on the stuffing box
4. Place a polished rod clamp on the rod and snug it against the liner.

5. After tightening the rod clamp, engage the prime mover to move the walking beam until the rod weight has been removed from carrier bar
6. Set the brake and chain the brake of the pumping unit so that it cannot move.
7. Clean and oil the new holes, removing all rust and paint.
8. Change the pins to the new holes.
9. Tighten and key the nuts.
10. Grease the previously used holes to prevent rust.
11. Mark the nut so that position changes can be detected.

B3-5. Lowering and Raising Rods.

(NOTE: The following is intended as a guide only and should not be construed as specific instructions. There are certain dangers associated with performing these duties. These processes are to be performed by a competent, knowledgeable technician with experience in pumping unit operations. All tools and equipment should be designed specifically for use in performing these tasks. The use of faulty or improper tools or a lack of specific knowledge in performing these tasks could lead to serious injury or death. The person or persons attempting to perform these tasks are doing so at their own risk. This guide is only a suggestion and is not to be construed as specific instructions as different types of units require different processes in performing these tasks.)

There are several reasons that rods may have to be lowered or raised. Different wells have different problems, but pumps may have to be lowered to break a gas lock or to tap a pump to stimulate trash removal from under the balls and seats. If the pump has available space, occasionally pump action can be restored by raising the rods or raising and then lowering them. It may be possible to unseat the pump then re-seat it.

When rods are lowered to tap bottom, on the downstroke the pump is completely closed together and the top traveling part of the clutch strikes the standing clutch half. This sends a shock through the pump to loosen the trash under the seats and allow the pump to begin pumping again.

Pump repair companies may not agree that tapping wells is necessary, but many production companies perform this function as a matter of practice before pulling any well. Some shallow- and medium-depth wells must tap at all times; otherwise, they will not continue to pump for more than a few days or hours at a time. If properly adjusted, many shallow wells can tap for several years, and the pump shows no damage when pulled. Occasionally, the rods must be raised before lowering them to restore pump action. The procedure is:

1. Stop the unit with the head down and set the brake.
2. Loosen the polished rod liner packing nut and set screw.
3. Lower the liner until it is resting on top of the stuffing box.
4. Place a clamp on the polished rod sitting on top of the liner and tighten it.
5. Loosen the clamp on top of the carrier bar, raise it several inches, and re-tighten.

   WARNING: Never grab the polished rod between the carrier bar and the clamp. If the clamp slips, everything in between will be crushed.

6. Let the brake off slowly to allow the rod weight to be placed back on the carrier bar clamp.
7. Remove the lower clamp from the polished rod, raise the liner, retighten the packing, and tighten the set screw.
8. Turn on the unit.

This will lower the rods, and the unit should be tapping bottom lightly. If the pump does not tap, the lease pumper must repeat the process until it does tap.

The procedure to raise rods includes the following steps:

1. Stop the pumping unit with the crank at about the 10 to 11 o'clock position or about 15 degrees **before** top dead center and set the brake.
2. Lower the polished rod liner by loosening the packing nut, backing off the set screw, and lowering the rod liner down to the stuffing box.
3. Tighten the polished rod clamp with it sitting on the polished rod liner.
4. Loosen the brake.
5. Turn on the pumping unit.
6. As the head comes down with the weights at the 12 o'clock position, turn the power off and set the brake.

   WARNING: Several inches of rod will be exposed. Never grab this area. If the upper clamp slips, everything in between will be crushed.

7. Loosen the upper clamp, allow it to drop back down on the carrier bar, then re-tighten.
8. Remove the clamp above the polished rod liner.
9. Let the brake off and turn the unit until the horse head is down. Set the brake.
10. Lift the polished rod liner a few inches.
11. Tighten the packing nut and the set screw.

The lease pumper must never get in a hurry when lowering or raising rods. Experience teaches much of what needs to be known. By looking in the lease records book, the lease pumper will know the length of the pumping unit stroke and the stroke action available in the pump. This will assist greatly in deciding the correct action. Without adequate records, the lease pumper will just have to rely on judgment.

The Lease Pumper's Handbook

Appendix B
Pumping Units

Section 4

BELTS AND SHEAVES

B4-1. Introduction to Belts and Sheaves.

A good understanding of belts and sheaves is important in obtaining satisfactory performance from a wide range of belt-driven equipment, especially pumping units. Poor operation practices lead to unnecessary down time, loss of production, a decreases in income, and increases in lifting costs per barrel of oil

Belt manufacturers want their customers to obtain satisfactory results from using their product and publish free or low-cost booklets to assist in belt and sheave selection and maintenance. As an illustration, the Gates Rubber Company publishes two booklets that can be obtained through local Gates distributors:

- *The Pumper's Friend.* (A Guide for V-Belts and Sheaves). 12 pages
- *Gates Industrial Drive Products & Preventive Maintenance Guide.* 78 pages.

B4-2. V-Belt Sizes, Widths, and Depths.

Industrial V-belts (Figure 1) are available in two styles: super and high power. These come in the following sizes with widths and depths in inches:

Super HC V-Belt Sizes.

Size	Width	Depth
3V & 3VX	3/8	21/64
5V & 5VX	5/8	35/64
8V	1	7/8

Hi-Power II V-Belt Sizes.

A	½	5/16
B	21/32	13/32
C	7/8	17/32
D	1¼	¾
E	1½	29/32

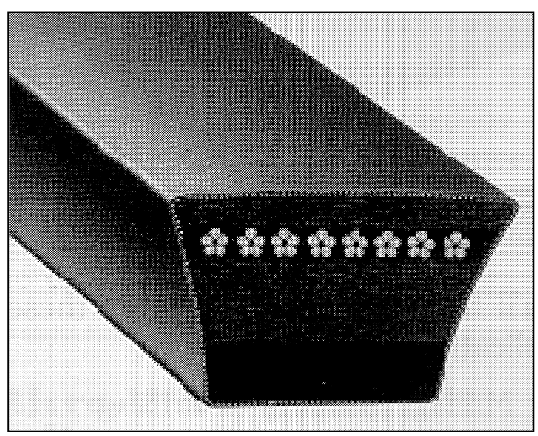

Figure 1. Cross-section of a high-power V-belt.
(courtesy of Gates Rubber Company)

B4-3. Types of Belts Based on Load Performance.

V-belts may be purchased in two or more qualities. The primary governing factor in deciding which quality to buy depends upon the load performance and type of service that is required. A standard style belt will have the rubber on the sides exposed to the atmosphere, while the more expensive styles will be fully encased in a tough, cloth, flex weave cover. For all-weather outdoor applications such as pumping unit belts, the fully cased belt is tough, shock resistant, and long lasting.

The second factor to consider when purchasing belts that will be placed on multi-belt sheaves is whether to purchase matched length individual belts or to order a joined power band belt, with the belts joined together with a common backing (Figure 2). The joined belts can solve many long span stability problems.

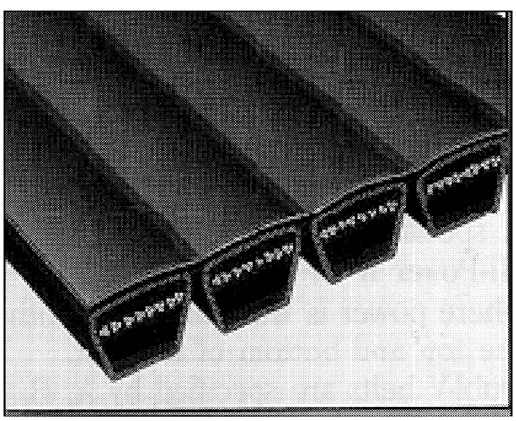

Figure 2. Cross-section of a power band joined belt.
(courtesy of Gates Rubber Company)

B4-4. Number of Belts Required to Start and Pull Loads.

Selecting the size and number of belts for an installation such as a circulating pump or liquid injection system will depend upon several factors, such as:

- The surge load placed on the belts when starting up the unit.
- The load while the unit is in operation.
- How often the unit starts and stops.

The starting load is possibly the most important consideration. If the belts slip under the starting load or if they are too small and run hot under severe load, the life of the belts will be short, and the company will be paying for these initial installation mistakes as long as the unit is left in operation without solving the problem. All installations require adequate planning and selection of a sufficient size belt to do the job efficiently. It is not unusual to expect some belts to last twenty years or longer.

B4-5. Lengths of Belts in Inches.

Size	Short	Long	Increments
3VX	25	140	1½" to 8"
5VX	50	355	3" to 20"
8V	100	560	6" to 25"
A	26	182	1" to 15"
B	31	316	1" to 15"
C	55	422	2" to 30"
D	110	663	7" to 60"
E	187	664	15" to 60"

As shown in the chart above, industrial belts may be purchased in lengths from about 2-55 feet. The shorter belts can be purchased in incremental lengths of 1 inch or less and, in the heavier belts, up to 60 inches between lengths.

As each size of belt gets longer, additional adjustment space must be provided. Since the side movement of the skid rails that support the prime mover provides for the selection of two or more belt lengths, small motors may be moved only a few inches to provide for belt replacement and correct tension, but the larger ones must have several feet of adjustment capabilities.

B4-6. Belt Life.

Belt life is governed by correct sheave sizes, speeds, balance of units, elimination of slippage with correct belt tension, correct belt selection, proper alignment, and other controllable factors. If an installation requires belt replacement too often, something is wrong in the design and should be corrected.

Each time a belt runs over a sheave, it must be flexed in and out under load. The faster the belt travels, the more times it flexes per minute, and the more heat that is generated. This can dramatically shorten the life of the belt. When planning high-speed or heavy-load installations, the manufacturer's belt engineering experts should be contacted to assist with planning the design of the installation. Idler pulleys will occasionally solve these problems.

B4-7. Styles of Sheaves.

There are two basic types of sheaves. Smaller sheaves, one inch or less in diameter, are usually one piece and bored to size to fit the shaft. Variable pitch sheaves that permit changing the speed of the equipment by adjusting the pitch are usually small sheaves. The larger sheaves used on pumping units and equipment with drive shafts over 1 inch in diameter typically use heavy-duty tapered split bushings and hubs. Two common styles of two-piece sheaves are the QD sheave (Figure 3) and the taper-lock sheaves (Figure 4). Of these two, the QD style is very popular in the oilfield.

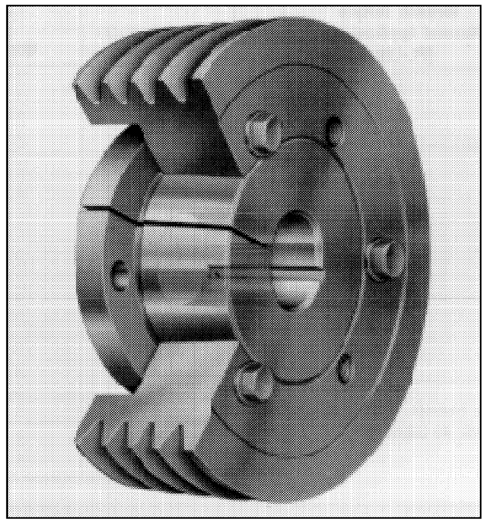

Figure 3. A QD sheave
(courtesy of Gates Rubber Company)

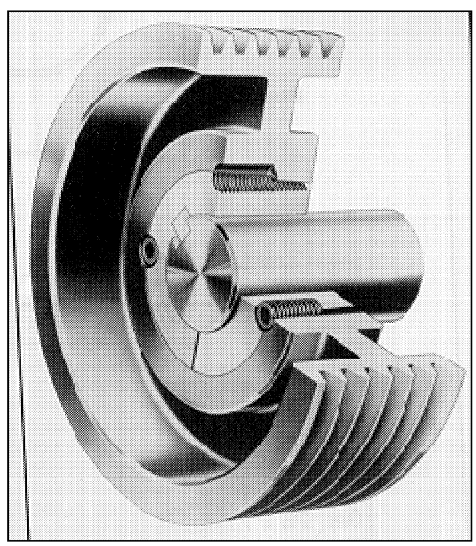

Figure 4. A taper-lock sheave.
(courtesy of Gates Rubber Company)

B4-8. Number of Grooves.

Smaller sheaves seldom use more than two or three belts, but the C, D, and E sizes may have up to ten or even twelve grooves. It is common for there to be grooves without belts so that more can be added if required.

Sheave diameter and belt flexing. When using a small belt, the sheave may also be small. Each belt has a limit as to how much bend it can be subjected to without severely weakening the belt and reducing its productive life. The speed at which sheaves run is largely determined by the number of feet per minute of belt travel. A maximum speed of 6,500 feet per minute seems to be typical. The minimum acceptable and largest diameters available for QD sheaves are as follows:

Belt	Diameter	Largest	Grooves
3V	2.20	33.5'	1 to 10
5V	4.40	50	1 to 12
8V	12.50	71	1 to 12
A/B	3.75	38.35	1 to 10
C	5.40	50.40	1 to 12
D	12.6	58.6	1 to 10

B4-9. The Keyway.

Inserting a key in a square keyway in the sheave locks the sheave with a keyway in the shaft and keeps the sheave from slipping. The sheave may also be held in place by a set screw, if needed. Keys will be of an appropriate size according to the diameter of the sheave. The larger the sheave, the larger the key and keyway. The end of the key will be slightly tapered to allow it to enter easily.

If the two key slots are of different sizes, combination keys are available to allow the use of sheaves on shafts that have a different size keyway. These combination keys are capable of performing satisfactorily without danger of failure caused by size.

B4-10. Math Calculations.

The lease pumper is often required to calculate various factors when installing and maintaining belts. These include:

- Calculating belt length, full formula
- Calculating belt length, short formula
- Changing sheave size to change revolutions per minute (RPM)
- Changing pumping unit strokes per minute (SPM)

Such calculations are reviewed in Appendix F, Mathematics.

APPENDIX C

TANK BATTERIES

The Lease Pumper's Handbook

Appendix C
Tank Batteries

Section 1

UNDERSTANDING THE TANK BATTERY

The purpose of this appendix is to provide information about basic tank batteries, the purpose of each vessel, where it is installed in the system, what vessels should be installed ahead of it, what vessels should be installed after it, and how to operate most of them with a minimum number of problems.

Two tank batteries, even when they support oil or gas production from the same formation, are seldom alike. The lease pumper needs to be able to approach a vessel, look it over, generally understand what is taking place inside the vessel, and know how it is being used for that particular tank battery. The petroleum industry is flexible in handling special production problems, and an understanding of the problems at a lease site may be necessary to explain why a vessel was installed in a particular fashion that may not be the method normally expected.

Generally, the term *vessel* is applied to all the containment structures in the tank battery. More precisely, only those structures that are pressurized are vessels, while those that are atmospheric are referred to as tanks. Thus, vessels are generally involved in some process, such as phase separation, while tanks are usually storage containers, as in stock tanks. In this discussion of the tank battery, both atmospheric and pressurized vessels are described and the generic term vessel is used unless specifically referring to a tank.

C1-1. Openings to Vessels for Lines.

There are six standard vessel openings for line attachment, plus a few special purpose ones. Standard openings are:

- Inlet
- First liquid outlet
- Gas vent
- Drain
- Overflow
- Second liquid outlet

These lines all meet a specific need. Some vessels may have two openings to meet the same need. This may make the vessel flexible for right- or left-hand installations. The opening may be a bolted flange or a welded half coupling, which is a heavy-duty grooved nipple welded to the vessel, such as Victaulic of America fittings.

Inlet. The purpose of the inlet is to receive produced fluids. This includes everything that comes out of the well: oil, water, gas, and suspended solids such as sand, salt, paraffin, asphalt, scale or gyp, drilling mud, and a host of other elements and compounds.

Inlets are usually located above the fluid line on either the side of the vessel, as in vertical separators, or on the top, as in some horizontal vessels and stock tanks.

The third location for an inlet line is approximately a foot above bottom when the vessel serves as an automated surge tank. This is common in automated water disposal tank lines or oil sales lines just ahead of the LACT unit. The inlet line is basic to every vessel.

Gas Vent. The purpose of the gas vent is to remove the produced gas. It is usually located at the highest point at the top of the vessel. This line may also contain a safety release or pop valve and a pressure safety rupture plate. The gas vent opening is basic with every vessel.

Oil outlet. The purpose of the oil outlet is to remove crude oil from the vessel. This outlet line is located either at the operating fluid level of the vessel or below the fluid level and activated by an indiscriminate float. In stock tanks, this outlet is generally located one foot from the bottom and can be automated or controlled by a valve.

Drain line. Vessels have to be emptied occasionally, so a drain is provided.

Overflow line. When fluid is flowing into a vessel with no automatic outlet, an overflow line is provided. On tank batteries, this line is used regularly and is often referred to as an *equalizer line*.

Second liquid outlet. The purpose of the second liquid outlet is to remove the produced water. This outlet is located near the bottom of the tank. This is an optional line that is installed in three-phase vessels where the fluid is separated into gas, oil, and water.

Special purpose lines. There are a host of reasons why a special purpose line may be attached to a vessel, such as oil sales lines, rolling system lines, etc. Small openings are also provided with many vessels for installing pressure gauges, fluid level gauges, safety alarms, and other attachments. These are discussed with each vessel.

C1-2. The Shape and Purpose of Vessels.

Major considerations in tank battery design include:

- Shape of vessel
- Pressure rating
- Number of phases
- Temperature
- Purpose of vessel

Shape of vessel. Vessels may be rectangular, with or without tops. Round vessels may be vertical with a rounded top and bottom, horizontal with rounded ends, or spherical. Each shape has special applications.

Pressure rating. As fluid is produced from the well, it may be flowing under high pressure or under low pressure with artificial lift. Regardless of how the well is produced, there must be enough pressure for the fluid to reach the surface, flow to the tank battery, and into the vessels.

Initial vessels in the tank battery are usually pressurized vessels, such as the separator, heater/treater, flow splitter, line heater, and the free water knockout. Separators have working pressures, ranging from a few pounds to many thousands of pounds. Pressurized vessels have rounded corners.

Atmospheric pressure tanks in the tank battery system include the gun barrel (or wash tank), water disposal tanks, skimmer tanks, power oil tanks, slop tanks, and stock tanks. These tanks are designed to operate with a maximum pressure of only a few ounces.

Number of phases. A two-phase separator is a vessel that separates the incoming emulsion into two fluids. The gas goes out the top gas line, and the liquid is dumped out of the vessel with an indiscriminate float. Most separators are two-phase vessels.

The gun barrel, the free-water knockout, and the three-phase separator are all good illustrations of three-phase vessels. The incoming emulsion is separated into three fluids. The gas goes out the gas line on the top of the vessel, the oil goes out a line at or near the upper fluid level of the vessel, and the produced water goes out the water line located near the bottom of the vessel.

Temperature. Crude oil is heated for any of several reasons. Heater/treaters heat crude oil to assist in removing the basic sediment and water content to a level to be able acceptable to sell the oil. This is the most common use of heat.

Other uses of heat include preventing ice from forming in the system, keeping heavy crude thin enough to make it flow to the tank battery, and keeping paraffin in a fluid state.

Purpose of vessel. Each field supervisor is faced with problems unique to that lease, and supervisors may solve the same problem in many different ways. Thus, a vessel in one tank battery may serve a purpose that is not required of that vessel in another nearby tank battery, and a vessel that is adequate for handling a problem at one lease may not meet that need at another.

C1-3. From the Well to the Tank Battery.

Two types of equipment can be located in the flow line between the well and the tank battery: the line heater and the satellite tank battery.

Installing a line heater in a flow line. There are several reasons for installing a line heater in a flow line. Emulsions produced from an oil well may freeze, jell, or solidify and block the flow line. Heat added to the emulsion may keep it in a fluid state until it gets to the tank battery. Some of the produced fluids that may solidify are water that does not contain salt, paraffin, asphalt, and crude oils with a very low API gravity. Occasionally, a line heater must be added even when the tank battery is constructed on the edge of the well location pad.

Satellite tank battery. A satellite tank battery is a separate system that may be added to the well or group of wells to serve any of several special purposes. These may include the support of:

- Well testing
- Separating water for disposal
- Separating gas for sale or re-injection.
- Pre-treating oil or water.

Various vessels can be selected to support these functions.

APPENDIX D

PIPE, CASING, AND TUBING

The Lease Pumper's Handbook

Appendix D
Pipe, Casing, and Tubing

Section 1

PIPE, CASING, AND TUBING

This appendix has been designed to give the lease pumper a basic knowledge of the use of oilfield production pipe and fittings, casing, and tubing.

D1-1. Seamed and Seamless Steel Pipe.

Iron in its pure form has limited use in manufacturing pipe. After it has been combined with one or more other metals, a new compound called *steel* is formed. Steel is much stronger than iron, and steel pipe has been used in oilfield construction since the first wells were drilled.

Through the history of oil production, efforts have been made to improve steel pipe to make it more resistant to deterioration due to corrosion and the action of acids and salt found in hydrocarbons.

Pipe is available in both welded and seamless manufacture. The seamless pipe is more expensive but is stronger and more resistant to problems. Welded pipe is fused with heat and electricity applied to the parent materials without using welding rod.

D1-2. Pipe Schedules for Surface Construction.

Pipe that is purchased for surface construction is available in several wall thicknesses and quality ratings. This is referred to as the pipe *schedule number.*

Pipe schedule numbers range from the lightest weight, 10, to a maximum weight of 160. From 10 to 40, it is numbered in 10-point increments. From 40 to 160, it is numbered in 20-point increments. Thus, the schedule increments are 10, 20, 30, 40, 60, 80, 100, 120, 140, and 160.

Many pipe suppliers stock pipe 4-6 inches in diameter in schedule 40 for low- and medium-pressure installations, schedule 80 for high-pressure use, and schedule 160 for extra high-pressure applications. In larger sized pipe applications, all of the scheduled weights are available on order.

D1-3. Length or Classes of Pipe.

Pipe in common use in the oilfield is not always the same length as pipe purchased at the local hardware or lumber store for typical commercial use. Pipe for oilfield use is usually purchased from the local oilfield supply store. Some pipe bought at either place may be of the same quality, but some is not. Lengths of small pipe at the hardware store will probably be available in lengths of 21 feet. The oilfield supply store may have pipe up to 2 inches in diameter available only in 21-foot lengths. Two-inch to 4-inch pipe is usually available in 25-foot lengths.

D1-4. Sizes of Pipe.

Pipe is sized by its diameter. There are many sizes of pipe with the sizes ranging from 1/8 inch up to several feet in diameter. Pipe used for surface applications such as flow lines and tank battery construction is measured by inside diameter and is usually referred to as *line pipe*. These lines are usually 2 inch and generally no larger than 4 inch.

The sizes of line pipe used in tank battery construction varies. Flow lines and the oil lines at the tank battery are usually 2-inch, and water drain lines may be any size from 2-4 inches. General use is as follows:

Table D-2. SIZES OF FIELD CONSTRUCTION PIPE

Pipe Size (inches)	Threads per Inch	Joint Length (feet)	Weight per Foot (pounds)	General Use
1/8	27	21		Special application
¼	18	21		Highly used
3/8	18	21		Special application
½	14	21		Highly used
¾	14	21		Special application
1	11 ½	21		Highly used
1 ¼	11 ½	21		Special application
1 ½	11 ½	21		Special application
2	11 ½	21/25	4.7	Highly used
2 ½	8	25	6.	Special application
3	8	25		General use
4	8	25	11	General use

The 1/16 inch size tap and die is readily available but the pipe and fittings are not. Thus, for practical purposes, the smallest size included in this listing is 1/8 inch and up.

D1-5. Tubing.

Tubing is the moveable string in the oil well. Tubing is manufactured in various different mixtures of steel. The stronger the steel is, the higher its tensile strength and the more each joint costs. The lowest grade or class of tubing is called H-40. This tubing is approved for use in shallow wells. For deeper wells, tubing of higher grades must be used, selected to match the well depth. The general classes of tubing most commonly used for oil production include:

H-40	Shallow wells
J-55	
C-75	Deeper wells
N-80	
P-105	Deep wells

Tubing is available with inside diameters of 1-4 inches but tubing size is measured by outside diameter. The two most common sizes are 2-3/8" O.D. and 2-7/8" O.D.

Tubing comes in random lengths of 28-32 feet long. Standard well tubing comes with upset ends. The joints within the string, other than possibly the bottom mud anchor, are installed without cutting and threading. Joints less than full length are called *pup joints* and are available in 2-foot increments from 2-12 feet. Lengths in the 18-24 foot range may be available on special order.

Upset tubing must be installed to an exact depth from the braiden head or the top of the wellhead downhole to the tubing perforations. By measuring and selecting tubing of required lengths, a tubing string can be made up to an exact depth.

Accurate records must be kept listing every joint of tubing in every well. These records must show the type, size, and length of every joint in order of installation.

Table 2. TUBING SIZE (EXTERNAL UPSET END)

OD	Weight	I.D.	Cu. Ft /Ft	Ft/Cu. Ft	Bbl/Ft	Ft/Bbl
1.050	1.20	0.824	0.00370	270.270	0.00066	1515.152
1.315	1.80	1.049	0.00600	166.667	0.00107	934.579
1.315	2.25	0.957	0.00500	200.000	0.00089	1123.596
1.660	2.40	1.380	0.01039	96.246	0.00185	540.541
1.900	2.90	1.610	0.01414	70.721	0.00252	396.825
2.375	4.10	2.041	0.02272	44.014	0.00405	246.914
2.375	4.70	1.995	0.02171	46.062	0.00387	258.398
2.375	5.95	1.867	0.01901	52.604	0.00334	294.985
2.875	6.50	2.441	0.03250	30.769	0.00579	172.712
2.875	8.70	2.259	0.02783	35.932	0.00496	201.613
3.500	8.50	3.018	0.04968	19.478	0.00870	112.994
3.500	9.30	2.992	0.04882	20.483	0.00870	114.943
3.500	12.95	2.750	0.04125	24.242	0.00735	136.054
4.000	9.50	3.548	0.06866	14.565	0.01223	81.766
4.500	12.75	3.958	0.08544	11.704	0.01522	65.703

D1-6. Casing.

Casing is the fixed or cemented string of pipe in oil and gas wells and is measured by outside diameter. Sizes for land wells may be as small as 4½ inches. As the well gets deeper, the surface casing gets much larger. Tubing and casing are measured by the diameter of the lifting tools or elevators. With oilfield pipe strength ratings, even as the pipe wall increases in thickness so that the pipe will be stronger, the outside diameter remains the same size so that the lifting and makeup tools continue to fit. This means, of course, that the higher strength pipe will have a smaller inside diameter than a lower rated pipe with the same outside diameter.

Perforating casing. When an oilwell is perforated, the shooting of the jet gun causes a shock to the joint being perforated. For this reason, the perforation joint or joints may be heavier pipe to try to prevent problems that would result if lighter pipe were perforated. This means that they are at or near the bottom of the string and have a smaller inside diameter.

Because of problems caused in casing strings with a smaller inside diameter, such as having tools get stuck near the bottom of the hole, the top joint of casing is always the same size on the inside as the smallest inside diameter joint. By adopting this practice, any tool that will go through the first joint will go through any joint in the string, including the perforated joint.

APPENDIX E

CHEMICAL TREATMENT

The Lease Pumper's Handbook

Appendix E
Chemical Treatment

Section 1

SPECIAL INFORMATION ABOUT CHEMICAL PUMPS

E1-1. The Principles of Chemical Pumps and Injectors.

Chemical pumps can be a great help in treating oil, or they can be nothing but trouble if the lease pumper does not understand how they work and does not keep them repaired and adjusted correctly. When they are in good shape they will save time and help keep the oil properly treated.

The heart of the chemical pump is the chemical injector. The body of the injector is made of forged steel. The chemical must move upward through the injector to prevent air locks. When the body of the pump is worn due to plunger friction, it can be machined out oversize and last many more years with a larger plunger.

Figure 1 shows a typical injector. The numbers in the following paragraphs refer to the part labels in the illustration.

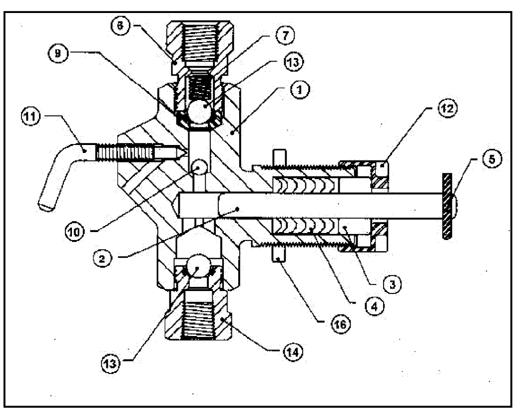

Figure 1. Parts of an injector.
(courtesy of Arrow Specialty Co.)

The plunger moves back and forth in a reciprocating action. As it moves back, vacuum lifts the lower ball check valve (13, bottom) open, pulling fluid in from the chemical reserve tank. The plunger can be pulled back by a gear (5) or have a pin dropped in through a hole.

As the plunger is pushed back into the injector, the upper ball check valve (13, top) is opened by the pressure on the chemical, and the chemical is injected into the oil being treated.

The plunger stem packing nut (12) must be tightened a small amount occasionally to keep the packing (4) tight to form a seal against the plunger. This packing will have to be replaced every few years to prevent chemical loss and air locks. To remove air locks from between the two ball valves, while the plunger is being pulled out the air bleeder rod (11) must be kept closed, and while the plunger is being pushed back in, the air bleeder rod (11) should be opened so that the air can be removed.

E1-2. Mechanical Chemical Injectors.

Mechanical chemical injectors are usually located at the well site mounted on the base of the mechanical pumping unit. This pump has been very popular through the years and gives good service.

Mechanical injectors are usually driven by the use of a flexible line to lift the arm and a weight to lower it. In years past, steel reinforcement rods were popular, but if the lease pumper placed an arm or leg under the rod on the downstroke, serious injuries were possible. The upper end is attached to the H-section of the walking beam and can be moved away from the saddle bearing for a longer stroke or closer for a shorter stroke.

The mechanical chemical injector in Figure 2 would work well when a surfactant must be injected for oil treating, and paraffin solvent must be injected down the casing to reduce paraffin accumulation downhole.

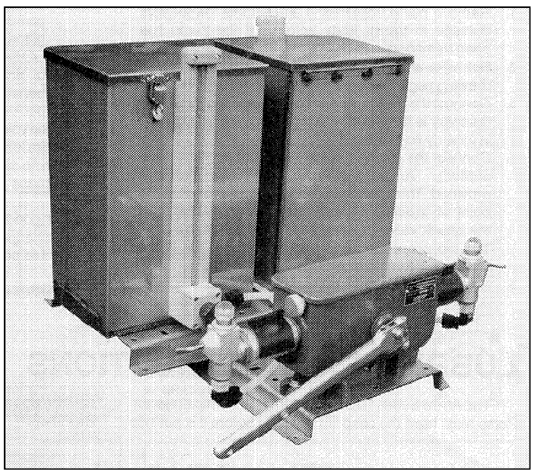

Figure 2. A mechanical chemical injector that is installed on the pumping unit.
(courtesy of Arrow Specialty Co.)

E1-3. The Low-Pressure Pneumatic Injector.

The low-pressure chemical injector is utilized where very low gas pressure is available. If a tank battery has no high-pressure vessels, such as a separator, but has only a gun barrel and stock tanks, chemical may be injected mechanically and accurately with the low-pressure pneumatic pump. By installing 2- to 4-ounce backpressure valves on an atmospheric vessel gas vent, this pressure can be used to operate the injector as well as to control the vapor recovery unit.

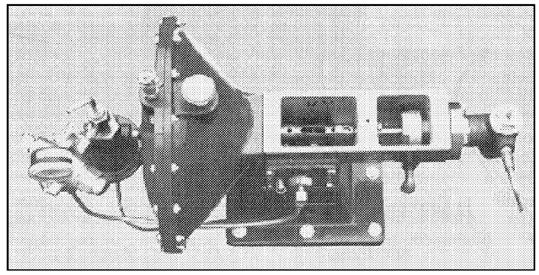

Figure 3. A low-pressure, diaphragm-operated chemical injector.
(courtesy of Arrow Specialty Co.)

Figure 3 shows that the pneumatic gas enters on the left side to operate the large diaphragm, and the chemical enters the chemical injector on the right side of the picture. This unit is then mounted on some type of base.

It is easy to compute the force the diaphragm pump will exert in pounds per square inches using the formula:

Pressure = π x Radius^2 x Pressure in lbs.

If the diaphragm is 18 inches across and the gas pressure is 4 ounces, then

Pressure = (3.14) x (9 x 9 inches) x □ pound

= (3.14) x (81) x (□)

= 63.6 pounds per square inch

This is the pressure on the plunger. Since the plunger occupies no more than 1/3 of a square inch, 4 ounces of pressure can produce tremendous force.

Low pressure pneumatic injectors can be used for as long as they are maintained. There are few parts to replace, and the lease pumper should be able to keep them functioning if no mechanical assistance is available.

E1-4. The High-Pressure Pneumatic Injector.

The high-pressure pneumatic injector has many applications in the oil field other than treating crude oil. Since it operates under high pressure, it is used on flowing wellheads, gas wells, pumping wells, and many other applications.

A typical high-pressure pneumatic injector is shown in Figure 4. The two high-pressure brass cylinders that stick out from the square cast iron body of the pump contain a soft-faced piston and have a hollow connecting rod. The gas is injected slowly into the space outside the end of the piston and this pushes it toward the square body. As the opposite piston approaches the end of its stroke, it engages a reversing valve that relieves the pressure from the end that just completed its stroke and places pressure against the surface of the opposite piston.

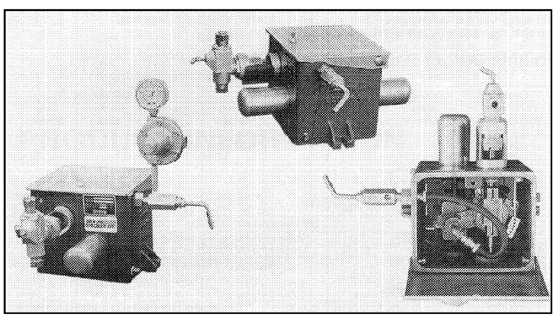

Figure 4. Views of a high-pressure pneumatic injector.
(courtesy of Arrow Specialty Co.)

As shown in Figure 5, three speed adjustments are available. The first adjustment is opening the bent arm of the inlet needle valve handle. This stem has a set nut so that it can be locked at the desired inlet volume. A second adjustment changes the hole that has an arm going to the adjustment plate. The third adjustment is to change a pin that regulates the length of the stroke of the piston.

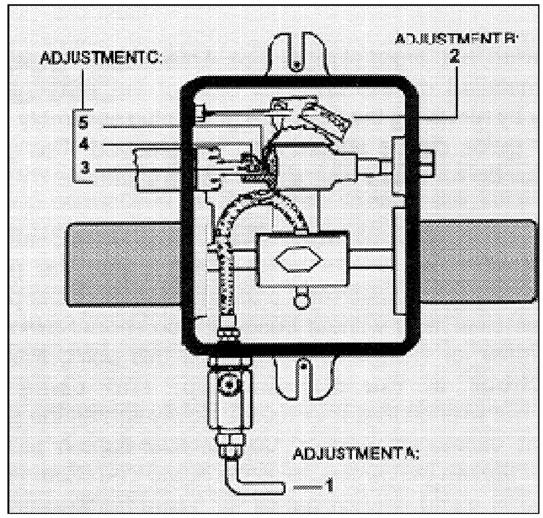

Figure 5. Adjusting the speed of the high-pressure pneumatic injector.
(courtesy of Arrow Specialty Co.)

When this injector is installed on a flowing oil or gas well that has a bottom hole packer in it where no annulus gas pressure is available, a round cylinder similar to the surge tank used to prevent fluid shock to triplex pumps is installed as a gas volume tank on top of the wellhead. Even when flowing a high volume of crude oil, enough gas will break out of the oil being produced and rise in the cylinder to operate the injection pump.

High-pressure injector pumps are used extensively in the production of natural gas for injecting such solutions as tri-ethyl glycol (TEG), ethyl glycol (EG), and methanol.

When using a high-pressure chemical injector, the lease pumper should compute the injected volume every few days in order to ensure that the oil is being correctly treated.

E1-5. The Electrical Injector Pump.

The electrically driven chemical pump usually has fewer problems than the other systems. It also has the advantage of being programmable by use of the electric clock. Since electricity is required, this system is not possible or practical for many installations.

For a high-volume tank battery with several pieces of equipment driven by electricity, such as the circulating pump, vapor recovery unit, and the LACT, the chemical injectors can also be electrical (Figure 6).

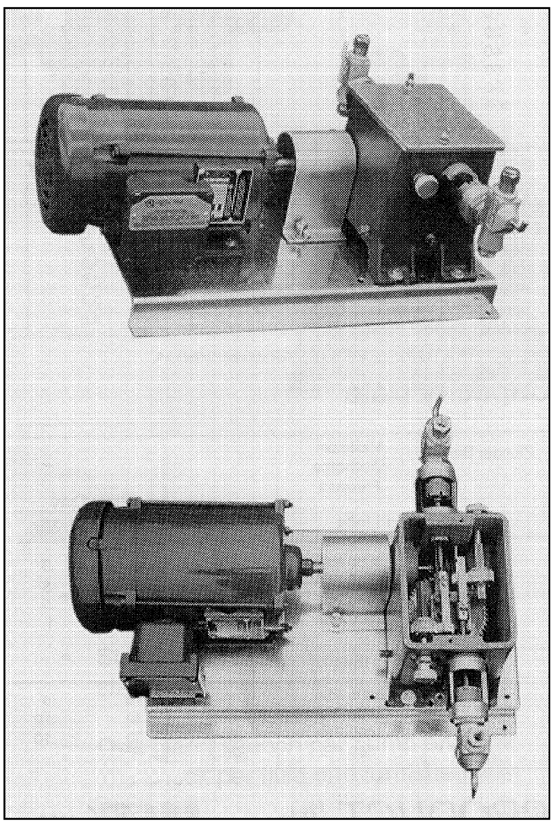

Figure 6. Views of an electrically driven high-pressure chemical injector.
(courtesy of Arrow Specialty Co.)

E1-6. The New Style of Chemical Pumps.

During the past decade, great strides have been made in the development of improved injector pumps, including the use of inexpensive computer cards to automatically control pump volume. Ease of operation, simplicity in style, and low cost have led to growing sales for these enhanced models, although the older designs are still in demand.

For example, the Gas-O-Matic style chemical injector discussed in Chapter 13-C has become very popular during the past few years and is capturing much of the market (Figure 7). This system can be powered by gas or air.

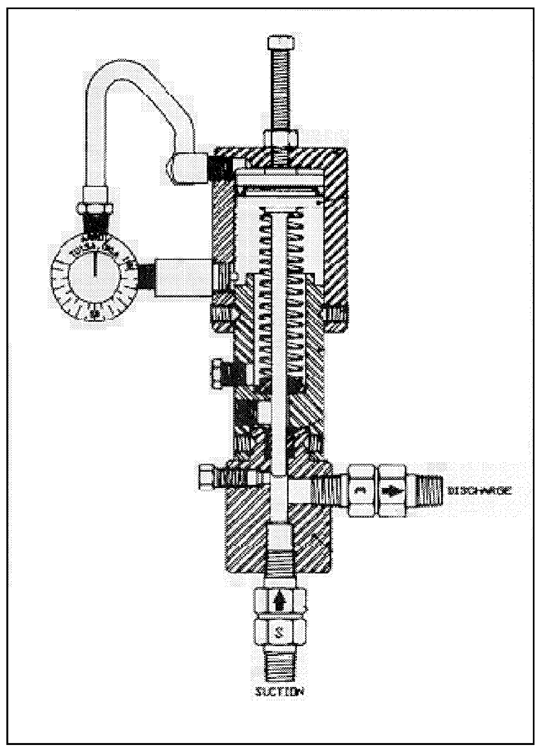

Figure 7. Diagram of the Gas-O-Matic injector valve.
(courtesy of Arrow Specialty Co.)

E1-7. Barrel Racks and Bulk Storage Containers.

Barrel racks and bulk storage containers along with accessories like sight gauges and chemical injectors are illustrated in Figures 8 and 9.

The 55-gallon drum and rack system remains popular for smaller installations, but in larger fields, a bulk storage container is generally installed and filled by a chemical supplier. With this system, the lease pumper does not have to handle heavy barrels or become involved in blending large volumes of chemicals. Also, bulk purchases are usually cheaper than the cost of the drums.

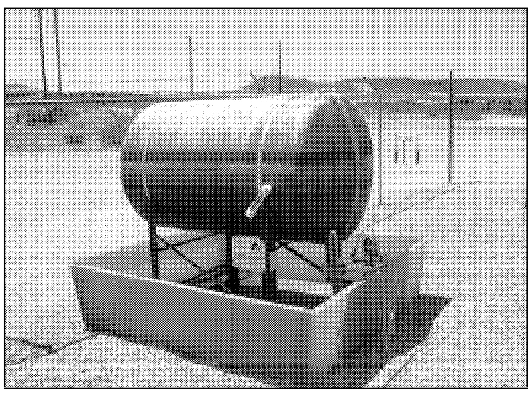

Figure 8. A fiberglass storage tank with knee tub and injector.
(courtesy of Arrow Specialty Co.)

Bulk storage containers can be purchased in fiberglass, stainless steel, and other materials. Fiberglass is the most common because of the low cost and because the amount of chemical remaining can be determined at a glance.

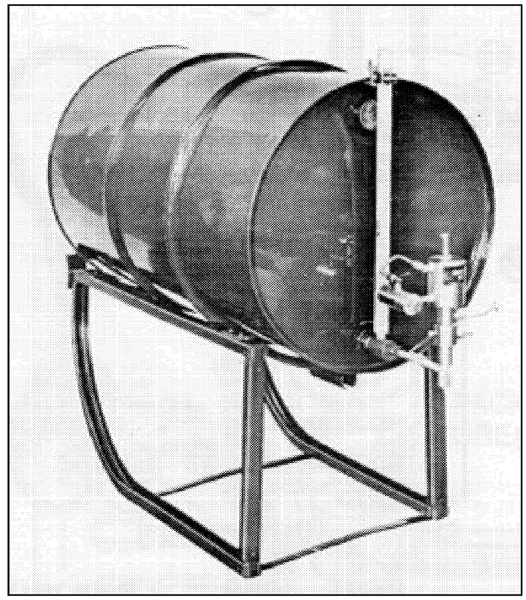

Figure 9. Chemical barrel and rack with liquid level gauge and injector.
(courtesy of Arrow Specialty Co.)

Chemical tanks, injectors, and the quality of chemical have been greatly improved over the past few years and regulations to protect the lease pumper have also been modified.

The Lease Pumper's Handbook

Appendix E
Chemical Treatment

Section 2

SOLVING SPECIAL TREATING PROBLEMS

E2-1. Location, Installation, Operation and Maintenance of Chemical Injectors.

Once the determination has been made to use chemical injection, the lease pumper must then decide how to stabilize and mount the injection equipment. Many mechanical injectors can be easily mounted on the front of the pumping unit base (Figure 1).

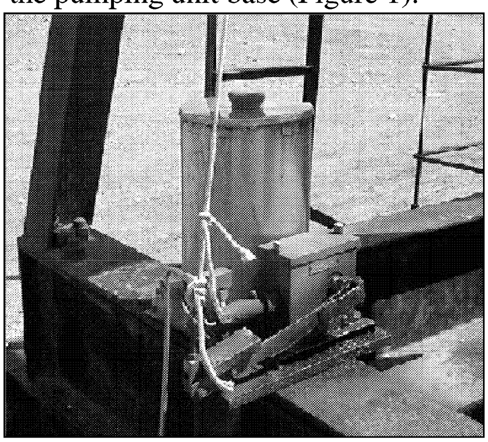

Figure 1. A mechanical chemical injector mounted directly to the base of the pumping unit.

When the chemical injector is located on the ground near a chemical tank, it is usually set on a concrete base (Figure 2). If the pump is placed on a board or on a graveled surface, weeds will soon engulf the whole installation, and it will be difficult to keep clean. When a concrete pad is used, the concrete should extend at least six inches beyond the edges of the chemical injector on all four sides.

Figure 2. Chemical tanks and injectors set on a concrete base.

E2-2. Treating Oil: A Review.

There are numerous chemical injector designs to support the various approaches to chemical injection (Figure 3).

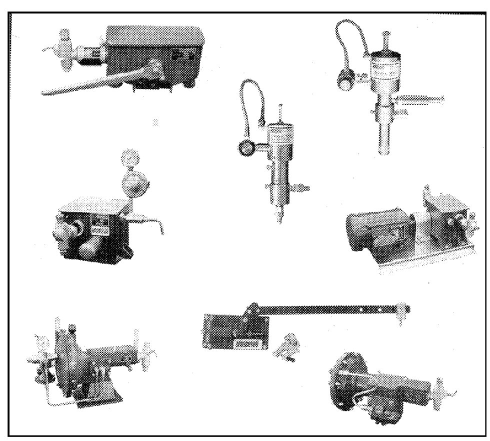

Figure 3. Types of chemical injectors.

Some of the more common methods of treating oil include:

Injecting chemical at the wellhead downhole. This includes injecting the chemical into the annulus and allowing it to flow downhole. By circulating a small amount of produced liquid from the bleeder side of the pumping tee to supplement the volume of injected chemical, it will reach the bottom of the hole in a reasonable length of time. This procedure is important in:

- **Treating crude oil.** The treatment will begin as the injected chemical mixes with the fluids entering the annulus from the formation.
- **Treating corrosion and scale**. This treatment will keep the casing and tubing perforations open, as well as keeping the inside of the tubing and the rod string clean.
- **Injecting paraffin solvent**. As the fluid travels up through the tubing, the melted paraffin begins to stick to the rods and tubing and accumulate in the well. Paraffin can accumulate and become so stiff and hard that it can support the weight of the rod string, so that the rods fall slowly on the downstroke. The horse head bridle and carrier bar will run out from under the polished rod clamp on the downstroke, and this causes tremendous shock when the pumping unit again accepts the rod load. Occasionally hot oil must be injected to allow the paraffin to become a fluid again and be pumped to the tank battery. This widely used practice can plug perforations and the formation. Chemical treatment has proven to be far superior to hot oiling.

Injecting chemical into the flow line. All of the chemicals injected into the annulus can also be injected into the flow line to achieve the same goals in the flow line as achieved downhole.

Injecting chemical at the tank battery. Chemical is injected at the tank battery after the header but before the first pressure vessel. The primary purpose in injecting chemical at this point is to treat the oil. This is the first location in the system at which the injected chemical will treat all of the oil being produced.

Dripping chemical into the thief hatch. Dripping chemical into the thief hatch from a gallon bucket with a very small hole in the bottom while circulating the oil will stimulate BS&W removal dramatically. The action of circulating without adding chemical will also assist in cleaning the oil. After treatment, the fluids will need a satisfactory amount of settling time, usually until the following day.

Hot oiling the oil in the tank. Calling out a hot oil unit to treat oil from stripper wells is sometimes necessary, but this is an emergency treating procedure and is seldom done if other solutions can be found. This is because the margin of profit is so low that expenses may exceed income.

E2-3. Other Treating Procedures That Have Not Been Reviewed.

There are many ways of reducing the BS&W level in oil that have not been discussed in this manual. A purpose of this section is to provide information about designing and implementing additional innovative procedures that will assist in solving treating problems. Occasionally small changes in the piping may have to be made and openings and valves installed to make the tank battery piping arrangement accommodate an oil treating procedure.

Batch treating down the annulus. Occasionally it will be necessary to address a downhole problem by batch treating oil, scale, corrosion, or other problems. Figure 4 shows one shop-made style of treating trailer. The lease pumper can pour in the correct amount of chemical, then finish filling the tank with water or crude oil. Three or more wells can be treated with one tank load.

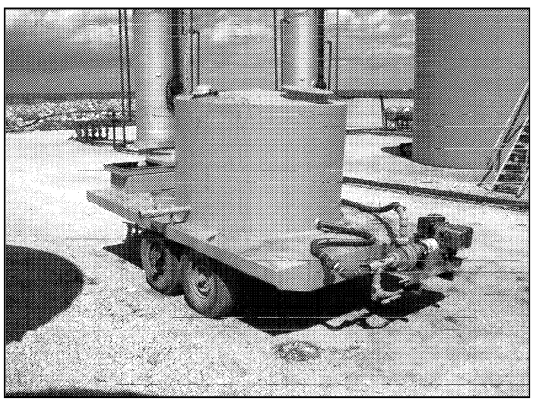

Figure 4. A chemical tank and pump mounted on a tandem-axle trailer for injecting chemical and oil or water into the annulus.

Batch treating and circulating. With many wells, after batch treatment, it may be desirable to open a circulating line going from the flow line into the annulus. To allow circulation, the valve from the flow line is opened to permit the produced fluid to fall back to the bottom of the well. The flow line valve to the tank battery is closed while circulating. The lease pumper may circulate the oil for several hours or some appropriate time, then switch it back to normal operation. Occasionally, this treatment may also require a shut-in period or an overnight circulating treatment. Batch treatment may be done once a month or on some set time schedule.

Some lease operators will contract with a chemical company to treat and circulate the wells on a regular basis. It takes a very productive lease to be able to have the available funds to subscribe to this service.

E2-4. Batch Treating the Heater/Treater.

Occasionally, the lease pumper may need to send an extra slug of chemical to the tank battery to inject extra chemical throughout the heater/treater to bring the system back into balance and treat exceptionally bad oil created in the system by some special activity such as a well workover.

The chemical must be pumped in at the oil entry opening. Because there are two ways of producing into the vessel the treatment must be either from the well or from the tank battery.

Method 1: From the well. There are several ways of injecting a batch treatment of chemical from the well. To batch treat, the lease pumper will add 2-4 quarts of additional chemical to the heater/treater. A small ½-inch positive displacement pump with a hand crank to drive it can be mounted on a small frame stand. First, a ½ inch x 3 inch swage is screwed into the inlet opening using a street ell. With the opening of the swage up and a small hose connected to the bleeder valve, a batch treatment of chemical can be injected.

Another method is to install a standing riser ahead of the heater/treater inlet a few feet before it enters the vessel. By installing a tee in the running position in the line just ahead of the heater/treater, installing a nipple and valve pointed up, a 4-foot piece of pipe, then a bell reducer on top with a quarter-inch bleed off valve, a surge tank that also injects chemical is installed.

Method 2: From the tank battery. Some operators bury a drum behind the tank battery with only two inches of the top above ground. Chemical can be poured into the 2-inch opening, then the barrel filled by a small hose attached to the drain line. The hose is small enough to reach the bottom of the drum to mix the chemical with the oil.

When the level in the drum is almost full, the tank valve is closed and the hose lowered to near the bottom of the drum. By turning the circulating pump on, this chemically enriched mixture is sucked out of the drum and into the line to the tank battery. The line to the drum is closed and the tank drain opened long enough to circulate the chemical into the heater/treater. The pump is then turned off so that the chemical will remain in the heater/treater long enough to give it a soak time treatment.

Giving the heater/treater a boost treatment can restore much of its treating ability when it gets overloaded with BS&W. This situation occurs when there has been under-treating of the oil over a period of time, especially in the summer when the heat is turned off and the heater/treater is being used as a three-phase separator or a gun barrel. By discussing the problem with a supervisor, the lease pumper can probably find an economical solution that is possible with any battery line arrangement.

E2-5. Treating High Tank Bottoms by Circulating with Pump and Hoses.

Most tank batteries can develop high tank battery bottoms that interfere with selling oil. Sometimes circulating tank bottoms regularly and after selling every tank is not enough. The bottoms build up and the tank of oil cannot be treated low enough.

The drain in a tank should have a line inside that extends across the tank to a location near the thief hatch. Otherwise, circulating creates a small clear area at the back while the front still has a 10 inch bottom.

Suitable portable circulating pumps. The operator must back the lease pumper's actions in developing methods for one person to treat the bottom of the tanks. This is especially true when using a portable circulating pump that must be moved from battery to battery by hand loading it into the pickup. Skid pumps are too bulky and heavy. The unit with the 1½" centrifugal pump imounted directly on the motor can be lifted with one hand. By placing a swage and union on each opening and a valve on each hose with both unions facing toward the pump, the hoses can be hooked up to the tank drain and a *stinger* line of 1" PVC stuck down into the tank. By merely closing the two valves on the hoses and loosening the unions, the pump may be turned around to pump in the opposite direction in a few minutes.

Stirring high bottoms during treatment. When stirring bottoms during treatment, the lease pumper needs to place the added chemical in the bottom of the tank at the front, right into the emulsion. To stir a high bottom, the first thing to do is produce into the tank long enough that at least 1-2 feet of fresh oil is above the emulsion.

The second step is to stand a small PVC line up through the hatch. If the bottom of the PVC tube is cut at an angle, it will not seal against the bottom. A quart of chemical can then be poured through a funnel into the tube. By placing chemical in several locations, the chemical is in the bottom of the tank, right in the emulsion.

With the pump hose connected to the PVC and inlet pump hose fastened to the tank drain line, the lease pumper can start the pump and inject the stream of oil directly into the bottom emulsion. By moving the bottom of the PVC to new areas and toward the back of the tank, eight inches of emulsion will grow by several inches as it is stirred. By stopping the engine and turning it around occasionally, the emulsion is pulled from the front and injected into the back. The lease pumper can also send the oil through the heater/treater, and, if necessary, fire up the heater/treater to warm the oil. If only a gun barrel is available with no heat, this vessel will also do a good job in most situations. If neither vessel is available, the lease pumper can treat it in both directions, shut it down, leave it, and then bleed off any separated water the next day and do it again. This is a problem that must be addressed regularly in order to have clean bottoms. Clean bottoms are bottoms with no more than 5 inches of BS&W.

When a high bottom is accumulated that is difficult to treat, the lease pumper may have to sell from the second tank until the first is clean. This may take several treatments with the pump and the tube down the hatch.

Regardless of the volume of oil that is produced, chemical is expensive, and oil can be difficult to treat. After trying various methods to treat oil, each try becomes easier.

NOTE: Large volumes of chemical introduced into small volumes of BS&W can cause a condition known as *burned oil*. The oil is over-treated and cannot be corrected. The lease pumper must be careful not to burn oil when trying to treat bad tank bottoms.

APPENDIX F

MATHEMATICS

The Lease Pumper's Handbook

Appendix F
Mathematics

Section 1

IMPORTANT CONVERSION FACTORS

A mathematical constant is a number that represents the relationship between one value and another. Perhaps the best known of all constants is *pi*, often shown as the Greek letter π. Pi is the relationship between the diameter of a circle and the distance around the outside of the circle or its circumference. The circumference of a circle is approximately 3.14 times its diameter, so pi is equal to 3.14. It does not matter how the circle is measured, the relationship between the circumference and the diameter will always be 3.14:1. Thus, a circle with a diameter of 1 inch will have a circumference of about 3.14 inches, while a circle with a diameter of 1 kilometer will have a circumference of 3.14 kilometers.

Another common use of constants is to convert from one type of measurement system to another. Because there are 12 inches in 1 foot, it is easy to determine that 108 inches total 9 feet by dividing by the constant 12. Constants can also be used to convert from one system of measurement to another, such as converting between U.S. standard measurements and the metric system. For example, there are 39.37 inches in a meter. To convert 5.7 meters to inches, one need only multiply 5.7 by 39.37, while converting 144 inches to meters would require dividing 144 by 39.37. This value is the constant relationship between inches and meters.

The table below provides a number of useful constants that can be used to convert from one type of measurement to another, many of which have practical application for leasepumpers.

Multiply	**By**	**To Obtain**
Acres	43,560	Square feet
Acres	4047	Square meters
Acre feet	7758	Barrels
Acre feet	1233.5	Cubic meters
Atmospheres	33.94	Feet of water
Atmospheres	29.92	Inches of mercury
Atmospheres	760	Inches of mercury
Atmospheres	14.7	Pounds per square inch
Barrels	5.6146	Cubic feet
Barrels	0.15898	Cubic meters
Barrels	42	Gallons
Barrels	158.9	Liters
Barrels per hour	0.0936	Cubic feet per minute
Barrels per hour	0.700	Gallons per minute
Barrels per hour	2.695	Cubic inches per second

Barrels per day	0.02917	Gallons per minute
Centimeters	0.03281	Feet
Centimeters	0.3937	Inches
Centimeters of mercury	0.1934	Pounds per square inch
Cubic centimeters	0.06102	Cubic inches
Cubic feet	0.1781	Barrels
Cubic feet	7.4805	Gallons (U.S.)
Cubic feet	28.32	Liters
Cubic feet	1728	Cubic inches
Cubic feet	0.02832	Cubic meters
Cubic feet	0.03704	Cubic yards
Cubic feet per minute	10.686	Barrels per hour
Cubic inches per second	28.8	Cubic inches per second
Cubic feet per minute	7.481	Gallons per minute
Cubic inches	0.00433	Gallons
Cubic inches	0.0164	Liters
Cubic meters	6.2897	Barrels
Cubic meters	35.314	Cubic feet
Cubic meters	1.308	Cubic yards
Cubic yards	4.8089	Barrels
Cubic yards	27	Cubic feet
Cubic yards	0.7646	Cubic meters
Feet	30.48	Centimeters
Feet	0.3048	Meters
Feet of water @ 60° F	0.4331	Pounds per square inch
Feet per second	0.68182	Miles per hour
Foot pounds per second	0.001818	Horsepower
Gallons (U.S.)	0.02381	Barrels
Gallons (U.S.)	0.1337	Cubic feet
Gallons (U.S.)	231	Cubic inches
Gallons (U.S.)	3.785	Liters
Gallons (U.S.)	0.8327	Gallons (Imperial)
Gallons per minute	1.429	Barrels per hour
Gallons per minute	0.1337	Cubic feet per minute
Gallons per minute	34.286	Barrels per day
Grain (Avoirdupois)	0.0648	Grams
Grains per gallon	17.118	Parts per million
Grains per gallon	142.86	Pounds per million gallons
Grains per gallon	0.01714	Grams per liter
Grams	15.432	Grains
Grams	0.03527	Ounces
Hectare	2.471	Acres
Horsepower	550	Foot pounds per second
Horsepower	1.014	Horsepower (Metric)

Horsepower	0.7457	Kilowatts
Inches	2.54	Centimeters
Inches	0.08333	Feet
Inches of mercury	1.134	Feet of water
Inches of mercury	0.4912	Pounds per square inch
Inches of water @ 60°F	0.0361	Pounds per square inch
Kilograms	1000	Grams
Kilometers	0.6214	Miles
Kilowatt	1.341	Horsepower
Liters	1000	Cubic centimeters
Liters	61.02	Cubic Inches
Liters	0.2642	Gallons
Liters	1.0567	Quarts
Meters	3.281	Feet
Meters	1.094	Yards
Miles	5280	Feet
Miles	1.609	Kilometers
Miles per hour	1.4667	Feet per second
Ounces (Avoirdupois)	437.5	Grains
Ounces (Avoirdupois)	28.3495	Grams
Parts per million	0.05835	Grains per gallon
Pounds	7000	Grains
Pounds per gallon	453.6	Gram
Pounds per gallon	0.052	Pounds/sq. in/ft of depth
Pounds per square inch	2.309	Feet of water at 60°F
Pounds per square inch	2.0353	Inches of mercury
Pounds per square inch	0.0703	Kilograms per square cm
Pounds per square inch	6.8947	Kilopascals
Quarts	0.946	Liters
Square centimeters	0.1550	Square inches
Square feet	0.0929	Square meters
Square kilometer	0.3861	Square miles
Square meters	10.76	Square feet
Square meters	1.196	Square yards
Square miles	640	Acres
Square miles	2.590	Square kilometers
Tons (Long)	2240	Pounds
Tons (Metric)	2205	Pounds
Tons (Short or Net)	2000	Pounds

Temperature conversions

Temperature Centigrade = 5/9 (Temp. °F - 32)

Temperature Fahrenheit = 9/5 (Temp. °C) + 32

Volume Capacity of Pipe
Gallons per 1000 feet = 40.8 x (I.D. in inches $)^2$
Barrels per 1000 feet = 0.9714 x (I.D. in inches$)^2$

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Appendix F
Mathematics

Section 2

LEASE PUMPER SAMPLE MATH PROBLEMS

A lease pumper is frequently required to use mathematics in performing various duties associated with the job. Some of these calculations include:

- Gauge tanks.
- Daily production.
- Oil sold.
- Liquids hauled by transport.
- Gas produced and sold.
- Water produced and injected.
- Rod strings pulled and run.
- Tubing strings pulled and run.
- Quantity of chemicals needed and injected.
- Pipe transfers.
- Production for well tests.
- Percentages, ratios, and proportions in production and waste.
- Convert fractions, decimals, and percentages.
- Fill in time forms and other records.

Rules of Thumb

From the conversion constants given in Section 1, we find that multiplying the pounds per gallon by the constant 0.052 gives the pressure in pounds per square inch for each foot of depth. These values can be use to compute the bottom hole pressure based on various columns of liquid.

1. One foot of oil weighs approximately 1/3 pound. If the oil well has a standing column of oil 3,000 feet high, bottom hole pressure holding the standing valve closed is 1,000 pounds.

   Example Problem # 1: 35 API gravity oil
   0.052 x 7.08 pounds per gallon x 3,000 feet = Bottom Hole Pressure of 1,104 pounds.
   This is 0.368 pounds per foot, which is close to .333 or 1/3 pounds per foot.

2. One foot of saturated salt water weighs approximately ½ pound. If the oil well has a standing column of salt water 3,000 feet high, the bottom hole pressure is 1,500 pounds.

Example Problem # 2: 10 API gravity fresh water
0.052 x 8.33 pounds per gallon x 3,000 feet = Bottom Hole Pressure of 1,300 pounds.
Fresh water has a weight of 0.433 pounds per foot, a little under ½ pound per foot.

Example Problem # 3: Nearly saturated salt water weighing 9.4 pounds per gallon
0.052 x 9.5 pounds per gallon x 3,000 feet = Bottom Hole Pressure of 1,482 pounds.
This salt water has a bottom hole pressure of 0.494 or almost ½ pound per foot.

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Section 3

BELTS AND SHEAVES

ABBREVIATIONS

D	=	Diameter of Pump Sheave
d	=	Diameter of Prime Mover Sheave
L	=	Belt Length
SPM	=	Strokes Per Minute
RPM	=	Revolutions Per Minute (of Prime Mover for these calculations)
R	=	Pumping Unit Gear Box Ratio
C	=	Shaft Center Distance (Prime Mover to Shaft Center of Driven Equipment)

CALCULATIONS.

Use the appropriate formula to determine the unknown value. For example, use the formula

$$SPM = \frac{RPM \times d}{R \times D}$$

to determine the number of strokes per minute if the diameters, center distance, and gear box ratio are known. The same formula can be used to determine how SPM will be affected if the pump sheave diameter (D) is changed.

1. Calculating Belt Length, Full Formula

$$L = 2C + 1.57\,(D + d) + \frac{(D - d)2}{4\,C}$$

2. Calculating Belt Length, Short Formula (Note: This method is generally satisfactory for oilfield work.)

$$L = 2C + 1.57\,(D + d)$$

3. To determine the required diameter of the pump sheave to the effect of changing the pump sheave diameter

$$D = \frac{RPM \times d}{SPM \times R}$$

4. To determine the required diameter of the pump sheave to the effect of changing the pump sheave diameter

$$d = \frac{SPM \times R \times D}{RPM}$$

5. To determine the stokes per minute or the effect on strokes per minute if the RPM, diameters, or gear ratio is changed

$$SPM = \frac{RPM \times d}{R \times D}$$

6. To determine the revolutions per minute or the effect on revolutions per minute if the SPM, diameters, or gear ratio is changed

$$RPM = \frac{SPM \times R \times D}{d}$$

7. To determine the gear ratio or the effect on gear ratio if the RPM, diameters, or SPM is changed

$$R = \frac{RPM \times d}{SPM \times D}$$

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Section 3

Multiplication Table

	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
1	1	2	3	4	5	6	7	8	9	10	11	12
2	2	4	6	8	10	12	14	16	18	20	22	24
3	3	6	9	12	15	18	21	24	27	30	33	36
4	4	8	12	16	20	24	28	32	36	40	44	48
5	5	10	15	20	25	30	35	40	45	50	55	60
6	6	12	18	24	30	36	42	48	54	60	66	72
7	7	14	21	28	35	42	49	56	63	70	77	84
8	8	16	24	32	40	48	56	64	72	80	88	96
9	9	18	27	36	45	54	63	72	81	90	99	108
10	10	20	30	40	50	60	70	80	90	100	110	120
11	11	22	33	44	55	66	77	88	99	110	121	132
12	12	24	36	48	60	72	84	96	108	120	132	144

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GLOSSARY OF PRODUCTION TERMS

This glossary focuses on oilfield production terms. The meanings of most entries are limited to an explanation of the term's use in oil and gas production and may not include all meanings of the word or words. Words found in basic dictionaries are not generally included. Some abbreviations are included.

Abandon. To cease production of a well or the use of a piece of equipment. Also see *Plug and Abandon*.
Abrasion. Wearing away, scuffing, scarring, or scratching action on a surface that can lead to premature failure.
Absolute Pressure (PSIA) The pressure of surrounding air; also referred to as *ambient air pressure.* The second type of pressure is **Gauge Pressure** (PSIG). See also *atmospheric pressure.*
Absorption. The process of soaking up or holding a liquid, especially water.
Accumulator Equipment that stores pressure that can be used to close a blowout preventer on a well in an emergency. Generally, the pressure of nitrogen or hydraulic fluid is used.
Acetylene The combustible gas used in an oxygen-acetylene torch.
Acid Fracturing. The injection of acid into a limestone formation in an effort to dissolve limestone so that passages are formed through which oil and gas can enter the wellbore. Also referred to as **acidizing**.
ACT. Automatic Custody Transfer. See **Lease Automatic Custody Transfer**.
Additive. Chemical blended into petroleum products, usually in small amounts, to achieve a specific purpose.
Adjustable Choke. A large needle valve used to control the flow of fluids, usually from a flowing well. The needle or dart of the stem may be opened or closed to change the rate of flow.
Adsorption. The accumulation of molecules of gas or liquid on a solid surface in a condensed layer.
Aerobic. Occurring in the presence of oxygen, as in*aerobic corrosion.*
Allocation. The amount of oil and gas that may be produced in a given period of time, usually daily and monthly. Similar in meaning to*allowable.*
Allowable. The maximum amount of fluid that the oil regulatory agency allows to be produced in a given period of time, usually expressed as allocation or allowable per day. With stripper wells, the allowable is larger than the well is capable of producing.
Alloy. A combination of two or more metals. In a *ferrous alloy*, such as steel, one of the metals must be iron. In a *non-ferrous alloy*, no iron is included.
Ambient Temperature. The temperature of the surrounding air.
Amine. A glycerin solution used in gas dehydration units.
Anchor. A means of fastening guy lines to the ground. Four anchors are used to guy a well servicing rig to stabilize the mast.
Anaerobic. With atmospheric oxygen absent.

Annulus. The space down hole in a well between the tubing and the casing. This may also be referred to as the *annular space.*
Anode. The positive element in a **cathodic protection element** from which electricity flows and corrodes. May also be referred to as a **sacrificial anode**. Used extensively in heater/treaters to protect against corrosion.
AOSC. Association of Oil Well Servicing Contractors, located in Dallas, Texas.
ANSI. American National Standards Institute.
Antifreeze. An ethylene glycol compound mixed with water to prevent engine cooling systems from freezing.
API, American Petroleum Institute. Founded in 1920. Sets drilling and production standards.
API Gravity See API Gravity Ratings in Appendix A.
Apron Ring. The lowest ring of plates on a tank.
Arc Welding. Process for joining two pieces of metal by passing an electric arc between them through a rod or continuous wire. The generated heat of the arc melts the rod and metal fusing them together.
Artificial Lift. Methods utilized to lift oil to the surface when bottom hole pressure is too low to cause the oil to flow. Lifting methods include 1) mechanical lift (the pumping unit), 2) centrifugal lift, 3) hydraulic lift, and 4) gas lift.
ASME. American Society of Mechanical Engineers.
Associated Gas. The natural gas cap that overlies and makes contact with crude oil in a reservoir.
Atmospheric Pressure. The pressure exerted by the air or atmosphere around us. At sea level, it is approximately 14.7 pounds per square inch but it decreases with increasing altitude. A pressure equal to 14.7 PSI may be referred to as *one atmosphere*. See also *absolute pressure* and *gauge pressure.*
Atmospheric Vessels. Vessels that are designed to hold liquids but with a maximum pressure of only a few ounces.
Atom. The smallest particle of matter and the basic unit of an element, such as oxygen (O), iron (Fe), etc.
Back-off. To unscrew.
Backpressure. The pressure caused by a restriction of the full flow of oil or gas.
Backpressure Valve. A valve designed to regulate the pressure ahead of it. Backpressure valves are utilized on outlet lines of all pressure vessels.
Back-up. A wrench or chain tong utilized on the already tight side when making up connections of pipe.
Baffles. Plates that control the flow of fluids inside vessels.
Ball and Seat. The main parts of the valves in a plunger-type oil well pump.
Barrel. The standard measurement in the U.S. oil industry. One barrel contains 42 gallons of liquid and 5.6146 cubic feet and 0.15898 cubic meters of volume.
Barrel Wrench. A friction wrench used in repairing oil well pumps. This special wrench prevents damaging the barrel in disassembly and re-assembly.
Battery. Means *group of.* A group of tanks and vessels is a tank battery. A group of wells can be called a well battery, etc.
Bbl. Abbreviation for *barrel.*

BCPD. Barrels of condensate per day.
BCPH. Barrels of condensate per hour.
BDPD. Barrels of distillate per day.
BDPH. Barrels of distillate per hour.
Bean. A positive choke inserted into a line to regulate the flow of fluid from a well. Different sizes of beans are used to produce different flow rates. Beans are generally measured in sixty-fourths of an inch.
Bell Hole. A hole dug beneath a pipeline to provide room for tools or repair procedures. The pipeline may be buried or on top of the ground.
BF. Barrels of fluid.
BHP. Bottom hole pressure.
Bird Cage or Bird's Nest. The spreading of the individual wire strands of the end of a wire rope in preparation for running a new *rope socket* made of babbit or lead.
Black Magic. An oil-based drilling andworkover fluid.
Blank Flange or Blind Flange. A solid disk with bolt holes used to dead end a companion flange.
Bleed-down or Bleed-off. To reduce pressure by *cracking* or throttling or barely opening a valve to release the pressure slowly.
Bleeder or Bleeder Valve. The valve on the pumping tee of a pumping well used to check pump action and to draw samples.
Blow Down. The act of removing all pressure from a vessel or line, usually done prior to working on the system.
Blowout. An uncontrolled loss of pressure from a system.
Blowout Preventer. A special type of valve installed to prevent a blowout on a drilling or workover rig. A smaller version is used under a pumping stuffing box to assist in re-packing the box while under pressure.
Blg. Bailing.
BO. Barrels of oil.
Bob Tail. Any short truck or a truck with the trailer removed.
Boilerhouse. The act of guessing at a gauge, pressure reading, etc. instead of observing it. Making up a false report showing work not physically done.
Boll Weevil. A term applied to an inexperienced worker.
Bolster. A swiveling rack placed on a pipe trailer and a truck bed that can swivel or spin to allow the truck to turn corners without placing the load in a bind.
Bomb. Slang term for any tool that is lowered on a wire line to collect information, such as temperature or pressure.
Bonnet. The part of a valve that contains the stem packing and the valve stem.
Boomer, A load binder used to place tension on a chain to secure or tighten a load to be transported.
Boot. A large tubular section of pipe on the side of a wash tank that permits the gas to separate from the liquid before the liquid flows down and into the bottom of the vessel. The boot is usually attached to the outside top edge of a tank, and a flume or conductor normally goes down through the center.
BOP. Blowout preventer.

BOPD. Barrels of oil per day.
Bore. The inside diameter of a casing or an engine cylinder.
Bottom-Hole Pressure. The pressure at the bottom of the well in pounds per square inch.
Bottom Water. Water in a producing formation that is below the oil and gas in that formation.
Bowl. The holding device that the slips fit into when supporting the tubing string in well servicing.
BPD. Barrels per day.
BPH. Barrels per hour.
Brass. An alloy of copper and zinc. The copper is usually 60% or greater.
Bronze. An alloy of tin and copper. May also be referred to as *brass.*
Break Out. To loosen or screw out a *made up* or tight joint in line pipe, tubing, or sucker rods.
BS. Basic sediment. May also refer to BS&W.
BS&W. Basic sediment and water.
Buck Up. To tighten a thread or connection tight enough that it will not leak under pressure.
Bull Headed. Referring to a tee connection in a system where the openings go to the right and the left. Opposite of *running.*
Bump Down, Bump Bottom, or Tap Bottom. To have a pump hit bottom on the downstroke because of excess rod length. Often set this way on purpose. Also refers to firmly seating the pump cups after going into the hole with a replacement pump. May also be done to try to stimulate a pump before pulling.
BW. Barrels of water (D = day, H = hour, etc.).
Cage. The part of the pump that holds the ball and seat to limit ball movement.
Carbon Dioxide (CO_2). A heavy poisonous gas that is injected into oil wells to stimulate enhanced recovery because it combines with and thins crude oil.
Carbon Monoxide (CO). A heavy poisonous gas given off as a result of combustion in an engine.
Cased Hole Completion. Method of finishing a well such that the casing is run all the way through the pay zone, then cemented, and perforated. This is the most common type of completion.
Casing. Heavy steel pipe that lines the hole. The fixed or cemented string in a well.
Casinghead Gas or Oil Well Gas. Associated (from above) and dissolved gas produced along with crude oil from the well.
Casing Pressure. Gas pressure built up between the casing and the tubing.
Cast Iron. Iron made with a small amount of carbon (about 3%). By removing more of the carbon and making the iron flexible, *wrought iron* is produced.
Cat. A crawler-type tractor.
Cathead. A spool-shaped attachment on a winch to which a rope is attached; utilized for hoisting and pulling loads.
Cathode. The metal that does not corrode when corrosion occurs.
Catline. A hoisting or pulling line operated from a cathead.
Cat Walk. The narrow steel walkway near the top of a tank battery.
Cat Walk Ladder. The steps leading up to the cat walk.

Cellar. A hole, usually square, dug before drilling a well to allow working space for the casinghead equipment and blowout preventer.
Centrifugal Lift. The use of a liquid pump and electric motor located on the bottom of the tubing string with rotating stages (impellers and diffusers) above it to lift the liquid to the surface. Also referred to as **Electrical Submergible Pumping**.
Centrifuge. A shake-out or grind-out machine. Samples of oil in test tubes are placed in the machine and rotated at high speed to settle out BS&W.
CFG. Cubic feet of gas.
CFGPD. Cubic feet of gas per day.
Chase Threads. To straighten and clean machined threads.
Cheater. A short length of pipe used to increase the handle length and leverage of wrenches.
Choke. A restriction through which the well is produced. A short drilled nipple is often referred to as a **Flow Bean** or a **Positive Choke**. An **Adjustable Choke** is a large, heavy duty **Needle Valve** that is measured in sixty-fourths of an inch openings.
Christmas Tree. The wellhead on a flowing oil well consisting of a master gate, wing gate, and other fittings associated with the tubing. Casing valves are a part of the wellhead.
Clean-out Plate, Manhole, or Manway. Various names given to entry openings into vessels.
Clip. A U-bolt or similar device used to fasten two strands of a wire rope or cable together.
Close Nipple. A very short nipple having threads over its entire length and even shorter than an all-thread. Cannot be used with fittings that have recessed threads or a stabbing bell.
CO. Carbon monoxide.
Collar or Coupling. Device threaded on the inside used to connect two threaded joints.
Come-Along. A tightening device that crawls along a length of chain. Used for tightening guy lines on a well servicing rig.
Completion. The process of placing a drilled oil well into operation. It includes running the final string of casing, cementing it into place, perforating, running tubing, and any special procedure needed to prepare the well for production. May also include acidizing or fracing.
Computer. A device capable of storing and supplying information, solving problems, and supplying results from data. Examples are calculators, digital computers, and analog computers.
Computer Control. A system where field devices such as switches, valves, gauges, alarms, shut-in devices, etc., are controlled by computerized devices.
Computer Program. A procedure or routine for solving problems on a computer.
Condensate. A fluid that leaves the formation as a vapor but condenses into a liquid in the tubing or within the surface processing. These liquids can be propane, butane, heavier hydrocarbons used in making gasoline, and may also contain some water. Also called *distillate* or *natural gasoline*. Distillate is highly used by refiners for jet fuel, kerosene, diesel fuel, or heating oil.
Connate Water. Water contained within the producing formation when it was deposited.
Connection. The joining of two or more fittings. *Making a connection* is a drilling term for adding another joint.
Connections. Another term for fittings. See *Fittings*.
Control Panel. Part of an electrical control system that controls the functions of the equipment.
CO_2. Carbon dioxide.
Corrosion. An eating away by degrees of a material.

Coupon. A small metal strip that may be held in a corrosive system to measure the nature and severity of the corrosive action.
CP. Casing pressure.
CPSI. Casing pressure shut in.
Crack a Valve. To open a valve a small amount. Oilfield valves are always opened slowly to prevent downstream damage caused by sudden shock before the control equipment has time to react and normalize.
Crater. Slang for equipment failure.
Crude Oil. Liquid petroleum as it comes out of the ground. Crude oils range from very light (high in gasolines) to very heavy (high in residual oil). The fluid remains a liquid after pressure is removed.
Csg. Casing.
Cut Oil or Wet Oil. Oil that contains water.
Dead Man. A piece of wood, steel, or concrete that is buried to attach a guy wire for bracing a mast, tower, or piece of equipment. Acts as an anchor.
Dead Oil. Oil that no longer contains light ends or gas.
Dead Well. A well that will not flow.
Depletion, A deduction allowed in computing the taxable income from oil and gas wells.
Die. A tool used to make or clean male threads. Opposite of *tap*.
Dike or **Fire Wall** or **Escarpment**. Earthen mound used to contain sludge from wells during drilling or to contain leaks from tanks or vessels.
Discovery Well. A wildcat well that discovers or finds a new reservoir.
Disposal Well or Injection Well. A well through which produced water is returned to subsurface formations. A general term that does not indicate if the water is being used for water flood.
Dissolved Gas. Natural gas that is in solution with the crude oil in the formation.
Distillate. A term highly used by refiners to refer to heavier condensates from gas wells that are called jet fuel, kerosene, diesel fuel, or heating oil. Also used by many in reference to condensate.
Dog House. A small building used for keeping lease records, changing clothes, and for general supply storage.
Dog Leg. A bend in pipe usually to lift a meter higher for convenience. Can also apply to a ditch or downhole deviation from absolute vertical in a well.
Dope. A lubricant used on threads to promote easier and better make-up and to prevent gauling of threads. There are many dope compounds for a variety of purposes.
Double. Usually refers to two joints of pipe that are standing in the derrick or two sucker rods hung. This speeds up the process of pulling and running pipe.
Doughnut. Slang expression for a tubing hanger or ring of wedges that supports a string of pipe.
Downcomer. A pipe through which flow is downward.
Dozer. A powered machine for earthwork. Short for bulldozer.
Dresser Sleeve. A sleeve slid over the ends of two pieces of pipe to join them together to hold pressure without the need for threads.
Drifter. A worker who never stays in one place very long.
Drip. Small quantities of liquid that condenses out of natural gas. Very flammable and dangerous to handle.

Dry or Lean Gas. Gas that has been produced without liquids or has been through treating equipment to remove all or most liquids.
Dry Hole. A well that does not find a commercial volume of oil or gas. Sometimes referred to as a *duster*.
Dutchman. A piece of thread that has broken off inside a fitting that must be removed before the fitting can be used again.
Electrical Submergible Pumping. Use of a centrifugal pump and electrical motor located at the bottom of the tubing string with rotating stages (impellers and diffusers) above it to lift the liquid to the surface.
Electrochemical. Chemical changes associated with the flow of electrical current, as in corrosion.
Electrolyte. A mixture of soil or liquids capable of conducting an electrical current.
Emissions. Gases discharged as waste material.
Embrittlement. The loss of strength in a metal losing caused by its absorption of gasses, such as carbon dioxide or hydrogen sulfide. Stainless steel is used to replace some parts such as bolts and gaskets because it is impervious to embrittlement.
Emulsion. The proper name for all of the elements and compounds produced from an oil well usually in a fluid state. After this fluid goes through a separation process, it is then called Natural Gas, Crude Oil, and Produced Water. This water is usually salty.
Enhanced Recovery. The process of adding a force and chemical reaction into the reservoir to stimulate production and extend the life of the field and the amount of hydrocarbons produced.
Et Al. Abbreviation for *et alii* which is Latin for *and others*. Used on signs where the owners are too numerous to be listed.
Farm Out. To share drilling rights on leased acreage.
Fatigue. Failure of metal due to repeated loading or stress.
Female Connection. A connection with internal threads.
Fireflooding. The use of high volumes of air that are pumped underground to drive fire through the formation to aid in production. Also referred to as *in-situ* combustion.
Fire Wall. A wall of earth built up around an oil tank or tanks to hold the oil in event of tank failure.
First Stage or **Primary Recovery.** The initial production produced from a well when nothing is added back into the formation to stimulate future production.
Fittings. All of the valves, nipples, tees, unions, ells, etc. used to make up a system of piping. Also called *connections*.
Flange Up. To complete or finish a job.
Float. A long flat-bed trailer used to haul oilfield equipment.
Flood. A term used in enhanced recovery to indicate that a force is injected in an injection well, travels across the formation. and is produced back from other wells.
Flow Line. The line that goes from the wellhead to the tank battery.
Flow Splitter A large horizontal three-stage separator where the gas flows into the gas system and the water, by use of an interface float, is diverted into the water disposal system. The flow of oil by use of diverter weir gates can be diverted to several heater/treaters so that it can be slowed down, heated, and treated prior to flowing to the stock tank.

Flowing Well. A well that has enough bottom hole pressure to flow the fluid from the formation, to the surface and through the production facilities all the way to the tank battery.
Fluid. Any substance that can easily change its shape to fit a container. This includes natural gas, air, crude oil, water, drilling mud, etc.
Fluid Level. Distance from the wellhead to the fluid level in the pipe. Because of the differences in diameter, it will be different in the tubing and in the casing.
Flume. A large pipe that extends down into the center of a wash tank that permits the separation of gas and liquid before the liquid flows down and enters the wash tank at the bottom of the vessel. If the flume is mounted externally on the side of the vessel it is called a *boot.*
Formation. See *reservoir.*
Fracturing or Fracing. Process of opening up the underground formation in the reservoir by pumping in liquids under high pressure to increase the permeability of the formation. Sand may be pumped in as a propping agent or acid to etch the formation to stimulate production.
Frozen. Condition of components in which they will not operate freely, if they will move at all. Also a condition of lines where ice has formed on the inside from expanding gas and the moisture has turned to ice.
Ft. Feet.
G. Gas.
G&O. Gas and oil.
Gal. Gallon.
Galvanize. To coat a metal with zinc to prevent corrosion.
Gas Lift. A process of injecting natural gas into the column of fluid in the tubing string to cause the well to flow the production to the tank battery.
Gas/Oil Ratio. The amount of gas produced for each barrel of oil.
Gas Processing Plant. A plant strategically located in the oilfield to remove hydrocarbon liquids, primarily butane, propane, and heavy gasolines, before the gas is transported by pipeline to market.
Gas Well. A well that produces natural gas. Condensate may also be produced and may be as clear as potable water.
Gage. Alternate spelling of*gauge***.**
Gauge. Tool used for measuring daily production.
Gauge Line. A tool used to measure the amount of fluid in a vessel.
Gone to Water. Term applied to a well in which the water production has dramatically increased and almost no oil is being produced.
GOR. Gas/oil ratio.
Gradient. Pressure drop.
Gravity or API gravity. The API standard for measuring the density of a liquid. A specific gravity of 1.0 is equivalent to 10. Degrees API. See comparison chart located in Appendix A.

$$\text{API gravity} = \frac{141}{\text{specific gravity}} - 131.5$$

Grease Book. Slang term for the lease pumper's daily gauge book.
Gun Barrel. Popular slang term for a *wash tank,* a large three-stage atmospheric separator utilized to separate crude oil and water. Being large, the fluid goes through it slowly, allowing additional time for separation.

Guy Wire or Guy Line. A cable or wire rope used to steady a mast or pole. The load guy line supports the pulling load, and the wind guys protect the mast from winds.
HCl. Hydrochloric acid.
Handy. A connection or fitting that can be unscrewed by hand.
Hard Hat. A plastic hat worn to protect the head from falling objects. Two styles are common. One has a bill in front while the other has a brim all the way around.
Hatch or Thief Hatch. An opening in the top of a tank with a hatch that can be opened to gauge or test the condition of the produced oil.
Headache or Headache Rack. A steel frame mounted on a gin pole truck at the front of the bed to protect the cab when the poles are folded over and also to support the poles when folded down.
Heater/Treater. A large three-stage separator with direct heat. The most common style is about 20 feet tall and 6-8 feet in diameter. Most operators try to heat them only in the winter. Many are pressurized but can be operated with atmospheric pressure.
Holiday. A missed or skipped spot when painting or any action where full coverage is important.
Horizontal Drilling. A procedure of turning the well hole horizontally and drilling a long distance in the reservoir to increase the well's potential production.
Hot Oiler. A truck with a heating unit that can pump oil through it and heat it to melt paraffin and treat oil to clean it enough to be sold.
Hot Tap. To tap a new line into an existing one while the line being tapped is under pressure and not shut it down while the new connection is being made.
H_2O. Water.
H_2S. Hydrogen sulfide.
H_2SO_4. Sulfuric acid.
HP. Hydrostatic pressure, also horsepower.
Hpf. Holes per foot.
Hydraulic Lift. A method of pumping oil or water down a well to operate a reciprocating hydraulic pump to produce the well.
Hydrocarbons. Any organic compound made up entirely of hydrogen and carbon. Often called fossil fuels, it is produced as crude oil and natural gas.
Hydrogen Sulfide (H_2S). A deadly gas that occurs naturally in crude oil. Has the odor of rotten eggs and can kill quickly in many situations. Heavier than air and settles.
Infield Drilling. Drilling in an area that has near-by production.
In Situ Combustion. Burning a portion of a reservoir underground with fire to produce hot gases to drive oil to the producing well.
Injection Well. A well used to pump fluids underground. It may be a disposal well in a neutral zone to get rid of produced water or in a producing zone to inject gas for pressure maintenance or water for water flood.
Insulating Flange or Union. A flange that contains plastic bolt sleeves, washers, and gasket to insulate the two halves to break the possibility of electrical current flowing through the pipe. Other styles are available. This is done as a form ofcathodic protection.
Ion. Electrically charged particle, atom, or radical.
Iron. A naturally occurring element. After being processed with one or more metals, it is formed into steel.

Joint Venture. Arrangement in which two or more parties join together in a petroleum venture.
Jack or Pipe Jack. A short slender pipe with short projections to one side and a bottom plate. It is utilized to support a joint of pipe while it is being made up.
Joint. One full length of pipe. This is usually twenty five to thirty two feet.
Junk. Equipment or materials that have been retired from service. Occasionally a piece of **junk** cannot be re-used but has a high salvage value and is not to be confused with **scrap**, which just has a weight value. Parts from a junked pumping unit may be used to repair several other similar units as the need arises.
KB Kelly bushing. Point from which drilling measurements are made when measuring downhole.
KCl Potassium chloride. Used in fresh water to prevent formation hydration (swelling) in formations that contain shale. Shale is clay that has been compressed until it becomes rock.
Kill a Well. Process in which water or oil is pumped down a well in preparation for working it over or making a change in the hook-up. This procedure is carefully calculated to prevent damaging the formation.
LACT. See **Lease Automatic Custody Transfer.**
Lead Time. Planning time set aside before a project begins.
Lean or Dry Gas. Dry gas from a gas well or gas that has been treated to remove most of the liquids.
Lease Automatic Custody Transfer or LACT unit. When oil is sold to a pipeline company, it may go through a LACT unit to measure the number of barrels, and a sampler aids in determining gravity, temperature, and BS&W. After the crude oil goes through the backpressure valve, ownership of the oil is transferred from the production company to the pipeline company.
Liquid. State of matter in which a substance fits the shape of its container but its volume remains almost constant and is not greatly influenced by pressure.
Live Oil. Crude oil that still contains light ends and natural gas.
Load Binder. Chain or cable used to tie down a load of equipment on a float .
Location. The site at which a well is to be or already has been drilled. Normal spacing for medium depth wells is one per forty acres or sixteen per section. There will be more shallow wells per square mile and fewer deep wells.
Loop. A circle of pipe placed in a line to absorb changes in the length such as contraction in cold weather and expansion in hot weather.
LPG or Liquefied Petroleum Gas. Butane, propane, or a mixture of these two fuels.
Lubricator. 1. A swab tool holder that is set on top of a well during swabbing. 2. An oiler used to lubricate pistons in a gas compressor or single cylinder horizontal engine.
Make a Hand. To be a good, dependable worker.
Male Connection. Connection with external threads.
Manway, Manhole, or Clean-out Plate. Various names for entry plates into vessels.
Marginal Well. An oil or gas well where the production is so limited in relation to production costs that the profit is approaching the vanishing point.
Master Gate. A large vertical tubing valve on the Christmas tree that is full opening (tools can be run through it) and can be closed in emergencies. High-pressure gas wells normally have two master gates, one mounted directly on top of the other.
MCF. Thousand cubic feet.

Misc. Miscellaneous.
Miscible Flood. An enhanced oil recovery procedure involving the injection of solvent followed by a displacing fluid, usually water.
MMCF. Million cubic feet.
MCFGPD. Thousand cubic feet of gas per day.
MI&RU. Move in and rig up. A drilling rig and well servicing abbreviation to explain rig expense.
Multiple Completion. A method in which the well is completed to provide the capability of producing hydrocarbons from two, three, or even four different zones at the same time.
NaCl. Sodium chloride or salt.
Natural Gas. Consists largely of the hydrocarbon methane. Occurs naturally in underground reservoirs and is the cleanest burning of all fossil fuels.
Nipple. A short piece of threaded pipe. Available in two inch increments up to twelve inches long. May be seamed or seamless, and low, medium, or high pressure.
Non-associated Gas. Natural gas that while in the reservoirs does not contain a significant amount of crude oil.
O. Oil.
O&G. Oil and gas.
Octane Number. A rating of a gasoline's ability to burn without abnormal knocking. The octane number is the percentage of isooctane in the fuel blend.
Off Production. A term used to describe the condition of a well that has a production problem or is temporarily shut in for many reasons. Opposite of *on production.*
Offset Well. Well drilled on the next location near another one.
Oil. A compound composed of hydrogen and carbon. See also *crude oil.*
Oil Well. A well completed for the purpose of producing hydrocarbons from an underground reservoir.
Oil Shale. Shale deposits that contain oil. The United States owns huge oil shale deposits primarily in Colorado, Utah, and Wyoming. The oil is difficult to extract.
Old Hand. Someone who is highly experienced at what is being done.
On the Line. A term used to describe a stock tank while oil is being sold out of it. It is not uncommon for it to be "on the line" for several days when the gauger does not come every day.
On the Pump. A term for a well that has a pumping unit on it.
OPEC (Organization of Petroleum Exporting Countries). An association of some the world's largest oil producing and exporting countries.
Open Hole Completion. Un-cased portion of the hole. The bottom end of the casing stops just above the oil in the impervious zone and is cemented. The pay zone is then drilled and left as open hole.
Oxidation. Condition of a substance combining chemically with oxygen to form an oxide, or electrochemically, as the loss of electrons at the anode of a corrosive cell.
Parting. Breaking, such as "the rod string parting" (a rod breaking)
Pay Zone. The down hole reservoir from which the oil and/or gas is being produced.
Permeability. The ability of the reservoir rock to transmit fluid through the porous spaces. This regulates the ability of fluids to move through the reservoir. The rock is impermeable if there is no communication between pores. Not to be confused with porosity.

pH. A symbol used to express the concentration of the hydrogen ion in a solution, such as acidity (0 to 7), or the alkalinity (7 to 14.7). Declining numbers less than 7 indicate increasing acidity, and numbers increasing above 7 indicate increasing alkalinity, with 7 being neutral. pH 6 means a concentration of 10^{-6}, 0.000001 and indicates slight acidity.
Pig. A scraping tool run through a line to clean out paraffin or other deposits. A *rabbit* checks the clearance to see if it is still round, although it will also check for obstructions.
Pipe. A general term that includes all forms and classes of pipe. It includes line pipe, tubing, and casing.
Pipeline. A transportation system for moving oil and gas from the field to a refinery, although it is also a general word used in referring to many other types of line.
Pipeline Oil. Oil clean enough to be sold. This is usually no more than one percent BS&W.
Pit or **Slush Pit** or **Overflow Pit.** An earth pit with dikes around it, usually rectangular or square, with a plastic liner and a net cover.
Pit. A depression or the eating away of a metal part caused by corrosion.
Plug and Abandon. To stop producing a well, plug the depleted formation, and salvage all pipe, materials, and equipment possible.
Plug Back. To shut off the lower formation in a well bore, usually to reduce water production.
Polarize. To reduce or retard an electrochemical corrosion reaction by deposition of a corrosion product.
Polymer. A compound formed by linking one molecule with another to form a very long chain. A process used extensively in enhanced flood recovery.
Poor Boy. Descriptive term for any homemade or shop-made substitute or practice usually done to save money.
Plunger Lift. A method of lifting oil to the surface by a plunger and bottom hole gas pressure.
Porosity. The percentage that the volume of pore space bears to the total bulk volume. This determines the amount of space available for the storage of fluids.
Positive Choke. A choke with a hole drilled through it to flow the produced fluid through. It is not adjustable. To change the flow rate, the positive choke must be replaced.
Potential Test. A test to determine the maximum rate at which a well can produce oil. Continuous production at this rate may cause serious problems with the well.
Power Oil Tank. A tank added into the tank battery system just ahead of the stock tank to supply oil to be utilized downhole in a hydraulic lift system. In other applications where water is used, this vessel will be located just ahead of the water disposal system to supply water.
Ppm. Parts per million.
Pressure Maintenance. Injecting gas back into the reservoir to maintain reservoir pressure to push new oil to other wells to be produced.
Pressure Regulator. A regulator utilized to control the pressure downstream or after the regulator.
Pressure Relief Valve. An automatically opening valve utilized to limit the pressure that can be placed inside a vessel.
Primary or **First Stage Recovery.** The initial production produced from a well where nothing is added back into the formation to stimulate future production.
Production. The amount of oil, gas, and water produced, or a company that owns oil and/or gas producing wells and produces oil and/or gas.

Productivity Test. Producing a well at several different rates or ways to determine the best method of producing the well.
Prorationing. Regulating oil and/or gas production to maximize production
PSI. Pounds per square inch.
PSIA. Pounds per square inch absolute.
PSIG. Pounds per square inch gauge.
Pump Off. To pump a well too long or too rapidly so that the liquid level in the well bore or casing is lowered to the level of the standing valve in the pump.
Put on Pump. To install a pumping unit, and all necessary equipment to pump a well.
Qts. Quarts.
Rabbit. A device run through pipe to check if it is still round or partially plugged, such as casing and tubing before it is run in the hole. A *pig* is a line cleaner.
RB. Rotary bushing.
Refining. The manufacture of petroleum products from crude oil by a series of processes into major finished products as well as supporting a wide petrochemical industry.
Remote Control. A control placed in the field to control and regulate operations in the field. May be changed by remote signal from the office.
Reserves. Estimate of already located oil and gas still in the formation that may be produced.
Reservoir. An underground formation where oil and gas have accumulated.
Reservoir Pressure. The pressure on the well after the well has been shut in for twenty-four hours.
Rich or Wet Gas. Natural gas that contains liquid hydrocarbons in vapor form as produced from an oil or gas well.
Riser. A pipe through which fluid moves upward when moving through it.
Rock a Well. To alternately remove pressure off the casing and tubing of a well to stimulate it to flow again by itself. The alternate procedure might be to call a *swabbing unit.*
Rod Job. Process of pulling and running rods.
Rod. A general term for rods used to pump an oil well, including steel and fiberglass.
Round Trip. Act of pulling and running rods or tubing.
Running. Making up a tee in a system where one opening points to a side and the other continues straight ahead.
S. An abbreviation used on fittings to indicate approval for use with steam.
Sand Fracture. The injection of oil and sand or water and sand into the well under high pressure to open up the formation to allow the well to produce more hydrocarbons. It may also be used in injection wells in order to increase the injection rate or lower the injection pressure.
Sanded Up. Condition in which sand has accumulated in the casing of a producing well causing the tubing or pump to stick in the hole. Sand enters with the produced emulsion but falls to the bottom.
Scrap. Material retired from service that has a weight-only value. Not to be confused with *junk*, which may have a high salvage value.
Scraper. A device run in a well on a wire line to check the hole clearance prior to running a packer. It is also the name for a tool used to remove scale or salt bridging.
SD. Shut down.
SDR. Shut down for repairs.

Seamless. A term describing pipe made with an extrusion process where the pipe is not welded. Pipe is sold as seamed or seamless. Cheaper pipe is rolled round and parent material welded.
Secondary Recovery or **Second Stage Recovery.** Production in which force is added to the formation. Water flood and pressure maintenance are classified as second stage recovery.
Scale. A deposit on a metal. Scale is usually deposited out of water. Often referred to as *gyp*.
Seismic Exploration. Method of prospecting for oil and gas by sending shock or other waves down into the earth. A geophone captures these reflections and computers aid in analysis.
Separator. A pressurized vessel whose purpose is to separate gas from liquids at the tank battery.
Separator, Two Stage. A separator designed to divide the incoming emulsion. The gas will go out the top, while the oil and water is still combined and the liquid is dumped through a float controlled valve to the next vessel in the system.
Separator, Three Stage. A separator designed to separate the emulsion into gas out the top, water into a line off the bottom, and the oil leaving the vessel through the oil line.
Shake-Out. A centrifuge that rotates at high speed to settle BS&W to the bottom of the test tube.
Sharpshooter. A long, narrow shovel.
Sheave. A grooved pulley. May have one to eight or more grooves and belts.
Shut In. A well that can produce oil, but the valves are closed. May be shut in for many reasons.
Shut in Pressure. Pressure taken after well has been shut in for twenty-four hours to reach maximum.
SI. Shut in.
SIBHP. Shut in for bottom hole pressure test.
SICP. Shut in casing pressure.
SITP. Shut in tubing pressure.
SIP. Shut in pressure.
Slack Off. To lower a load or ease up on the tension on a line.
Sling. A wire rope loop used to lift heavy loads.
Slips. Wedge-shaped toothed pieces of metal that fit inside a bowl and are used to support drill pipe, tubing, or fished broken sucker rods.
Slop Tank. A vessel installed to hold very difficult-to-treat oil for a longer period of time while the majority of the oil is being sold. Careful utilization of a slop tank can dramatically reduce treating costs without slowing down sales or risk filling the tank battery with oil that cannot be sold.
Slush Pit, or **Pit**, or **Overflow Pit** See *pit*.
Snatch Block. A sheave or pulley where one side can be opened up so a wire line can be inserted.
Soft Rope. A three- or four-foot piece of large rope cut off. The small strands are unwound individually and utilized to tie many things. These individual strands are called soft rope.
Sour and Sweet Crude Oil. Sour crudes usually have more than one percent sulfur and sweet crudes has less. The sweeter crudes are more valuable.
Sour Gas. Gas that contains impurities such as sulfur or hydrogen sulfide.
SPE. Society of Petroleum Engineers.

Skimmer Tank. A tank designed to allow water to flow through it but to skim off any oil that enters to be retained and added back into the produced oil. Works very similarly to the gun barrel or wash tank except it is utilized to reclaim very small amounts of oil that would otherwise be lost into the water disposal system.
Spacing. Refers to the number of acres designated for each oil well, such as twenty-acre spacing.
Spaghetti. A very small tubing string.
Spalling. Condition in which metal breaks up, chips, or flakes away.
Specific Gravity. See API reference chart in Appendix A.
Stabilized. Condition in which a well is considered has produced long enough that it continues to produce the same amount in a given period of time, usually one day.
Steel. A metal alloy of two or more metals, one of which must be iron
Storage Tank. Any tank capable of holding liquids. The word *storage* is not specific and can be used in reference to oil, water, or workover mud.
Strike Plate. An extra plate of metal attached to the bottom of a tank under the thief hatch to prevent damage to the bottom tank plate caused by the plumb bob on the end of a gauger's gauge line.
Strip a Well or Stripping Job. Pulling the rods and tubing at the same time.
Stripper Well. A well that *strips* the remaining oil from a reservoir. Efficient operations and conservative lease pumping practices can keep thousands of low-volume wells in profitable operation. These wells contribute a large percentage of U.S. crude production.
Strap aTank. To measure a tank for the purpose of making a chart that shows the tank volume every quarter of an inch. This is usually done by the oil purchaser.
Submersible Pumping. Procedure in which a pump is installed below the liquid level in a well. The electric motor is on bottom and rotates fluid cups above it to lift the liquid. This manual refers to this type of pumping as *centrifugal lift.*
Swab. To drop a swabbing tool down the tubing and pull a column of oil to the surface.
Swamper. A helper on a truck.
Swb. Swabbed.
Sweet Crude. Oil that contains no sour impurities.
T/ Top
Tail Chain. 1. A chain put on the end of a rope on a drilling rig used to spin pipe. 2. A chain put on gin poles at the back of the truck and tightened so that the poles cannot fold over on the headache post.
Tailboard. The back edge of the bed of a bob tail truck. It may be rolling (free to roll while winching) or welded solid.
Tail out Rods. To pull the bottom of a rod out or tail them out when laying them down on a rack, or tail them back in when running rods that have been laid down.
Take a Strain On. To lift a heavy or awkward load on a wire line gently.
Tally. The act of measuring pipe, usually in increments of one hundredth of a foot.
Tank. A vessel designed to hold liquid. May be rectangular or round, horizontal or vertical.
Tank Battery. A series of vessels and connecting lines designed to separate oil, water, and gas, and flow it into the correct vessel or line destination. A tank battery usually has tanks, but in high volume, clean oil may not use any vessels.

Tanker. An ocean-going ship designed to haul crude oil in bulk from a producing area to a refinery.
Tap. 1. To strike lightly. 2. A tool used to cut or clean female threads. Opposite of *die*.
Tap Bottom or Bump Bottom. To allow the pump to hit bottom with each stroke of the pumping unit. Often done deliberately on shallow wells or when trying to stimulate a well that has stopped producing oil before pulling.
Tar Sand. Rock impregnated with tar or heavy crude that cannot be recovered by ordinary production methods.
Tbg. Tubing.
Telecommunications. The transmission of signals over long distances, such as radio.
Telemetry. Use of radio or other methods to transmit field measurements over a distance.
Tertiary or **Third Stage Recovery.** Final oil recovery requiring two or more forces such as temperature and pressure, or chemical and pressure.
Thief. A tool utilized to secure liquid samples from the top, center, or the bottom of a tank.
Thief Hatch. An opening on the top of a tank with a hatch that can be opened to gauge or test the condition of the produced oil.
Third Stage Recovery, or **Tertiary Recovery**. Final oil recovery requiring two or more forces such as temperature and pressure, or chemical and pressure.
Thread Protector. A steel or plastic cover to screw on threads while the pipe is in storage.
Tie Down. Secure a load to be hauled prior to moving the vehicle.
Tong. A form-fitting wrench used to back up, or make up pipe. Form fitting to prevent egging or crushing the pipe. Used on the rig floor and in pipe laying tools.
TP. Test Pressure.
Trip. The action of pulling or running rods or tubing. Pulling and running is called a *round trip*.
Triple. Refers to three joints of pipe stood up in the derrick or three rods hung up together. This speeds up the process of pulling and running rods and pipe.
Tubing. Random length upset pipe that is moveable in a well. Fluids are produced through it and it can be pulled when working the well over.
Tubing Job. The pulling and running of tubing.
Unitize. To produce from a reservoir so that one company operates every well in a pay zone although it does not own all of them. The income is prorated according to percentage of units owned.
Vacuum Truck. A truck with a low-pressure pump that operates with a large diaphragm and a reciprocating motion. Can pump thick emulsified oil containing scale and small solid objects.
Vapor. A gas that can be compressed into a liquid.
Viscosity. The thickness of an oil and the rate that it will pour.
Warm Up or Heat Up a Connection. To apply slight heat or pressure, such as a hammer blow, to a connection that is difficult to loosen.
Wash Tank or Gun Barrel. A large three-stage atmospheric separator utilized to separate crude oil and water. Because the tank is large, the fluid goes through it slowly to give it additional time to separate.
Water Disposal Tank. A tank in a battery to receive any produced water.
Waterflood. Process of injecting water into an injection well and recovering it from another well.

Water Leg. A line coming off the tank near the bottom of a vessel that regulates how much oil is retained in the gun barrel or heater/treater.
Well. A general term for all petroleum producing wells, but can also include water and injection wells.
Wet or Rich Gas. Natural gas just as it was produced from an oil or gas well, which contains wet hydrocarbon vapors.
Widow Maker. Any condition or act that is liable to cause death or serious injury to a worker.
Wicker. A broken strand of wire on a wire rope. Often common on winch lines.
Wildcat. An exploratory well drilled in an area where no previous production is present. Usually five miles or more from producing wells.
Winch or Gin-Pole Truck. A bob tail truck with a winch. Medium size winch trucks may have two winches, and a large one may even have three.
Wiper. A rubber ring or device for wiping rods and tubing clean on the outside while pulling.
Wireline. A small diameter wire line used to lower a wide assortment of downhole tools into a well for performing many functions, such as surveys. A general term for downhole lines.
Wire Rope. A steel cable composed of steel wires wrapped around a central core to create a line of great strength and flexibility.
Wing Gate. The horizontal gate valve on a Christmas tree. The well is usually controlled from this valve, and the master gate is available upon need.
WOC. Waiting on cement, a drilling term used for the time spent waiting for cement to set or get hard before resuming the drilling or completion operations.
WOG. Water, oil, gas. (Stamped on some fittings)
Working Pressure. The pressure at which a piece of equipment is designed to work.
Work Over. To solve a downhole problem on a well that is more difficult than basic well servicing.
Wtr. Water.
WSP. Working steam pressure. (Stamped on some fittings).
Yield Point. The maximum stretch or pull that can be placed on metal and still have it return to its original shape. Used extensively in well servicing, especially when pulling rods.
Zone. The downhole area that the well is being produced from. Referred to as *pay zone.*

INDEX

Instructions for Using Index.

CHAPTERS.
The beginning number refers to the chapter. The letter that follows identifies the section. The number after the dash refers to the page within that section on which the information begins. For example, an entry of 3C-2 indicates that the topic begins on Chapter 3, Section C, Page 2. The information may be continued on following pages.

APPENDIXES.
If the topic location begins with a letter, then the reference is located in an appendix. The letter represents the appendix and the number tells the page within that appendix on which the topic discussion begins. For example, A-9 indicates that the information is located in Appendix A, and is found on page 9.

The Lease Pumper's Handbook
Being Written For
Commission On Marginally Producing Oil and Gas Wells
State Of Oklahoma

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