Packaged Liquid Hydrocarbon Recovery Units

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Because of the network of gas-gathering and transmission pipelines throughout the oil country, almost all production has access to gas sales. Consequently, the smaller packaged liquid hydrocarbon recovery units or gas plants have continued to become more feasible and in many cases have become very profitable to the plant operators.

Sometimes it becomes extremely difficult to justify larger plants since in most cases the development of an oil field generally takes from one to three years. During this period of development considerable amounts of raw gas are flared or vented to atmosphere. In cases such as these, the small packaged gas plant has a definite advantage over the larger plant in that smaller plants may, in many cases, be installed early in the life of the field. Quite frankly, this in itself often is the difference between a feasible project and a non-feasible one, especially in fields containing rather limited reserves.

Taking many things contained herein into consideration, the minimum volume of gas available to process initially probably would be at least 1,000,000 SCF/day although a plant probably should not be designed to process less than 2,000,000 SCF/day. If compression is necessary, gas compressor units may be added as volumes of gas increase. Casinghead gas, although requiring more compression facilities than gas well gas, is much richer in liquid content. Consequently, a plant designed to process 2,000,000 SCF/day of casinghead gas could probably handle 3,000,000 SCF/day of gas well gas.

The type of separation facilities at the well or lease site has considerable bearing on hydrocarbon analysis of the separator gas. Normally, single-stage mechanical type separators, production units or heater treaters are found, but occasionally LTX units or separators in a series are installed. The type equipment installed is an e-onomic decision which must be made by the producer, taking into consideration all factors involved. It must be noted here, however, that in some instances, especially where casinghead is derived from leases where the crude oil is 40 degrees API gravity or above, lease separators or heater treaters operated at higher pressures will carry over to stock tanks more light ends containing butane and propanes. Most of these products weather off the stock tanks and are lost. Also, in some instances the portion of the lighter ends which is held or blended with the crude oil in the stock tanks raises the gravity of the crude oil enough so as to cause a gravity penalty by the crude purchaser.

In many instances in order for the producer to remove B.S. & W. from the crude oil, heated separators or heater treaters are used. The liquid content of the gas obtained from vessels of this type is considerably higher than that obtained from non-heated separation facilities.

The small packaged plant such as shown in Fig. 1, is usually designed to recover a one-product hydrocarbon mixture. The amount of recovery will depend upon ahe design of the plant and the GPM content of the inlet gas stream. If the gas is not at high pressure, it must be compressed to a pressure of 250 to 500 lbs or to the sales gas line pressure. The gas stream is then chiled by refrigeration to a temperature of 0°F. to 20°F. The lower the operating temperature, the more propane will be recovered in the hydrocarbon mixture, rasing the vapor pressure of the product accordingly.

These small plants will recover at a + 20° F. operating temperature, 10 to 15 per cent butanes; 85 to 90 per cent pentanes plus. By lowering the temperature to a -20° F.,the maximum recovery of this plant is increased to 48 per cent propane;76 per cent butanes; 96.5 per cent pentanes plus. General averages of the GPM content of gas-distillate wells produced into a high pressure separator contain between 1.8 and 2.15 GPM:

Propane	1.16
Iso Butane	.21
Nor Butane	.39
Iso Pentane	.09
Nor Pentane	.10
Hexane Plus	.20
	2.15 GPM

The maximum recovery fro mthis 2.15 GPM gas steam would be 1.41 GPM of 1410 gals of approximately a 150-lb RVP hydrocarbon mixture per million ft of gas.

General averages of th GPM content of low pressure separation, operating at 15 to 30 lbs at 70° to 80° are:

Propane	2.44
Iso Butane	.25
Nor Butane	.80
Iso Pentane.	.23
Nor Pentane	.24
Hexane Plus	.57
	4.53 GPM

Maximum recovery of product from this 4.53 gas stream would be 3.01 GPM of 3010 gals per million cu ft.

General averages of the GPM of heater-treater gas operating at 12 to 15 lbs at 120° are:

Propane	4.79
Iso Butane	.67
Nor Butane	2.09
Iso Petane	.53
Nor Pentane	.43
Hexane Plus	.59
	9.20 GPM

Maximum recovery from this 9.20 GPM gas steam would be 6.07 GPM or 6070 gals per million cu ft.

From these examples it becomes apparent how much operating pressure and temperatures of lease separation equipment affect the GPM content of the separator gas.

Considerable care must be taken in sizing gathering lines in the field. In most instances these small plants are installed on casinghead gas situations since the gas stream is so much richer. This presents a problem in gathering the gas at such low pressures in that the differential of pressures is so small and the gravity of the rich stream of gas is so high. For example, assume a volume of 1,500,000 SCF of casinghead gas having a specific gravity of 1.05 (air= 1) coming from a group of heater treaters located three miles fom the plant site and operating at a pressure of 16 lbs, a 6-5/8 in O.D. pipeline would be required to gather this volume of gas to the plant at O-lb gauge pressure. This would be a 15-lb differential as approximately 1 lb would be lost in metering.

Especially at low pressure, metering equipment should be designed and sized so as to obtain accurate metering of gas at a minimum of pressure loss. This would mean that full-opening valves, larger meter tubes, larger orifice plates, and low pressure meter recorders are most desirable.

In instances where plants are installed on low pressure casinghead gas situations, gas compressors are necessary to compress the gas a pressure sufficient to obtain proper plant recovery or to a pressure sufficient to enter the pipeline of the residue gas purchaser. Since 250 lbs is about the lowest pressure at which a plant will operate efficiently, it can be concluded that it is necessary to compress the gas to a minimum of 250 lbs and to a maximum in some instances of 1000 lbs, although most gas purchasers' pipeline pressures will not carry over 500 to 700 lbs pressure.

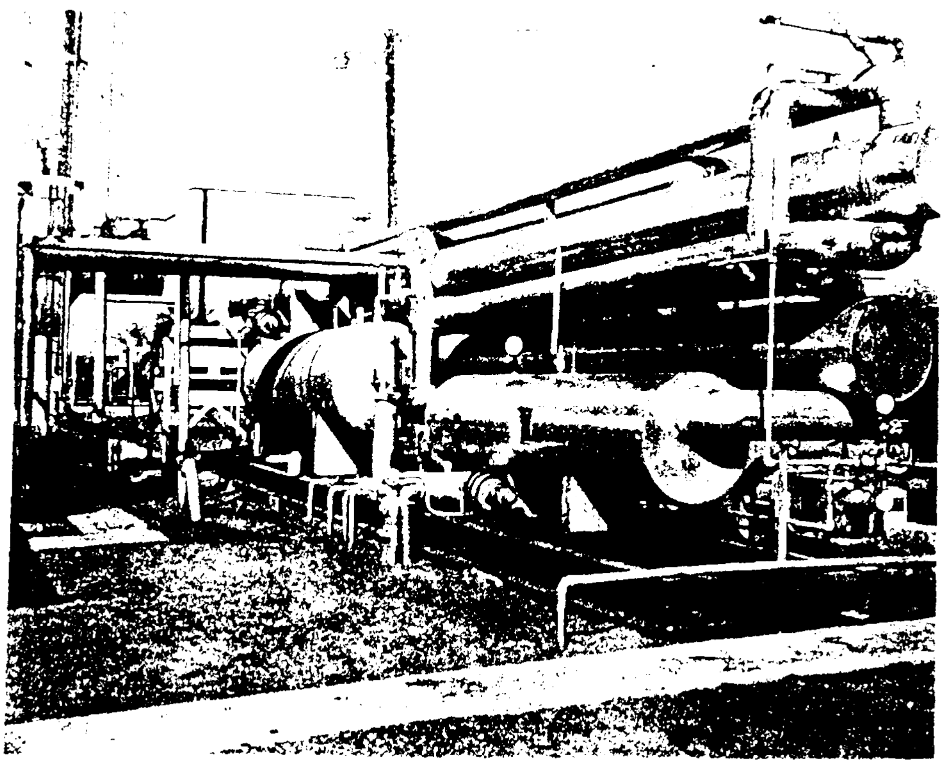
A rule of thumb calculation to be used in compressing gas is a maximum of 4.5 compression ratios per stage of compression. Using the same example as in the gathering pipeline example, the gas would arrive at plant site at O-lb gauge. To compress to 250 lbs would require two stages of compression; to compress to 500 or 700 lbs would require three stages of compression.

In the last few years, the packaged, skid-mounted, high speed, prime mover- compressor sets have come into their own. While it is conceded that they will not have the length of life of the slower speed integral compressor units, they can be installed at nearly one-half of the cost of the integral units and are far more portable.

Even the inter-stage and after-cooling coil sections can be added to the same skid. A minimum amount of concrete foundation is required for this type compressor unit, making it highly desirable especially where the reserves of gas to be processed are limited and there is a possibility the equipment will be moved to another site at a later date. It is not unreasonable to expect a 20° F. approach to 100° F. ambient air with aerial cooling.

The design of the plant process facilities in most cases is contingent on the available market

Figure 1
GENERAL PLANT AREA



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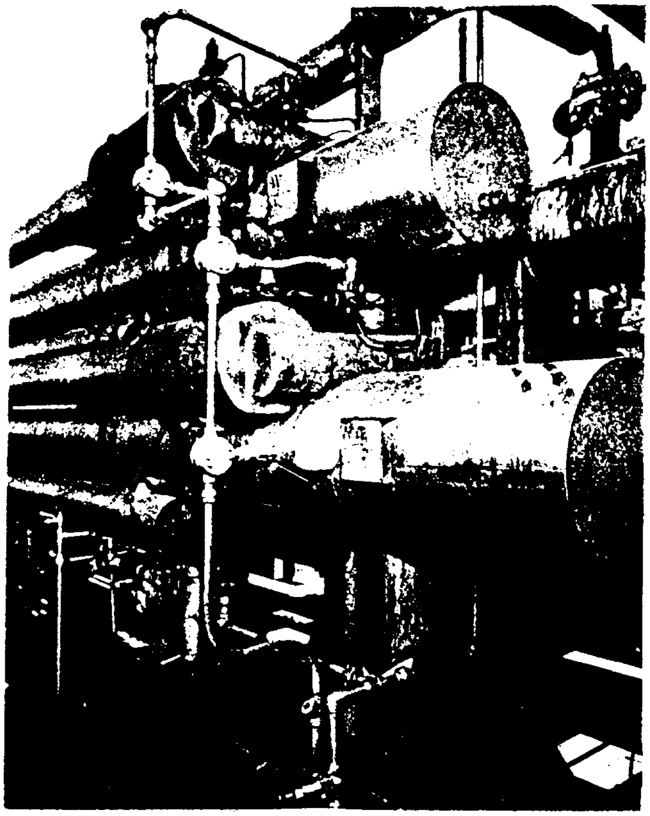

Figure 3
REAR VIEW OF MAIN PROCESS SKID

for the liquid hydrocarbon product. While these plants are flexible and can be refrigeration only or a combination refrigeration-absorption plant, the following example is a description of a small packaged liquid hydrocarbon recovery unit or gas plant. All of the plant components are packaged and pre-piped on skids. Even the refrigeration compressors are packaged and pre-piped on skids. The refinement with which this small plant has been designed and packaged makes it highly portable and requires very little foundation work and connecting piping. This plant (Figs. 1, 2, 3 and 4) in its entirely, including two gas compressors, could probably be loaded on six trucks. The flow pattern of the gas stream in this plant would be as follows:

Inlet from the compressor or high pressure separator enters the plant into an inlet scrubber. The liquid product from this scrubber is taken back to a lease separator of to stock tanks.

Downstream from the scrubber, lean glycol is injected into the gas stream to prevent hydrate formation. The gas is then taken to a gas-to-gas heat exchanger, which uses the cold gas from the cold separator, to do a large amount of cooling. This exchanger reduces the amount off re-

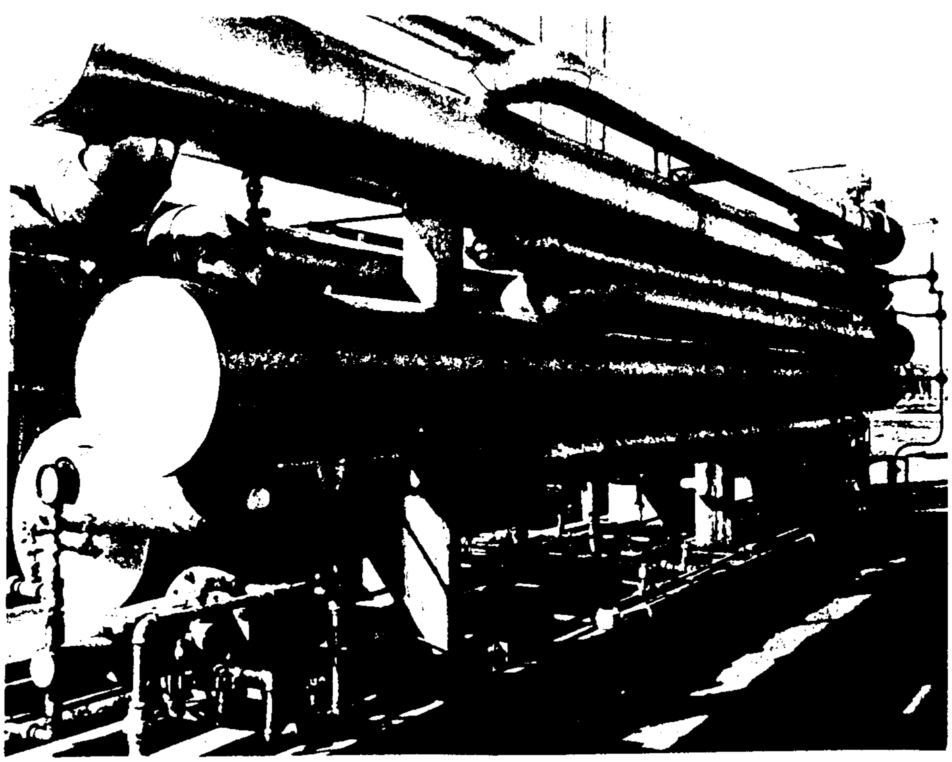

Figure 4
REAR VIEW OF MAIN PROCESS SKID AND GLYCOL PUMP

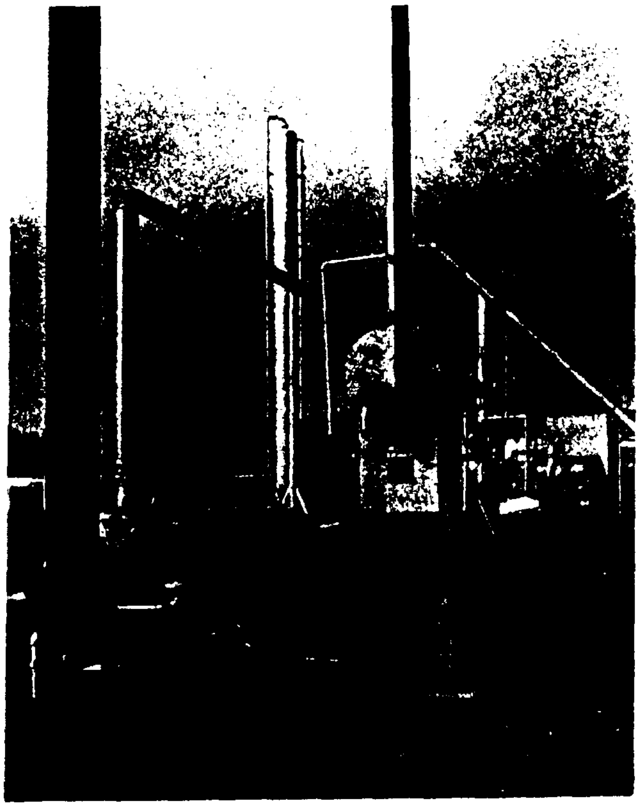

Figure 5
STEAM GENERATOR AND GLYCOL RE-BOILER

frigeration load of the plant. The pre-cooled gas enters the chiller.

The chiller provides enough cooling to reduce the gas stream temperature to the design operating temperature. At this temperature and an operating pressure of 250 lbs or higher, the entrained liquids will fall out. The gas stream with the condensed liquids are passed on to a cold separator

The three-phase cold separator will separate the gas-distillate and water-glycol mixture. The cold gas from the separator is passed back to the heat exchanger to cool the incoming gas to the chiller. The gas, after passing through the exchanger, is then delivered to the sales gas line. The cold gas separator has a side stream heating coil which will supply enough heat to the liquid to separate the hydrocarbon liquids from the water-glycol mixture.

The water-glycol mixture is fed back to a standard glycol reconcentrator, or reboiler (Fig. 5) where the water is cooked out of the glycol. In this unit the glycol is brought back to specifications and then stored in a surge tank ready for pumping back into the wet gas stream.

The hydrocarbon liquids are dumped from the cold separator into a heat exchanger, that exchanges with the refrigerant, and then into the

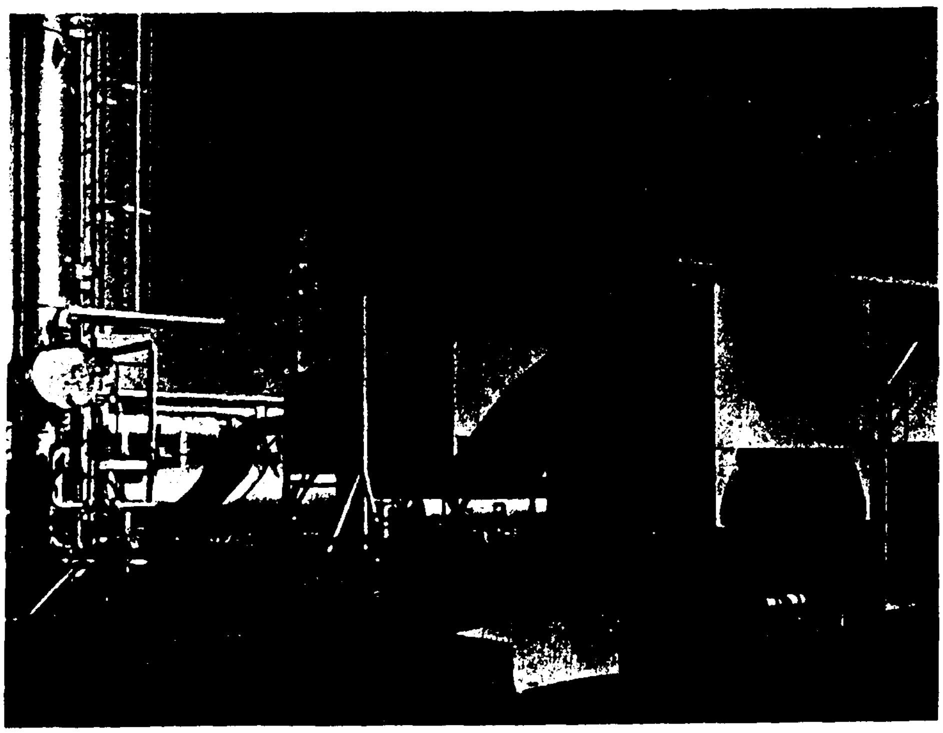

Figure 6
STABILIZER AND CONDENSER SKID

top of the cold-feed stabilizer (Fig. 6). The liquid is cold enough that it acts as the top reflux for the stabilizer column.

The stabilizer tower (Fig. 7) is operated at a back pressure on the top of the tower and at a temperature on the bottom of the tower to make the desired vapor pressure product. The overhead gas fom the stabirlize that is flashed off is used for fuel in the glycol reconcentrator, Stabilizer reboiler, gas compressors, and the gas engines of the refrigeration compressors. The stablizer is a bubble cap tray, or a packed tower, that will make a constant vapor pressure product. The liquid vapor pressure can be closely controlled by regulating the temperature and pressures on the stabilizer tower. Part of the hot liquid from the stabilizer bottom is used as a side stream to heat the base of the cold separator in order to separate the glycol water mixture and the liquid hydrocarbons. All of the hot liquid stream is then passed to one bank of an aerial cooler where the temperature of the product is reduced to atmosphere, and from there taken to product storage. This plant can make any one product from 8 to 12 lb RVP liquid hydrocarbon,

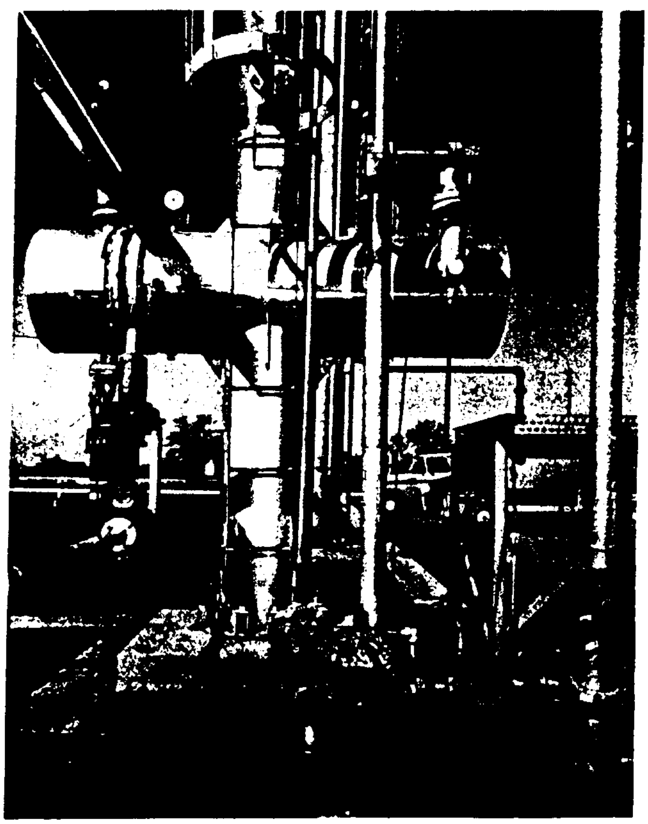

Figure 7
STABILIZER WITH STEAM BUNDLE AND AERIAL PRODUCT COOLER

up to a 150-lb RVP LPG mixture. The type product made by the plant would determine the working pressure of the stock tank storage.

Heat for the stabilizer is furnished by a steam generator or a heater of a size required to bring the stabilizer bottom to the necessary temperature, usually from 210° to 350° F.

The refrigeration system (Figs. 8 and 9) is a closed cycle. Propane, ammonia or freon is used in the chiller, and as the pressure in the chiller is reduced, the vaporization of the refrigerant cools the gas. From the chiller the refrigerant is picked up as a vapor in a suction scubber on the inlet to the compressor. The refrigerant compressure will boost the gas to a pressure that, after cooling in a separate bank of the aerial cooler, will condense back to a liquid. Additional cooling in a liquid-to-liquid heat exchanger assures that the refrigerant is a liquid. As the refrigerant is required iin the chiller, by means of liquid level control and valve, it is fed back upon completing the closed cycle.

The self-contained portable plant normally needs only electrical power for the aerial cooler (Fig. 7.) The installation cost and time consumed are of a minimum because of the packaging of the plant. This type plant can be utilized on various inlet GPM gas streams and volumes, and still operate at an acceptable level of efficiency.

The two general types of product from this plant have a ready market. The high vapor pressure 150-lb RVP LPG mix could be sold to another plant which could fractionate it into propane, butane, etc. The 35 to 40-lb RVP hydrocarbon mix has a ready market to crude oil purchasers and refining companies.

Almost always the gas purchaser or pipeline company will welcome these small plants because they offer the gas company several advantages. While the minimum BTU requirement is generally 1000 BTU'S per cu ft of gas, many gas companies have utilization factor requirements which also control the maximum BTU content of the gas. Nearly all casinghead gases derived from heater treaters must be processed to be able to comply with the utilization factor. Also, much of the hydrocarbons that would otherwise condense and collect in the gas pipelines would be removed, but still leaving the BTU content of the gas well in excess of 1000 BTU's per cubic foot. This condensation would cause erratic gas flows, reduced pipeline capacity due to liquids occupying space in the pipeline,

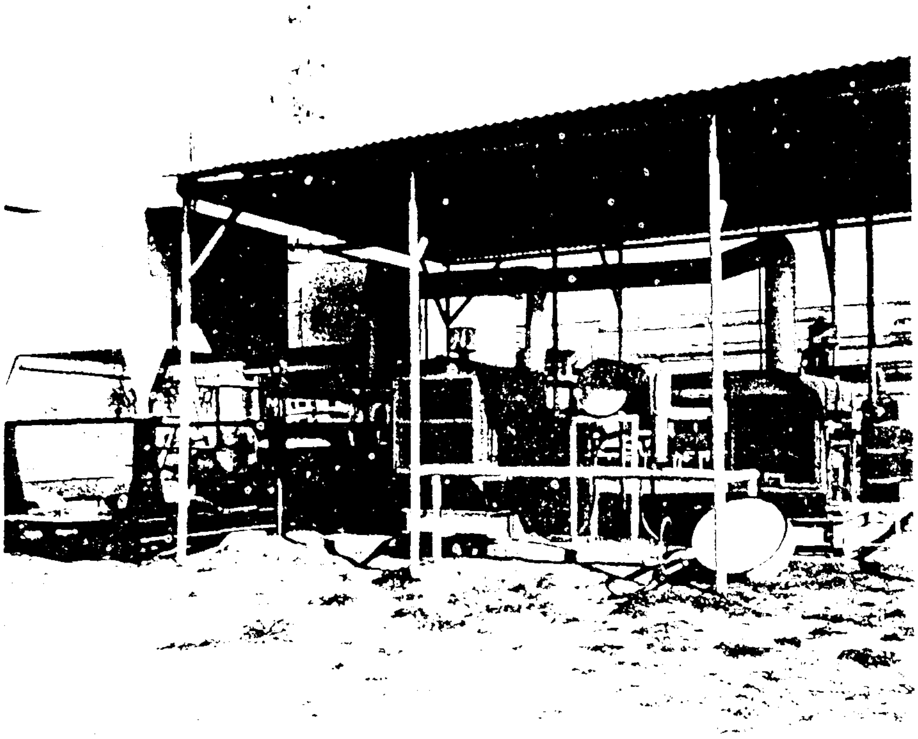

Figure 8
REFRIGERATION UNITS AND CONDENSER
SKID

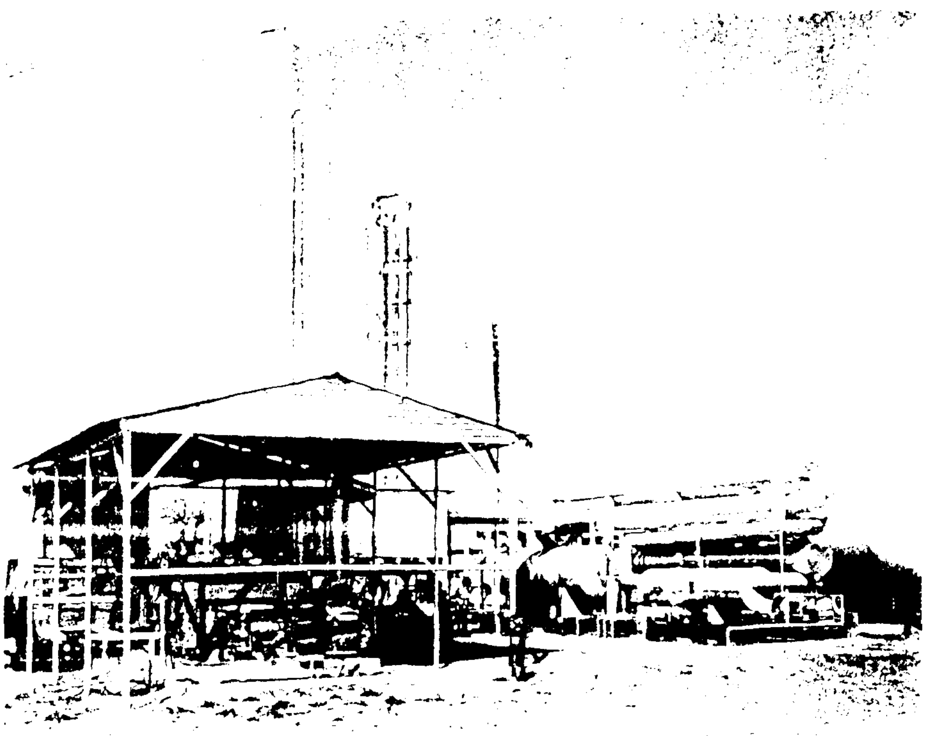

Figure 9
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UNIT

and increased compressor horsepower in order to handle the desired volumes. Another advantage is that the residue gas leaving the plant will be dehydrated gas. The plant, by the use of glycol absorption, reduces the water saturation of the gas which eliminates line freezing problems and greatly reduces pipeline corrosion.

While the cost of the packaged liquid hydrocarbon unit or gas plant and related gathering and compressing facilities will vary, depending upon the length and size of gathering pipelines, amount of compressor horsepower, and capacity of the plant, some rule-of-thumb cost figures are as follows:

Gathering pipelines, using light wall pipe because of the low pressure, including valves and fittings, can be laid for about 1.5 dollars times the diameter of the pipe per mile of pipeline. In other words, a 6-5/8 in. pipeline can be laid for approximately $10,000 per mile.

Using high speed packaged compressor units, an installed cost of $130 per horsepower of compression could be expected.

Refrigeration plant facilities designed to process casinghead gas could be expected to cost in the area of $75,000 per million cu ft of gas capacity installed, excluding storage for the liquid product.

In most instances where proper engineering has been done, a payout of two to five years could be expected.

A conclusion has been reached, based on careful analysis of performance, that the packaged liquid hydrocarbon recovery unit or gas plant has proven it has earned for itself a place in the oil patch of our great country.