Stage & Low Temperature Separation For Gas-Condensate Production

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INTRODUCTION

The increasing market value of natural gas and the restricted proration schedules for crude oil production in recent years have made high pressure gas production economically attractive. In west Texas, most high pressure gas wells also produce some liquid hydrocarbons and water. Since the purchasers of natural gas have strict specifications on the maximum permissable liquid content of the gas, field processing is usually required to extract the condensate and water from the gas-condensate well stream. Although the total value of the condensate may be small compared with the total value of the high pressure gas, the condensate is usually of sufficient value to justify the installation of surface handling facilities.

It is the responsibility of the production engineer to select equipment which will divide the gas-condensate well stream into high pressure gas, low pressure gas, and condensate for maximum profit from the well fluids. Maximum profit will usually be realized when as much of the well stream as possible is sold in the liquid state. For example, ten pound moles of n-pentane may be sold as 3.79 MCF of high pressure gas for 60 cents. In the liquid state, this same n-pentane could be sold as 3.27 barrels of condensate for $8.99. It is the duty of the lease operator to maintain and operate the separation equipment at peak efficiency.

Two methods of gas-condensate processing have gained acceptance in west Texas. Conventional stage separation is relatively simple, and can be operated with a minimum of attention. Mechanical low temperature separation (LTS) can be expected to produce drier sales gas and to recover more condensate, but this method is inherently more complex and requires close supervision by trained personnel. The cost of a mechanical LTS system may exceed the cost of comparable stage separation equipment by $10,000 or more.

The higher initial cost for LTS can often be recovered in a short time by the increased condensate recovery, since gas-condensate wells in Texas are controlled on the basis of the gas produced and the condensate production is not prorated. The initial cost for LTS for certain wells in west Texas can be reduced by several thousand dollars if consideration is given to well characteristics which may make heat exchangers and free liquid knockouts unnecessary.

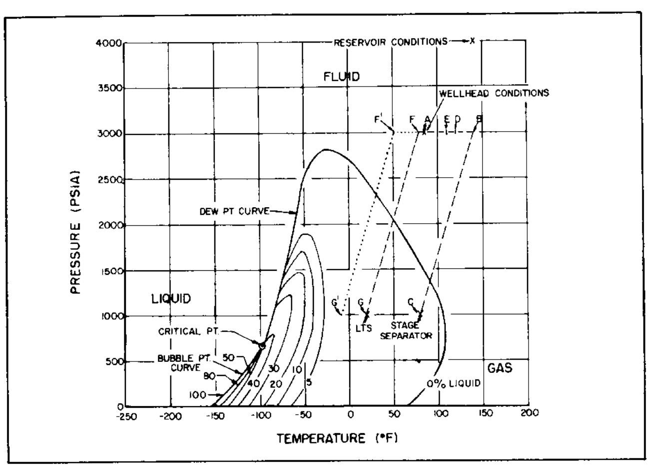

FIG. 1
PRESSURE-TEMPERATURE-PHASE DIAGRAM
FOR LEAN GAS-CONDENSATE WELL STREAM

This discussion will be limited to stage separation and mechanical LTS systems, although more involved equipment for processing gas-condensate well streams is available. The more complex systems are modifications of stage separation or LTS systems. For example, glycol injection or ammonia refrigeration may be used in conjunction with LTS. Dry desiccant hydrocarbon recovery and/or condensate stabilization equipment may be added to either stage separation or LTS systems. Therefore, a knowledge of stage separation and mechanical LTS is prerequisite to the understanding of the more elaborate systems. The particular application will dictate the equipment required for maximum profit.

FUNDAMENTALS OF GAS HANDLING

An understanding of the fundamentals of gas handling is essential for the proper selection and operation of gas-condensate separation equipment. The Joule-Thompson (autorefrigeration) effect, hydrate formation, and pressure-temperature-phase diagrams will be briefly reviewed.

It is well known that, for pressures below 6000 psig, choking a gas stream from a high to a lower pressure induces self-refrigeration. This autorefrigeration, or Joule-Thompson effect, was formerly considered a necessary evil, and many dollars were spent for field equipment to offset this effect. However, it is this phenomenon that makes possible mechanical low temperature separation.

The temperature drop in a gas-condensate well stream as it expands from a high to a lower pressure depends on the difference in the two pressures, the initial pressure, and the liquid content of the well stream. The greater the difference in pressure, the lower the initial pressure and the lower the liquid content, the greater will be the drop in temperature.

For example, a West Texas gas-condensate well flowing at 3000 psig at 80° F. contains approximately five barrels of free liquids per MMSCF. If this stream is choked to 1000 psig, the well stream temperature will be decreased to 30° F. If the free liquids are removed before choking, the well stream temperature will drop to 25 °F.

Hydrates are snow-like compounds of hydrocarbons and water which may form in high pressure gas systems at temperatures as high as 80° F., depending on the pressure and composition of the gas. Generally, the higher the pressure, the higher the hydrate formation temperature. Hydrates tend to collect in valves, chokes, elbows, meter runs and other restrictions, blocking the flow of gas. Once formed, hydrates can be removed only by a reduction in pressure (bleeding the system) or by the application of heat.

Hydrate formation can be prevented by the addition of sufficient heat to keep the temperature of the system above the hydrate point, by the injection of an antifreeze agent such as glycol or methanol, or by the removal of the water and water vapors. For a 0.65 specific gravity well stream at 3,000 psig, hydrate formation can be expected at approximately 73 °F.

Pressure-Temperature-Phase Diagram

The pressure-temperature-phase diagram for a lean gas-condensate well stream containing approximately 90 per cent methane is shown in Fig. 1. The bubble point and dew point curves meet at the critical point, and enclose the two-phase region within which gas and condensate can exist in equilibrium. It is within this two-phase region that separation of gas and condensate is effected. Lines of constant per cent liquid content are shown within the two-phase envelope. For a particular well stream, the physical state of the various hydrocarbon components is determined by the pressure and temperature.

At points on Fig. 1 for which the temperature is lower than the critical temperature, and the pressure is greater than the bubble point pressure at that temperature, the entire well stream will be in liquid state. If the pressure is lower than the critical pressure, and the temperature is greater than the dew point temperature at that pressure, the entire well stream will be in the gaseous state. The region outside the two-phase envelope between the 100 per cent liquid and 100 per cent gaseous regions is known as the "fluid" region. Within this region, it is impossible to differentiate between liquid and gas, as both have the same physical properties.

Fig. 1 was drawn for a gas-condensate well producing from the Devonian formation in the Emperor field, Winkler County, Texas. The reservoir, wellhead, and separation conditions for this well are shown. In this case, both the reservoir and flowing wellhead conditions lie within the "fluid" region. The paths traversed by the well stream from wellhead to separator for both stage separation and LTS, as shown by the dashed line, will be discussed in detail later.

Different well streams have different phase diagrams. Generally, as the percentage of heavier hydrocarbons in the gas-condensate well stream increases, the critical point moves toward the maximum pressure at which two phases can exist (the top of the two-phase envelope). This analysis considers only the hydrocarbon components. The example well stream contains water, which will be present as vapor, liquid or ice, depending on the temperature and pressure.

STAGE SEPARATION

A flow diagram of a three-stage separation system is shown in Fig. 2. Included are an indirect heater, adjustable choke, high pressure separator (first stage), low pressure separator (second stage), and stock tanks (third stage). The indirect heater adds sufficient heat to offset the Joule-Thompson effect as the well stream is choked from wellhead to sales gas pressure. This addition of heat prevents the formation of hydrates in the choke, flowline, and separators. The choke is usually mted on the in-indirect heater so that the nose of the cho}.e can be surrounded by the hot water bath.

The high pressure separator, which may be vertical, horizontal, or spherical, mechanically removes the liquids from the gas. The pressure of the first stage separation is usually dictated by the pressure of the sales gas line, whereas the temperature depends on the amout of heat added by the indirect heater. Optimum condensate recovery is usually realized if the first stage separator is operated at the lowest temperature possible without the formation of hydrates. This is shown in Fig. 1. As the temperature of separation decreases, the point depicting stage separation conditions (C) moves to the left, in the direction of increasing per cent liquid. The dashed line from wellhead to stage separator conditions illustrates the heating (A to B) and choking (B to C) of the well stream

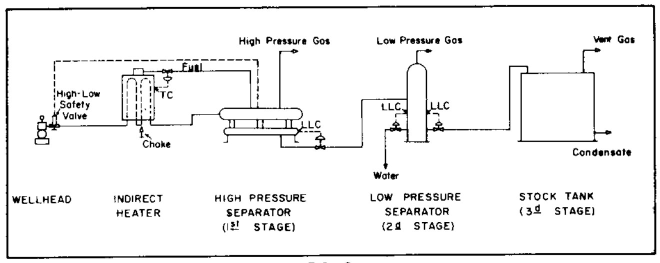

FIG. 2
CONVENTIONAL THREE-STAGE SEPARATION SYSTEM

The low pressure separator, operating at 100 to 125 psig, serves as an intermediate step for the condensate between the high pressure separator and the stock tanks. As in the case of the high pressure separator, the low pressure separator may be vertical, horizontal, or spherical. The second stage of separation permits the lighter hydrocarbons in the condensate to flash off without carrying with them many of the heavier hydrocarbons, which would occur if the condensate were discharged directly from the first stage separator into the storage tanks. An infinite number of separators between the first stage separator and the stock tanks, each providing a small decrease in pressure, would be ideal theoretically; but, of course, this is economically impractical.

MECHANICAL LOW TEMPERATURE SEPARATION

The flow diagram of a mechanical LTS system is shown in Fig. 3. This system consists of an indirect heater, low temperature separator, adjustable choke, heat exchanger, free liquid knockout, low pressure separator, and stock tanks. The low pressure separator and stock tanks perform the same functions as in the stage separation system. The most important part of the LTS system is the low temperature separator itself, which can be vertical, horizontal, spherical, or combination vertical-horizontal. The choke is mounted directly on the low temperature separator, the Joule-Thompson effect reducing well stream temperature to 20° to 30° F. Initial separation takes place at this temperature and sales gas pressure.

Usually hydrates form as the cold condensate and water fall toward the lower portion of the vessel. The liquids and hydrates collect in the lower portion of the low temperature separator, where they are heated to approximately 75° to 80° F. by heating coils. The hydrates melt, and the conden-

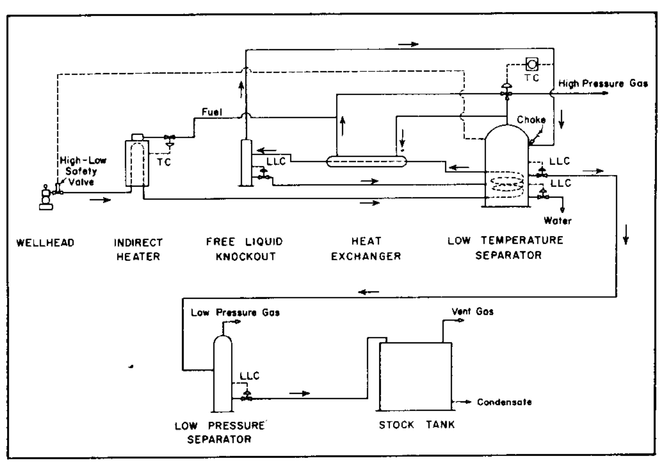

FIG. 3
MECHANICAL LOW TEMPERATURE SEPARATION SYSTEM WITH INDIRECT HEATER

sate and water separate into layers. As the condensate is heated, the lighter propanes and butanes are driven off to rejoin the sales gas, rather than being left in the condensate to be lost as flash gas in the second and third stages.

Some of the heavier pentanes and hexanes, although initially driven off with the lighter ends, are recondensed by the cold liquid falling from the choke. Thus the condensate is partially stabilized before it is discharged to the low pressure separator. The water may be dumped separately from the low temperature separator to a pit, although this separate dumping is not always provided.

In this LTS system, the well stream provides heat to the LTS heating coils. Since the heat-exchange area of the heating coils is limited by the size of the LTS vessel, a well stream temperature of 120° F. is required to provide sufficient heat to the LTS liquid bath. Gas-condensate wells in west Texas usually flow at 100° F. or less, so that this system of LTS requires that the well stream be heated. In other areas, the well stream temperature may be adequate without heating, so that the indirect heater is necessary only for start-up.

The well stream leaves the LTS heating coils at 100° to 110° F. A tube-bundle, gas-to-gas heat exchanger utilizes a portion of the cold sales gas to cool the well stream ahead of the free liquid knockout and the choke. A three-way gas-throttling valve, positioned by a temperature controller, automatically proportions the cold sales gas stream so that the well stream is cooled to 80° F., or the lowest safe temperature above the hydrate point. An important secondary function of the heat exchanger is the heating of the cold sales gas. This may be important for hydrate prevention in the sales line if the gas is mixed with relatively wet gas from other wells.

The free liquid knockout separates condensate and water from the well stream ahead of the choke so that maximum cooling can be realized from the available pressure drop. Also, the presence of water in the choke could lead to freezing problems. The free liquid knockout usually operates at wellhead pressure, between 2000 and 6000 psig. The liquids are discharged from the free liquid knockout into the liquid bath of the LTS for separation of condensate and water, and partial stabilization of the condensate.

Description of Fig. 1

Referring to Fig. 1 again, the dashed line A-D-E-F-G depicts the path followed by the well stream from wellhead to LTS conditions. The well stream is heated in the indirect heater (A to D), cooled in the LTS heating coils (D to E), cooled further in the heat exchanger (E to F), and finally choked to sales gas pressure (F to G). Since G lies to the left of C, a greater percentage of the well stream is liquid, and consequently more condensate can be separated in the cold section of the LTS than in the stage separator.

The addition of glycol would make it possible to cool the well stream at F to a temperature below the hydrate point, to F', and realize a still lower separation temperature (G'). Even more liquid could then be separated in the cold section of the LTS. However, this does not necessarily mean that more condensate could be sold, for if the additional liquid is composed of the lighter hydrocarbons, it may be revaporized in the LTS liquid bath, or in the second and third stages. Hence, for a particular well stream and particular pipe line specifications for condensate vapor pressure, there is an optimum temperature of separation, and nothing is gained by cooling the well stream below this point.

In the mechanical LTS system shown, the well stream flows first through the heat exchanger, and then through the free liquid knockout. In this way the liquids condensed in the heat exchanger, as well as the free liquids originally present in the well stream, are removed in the free liquid knockout. Consequently, maximum autorefrigeration effect for the available pressure drop is realized. However, if the well stream contains a paraffin base oil, cooling ahead of the free liquid knockout may lead to paraffin deposition in the heat exchanger. Also, in this arrangement, all of the free liquids as well as the gas must be cooled, placing a greater demand on the heat exchanger.

In some cases, the capacity of the heat exchanger must be increased to accommodate this added load. The positions of the heat exchanger and free liquid knockout can be reversed so that the well stream flows first through the free liquid knockout; in this arrangement, however, the liquids condensed in the heat exchanger are not removed ahead of the choke. Actually, two free liquid knockouts, one before and one after the heat exchanger, would be ideal, but the added expense can seldom be justified.

It is interesting to note that for our example well stream no liquid hydrocarbons exist at the free liquid knockout conditions (F in Fig. 1), and hence only water is separated at this point. This water could be dumped directly into a pit instead of being discharged into the LTS bath. However, since the temperature of this water is approximately 80° F., discharging it into the LTS bath helps to melt the hydrates and warm the condensate in the LTS liquid bath. The heating load on the indirect heater is thus reduced.

In a slightly different mechanical LTS system, shown in Fig. 4, a steam generator replaces the indirect heater. The use of a steam generator is sometimes advantageous if the wellhead flowing temperature is low, and the well can be started without the addition of heat. By using the steam generator, heating of the well stream is eliminated. Subsequently, little or no cooling of the well stream is required, and the heat exchanger may be reduced in size or eliminated.

Since the well stream no longer passes through the indirect heater and LTS heating coils, friction losses in these units are eliminated, and more pressure drop is available across the choke for refrigeration. This may be important in the case of high flow rates from wells with flowing wellhead pressures only 1000 psig or so above the sales gas pressure. With a steam generator, it is possible to apply heat to the LTS liquid bath even when the well is shut-in. This allows preheating the liquid bath for rapid start-up of the well without danger of freezing the LTS condensate and water dump valves. However, the use of the steam generator, by reducing or eliminating the heat exchanger, reduces the heating of the cold sales gas as it leaves the LTS, and may lead to problems in the gas gathering system. The path of the well stream from wellhead to LTS for this system is shown in Fig. 1 as A-F-G.

GROSS INCOME AND COST FOR STAGE AND MECHANICAL LTS

When the example well stream was processed through a

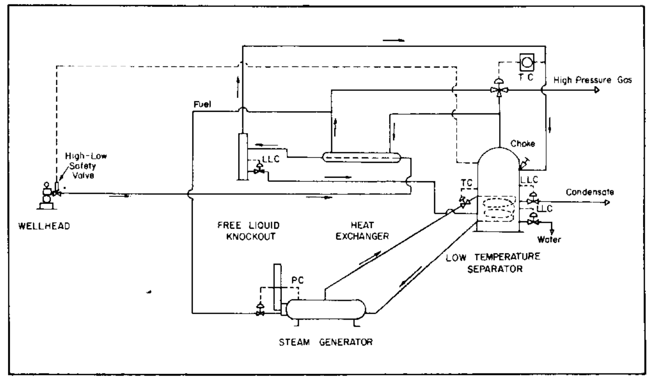

FIG. 4
MECHANICAL LOW TEMPERATURE SEPARATION SYSTEM WITH STEAM GENERATOR

three-stage separation system, approximately 1.27 molar per cent of the total well stream was separated as liquid in the first stage separator operating at 80° F. and 1000 psig. When this same well was equipped with a mechanical LTS system, approximately 1.70 molar per cent of the total well stream was separated as liquid in the LTS, operating at 25° F. and 1,000 psig.

The disposition and gross income for the reservoir fluids for each of the two systems is shown in Fig. 5. For comparative purposes, gross incomes of 16 cents per MCF and $2.75 per barrel have been assumed for the high pressure sales gas and condensate. With the well producing 8 MMSCF of high pressure sales gas per day in each case, the gross income for LTS was $46.75 per day more than for stage separation.

Although this well was produced at 8 MMSCFPD initially, the separation system was designed to handle 15 MMSCFPD at 1000 psig in order to accommodate any future increase in flow rate. A three-stage separation system rated at 15 MMSCFPD at 1000 psi would cost approximately $7,000 installed, not including stock tanks. A similarly rated mechanical LTS system, including a heat exchanger, free liquid knockout, second stage separator, and steam generator, was installed for $21,000.

The additional investment of $14,000 will be returned in approximately ten months with the recovery of 5100 barrels of additional condensate, assuming that the well produces at the rate of 8 MMSCFPD. A heat exchanger was included since the reservoir pressure is expected to decline within two years in which event the pressure drop from wellhead to LTS will no longer be sufficient for the necessary refrigeration. A free liquid knockout was necessary since the well produces water. Had it been possible to eliminate the heat exchanger, the installed cost of LTS could have been reduced by $6,000. Elimination of the free liquid knockout would have saved an additional $4,000.

PURCHASE, INSTALLATION, AND OPERATION OF LTS EQUIPMENT

An LTS unit has a long life, and may be used on several wells. This should be kept in mind when new equipment is purchased. Although initially the heat exchanger and free liquid knockout may not be needed, they may be necessary for a different well, or later for the first well as reservoir pressure declines or free water production increases. It is wise, therefore, to provide space on the skid so that these items can be added later.

If a system with a steam generator is purchased, the following points should be remembered. The 15 psig working pressure steam generator should operate at approximately 5 psig. The transfer of heat is effected by the vaporization and recondensation of the water, and little is gained by operating at higher steam pressures. Moreover, operation at pressures above 5 psig may cause nuisance popping of the steam pressure relief valve. Steam circulates through the LTS heating coils by the thermo-siphon effect, so the LTS heating coils should be at least two feet higher than the water level in the steam generator. The steam line must be insulated. The water return line can be buried, but an above-ground insulated water return line results in a lighter heating load on the steam generator. It is good practice to steam jacket the choke, to provide for emergency thawing.

Care must be taken to make the stream system absolutely leak-proof. During periods of operation, leaks would allow the loss of steam and water, making the constant addition of water necessary. If the steam generator were shut down, the system would go on vacuum and suck air. Upon start-up, the air would collect in the LTS heating coils and block the thermo-siphon effect. It would then be impossible to transfer heat to the LTS liquid bath, even though full steam pressure existed in the steam generator.

One way to bleed air from the steam system is to back-flow water from the steam generator through the LTS heating coils. To accomplish this, a small bleeder valve should be provided between the steam control valve and the LTS coils. There should be no check valve in the water return line. With pressure in the steam generator, the steam control valve closed and the bleeder valve open, water will back-flow through the LTS coils bleeding the air ahead of it. When a full stream of water appears at the bleeder valve, the system is free of air.

Low temperature separators designed to use the heated well stream in the heating coils are not always easily converted to use steam. In some, considerable heating coil area is exposed in the gas section, just above the condensate level, to melt hydrates. When steam is circulated through these coils, the steam is condensed and gives off its latent heat of vaporization to the gas section. There is little heat then available to warm the liquid bath. Consequently, the gas section operates too hot, and the liquid bath operates too cold.

A frequent cause of trouble in an LTS system is the free liquid knockout dump valve. A choke nipple or adjustable choke should be provided to reduce the velocity through this valve and thus avoid cutting out the valve stem and seat. It is also good practice to provide isolating block valves so that the stem and seat can be replaced, or the choke nipple cleaned, without shutting-in the well and bleeding the system.

Care should be taken to provide high quality supply gas for the liquid level and temperature controllers. The dehydrated sales gas is a good source of supply gas. Warm gas can be taken from the shell side of the heat exchanger and successfully choked to supply pressure. If the LTS system does not include a heat exchanger, some other means for heating the supply gas prior to choking must be provided. Attempts to use low pressure (second stage) gas as supply gas, or to choke cold sales gas without heating, can lead to controller failures, especially during cold weather. Gas from the low pressure separator can be used as fuel for the indirect heater or steam generator.

A three-stage separation system is relatively simple, and may include only three liquid level controllers and dump valves, and one temperature controller. A mechanical

THREE-STAGE SEPARATION

DISPOSITION OF RESERVOIR FLUIDS	MOLES OF RESERVOIR FLUIDS	% OF TOTAL WELL STREAM	DAILY UNITS OF SALE	GROSS INCOME	TOTAL/DAY
High Pressure Sales Gas	21,108	98.73	8,000 MCF	$.16/MCF*	$1,280.00
2nd-Stage Low Pressure Gas	70	.32	26 MCF	Vented	-
3rd-Stage Vent Gas	8	.04	3 MCF	Vented	-
Condensate	194	.91	79 Bbls.	$2.75/Bbl.*	217.25
	21,380	100.00			$1,497.25

Condensate Recovery: 9.9 Bbls/MMSCF of High Pressure Sales Gas
Gross Income per 1,000 moles of reservoir fluids: $70.03

*Prices assumed for comparative purposes.

MECHANICAL LTS

DISPOSITION OF RESERVOIR FLUIDS	MOLES OF RESERVOIR FLUIDS	% OF TOTAL WELL STREAM	DAILY UNITS OF SALE	GROSS INCOME	TOTAL/DAY
High Pressure Sales Gas	21,108	98.30	8,000 MCF	$.16/MCF*	$1,280.00
2nd-Stage Low Pressure Gas	113	.53	43 MCF	Vented	-
3rd-Stage Vent Gas	13	.06	5 MCF	Vented	-
Condensate	240	1.11	96 Bbls.	$2.75/Bbl.*	264.00
	21,474	100.00			$1,544.00

Condensate Recovery: 12 Bbls./MMSCF of High Pressure Sales Gas
Gross Income per 1,000 moles of reservoir fluids: $71.90

*Prices assumed for comparative purposes.

FIG. 5
DAILY GROSS INCOME FOR STAGE SEPARATION AND MECHANICAL LTS FOR A LEAN GAS-CONDENSATE WELL STREAM

LTS system may include four liquid level controllers and dump valves, three temperature controllers, and a three-way motor valve. The chances for controller failure or maladjustment are multiplied accordingly.

The flow path through an LTS system is inherently more complex, and it is often hard for the lease operator to understand. For this reason, it is imperative that there be close cooperation between the engineer, lease operator, and manufacturer's service personnel, especially during the first months of operation. After the lease operator becomes familiar with the system, LTS equipment can be operated with little difficulty. However, the temperatures, pressures and liquid levels should be checked twice each day so that failure of one component can be found and corrected before it leads to other, more serious failures.

CONCLUSIONS

There is no universally "best" system for processing gas-condensate well streams. The characteristics of each well stream must be analyzed to determine the system that will yield the maximum return for the reservoir fluids processed. For lean gas-condensate well streams from West Texas wells flowing at 90° to 100° F. and 3000 psi into high pressure gas gathering systems operated at 1000 psi or less, a mechanical LTS system will yield substantial profits over a three-stage separation system. The use of a steam generator may result in savings in capital investment, since the purchase of a heat exchanger may be eliminated or postponed. Operating problems often associated with LTS can be solved or prevented by the proper selection, installation, and operation of LTS equipment.

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