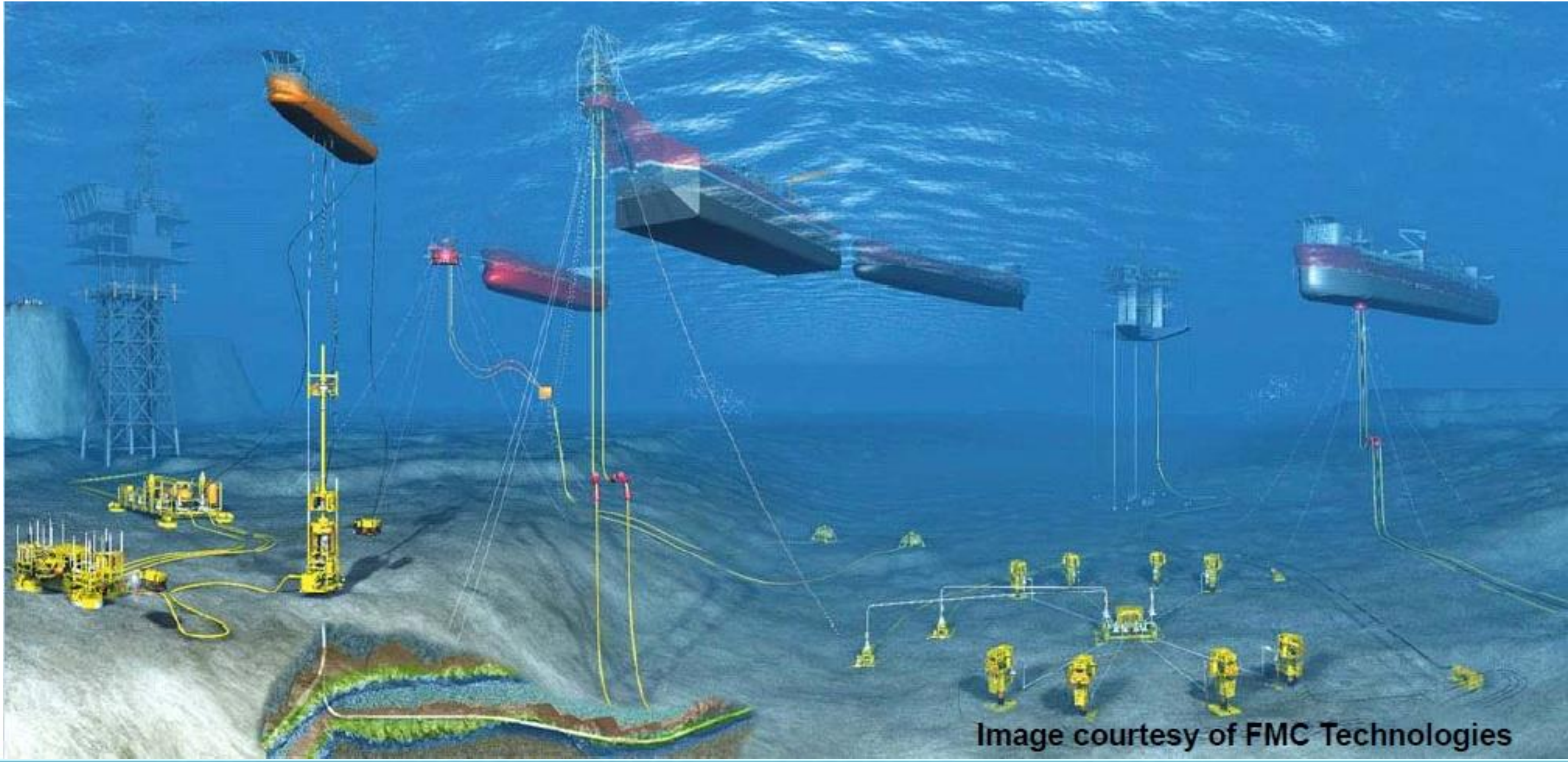


Offshore Equipment

Yutaek Seo

Components for offshore process

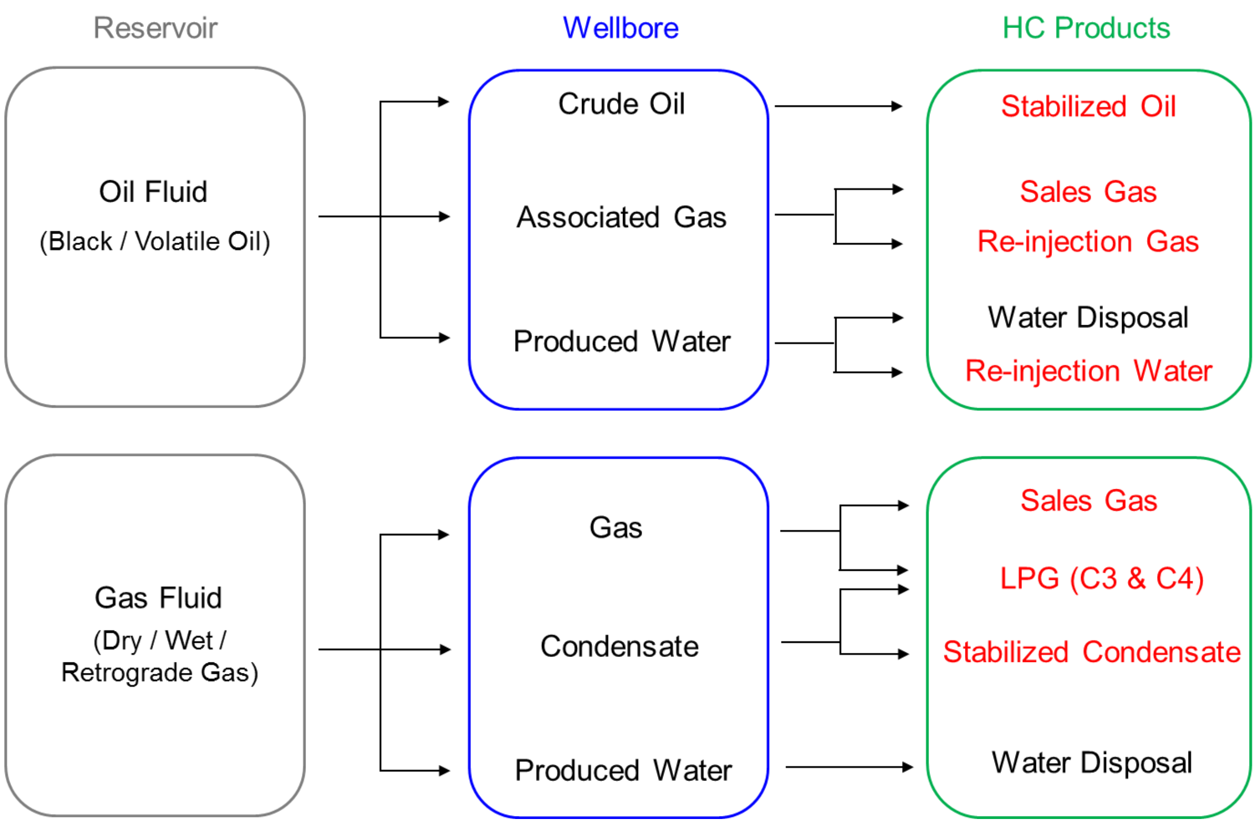
- Subsea pipeline
  : Material selection, Inner diameter calculation
  : understanding both subsea production and topside process
- Valve, Fittings, and piping selection
  : Ball, plug, Gate, Butterfly, Globe, Needle, Check, Choke valves
  : Piping design – MAWP, design temperature, thickness selection
  : Flange, welding, and branch connection
- Compressors
  : Reciprocating (high speed, low speed), Vane rotary, Screw rotary
  : Centrifugal
  : Determine stages and process selection for safe operation
- Reciprocating compressor
  : Frame, cylinder, distance pieces, crosshead, rods, crankshaft
  : Piston, bearing, packing, valves, capacity control
  : Cylinder sizing, rod load, cooling and lubricating
  : Volumetric efficiency, isentropic efficiency

Introduction

- The job of a production facility

  : to separate the well stream into three components, typically called "phases" (oil, gas, and water),

  : and process these phases into some marketable product(s) or dispose of them in an environmentally acceptable manner.



- Specification for pipeline quality gas

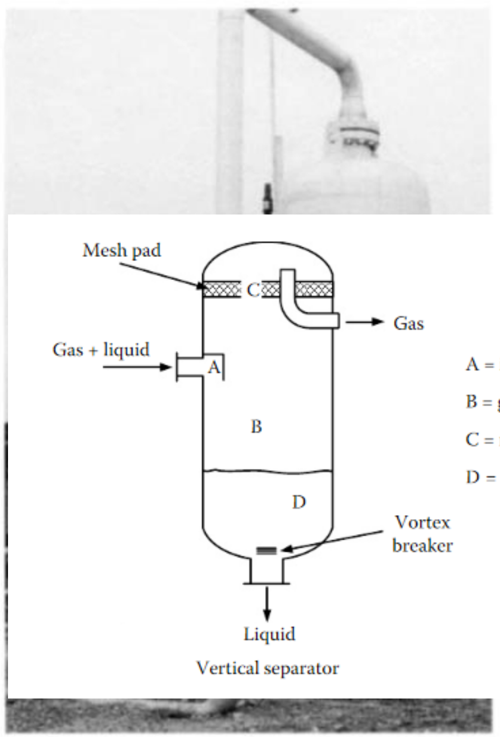
US Pipelines					
Specs	Alliance USA	Empire	GLGT	Iroquois	Northern Border
Hydrogen Sulphide	Max. 1 grains/Ccf^3	Max. 1 grains/Ccf^3	Max. 1/4 grains/Ccf^3	Max. 1/4 grains/Ccf^3	Max. 0.3 grains/Ccf^3
Total Sulphur	Max. 5 grains/Ccf^3	Max. 20 grains/Ccf^3	Max. 20 grains/Ccf^3	Max. 1.25 grains/Ccf^3	Max. 2 grains/Ccf^3, (0.3 grains mercaptan/Ccf^3)
Carbon Dioxide	Max. 2% by volume	Max. 2% by volume	Max. 2% by volume	Max. 2% by volume	Max. 2% by volume
Oxygen	Max. 0.4% by volume	Max. 1% by volume	Max. 1% by volume	Max. 0.2% by volume	Max. 0.4% by volume
Nitrogen	Not specified	Not specified	Max. 3% by volume	Max. 2.75% N_2+O2 4% N_2+ CO_2	Not specified
Temperature	Max. 122°F	Max. 120°F, Min. 40°F	Max. 120°F, Min. 20°F	Max. 120°F	Min. 32°F Max. 120°F
Heating Value	Min. 962 BTU/ft^3	Min. 950 BTU/ft^3 Max. 1200 BTU/ft^3	Min. 967 BTU/ft^3 Max. 1069 BTU/ft^3	Min. 967 BTU/ft^3 Max. 1110 BTU/ft^3	Min. 967 BTU/ft^3
Water	Max. 4 lbs/MMcf	Max. 7 lbs/MMcf	Max. 4 lbs/MMcf	Max. 4 lbs/MMcf at 14.73 psi & 60°F	Max. 4 lbs/MMcf
Hydrocarbon Dewpoint	Max. 14°F at opt. pres.	Not specified	Not specified	Max. 15°F or less	Max. -5°F (800psia), -10°F (1000 psia), -18°F at (1100 psia)
Interchangeability	Not specified	Not specified	Not specified	See Iroquois Tariff	Not specified

- Specification for exporting crude oil

NIGERIAN BONNY LIGHT OIL	
Specific Gravity @ 60F/15.55C	0.8397-0.8498
API Specific Gravity @ 60F/15.55C	35.0-37.0
Density at 60F/15.55C-Cg-CM-MAC	0.85Max
Pour Point	<40F/4.44C
Sulfur Content, %Wt	0.14Max
Colour	Dark Brown
Salinity TB at 0.10%/BS&W	47Max
Acid Number	0.39Max
Reid Vapour Pressure	6.52psig Max
Water & Sediment Content, Pct (%)	1.00%Max
Iron Wt, ppm	1.00Max
Nickel Wt, ppm	4.00Max
Vanadium Wt, ppm	2.00Max

Primary separation

- In mechanical devices called "separators“ gas is flashed from the liquids and "free water" is separated from the oil. These steps remove enough light hydrocarbons to produce a stable crude oil with the volatility (vapor pressure) to meet sales criteria.
- Figures 1-1 and 1-2 show typical separators used to separate gas from liquid or water from oil. Separators can be either horizontal or vertical in configuration. The gas that is separated must be compressed and treated for sales.



A = inlet device
B = gas gravity separation
C = mist extraction
D = liquid gravity separation

Figure 1-1. A typical vertical two-phase separator at a land location. The inlet comes in the left side, gas comes off the top, and liquid leaves the bottom right side of the separator.

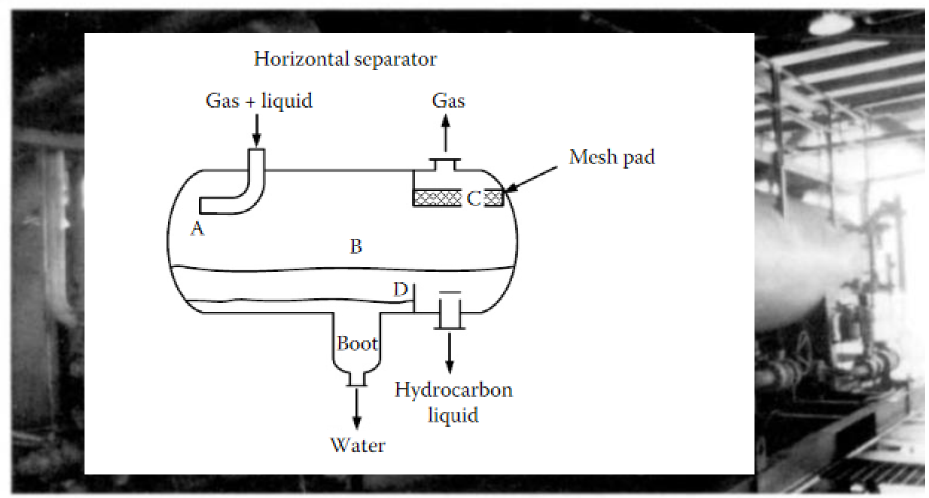


Figure 1-2. A typical horizontal separator on an offshore platform showing the inlet side. Note the drain valves at various points along the bottom and the access platform along the top.

Compression

- Compression is typically done by engine-driven reciprocating compressors, Figure 1-3. In large facilities or in booster service, turbine-driven centrifugal compressors, such as that shown in Figure 1-4, are used.

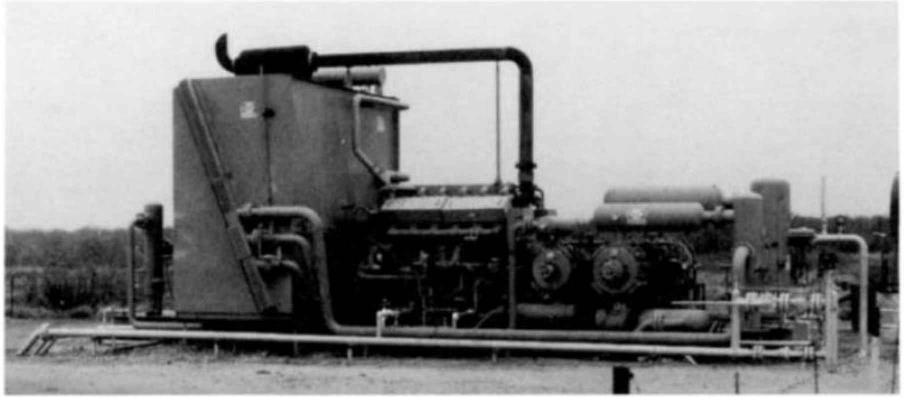


Figure 1-3. An engine-driven compressor package. The inlet and interstage scrubbers (separators) are at the right. The gas is routed through pulsation bottles to gas cylinders and then to the cooler on the left end of the package. The engine that drives the compressor cylinders is located to the right of the box-like cooler.

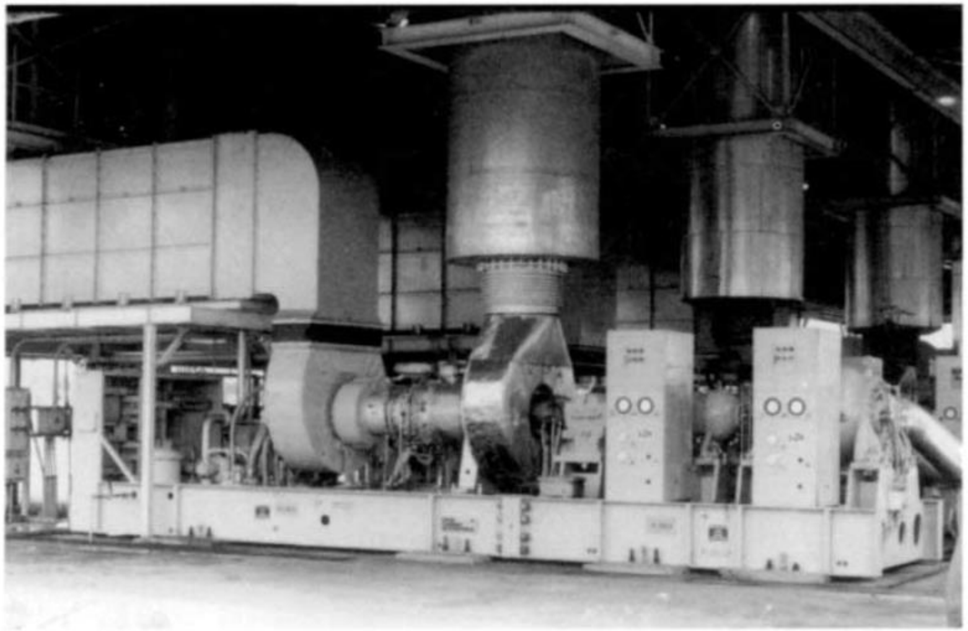


Figure 1-4. A turbine-driven centrifugal compressor. The turbine draws air in from the large duct on the left. This is mixed with fuel and ignited. The jet of gas thus created causes the turbine blades to turn at high speed before being exhausted vertically upward through the large cylindrical duct. The turbine shaft drives the two centrifugal compressors, which are located behind the control cabinets on the right end of the skid.

- Large integral reciprocating compressors are also used, Figure 1-5.

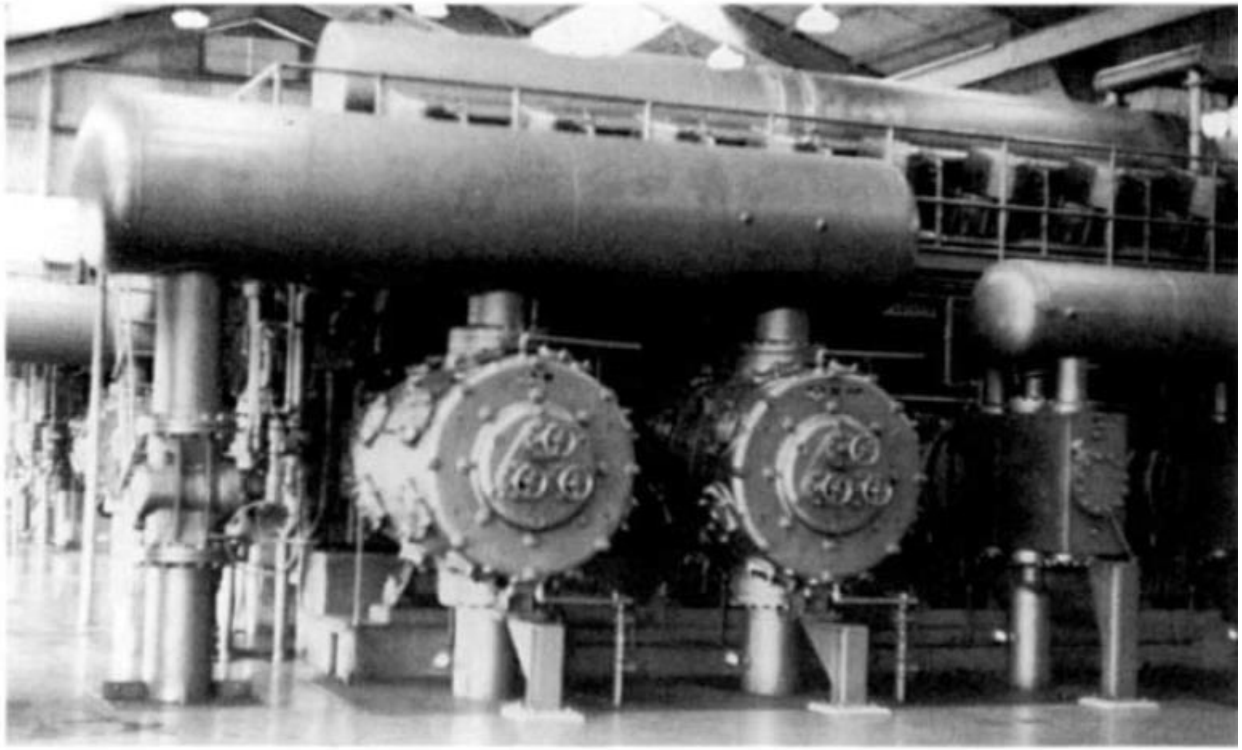
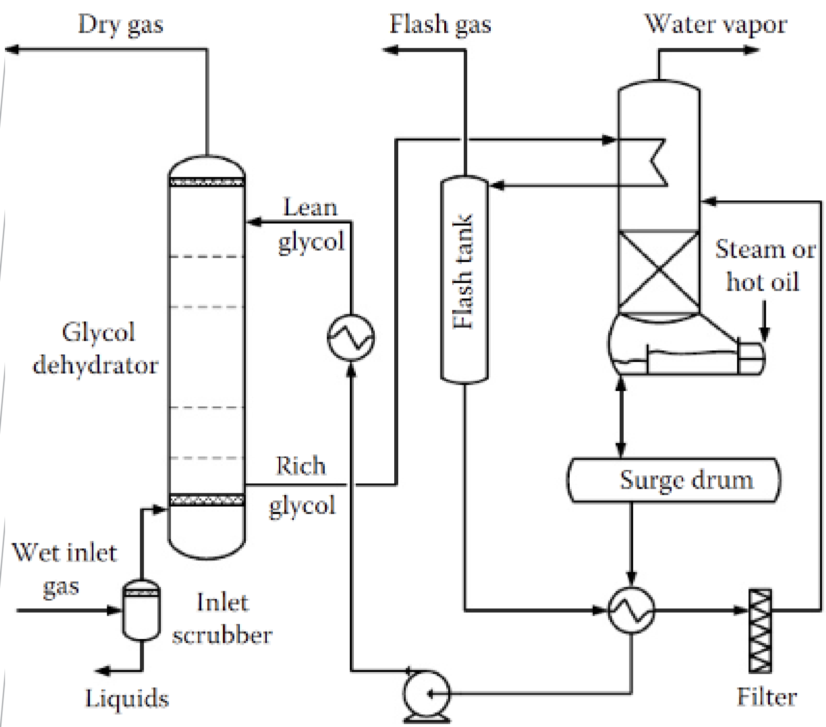


Figure 1-5. A 5500-hp integral reciprocating compressor. The sixteen power cylinders located at the top of the unit (eight on each side) drive a crankshaft that is directly coupled to the horizontal compressor cylinders facing the camera. Large cylindrical "bottles" mounted above and below the compressor cylinders filter out acoustical pulsations in the gas being compressed.

Gas processing - dehydration

- Usually, the separated gas is saturated with water vapor and must be dehydrated to an acceptable level (normally less than 7 lb/MMscf). Usually this is done in a glycol dehydrator, such as that shown in Figure 1-6.
- Dry glycol is pumped to the large vertical contact tower where it strips the gas of its water vapor. The wet glycol then flows through a separator to the large horizontal reboiler where it is heated and the water boiled off as steam.



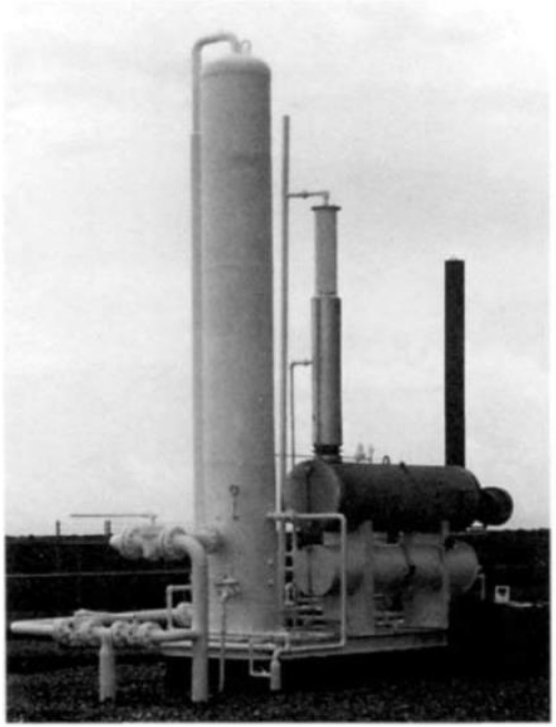
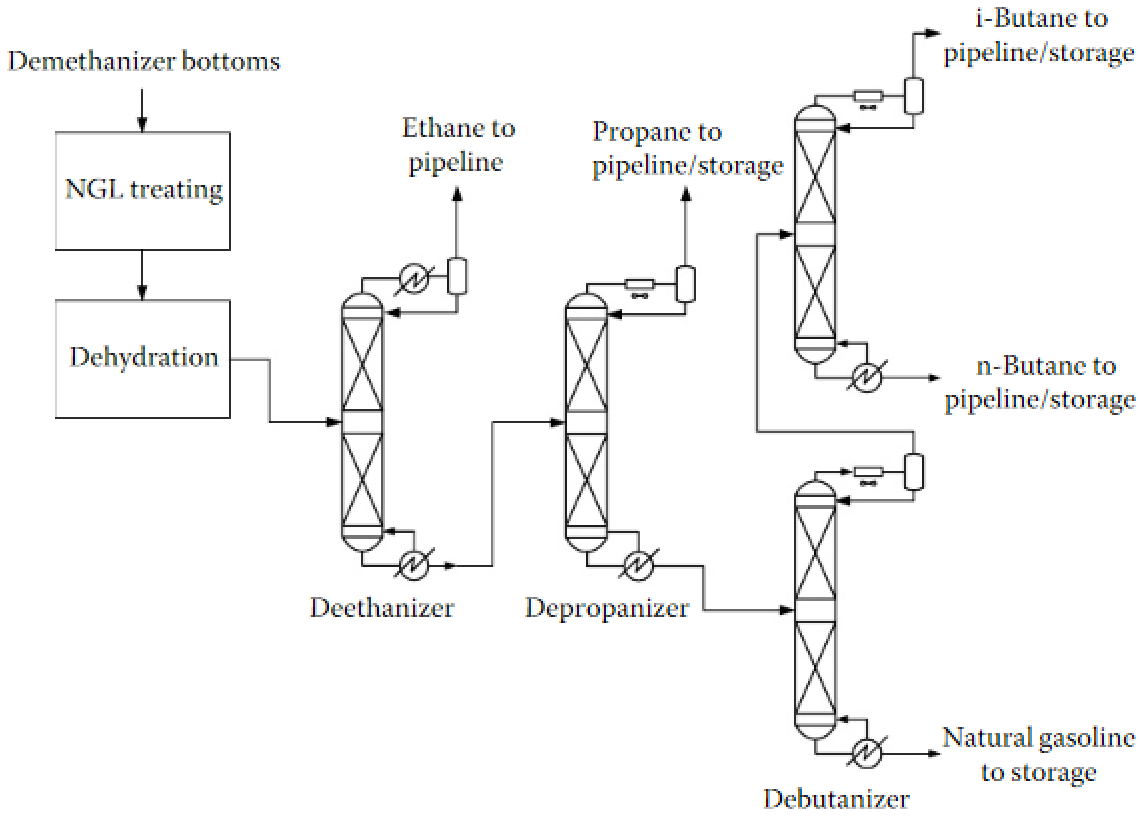


Figure 1-6. A small glycol gas dehydration system. The large vertical vessel on the left is the contact tower where "dry" glycol contacts the gas and absorbs water vapor. The upper horizontal vessel is the "reboiler" or "reconcentrator" where the wet glycol is heated, boiling off the water that exits the vertical pipe coming off the top just behind the contact tower. The lower horizontal vessel serves as a surge tank.

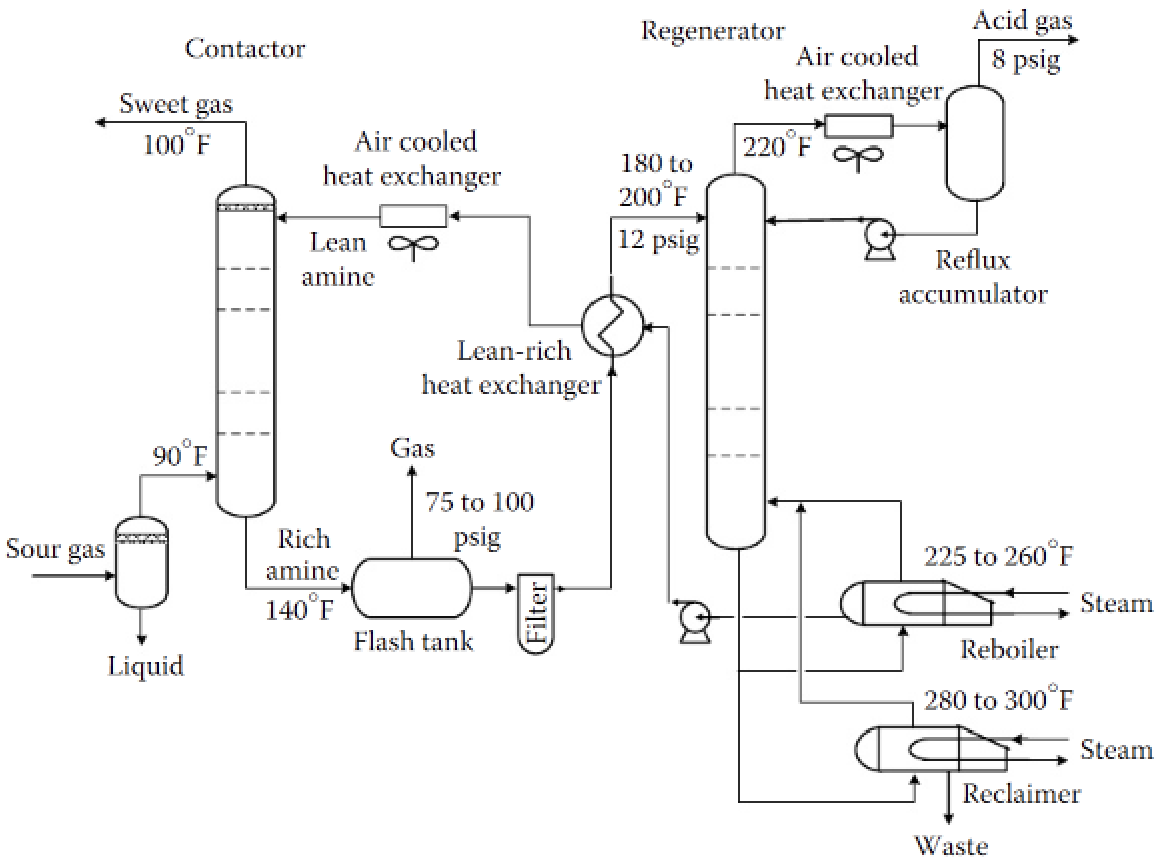
Gas processing – NGL recovery

- In some locations it may be necessary to remove the heavier hydrocarbons to lower the hydrocarbon dew point.



Gas processing – Acid gas removal

- Contaminants such as H_2S and CO_2 may be present at levels higher than those acceptable to the gas purchaser. If this is the case, then additional equipment will be necessary to "sweeten" the gas.

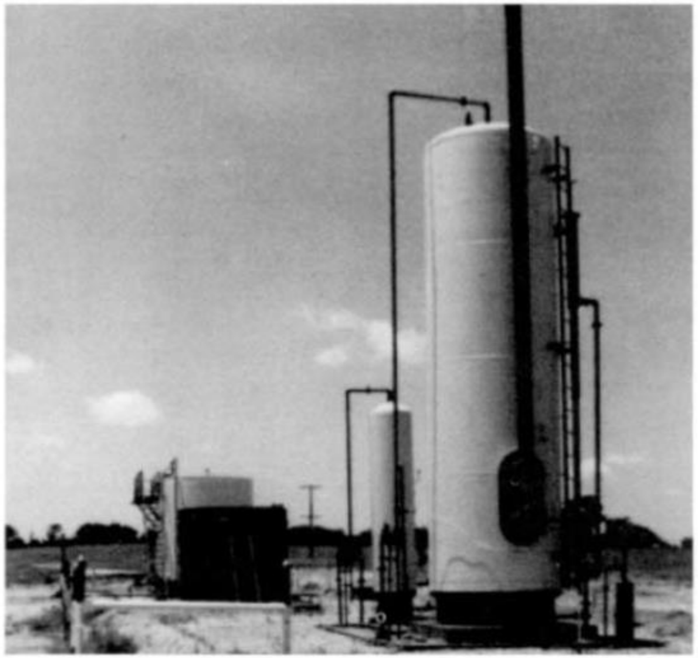


Oil processing

- The oil and emulsion from the separators must be treated to remove water. Most oil contracts specify a maximum percent of basic sediment and water (BS and W) that can be in the crude. This will typically vary from 0.5% to 3% depending on location.
- Some refineries have a limit on salt content in the crude, which may require several stages of dilution with fresh water and subsequent treating to remove the water. Typical salt limits are 10 to 25 pounds of salt per thousand barrels.

Oil processing – direct fired heater treater

- Figures 1-7 and 1-8 are typical direct-fired heater-treaters that are used for removing water from the oil and emulsion being treated.
- These can be either horizontal or vertical in configuration and are distinguished by the fire tube, air intakes, and exhausts that are clearly visible. Treaters can be built without fire tubes, which makes them look very much like separators.



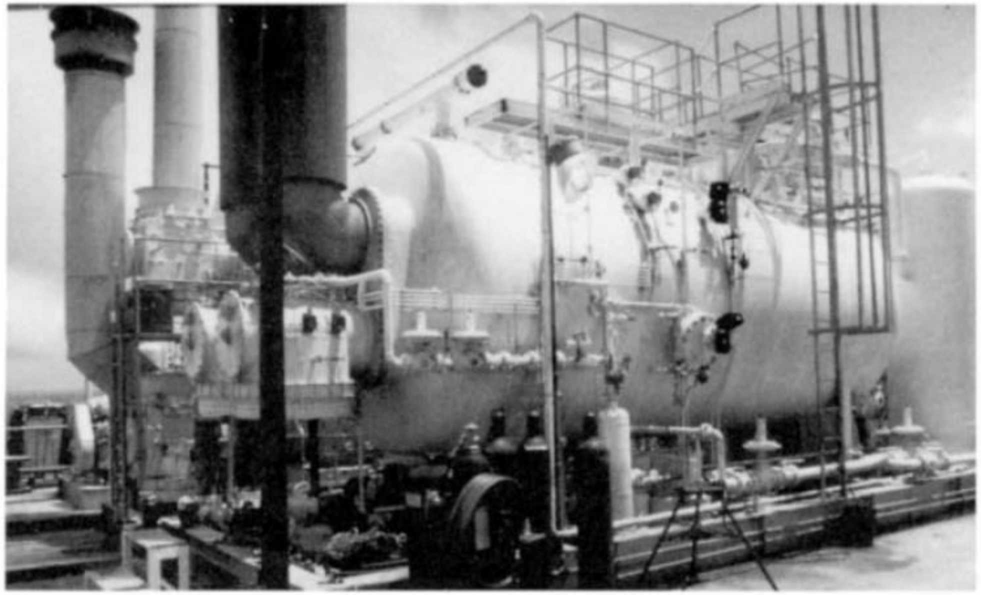


Figure 1-8. A horizontal heater treater with two burners.

Figure 1-7. A vertical heater treater. The emulsion to be treated enters on the far side. The fire tubes (facing the camera) heat the emulsion, and oil exits near the top. Water exits the bottom through the external water leg on the right, which maintains the proper height of the interface between oil and water in the vessel. Gas exits the top. Some of the gas goes to the small "pot" at the lower right where it is scrubbed prior to being used for fuel for the burners.

Oil processing – gunbarrel tank

- Oil treating can also be done by settling or in gunbarrel tanks, which have either external or internal gas boots. A gunbarrel tank with an internal gas boot is shown in Figure 1-9.

Figure 1-9. A gunbarrel tank for treating oil. The emulsion enters the "gas boot" on top where gas is liberated and then drops into the tank through a specially designed "downcomer" and spreader system. The interface between oil and water is maintained by the external water leg attached to the right side of the tank. Gas from the tank goes through the inclined pipe to a vapor recovery compressor to be salvaged for fuel use.

- Production facilities must also accommodate accurate measuring and sampling of the crude oil. This can be done automatically with a Lease Automatic Custody Transfer (LACT) unit or by gauging in a calibrated tank. Figure 1-10 shows a typical LACT unit.

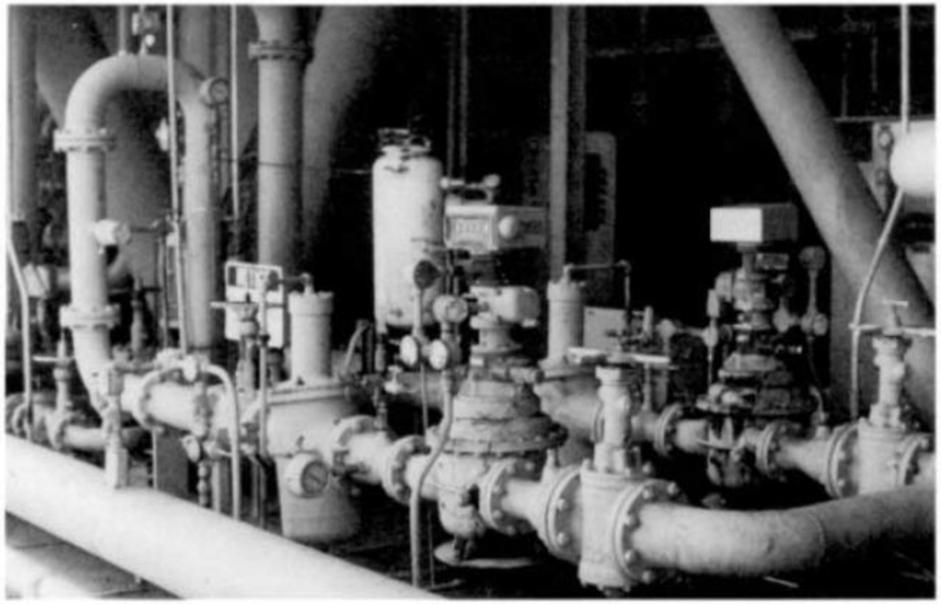


Figure 1-10. A LACT unit for custody transfer of oil. In the vertical loop on the left are BS&W probe and a sampler unit. The flow comes through a strainer with a gas eliminator on top before passing through the meter. The meter contains devices for making temperature and gravity corrections, for driving the sampler, and for integrating the meter output with that of a meter prover (not shown).

Water treating

- The water that is produced with crude oil can be disposed of overboard in most offshore areas, or evaporated from pits in some locations onshore. Usually, it is injected into disposal wells or used for water flooding.
- In any case, water from the separators must be treated to remove small quantities of produced oil. If the water is to be injected into a disposal well, facilities may be required to filter solid particles from it.

Water treating – oil removing

- Water treating can be done in horizontal or vertical skimmer vessels, which look very much like separators. Water treating can also be done in one of the many proprietary designs discussed in this text such as up-flow or down-flow CPIs (Figure 1-11), flotation units (Figure 1-12), crossflow coalescers/separators, and skim piles. Skim tanks with and without freeflow turbulent coalescers (SP Packs) can also be used.

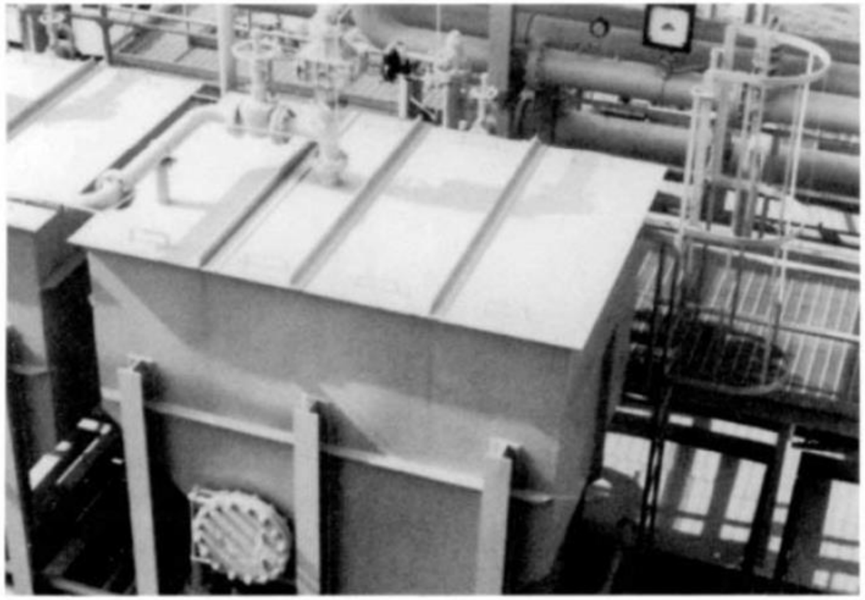


Figure 1-11. A corrugated plate interceptor (CPI) used for treating water. Note that the top plates are removable so that maintenance can be performed on the plates located internally to the unit.

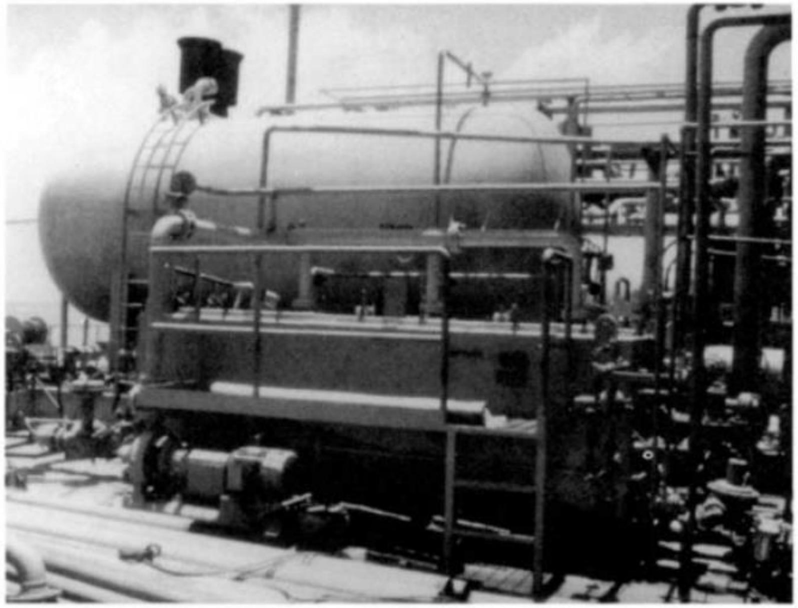


Figure 1-12. A horizontal skimmer vessel for primary separation of oil from water with a gas flotation unit for secondary treatment located in the foreground. Treated water from the flotation effluent is recycled by the pump to each of the three cells. Gas is sucked into the stream from the gas space on top of the water by a venturi and dispersed in the water by a nozzle.

Water processing - desander

- Any solids produced with the well stream must also be separated, cleaned, and disposed of in a manner that does not violate environmental criteria. Facilities may include sedimentation basins or tanks, hydrocyclones, filters, etc. Figure 1-13 is a typical hydrocyclone or "desander“ installation.
- The facility must provide for well testing and measurement so that gas, oil, and water production can be properly allocated to each well. This is necessary not only for accounting purposes but also to perform reservoir studies as the field is depleted.

Figure 1-13. Hydrocyclone desanders used to separate sand from produced water prior to treating the water.

Auxiliary systems

The preceding paragraphs summarize the main functions of a production facility, but it is important to note that the auxiliary systems supporting these functions often require more time and engineering effort than the production itself.

The auxiliary systems include

1. Developing a site with roads and foundations if production is onshore, or with a platform, tanker, or some more exotic structure if production is offshore.
2. Providing utilities to enable the process to work: generating and distributing electricity; providing and treating fuel gas or diesel; providing instrument and power air; treating water for desalting or boiler feed, etc.

- Figure 1-14 shows a typical generator installation and Figure 1-15 shows an instrument air compressor.

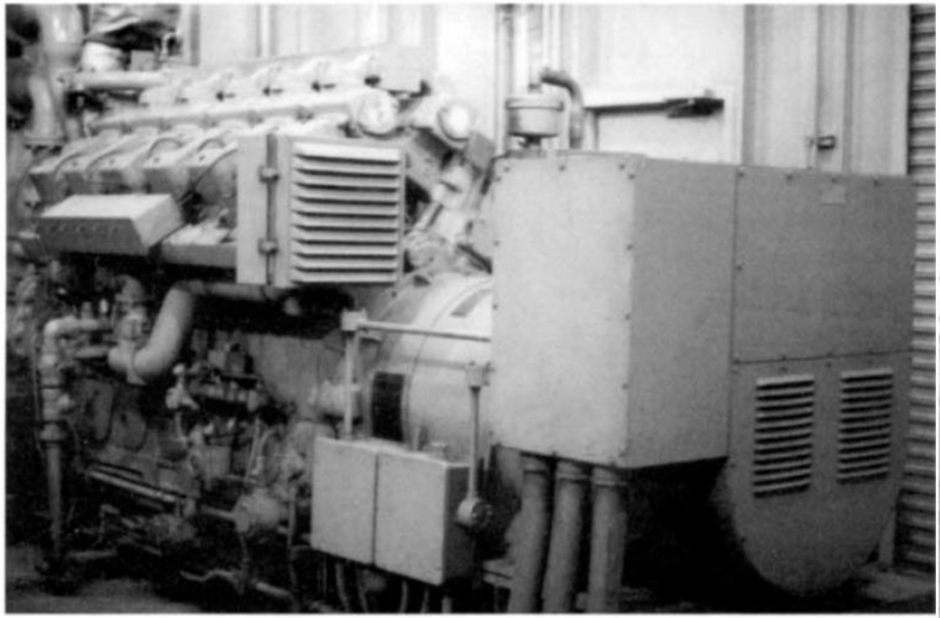


Figure 1-14. A gas-engine-driven generator located in a building on an offshore platform.

Figure 1-15. A series of three electric-motor-driven instrument air compressors. Note each one has its own cooler. A large air receiver is included to minimize the starting and stopping of the compressors and to assure an adequate supply for surges.

Auxiliary systems

3. Providing facilities for personnel, including quarters (Figure 1-16), switchgear and control rooms (Figure 1-17), workshops, cranes, sewage treatment units (Figure 1-18), drinking water (Figure 1-19), etc.

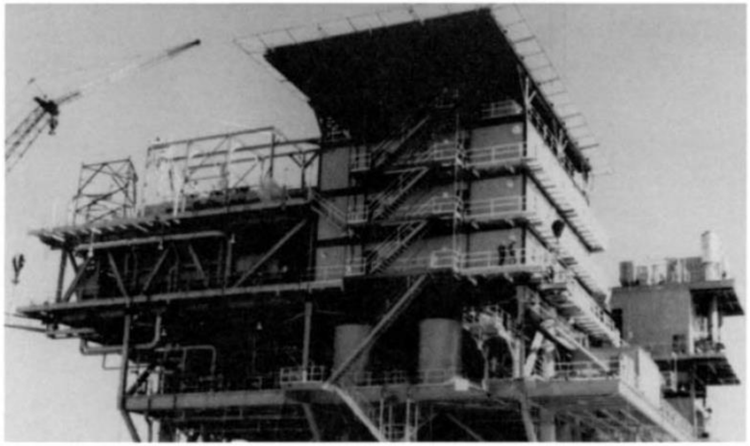


Figure 1-16. A three-story quarters building on a deck just prior to loadout for cross-ocean travel. A helideck is located on top of the quarters.

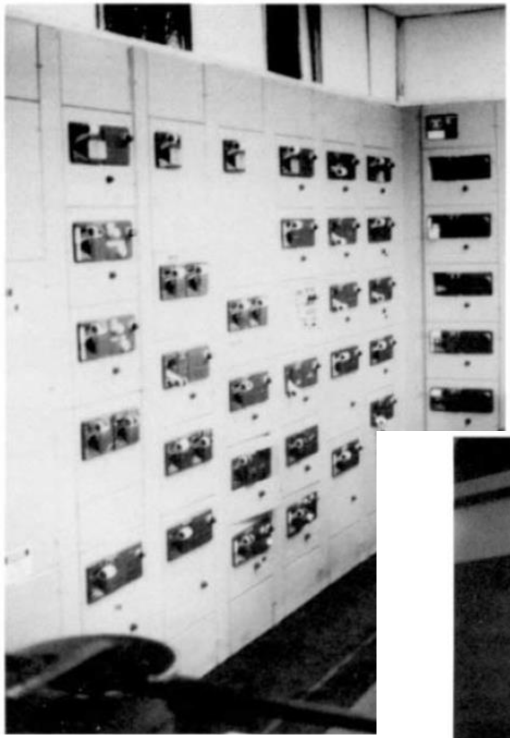


Figure 1-17. A portion of the motor control center for an offshore platform.

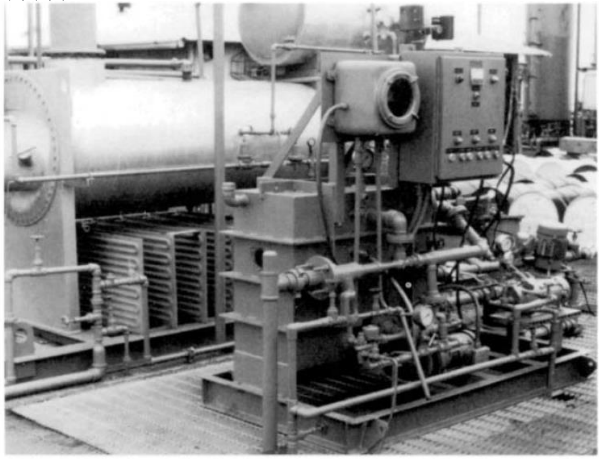


Figure 1-19. A vacuum distillation water-maker system.

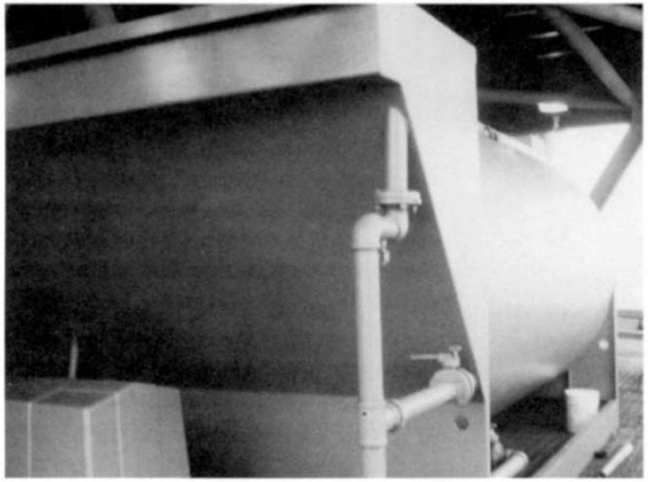


Figure 1-18. An activated sludge sewage treatment unit for an offshore platform.

Auxiliary systems

4. Providing safety systems for detecting potential hazards (Figures 1-20 and 1-21),

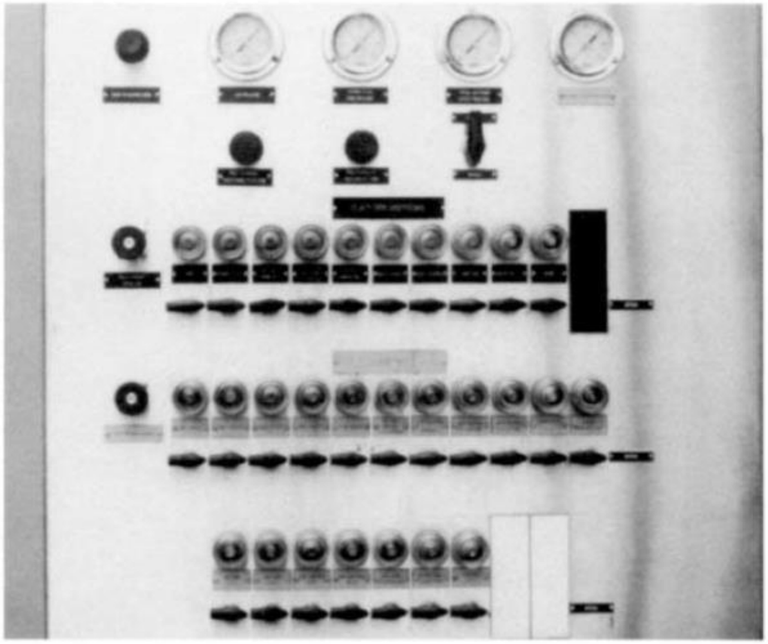


Figure 1-20. A pneumatic shut-in panel with "first-out" indication to inform the operator of which end element caused the shutdown.

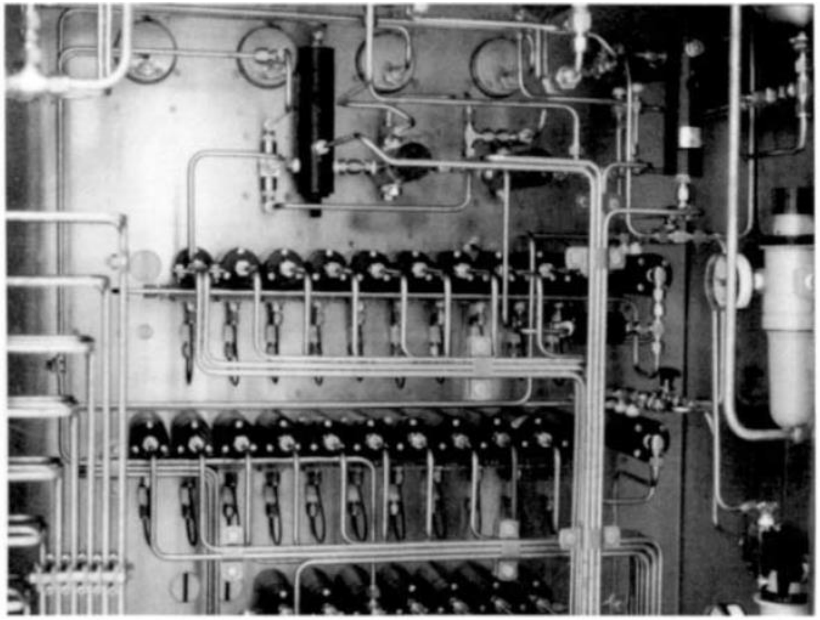


Figure 1-21. The pneumatic logic within the panel shown in Figure 1-20.

- fighting hazardous situations when they occur (Figures 1-22 and 1-23)

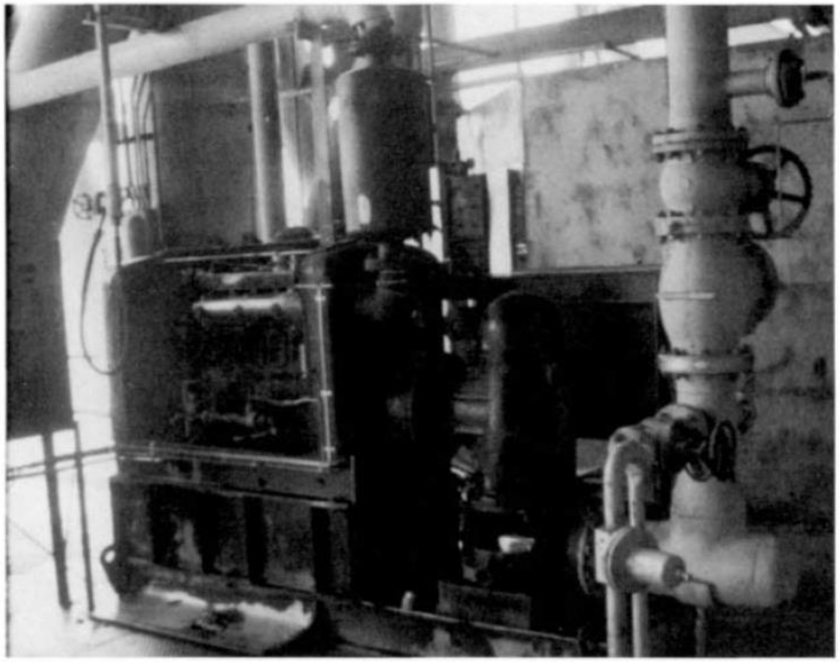


Figure 1-22. Diesel engine driven fire-fighting pump driving a vertical turbine pump through a right angle gear.

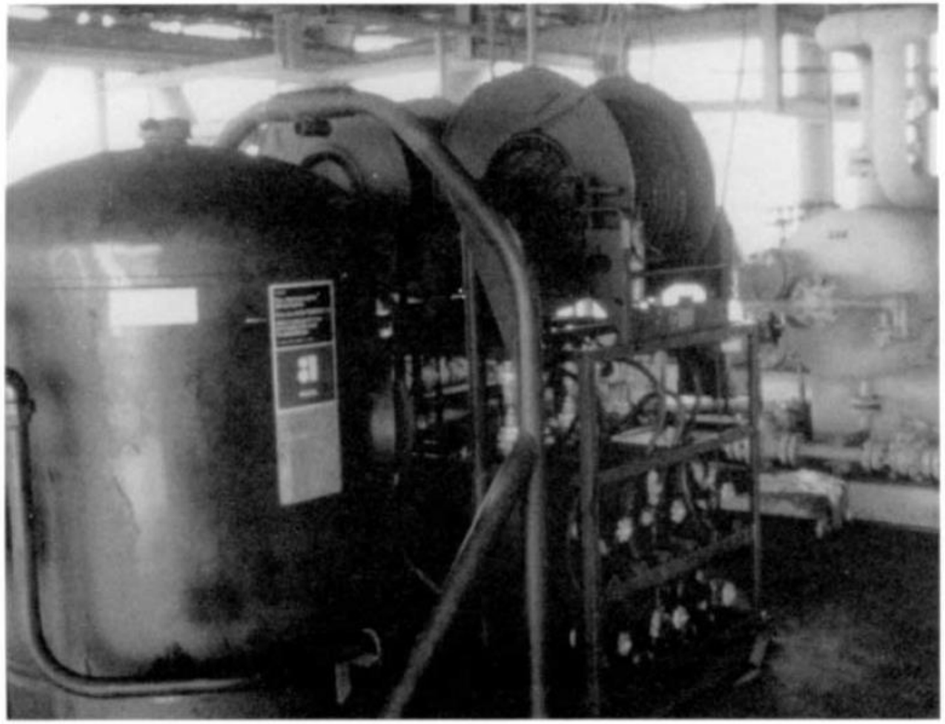


Figure 1-23. A foam fire-fighting station.

- and for personnel protection and escape (Figure 1-24).

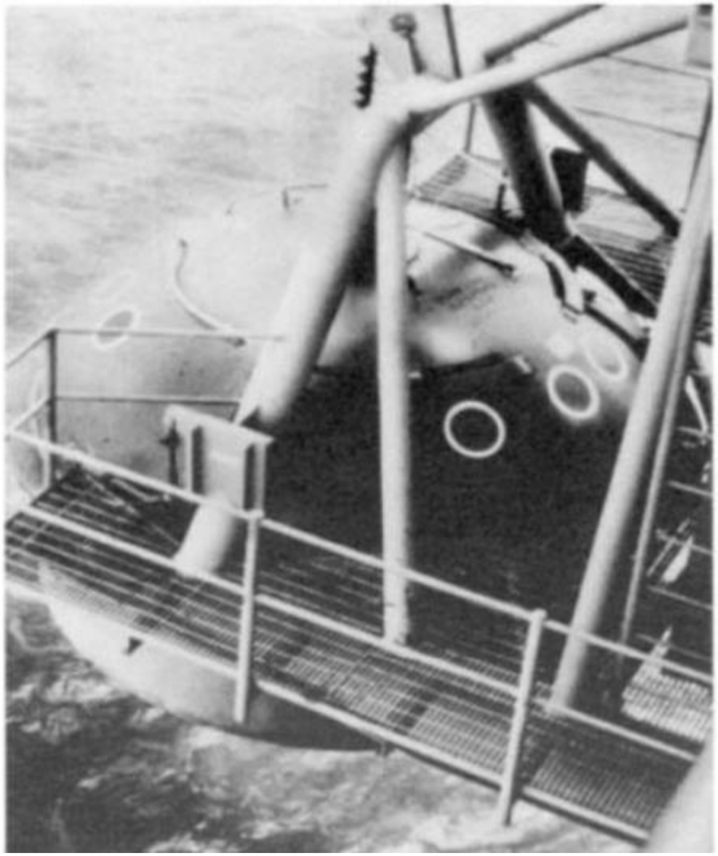


Figure 1-24. An escape capsule mounted on the lower deck of a platform. The unit contains an automatic lowering device and motor for leaving the vicinity of the platform.

Making the equipment work

- The main items of process equipment have automatic instrumentation that controls the pressure and/or liquid level and sometimes temperature within the equipment. Figure 1-25 shows a typical pressure controller and control valve.
- In the black box (the controller) is a device that sends a signal to the actuator, which opens/closes the control valve to control pressure.

Figure 1-25. A pressure control valve with pneumatic actuator and pressure controller mounted on the actuator. The control mechanism in the box senses pressure and adjusts the supply pressure to the actuator diaphragm causing the valve stem to move up and down as required.

- Figure 1-26 shows a self-contained pressure controller, which has an internal mechanism that senses the pressure and opens/closes the valve as required.

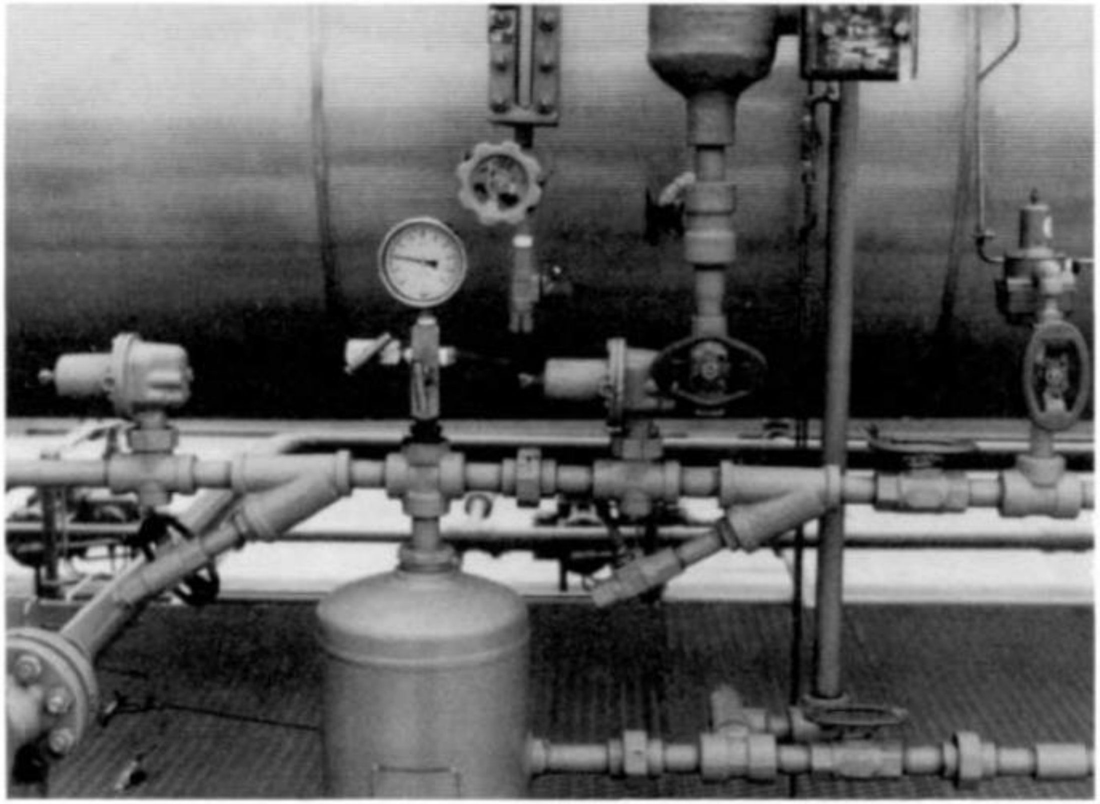


Figure 1-26. Two self-contained pressure regulators in a fuel gas piping system. An internal diaphragm and spring automatically adjust the opening in the valve to maintain pressure.

- Figure 1-27 shows two types of level controllers that use floats to monitor the level. The one on the left is an on/off switch, and the two on the right send an ever-increasing or decreasing signal as the level changes.
- These floats are mounted in the chambers outside the vessel. It is also possible to mount the float inside. Capacitance and inductance probes and pressure differential measuring devices are also commonly used to measure level.

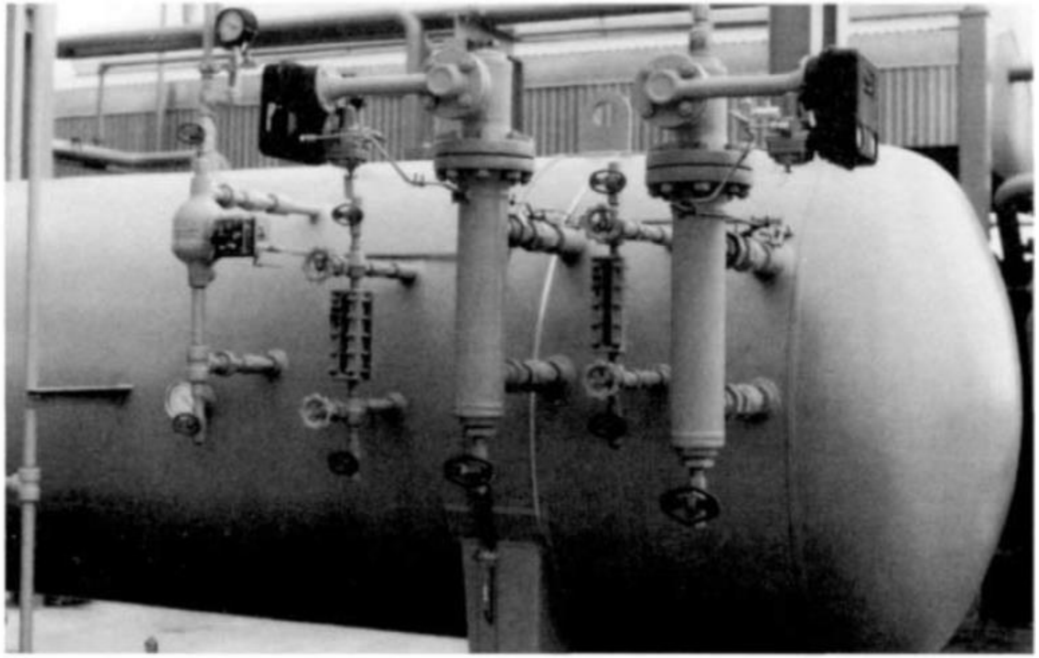


Figure 1-27. Two external level float controllers and an external float switch. The controllers on the right sense the level of fluids in the vessel. The switch on the left provides a high level alarm.

- Figure 1-28 shows a pneumatic level control valve that accepts the signal from the level controller and opens/closes to allow liquid into or out of the vessel. In older leases it is common to attach the valve to a controller float directly through a mechanical linkage.

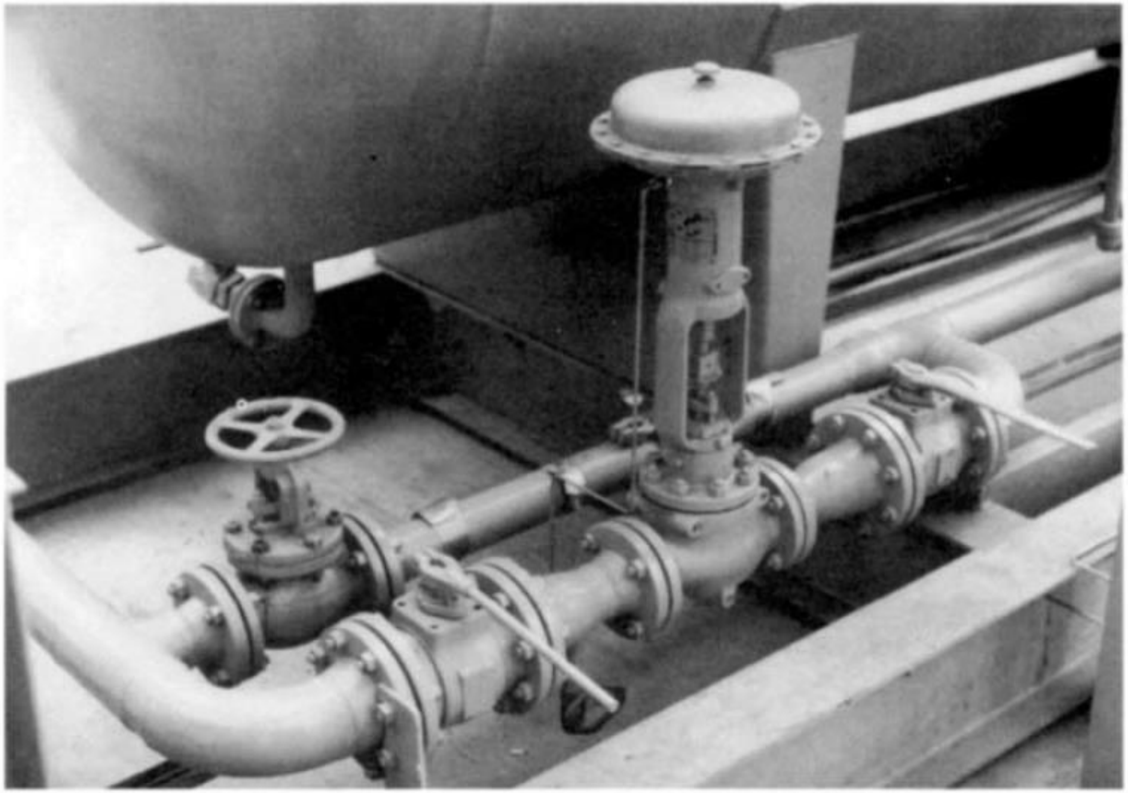


Figure 1-28. A level control valve with bypass. The signal from the controller causes the diaphragm of the actuator and thus the valve stem to move.

- Some low-pressure installations use a lever-balanced valve such as shown in Figure 1-29. The weight on the lever is adjusted until the force it exerts to keep the valve closed is balanced by the opening force caused by the head of liquid in the vessel.
- Temperature controllers send signals to control valves in the same manner as pressure and level controllers.

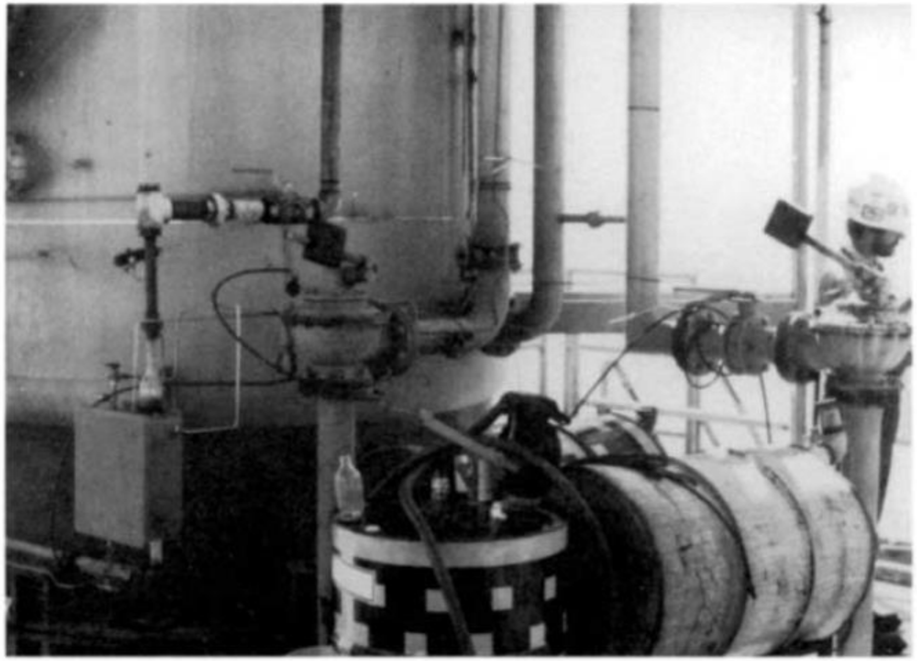


Figure 1-29. Two level-balanced liquid control valves. The position of the weight on the valve lever determines the amount of fluid column upstream of the valve necessary to force the valve to open.

Facility types

- It is very difficult to classify production facilities by type, because they differ due to production rates, fluid properties, sale and disposal requirements, location, and operator preference. Some more or less typical onshore facilities are shown in Figures 1-30, 1-31, and 1-32.

Figure 1-30. An onshore lease f horizontal two-phase separator

Figure 1-31. An onshore central facility with a knockout, and a horizontal heater treater.

Figure 1-32. A marsh facility where the equipment is elevated on concrete platforms. Note the two large vertical separators in the distance, the row of nine vertical heater treaters, and the elevated quarters building.

- In cold weather areas, individual pieces of equipment could be protected as shown in Figure 1-33, or the equipment could be completely enclosed in a building such as shown in Figure 1-34.

Figure 1-33. In cold weather areas it is sometimes necessary to insulate the vesse and pipe and house all controls in a building attached to the vessel.

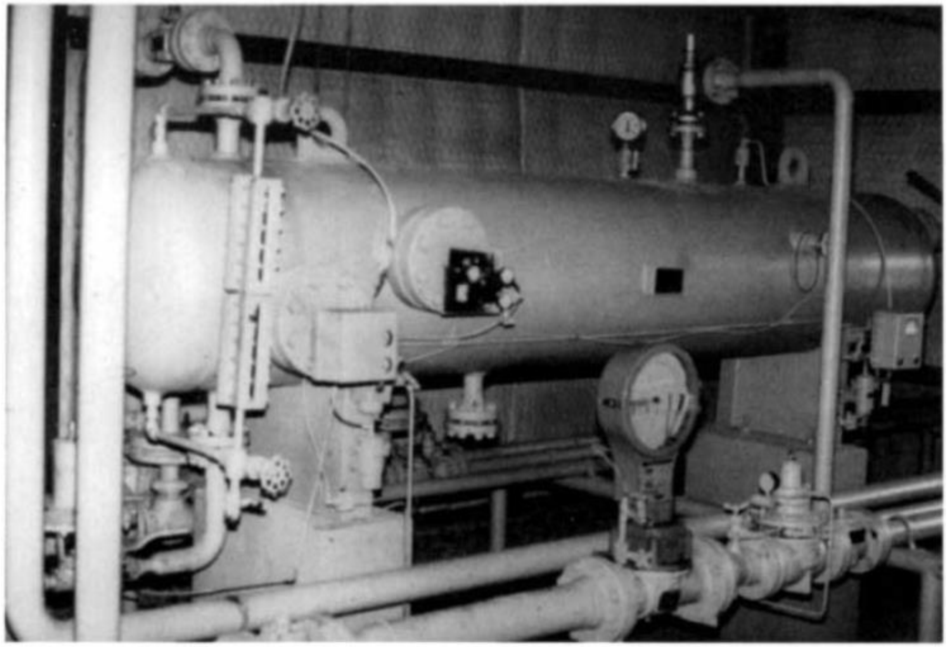


Figure 1-34. An onshore facility in Michigan where the process vessels are enclosed inside of an insulated building.

- In marsh areas the facilities can be installed on wood, concrete, or steel platforms or on steel or concrete barges, as shown in Figure 1-35. In shallow water, facilities can be installed on several different platforms connected by bridges (Figure 1-36).

Figure 1-35. In marsh and shallow water areas it is sometimes beneficial to build the facilities on a concrete barge onshore and then sink the barge on location.

Figure 1-36. In moderate water depths it is possible to separate the quarters (on the left) and oil storage (on the right) from the rest of the equipment for safety reasons.

- In deeper water it may be necessary to install all the facilities and the wells on the same platform as in Figure 1-37. Sometimes, in cold weather areas, the facilities must be enclosed as shown in Figure 1-38.

Figure 1-37. In deep waters this is not possible and the facilities can get somewhat crowded.

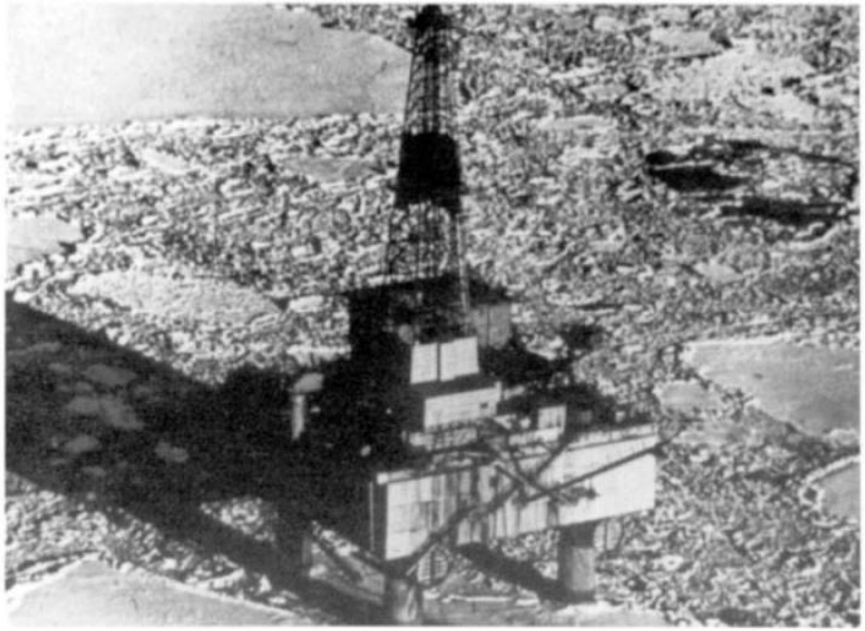


Figure 1-38. In cold weather areas such as this platform in Cook Inlet, Alaska, the facilities may be totally enclosed.

- Facilities have been installed on semi-submersible floating structures, tension leg platforms, tankers (Figure 1-39) and converted jack-up drilling rigs (Figure 1-40). Figure 1-41 shows a facility installed on a man-made island.

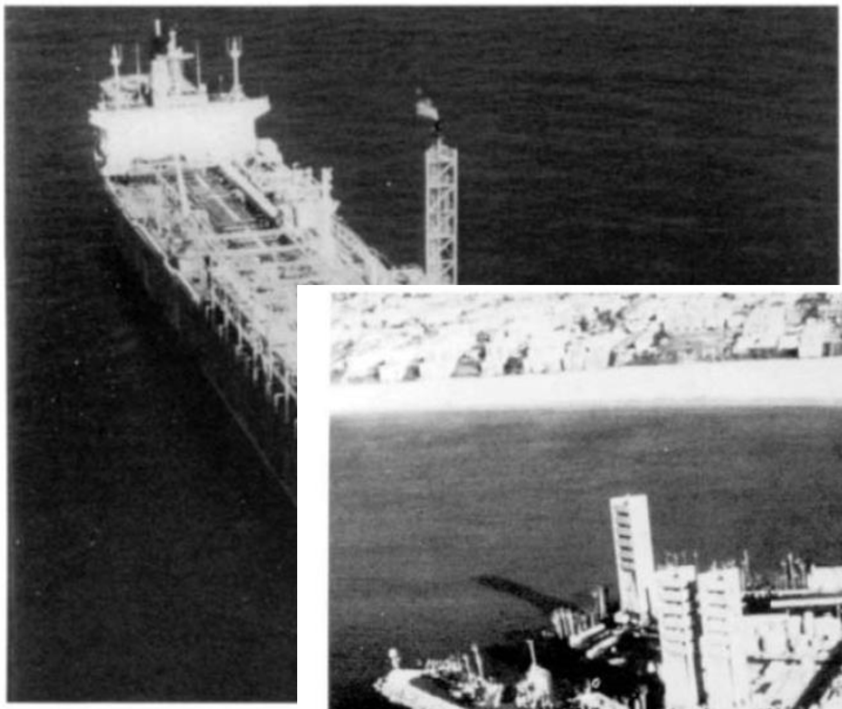
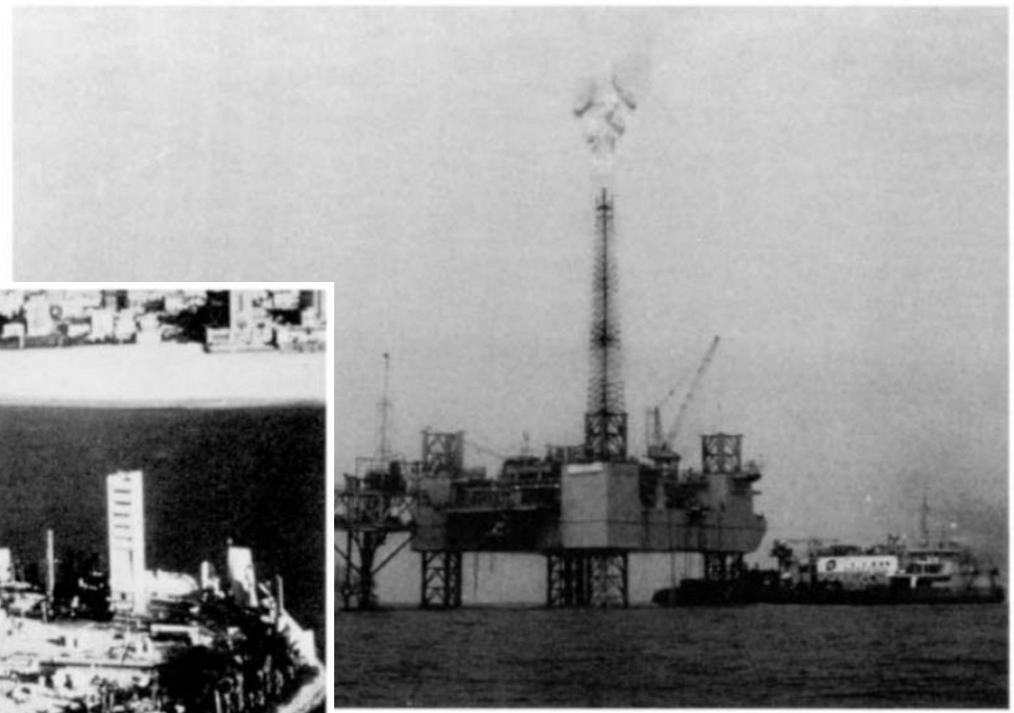


Figure 1-39. A tanker wi



jack-up rig was installed off the African coast.

Figure 1-41. Sometimes the facilities must be decorated to meet some group's idea of what is aesthetically pleasing. This facility off California has palm trees, fake waterfalls and drilling derricks disguised as condominiums.

Thank you, Question?