LIQUID HYDROCARBON RECOVERY AT WELLHEAD SEPARATORS

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Abstract

Over the years, considerable work has been done in evaluating wellhead equipment options available to the producer which will optimize the recovery of hydrocarbon liquids from Gas-Distillate wells. The value of these have been such that reasonable payouts of the liquid recovery facilities have been generally attributed to the various types of wellhead processing schemes. As these liquids become more valuable, some options which require additional capital investment may now present satisfactory amortization which a few years ago would not have. This paper deals with information regarding the relative merit of various processing options and estimates of the amount of increased liquid recovery attributable to such options. No attempt to present actual payouts will be made herein since there are always variables in such determinations which are beyond the scope of this paper. However, incremental increases in recovered liquids are illustrated which will assist the producer in making economic decisions.

Equipment To Be Considered

Illustrations will be made and charts presented herein which are based on computer simulation studies and field data. This paper deals with a review of such data and the impact of field operations on hydrocarbon liquids recovery.

This report will deal only with three schemes for wellhead process equipment. They are:

1) Heater - High Pressure Separator Unit
2) Heater - High and Low Pressure Separator Unit
3) Heater - High Pressure Separator-Stabilizer Unit

The above are the most basic elements for wellhead processing, but proper application of these can greatly affect liquid recoveries and quite often are the only options a producer need consider. With the addition of a Gas Compressor the same equipment can be used for gas recycling. Other processing equipment such as Low Temperature Extractions (LTX), HRU (Short Cycle Adsorption), Mechanical Refrigeration and Turbo-expanders with attendant dehydration capabilities are usually dictated by requirements for the sale of gas and liquids or by certain wellhead characteristics. For example, the LTX is best suited to wells with very high flowing pressures. These systems, then are usually special and will not be considered in this paper.

Wellstreams Studied

Three wellstreams are presented here. Some of the results of that study are included in this presentation. These gas streams are labeled:

Wellstream "A" - Lean-approximately 12 bbl/MMscf of sales gas by stage separation.

Wellstream "B" - Medium-approximately 26 bbl/MMscf of sales gas by stage separation.

Wellstream "C" - Rich-approximately 65 bbl/MMscf

	Wellstream "A"		Wellstream "B"		Wellstream "C"	
Component	MOL %	GPM C_3 Plus	MOL %	GPM C_3 Plus	MOL %	GPM C_3 Plus
C_1	87.13	-	89.81	-	81.57	-
C_2	6.84	-	3.82	-	7.75	-
C_3	3.13	.8592	2.57	.7055	3.78	1.0376
IC_4	0.69	.2251	0.56	.1827	0.97	.3165
NC_4	0.75	.2358	0.92	.2892	1.12	.3521
IC_5	0.31	.1132	0.29	.1059	0.45	.1643
NC_5	0.19	.0687	0.19	.0687	0.33	.1193
C_6	0.36	.1477	0.47	.1928	0.98	.4020
C_7+	0.60	.3684	1.37	.8411	3.03	1.8604
	100.00	2.0181	100.00	2.3859	100.00	4.2522

Computer simulations were made for the three process schemes mentioned above as well as other schemes not presented herein. Recovery curves were plotted from these computer calculations.

The recovery curves are shown in Figures 4, 5, and 6 attached.

Separator Temperature Is The Key

Figure 1 shows the most simple of wellhead process systems, a heater and a separator with the separator liquid flowing directly to the stock tank.

Referring to the lower curves of Figures 4, 5, and 6, operating the high pressure separator at 70° F instead of 80° F, the percentage increase in stock liquid ranges from 1% to nearly 5% for the three wellstreams. Note that this increase in liquid recovery occurs from lowering the separator temperature by only 10° F. Quite often the operator unknowingly adversely affects liquid recovery by operating the high pressure separator at elevated temperatures. The production separator should be operated at the lowest temperature possible, above the hydrate point. For most wellstreams at 1000 psi a temperature of 70° F will prevent hydrate formation. Sometimes with very low values of oil-gas ratios (high gas-oil ratios) it may be necessary to operate at a few degrees higher temperature to avoid hydrates which can occur through the refrigeration effect of flashing light liquids through the level control valve.

To illustrate the effect of larger temperature differences refer to Figure 7 which is a general chart and not based on our computer results, but agrees very well with our charts. Note that if wellstream "B" yielded 24.6 bbl/MMscf at 80° F, it would have yielded only 23.2 bbl/MMscf at 100° F.

Adding The Low Pressure Separator

Figure 2 shows a wellhead process system of a heater, high pressure separator, low pressure separator and stock tank. Referring to Figures 4, 5, and 6, two stages of separation can increase recovery by 6% to 10% with the high pressure separator operating at 80° F.

Heating coils in the low pressure separator can be useful to effect better oil-water separation, to control paraffin wax problems, and to drive off some of the lighter hydrocarbon components and thus have more intermediate pressure (60 psia) gas available for fuel or to be recompressed to sales line pressure. The heat added to the low pressure separator should only be enough to accomplish the desired results. Excess heat could cause heavier hydrocarbons to flash, reducing liquid recovery.

This combination of heater and two-stage separation is probably the most widely used and economically justifiable process scheme for yielding stock tank liquid gains. In some cases three stages of separation should be considered depending on operating conditions and composition of the wellstream.

When To Add A Stabilizer

Figure 3 shows a wellhead process system of a heater, high pressure separator, stabilizer and atmospheric pressure stock tank. A low pressure separator may also be included depending on the operating pressure and temperatures in the separators and the vapor pressure desired for the recovered liquid. Usually with low temperature separation or high gravity condensate the stabilizer will show an attractive payout. This is especially true if a higher vapor pressure liquid requiring pressure storage is desired. In general, a stabilizer should be used when a specific vapor pressure requirement is placed on the produced liquid or in the case of atmospheric storage tanks when it is necessary to minimize stock tank vapor losses. Usually the RVP* requirement for lease tanks is 12 psi to 14 psi RVP to minimize vapor losses.

The stabilizer is a trayed tower with a liquid reboiler. In lease operations the tower will nearly always be operated as a cold feed (on top tray) non-refluxed tower. The principle of its operation is liberation of undesirable hydrocarbons by differential temperature and constant pressure. The liquid is stage heated as it flows downward across the trays by mass heat exchange with rising hot vapors from the reboiler. Concurrently there is a reabsorption of desirable fractions in the rising vapors by the liquid on each tray. Figures 4, 5, and 6 show the increase in recovered liquids to be from 8% to 12% above a single high pressure separator at 80° F for three wellstreams.

Usually if a 12 psi to 14 psi RVP product is desired the tower should operate at less than 100 psig. The reboiler is usually a salt bath heater, but for some applications can be a more economical water bath heater or low pressure steam generator.
Stabilizing is not as widely used for lease operations as the stage separation approach, partly because it is a slightly more complex operation. However, stabil-

izers should be used if it is necessary to eliminate stock tank weathering losses or if the percentage increase in recovery offers satisfactory payouts. For liquid recoveries of 100 bbl/d or more the payout should be satisfactory.

Summary

From this brief look at basic lease production packages, it is seen that the addition of appropriate process equipment or a change in operating variables can increase the recovery of salable hydrocarbon liquids.

* RVP Reid Vapor Pressure. Vapor pressure is the pressure exerted by the vapor that is in equilibrium with the liquid (such as stock tank oil). RVP is recorded at 100° F.

SINGLE STAGE SEPARATION

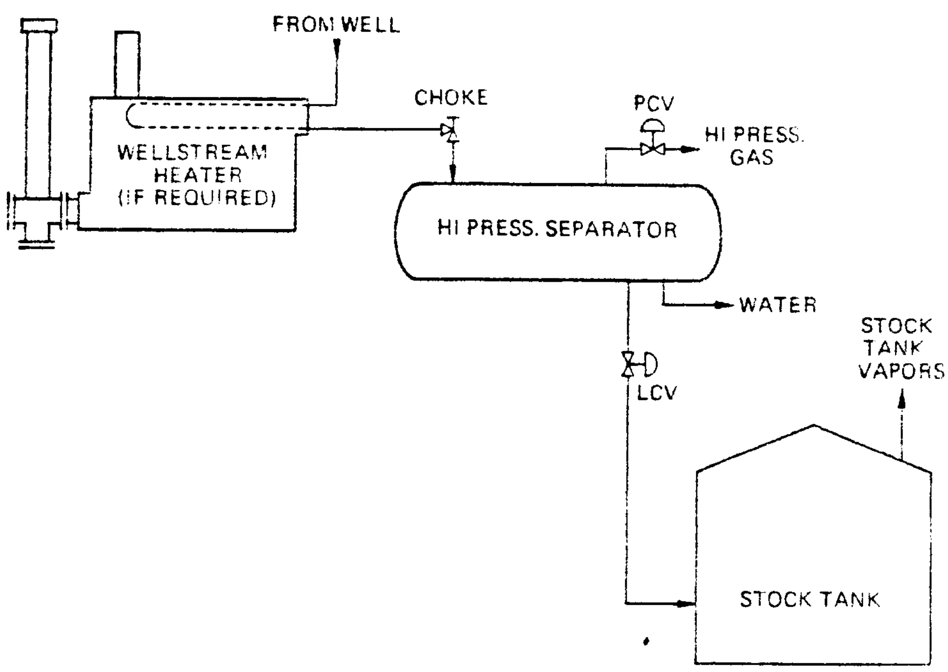


FIGURE 1

TWO STAGE SEPARATION

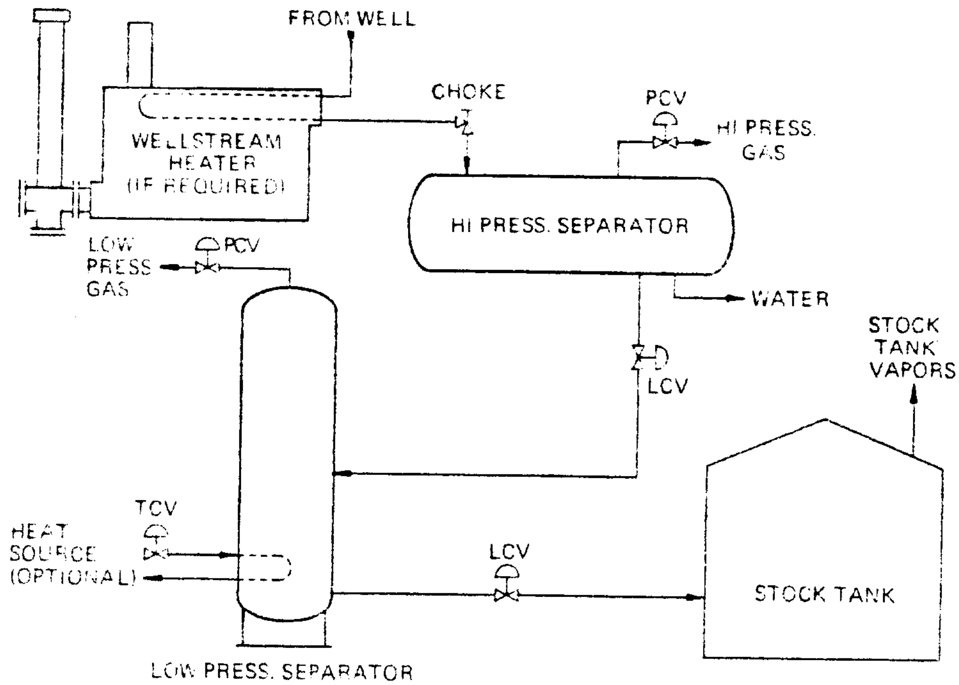


FIGURE 2

SEPARATION AND STABILIZATION

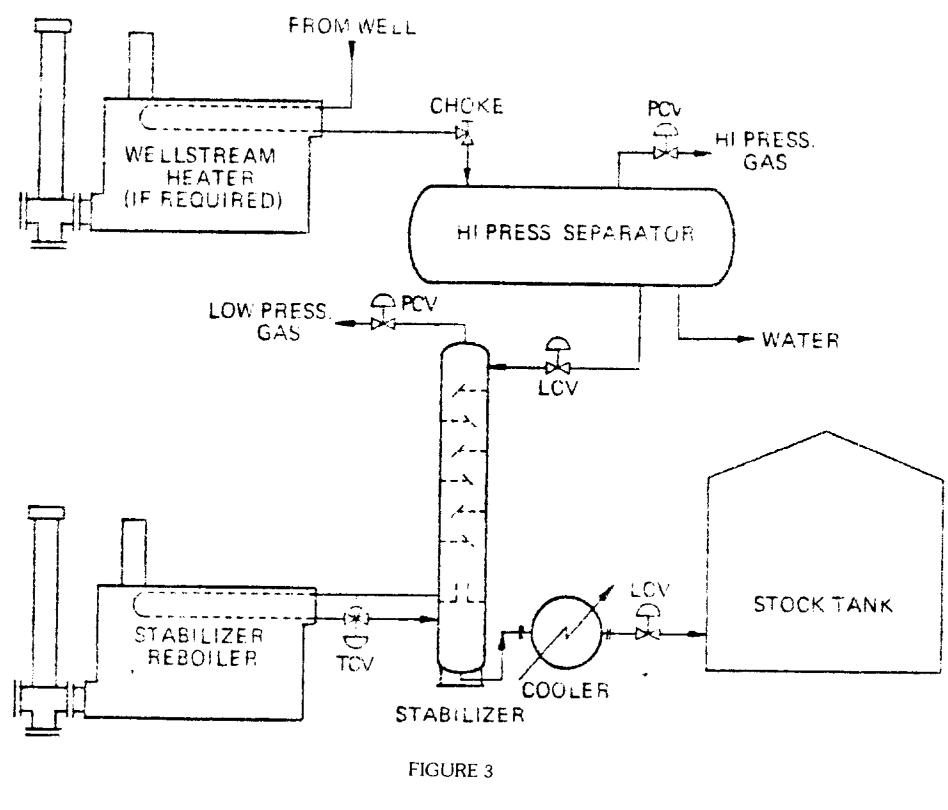


FIGURE 3

WELLSTREAM A

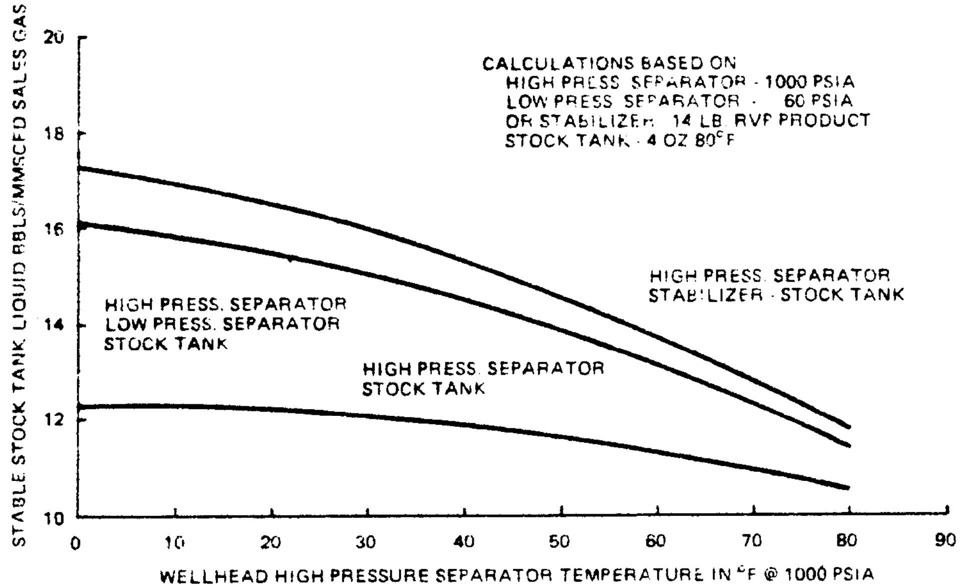


FIGURE 4

WELLSTREAM B

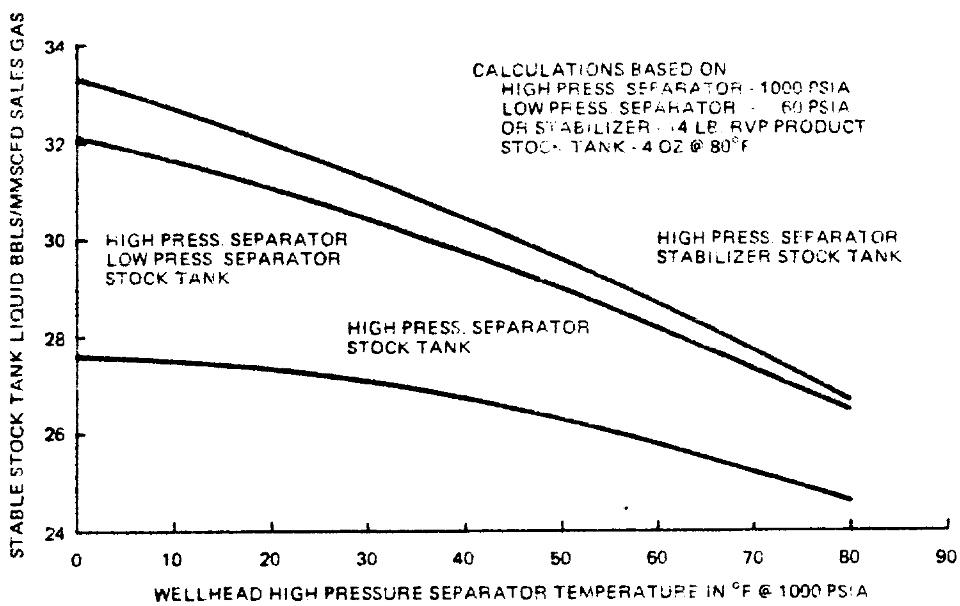
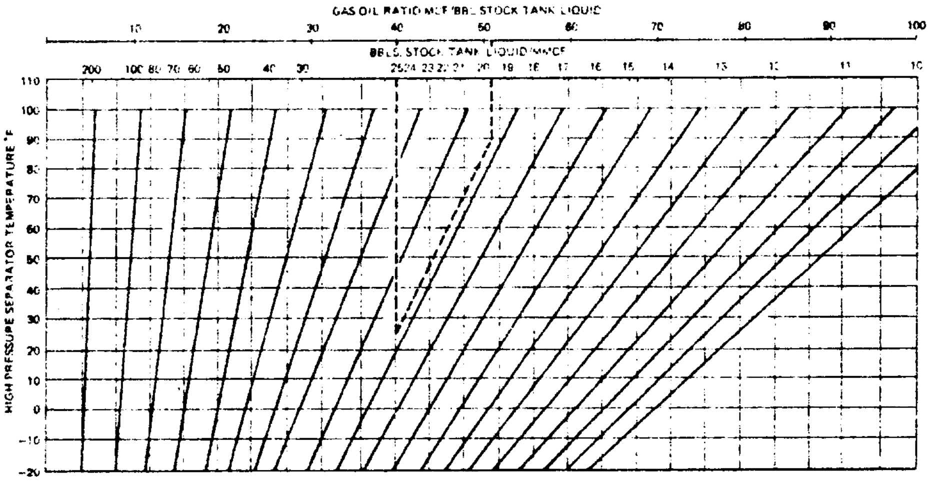


FIGURE 5

EFFECT OF SEPARATOR TEMPERATURE ON LIQUID RECOVERY



Purpose: To estimate liquid hydrocarbon recovery by low-temperature separation, knowing the recovery or gas oil ratio by conventional separation.
Method: (1) Locate point of intersection of the known GOR (or Bbl./MMSCF) and the temperature at which the conventional separation test was made. (2) Follow parallel to slanting lines to the intersection of the low-temperature separator temperature. (3) Read vertically from this point to the predicted Bbl./MMSCF recovery.
Example: A conventional separation test at 1000 psig showed a GOR of 51 MSCF/Stock tank bbl., at a flow rate of 10 MMSCFD at 90°F. If a low-temperature separation unit were used, with wellhead flowing pressure of 3000 psig and separation pressure of 1000 psig, how much additional recovery would result? Assume 90°F. upstream choke temperature, or high-pressure separator temperature.
Solution: With the separator operating to approximately 25°F., with a 2000 psi differential pressure across the choke, follow the dotted line example on chart. Locate 51 MMSCF/Bbl. on GOR scale. Follow it down to the 90°F. line. At this intersection draw a parallel line to the nearest slant line until it touches the 25°F. line. Then read vertically to 25 Bbl./MMSCF. Since 51 MSCF/Bbl. = 19.6 Bbl./MMSCF, the increased recovery by low-temperature separation would be approximately 25.0 − 19.6 = 5.4 Bbl./MMSCF. At a rate of 10 MMSCFD the increase would be 54 bbl./day. (Note: Well stream analysis and complete operating data are necessary to predict recoveries accurately. This graph gives a reasonable estimation of recovery.)

FIGURE 7

WELLSTREAM C

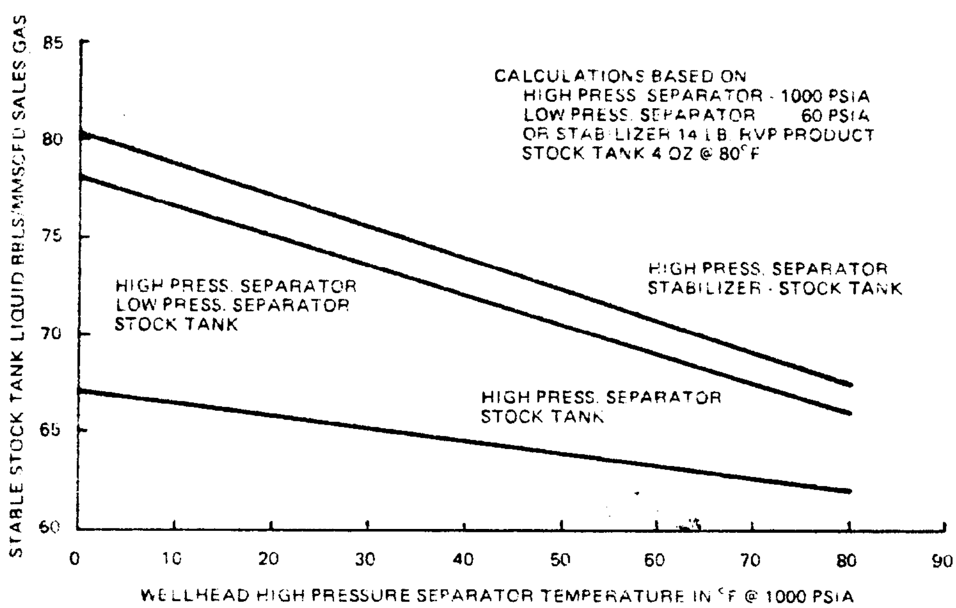


FIGURE 6