Training Module

Describe and Operate Beam Pump

Module A
Describe and Monitor Wellhead, Sucker Rod String, and Subsurface Pump

HDC Human Development Consultants Ltd.

Cover Photo
Courtesy of Husky Energy

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This training kit consists of the following parts:
- Training Module and Self-Check
- Blank Answer Sheet
- Knowledge Check and Answer Key
- Walkthrough

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Foreword

Beam pumps are used to lift a variety of liquids from subsurface wells to the surface. Beam pumps are commonly used at:

- oil wells to lift the oil to the surface
- gas wells to remove accumulated water which would prevent the gas from entering the wellbore
- coal bed methane wells to remove water from coal seams

While HDC's *Describe and Operate Beam Pump* series of training kits addresses beam pumping oil wells, the content applies to any beam pumping application.

The series consists of four modules, listed below. These modules are designed to address the needs of oil well operators responsible for operating, monitoring, and optimizing *existing* beam pumping oil wells. The modules are task focused (i.e., center around *what* the operator does, *why* he/she does it, *when* he/she does it, and *how*). The modules are sequential: Module A is a prerequisite to Module B and so on.

The four modules in the series are:

- Module A—Describe and Monitor Wellhead, Sucker Rod String, and Subsurface Pump
- Module B—Describe and Monitor Pumpjack and Prime Mover
- Module C—Describe Beam Pump Operation
- Module D—Optimize Beam Pump Operation

Modules A and B include:

- descriptions and principles of operation of typical surface and subsurface beam pumping oil well equipment
- operating variables
- reasons for specific operating requirements
- causes for variables to change, consequences, symptoms, and operator responses to abnormal operations
- monitoring tasks related to the equipment
- a walkthrough where the operator identifies the equipment at his/her site
- self-check review questions
- a stand-alone knowledge check

Module C provides:

- a description of a typical beam pump wellsite
- an overview of beam pump oil well safety
- production monitoring and record keeping
- a description of routine beam pumping tasks:
  - respond to oil well shutdowns
  - start up pumpjack oil well (engine)
  - start up pumpjack oil well (motor)
  - check pressure safety switch
  - pig flowlines
  - put sucker rod pump on tap
  - shut down pumpjack oil well; lock out; secure for maintenance
  - change pumpjack stuffing box
- self-check review questions
- a stand-alone knowledge check
- a stand-alone checklist for monitoring beam pump operation

Module D provides:

- a description of well performance analysis
- a description of pumping system analysis
- a description of pumping oil well diagnostics:
  - fluid level detector
  - dynamometer
  - pumpjack load analysis
- a description of pumping unit adjustments:
  - balance the pumping unit
  - change pumping speed
  - change stroke length
  - lower/raise sucker rod string
  - adjust casing gas or downstream pressure
- a description of the operator's role in optimization
- self-check review questions
- a stand-alone knowledge check
- a stand-alone troubleshooting table for beam pump operation

Contents

Contents (continued)

Training Objectives

Upon completion of this training kit, you will be able to:

- Describe the wellhead and piping used for beam pumping oil wells:
  - well components
  - wellhead
  - blowout preventer
  - pressure safety switch
  - stuffing box assembly
- Describe the sucker rod string:
  - polished rod
  - sucker rod string
- Describe the subsurface pump:
  - sucker rod insert pump
  - tubing pump
- Describe corrosion, wax, scale, and hydrate control

1 Introduction

Artificial lift *is used widely:*

- *at oil wells to move the oil to the surface*
- *at gas wells to remove accumulated water which would prevent the gas from entering the wellbore*
- *at coal bed methane wells to remove water from the coal seams*

When the pressure in an oil-producing reservoir is high, the oil flows naturally to the surface. However, when a reservoir does not have enough pressure to produce by natural energy, a means of *artificial lift* is used to lift the oil from the reservoir to the surface. Artificial lift methods include:

- beam pump (rod pump)
- progressive cavity pump
- electric submersible pump (ESP)
- gas lift
- plunger lift
- hydraulic pump

Beam Pumping Systems

Beam pumping is the most common type of artificial lift—some estimates claim that as many as 85% of artificial lift wells are equipped with beam pumps.

Beam pumping systems consist of (see Figures 1 and 2):

- the wellhead and flowlines
- the beam pumping system, which consists of:
  - a beam pumping unit (pumpjack) at the surface
  - a pump at the bottom of the well
  - a sucker rod string which connects the pumpjack and pump
  - a prime mover (electric motor or internal combustion engine) which provides the energy for pumping the well

Figure 1—Beam Pump at an Oil Well

HDC Photo

Beam pumping systems:

- are mechanically simple and durable and can run problem-free for a long time
- can be adapted to a variety of well conditions
- can be automated, when powered by an electric motor

Beam pumping systems are recommended for low volume, shallow-to-medium depth oil wells pumping light to medium crude oil. The maximum depth for a beam pumping system is limited by the weight of the column of oil in the tubing, the strength of the sucker rods, and the rate at which the rods drop during the downstroke.

Contents of Module A

This module describes the equipment, operating variables, operator monitoring, and safety issues for:

- wellheads and flowlines
- sucker rod strings
- subsurface pumps

This module provides an introduction to *typical* beam pumping oil well equipment. Because every oil well is different, the **Walkthrough** which accompanies this module is an important part of the training kit. The walkthrough allows the operator, working with a coach, to identify the *specific* equipment at the site and describe site-specific operating and safety concerns.

2 Wellhead and Flowlines

This section describes:

- well components
- the wellhead
- the blowout preventer
- the pressure safety switch
- the stuffing box assembly

2.1 Well Components

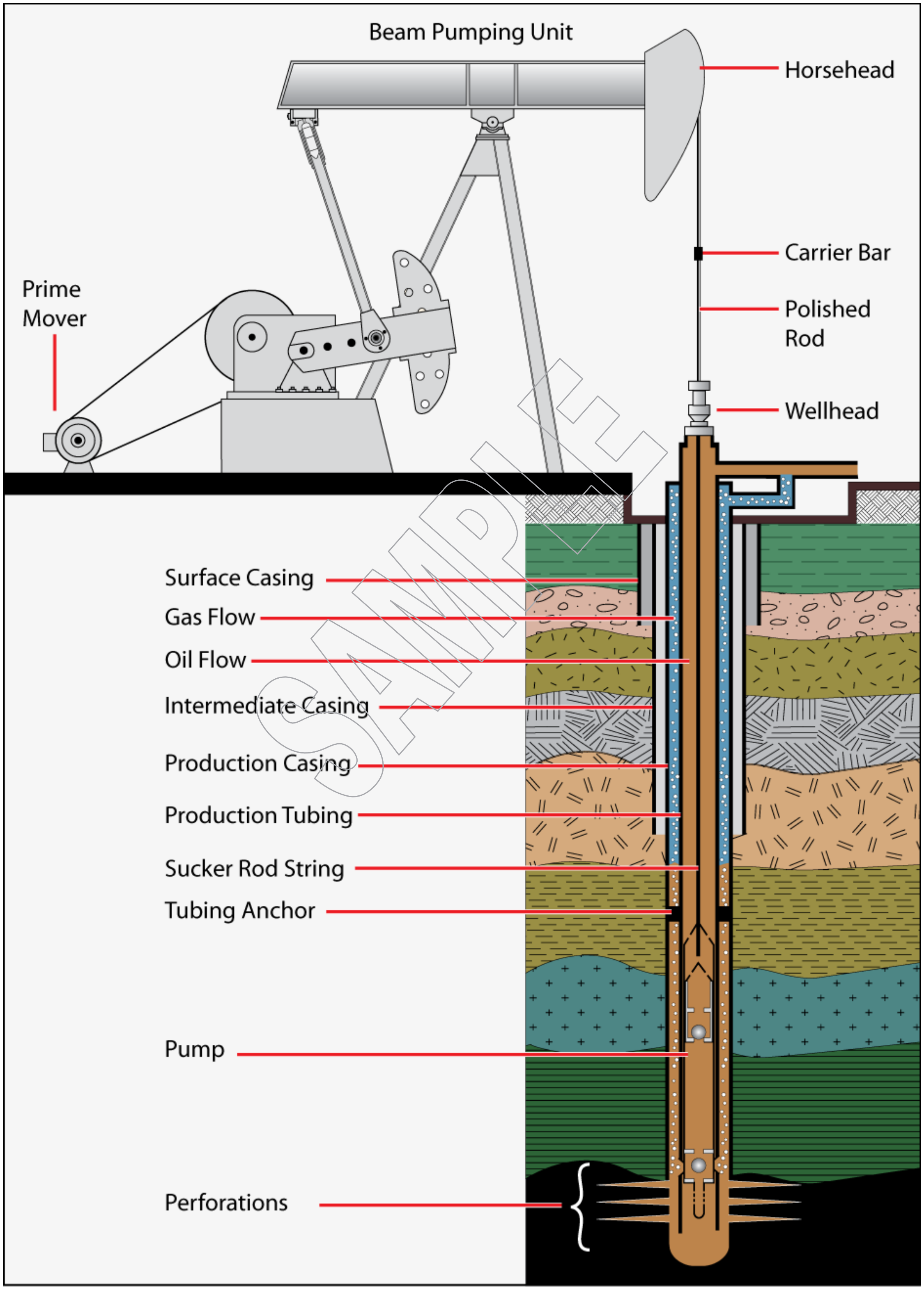
Perforations—*Holes in the casing, cement, and formation which allow the oil and gas to flow from the formation into the cased well. Perforations are commonly made with a jet gun.*

As a well is being drilled, pipe (casing) is installed to protect the drilling equipment and sides of the well and to isolate the well from the surrounding formations. After drilling is complete, the casing is cemented in place. Then the well is completed so that the well can start producing. Well completion activities include:

- perforating the casing, cement, and formation
- installing the tubing
- fitting the valves

Every well is different, depending on factors as such the depth of the well, the formations through which the well is drilled, the production zone formation, the characteristics of the fluid being pumped, and budgets. One common type of well, the **cased oil well**, is illustrated in Figure 2 and described below.

Figure 2—Beam Pumping System at a Cased Oil Well



Cased oil wells are usually configured as follows:

Conductor pipe (not shown on Figure 2)—the outermost steel piping, which is cemented in place and extends to approximately 9 m (20 ft) below the surface. During drilling, conductor pipe provides a path for drilling fluid to rise to the surface.

Surface casing—large diameter steel piping, which is cemented in place, only extends into the well deep enough to:

- prevent the walls of the well from caving in
- protect the adjacent groundwater from well fluids
- prevent groundwater from seeping into the well

Intermediate casing—an intermediate string of steel piping run inside the surface casing that extends below the surface casing for very deep wells, high pressure wells, or wells drilled through unstable formations. The intermediate string is partially cemented in place.

Production casing—steel piping run inside the surface/intermediate casing. In a cased well, the production casing extends to the bottom of the oil producing zone. The production casing is cemented in place and perforations are made to allow oil and gas to seep into the well.

Production tubing—steel piping run inside the production casing. The oil from the reservoir is pumped up through the tubing to the surface wellhead. Gas associated with the oil flows up the space (annulus) between the production tubing and production casing. One of the reasons production tubing is installed is to protect the casing from sucker rod wear: tubing is easier to replace than casing.

Tubing anchor—installed near the bottom of the production tubing just below or just above the pump. The tubing anchor (also called the *tubing holddown*) secures the tubing to the casing and prevents tubing stretch and tubing buckling during pumping. Tubing stretch results in lost production. Tubing buckling increases wear on rods, pumps, tubing, and casing.

2.2 Wellhead

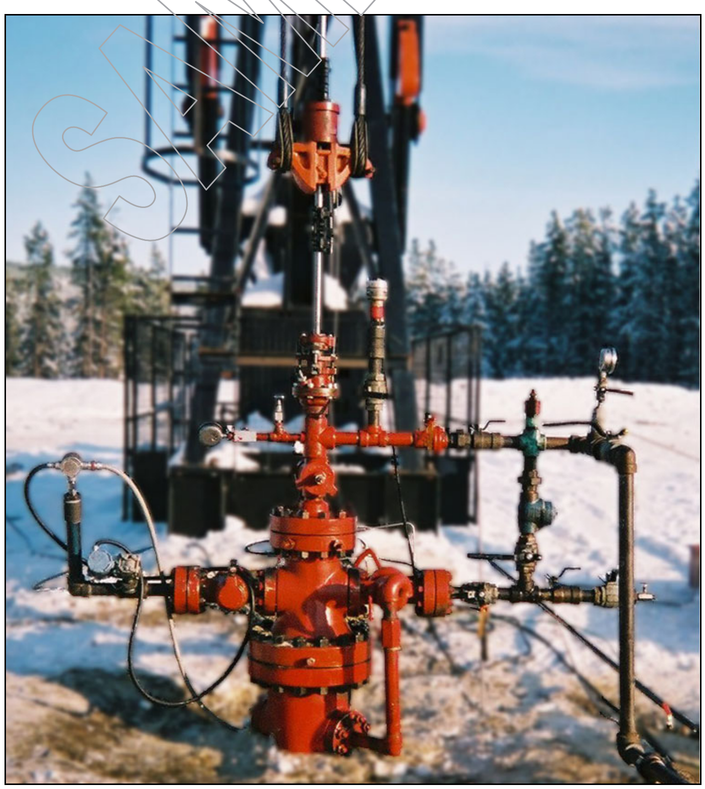
The wellhead consists of the aboveground assembly of valves and fittings through which the oil is pumped and the gas from the formation flows. The wellhead is used to maintain surface control of a well. The wellhead:

- sits on the well's surface casing and supports the well's intermediate casing, production casing, and production tubing
- seals the annulus (space) between the tubing and production casing
- prevents gas or oil from blowing out or leaking at the surface
- enables shutoff and regulation of fluid flow from the well
- provides downhole access if necessary

Fluid—*A substance that flows, moves, or easily changes shape. Gas and oil are both fluids.*

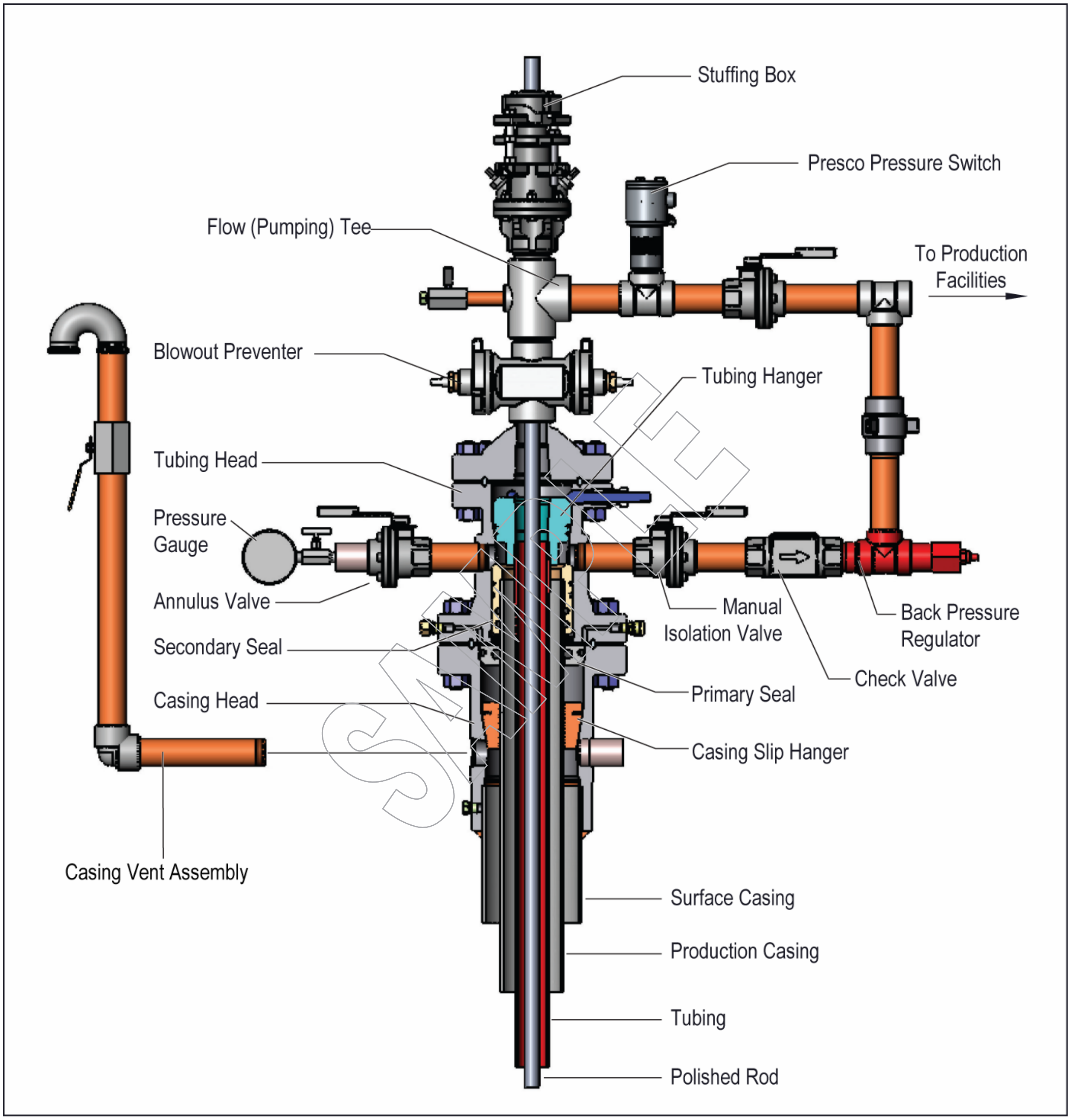
Figures 3 and 4 illustrate one common type of wellhead, a **pumping sweet oil wellhead**, to show a wellhead's basic structures.

Figure 3—Pumping Sweet Oil Wellhead



Courtesy of Husky Energy

Figure 4—Pumping Sweet Oil Wellhead



Courtesy of Wood Group Pressure Control Canada Inc.

2.2.1 Wellhead and Piping

Gas associated with the oil (called associated gas or casing gas) flows to the surface through the annulus between the tubing and production casing. Oil is pumped from the formation, up through the production tubing, to the tubing wellhead. The equipment above the tubing head is often called the Christmas tree assembly.

Figure 4 shows:

- casing vent assembly with a manual valve
- casing head, which is a heavy steel fitting from which the production casing is suspended. The casing head:
  - supports the production casing
  - seals the production casing, so that casing gas does not escape to atmosphere
- casing piping with:
  - manually operated isolation valve
  - check valve
  - backpressure regulator, which can be used to regulate the casing gas pressure
- annulus valve, which may be used to inject corrosion inhibitors and defoaming chemicals
- pressure gauge
- tubing head, which is a heavy steel fitting from which the production tubing is suspended. The tubing head:
  - supports the production tubing
  - seals the pressure between the production casing and production tubing
- blowout preventer (BOP) (described in Section 2.3)
- flow (pumping) tee
- tubing piping with:
  - pressure safety switch (described in Section 2.4)
  - manually operated isolation valve (wing valve)

Additionally, the following equipment (not shown on Figure 4) may be located at the tubing wellhead:

- check valve downstream of the wing valve on the tubing piping
- polished rod lubricators

- site for chemical injection, usually at the branch to the pressure safety switch to ensure flow to the pressure safety switch does not wax off. (Chemical injection is described in Section 6.5.)

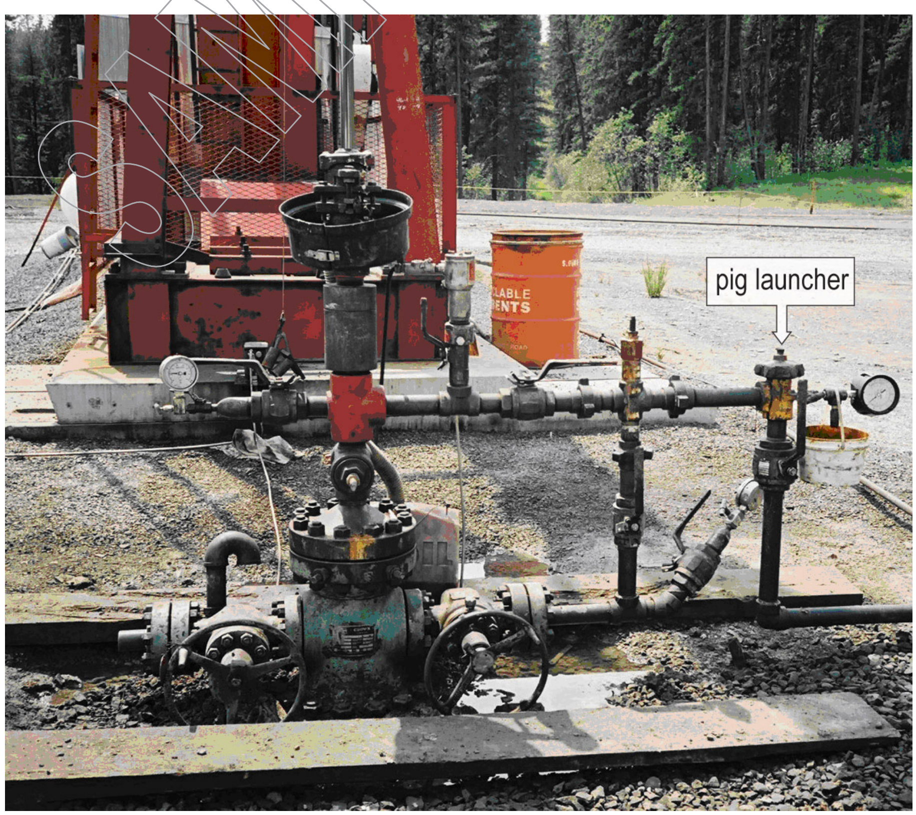
2.2.2 Combined Oil and Gas Piping

The tubing piping and casing piping combine and direct the oil and gas flow to the wellsite's separator or to a central battery. (Module C describes downstream equipment at a typical beam pump wellsite.)

The combined flowline may be equipped with (not shown on Figure 4):

- check valve
- manually-operated isolation valve (wing valve)
- pressure gauge
- pig launcher (see Figure 5)

Figure 5—
Pig Launcher at Beam Pump Oil Well



Courtesy of Husky Energy

2.2.3 Wellhead Equipment Classifications and Specifications

Wellhead equipment is configured according to the properties of the well and of the product being pumped:

- pressure
- temperature
- composition: sweet, sour (i.e., contains H_2S), corrosive

Wellhead equipment is stamped with its maximum working pressure. API Specification 6A/ISO 10423—*Specification for Wellhead and Christmas Tree Equipment* provides the technical requirements for wellhead equipment.

Wellhead equipment is regularly inspected for condition. Worn and damaged parts are replaced *in kind* (i.e., the replacement parts have the same pressure ratings as the original parts).

WARNING

Installing incorrectly rated equipment can lead to serious consequences. Do **not** replace any wellhead equipment (such as valves, fittings, bolts) without first determining the required pressure rating, equipment classification, and tension from well records or from your company's production engineer.

2.2.4 Monitor the Wellhead

Wax or debris can accumulate on a check valve, preventing the check valve from sealing properly. If the casing piping check valve passes (i.e., fails to seal), pumped oil can backflow into the annulus.

If there is a casing pressure gauge downstream of the casing check valve, casing check valve leakage can be checked by:

- closing the gauge cock on the casing pressure gauge and removing the gauge
- closing the casing wing valve
- opening the gauge cock on the casing pressure gauge

Flow from the open gauge cock indicates a passing (leaking) check valve.

2.2.5 Indications of Tubing Leaks

Tubing leaks may be caused by corrosion or by wear from rubbing sucker rods. The symptoms of a tubing leak depend on the characteristics of the particular well and on the location (depth) of the leak. Indications of a tubing leak include:

- decreased or no oil flow, even though the pump is running
- equal tubing and casing pressures
- decreased or no tubing pressure
- significantly changed casing pressure
- decreased pressure surge on the upstroke
- suction on the downstroke

Suspected tubing leaks can be verified using a dynamometer (described in Module D).

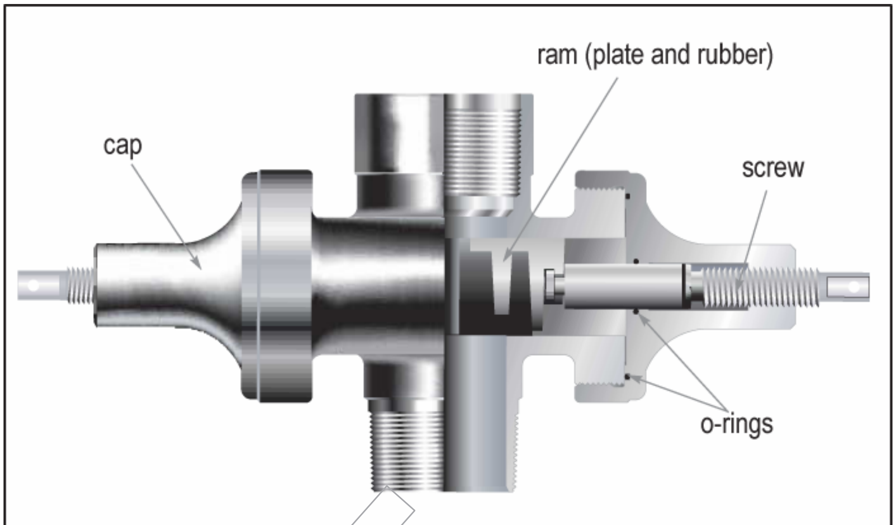
2.3 Blowout Preventer

A pumpjack well's blowout preventer (BOP) is designed to prevent oil spills in case the polished rod or sucker rod breaks (Figure 6). When activated, the BOP seals around the polished/sucker rod. The BOP is installed either:

- between the tubing head and pumping tee (as in Figures 3 and 4)
- between the pumping tee and the stuffing box

Depending on the model, BOPs for beam-pumping well applications can be operated manually or automatically (hydraulically, pneumatically, or through a coil-spring). Some BOPs are designed to automatically shut down the prime mover in response to stuffing box leaks.

Figure 6—
Pumping Oil Well
Blowout Preventer (BOP)



Courtesy of Double E, Inc.

2.4 Pressure Safety Switch

The pressure safety switch is a shutdown switch located on the tubing piping immediately downstream of the flow tee (see Figures 3, 4, and 5). The device protects subsurface and downstream piping from overpressure and, at some sites, underpressure. When a high (or low) setpoint pressure is reached, a contact opens and shuts down the pumpjack motor/engine.

Pressure safety switches at beam pumping wells are electrically operated. At engine-equipped wellsites, the pumpjack engine usually provides the electricity to operate the switch.

Figure 7—Pumping Oil Well Pressure Safety Switch (silver) and Pressure Isolation Valve (blue)

Courtesy of Argus Machine Co. Ltd.

The pressure safety switch is activated in response to:
- abnormally high tubing pressure
- abnormally high downstream line pressure (e.g., caused by an inlet ESD valve closure or flowline plugging)

Some pressure safety switches are also activated in response to:
- abnormally low tubing pressure
- abnormally low downstream line pressure (such as a line rupture)

Reset the Pressure Safety Switch

After the safety switch has tripped, some models automatically reset after the pressure returns to normal. Other models must be manually reset.

Test the Pressure Safety Switch

In some jurisdictions, the pressure safety switch must be tested once a month and the test results must be documented. Depending on the model and company practices, the pressure safety switch can be tested by:
- when the pumpjack is running:
  - closing the isolation valve (wing valve) downstream of the pressure switch
  - letting the pressure in the tubing build
  - recording the pressure at which the pressure switch trips
- when the pumpjack is not running:
  - injecting methanol into the pressure switch, using a hand-operated pump
  - recording the pressure at which the pressure switch trips

If the pressure safety switch does not trip at the required pressure, the operator notifies instrumentation personnel to recalibrate the device.

2.5 Stuffing Box Assembly

The stuffing box assembly is mounted above the flow tee. The assembly provides a seal between the moving polished rod (described in Section 3.1) and the wellhead, allowing the polished rod to exit the tubing without oil leaking. Depending on the model and requirements, stuffing box assemblies consist of:

- spray cone (split cone)
- scraper packing, to scrape wax and scale off the rod
- packing glands
- 1 to 4 sets of rubber or packing rings. The packing rings are compressed against the polished rod. Each set of packing rings can be tightened separately. The lower set of packing rings is left untightened during normal operations, and is only tightened against the rod when the top packing needs to be replaced.
- packing adjustment screws (bolt assemblies)

Figure 8 shows inside and outside views of a double-packed stuffing box.

Monitor the Stuffing Box

The operator monitors the condition of the stuffing box daily:

- Check the polished rod with an infrared temperature device (not with your hand). A hot polished rod can damage the stuffing box packing and may indicate that:
  - the stuffing box packing needs grease
  - the stuffing box packing is too tight
  - the flow of oil from the well has dropped off or stopped. Lack of production could be caused by a number of factors, such as pump failure, a broken rod string, or a pumped-off well. Look at the production data to confirm production. If production has decreased considerably, shut down the well. Work with your company's engineer to perform well diagnostics to determine the source of the problem.

- Ensure the polished rod is centered. Poor alignment will cause rapid polished rod wear and reduce the life of the packing rings. An off-center rod indicates:
  - unequal packing gland bolt tightening
  - a misaligned pumpjack

  If the off-center rod is not rectified by adjusting the packing gland bolts, the problem is probably caused by pumpjack misalignment. Advise maintenance personnel; they may need to adjust the pumpjack shims or level the base.
- Check the adjustment of packing gland bolts.
- Change the packing if:
  - the packing is starting to disintegrate and becomes visible
  - oil is leaking at the stuffing box
- Check for noise. Squealing indicates a lack of grease or pumpjack misalignment.

Maintain the Stuffing Box

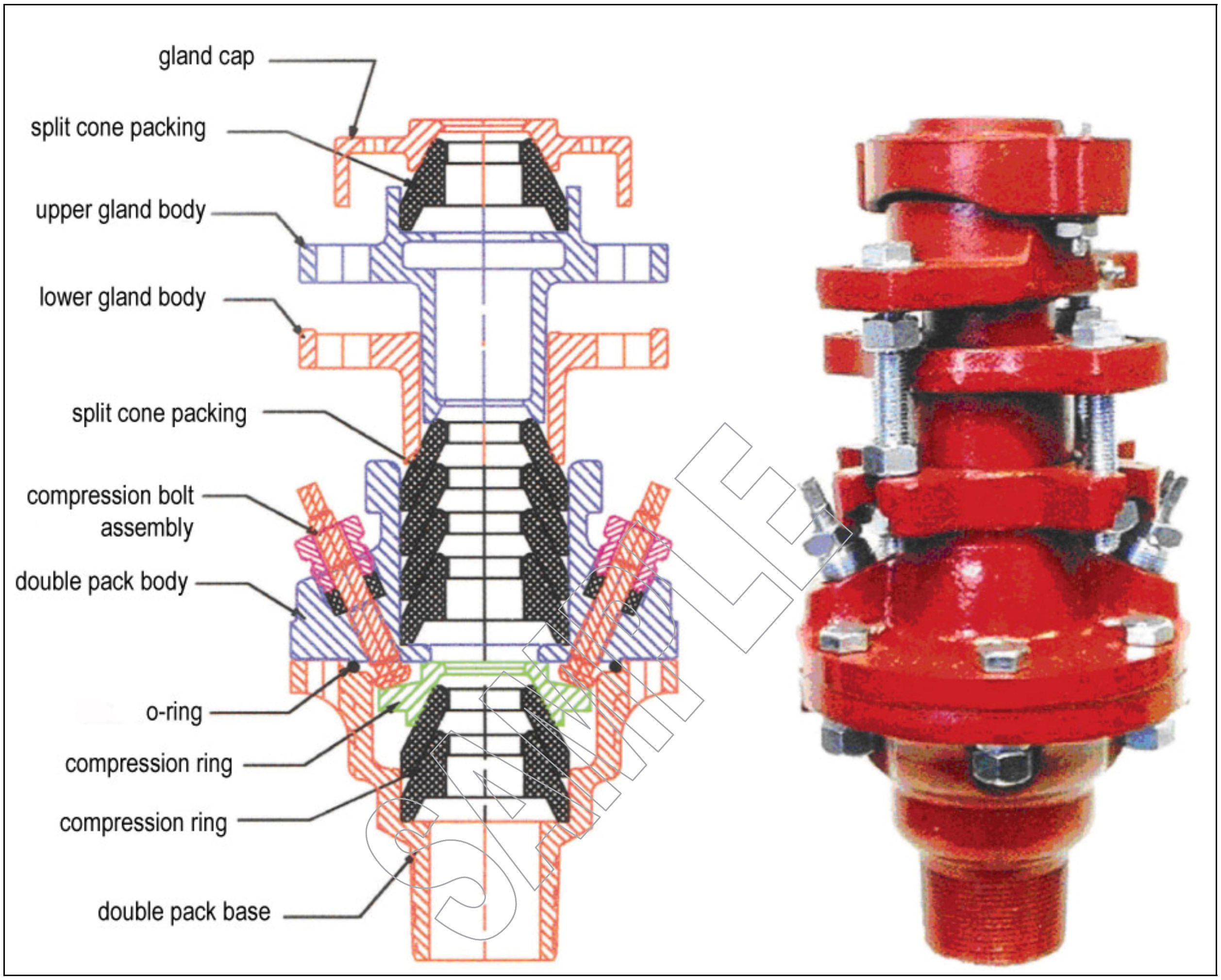
With proper installation and periodic tightening, a set of packing rings should last several years. When changing packing rings, make sure the rings are the correct size for the polished rod.

Add grease to seal, lubricate, and cool the packing rings.

WARNING

A correctly positioned stuffing box grease fitting is directed *away* from the pumpjack. At some sites, however, the grease fitting may point *toward* the pumpjack. At these sites, the operator needs to stand between the moving pumpjack and the stuffing box to add grease. Position yourself with extreme care so that the horsehead does not hit you on the downstroke.

Figure 8—Double-Packed Stuffing Box Assembly



Courtesy of Larkin Products Inc. and Carreau Oilfield Specialties

Do not over-tighten the adjustment screws when installing packing or periodically tightening the packing glands. Over-tightening causes polished rod overheating and premature packing failure.

API Specification 11B—*Sucker Rods (Pony Rods, Polished Rods, Couplings, and Subcouplings*) provides the specifications for stuffing boxes.

3 Sucker Rod String

The sucker rod string connects the pumpjack with the bottomhole pump. The rod string must be carefully operated and rigorously maintained. Sucker rod string maintenance is the largest expense in operating beam pumping systems.

This section describes:
- the polished rod at the top of the sucker rod string
- the downhole sucker rod string

3.1 Polished Rod

The polished rod, which connects the pumpjack to the downhole portion of the rod string, is the only rod that is exposed to the air. The polished rod is usually two or three times longer than the pumpjack stroke. The polished rod is the strongest rod in the sucker rod string and can be made of a variety of materials, including bronze, high-strength carbon steel, or stainless steel. The polished rod is highly polished so that it can slide easily through the stuffing box packing. Some polished rods are treated with a sprayed-metal coating, which provides a hard-wearing surface. Other polished rods may have liners to prevent rod wear.

Polished rods must be handled with great care during shipping, storage, installation, and removal. Before installation, polished rods must be carefully inspected. Damaged rods should not be installed.

Polished Rod Clamp

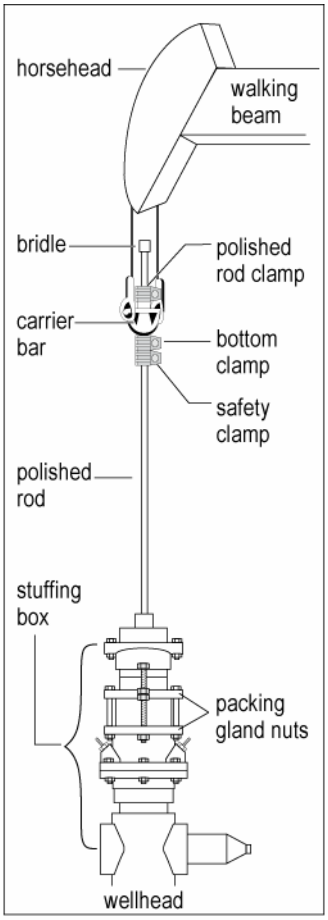


Figure 9—Polished Rod, Rod Clamps, and Stuffing Box

A polished rod clamp, fastened at the top of the polished rod, rests on the carrier bar (see Figures 9 and 10). The entire weight of the rod string is held by this clamp. The top of the polished rod extends above the clamp to allow the rod string to be lowered.

A second clamp is usually located below the carrier bar. This second clamp is particularly important on pumpjacks that have had a problem with polished rods breaking at the carrier bar. Some companies use a third clamp (safety clamp) below the second clamp. The second and third clamps prevent the polished rod from dropping through the stuffing box if the top clamp fails.

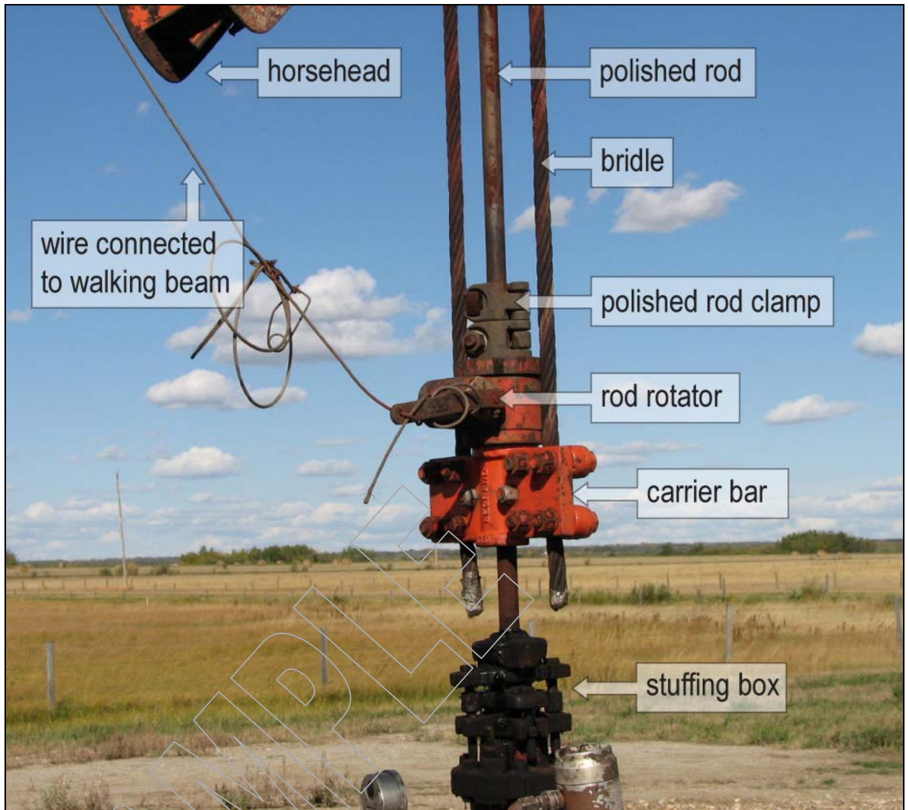
For rods with sprayed metal coatings or liners, clamps must be placed above the coating or liner to prevent damage: tightening a clamp on the coating/liner dents the coating/liner. Clamps may be moved to reposition the rod string. If the dented portion of the rod comes up through the stuffing box, a small amount of oil is leaked.

Polished rod clamps are available in a variety of sizes, depending on the rod load. For light loads, the clamps may have only one bolt; for heavy loads, the clamps may have as many as five bolts. Make sure the clamp is the correct size for the polished rod.

Polished rod clamps must be installed correctly to ensure they operate reliably and without being damaged:

- Do not install a clamp with bent hinges or bent bolts.
- Use only box-end or socket wrenches to tighten clamps. Do not use pipe wrenches, which tend to round off the edges of the nuts.
- Do not over-tighten a clamp; over-tightening may damage the rod. Clamp manufacturers specify the torque required to tighten the clamp.
- After tightening, make sure the top and bottom of the clamp are level with the carrier bar.

Figure 10—Polished Rod Clamps



HDC Photo

Rod Rotator

The rod rotator (see Figure 10) is a ratchet device which rotates the rod a fraction of a turn with each pump downstroke. A cable attaches the ratchet device to the walking beam. The rotation evenly distributes wear on the sucker rod guides and tubing, and, when used with the correct rod guide, can be used to control paraffin buildup. Rod rotators are only used when rod guides are used.

Causes of Polished Rod Failure

End of Sample

A full licensed copy of this kit includes:
• Training Module and Self-Check
• Knowledge Check and Answer Key
• Blank Answer Sheet
• Walkthrough