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8.12 FURTHER READING
LEARNING OUTCOMES:

Having worked through this chapter the student will be able to:

• Discuss the impact of the field location, well rate, produced fluid and secondary processing on the design and operation of the production facilities

• Relate the required Production Facility services to the field's oil recovery mechanism

• Draw a basic, outline production process scheme

• Describe the components and discuss the operation of a 3 phase separator

• Identify the advantages of horizontal and vertical separators

• Describe the operational problems associated with these separators

• Quantify the sizing (gas and liquid capacity) of a 3 phase separator

• Discuss fiscal measurement of produced crude oil

• Describe a pipeline “pigging” operation

• Describe the components of a gas handling facility viz NGL separation and stabilisation, gas dehydration and sweetenting.
8. 1. INTRODUCTION

This section covers the treatment of the produced fluid from and during its passage from the well-head, through the facility to the point of sale. The nature, scope and geographical spread of these facilities will vary greatly depending on the:

(i) Location: On or off-shore
(ii) Well and Field Production Rate
(iii) Oil, gas or condensate Field
(iv) Central gathering station or local (well-head) facilities
(v) Secondary processing requirements e.g. removal of contaminants such as H₂S

However, in all cases the facility is designed to separate the (multi) well stream into the three basic components (oil, gas and water) and to process the phases into:

(i) marketable products (i.e. to sales specification) - or
(ii) a form that they can be disposed of in an environmentally acceptable manner.

A simplified production scheme for an oil or gas field is given as Figure 1.

![Simplified processing oil facility scheme](image)

The primary separation process takes place in gravity separators. The process is driven by the density difference between the gas, oil and water phases and the high fluid pressure frequently available at the well head. Gas “flashes” from the well-head fluid as the pressure is reduced, while at the same time “free water” is separated from the oil.
The gas must be compressed to the export pipeline pressure and treated to remove water vapour and heavier hydrocarbons. More complicated processes may be required to “sweeten” the gas by removing other contaminants such as carbon dioxide, hydrogen sulphide etc.

Typically, the oil and water will only show partial separation, and an “emulsion”, or intimate mixture of oil or water droplets in the other phase, will require more intensive processing to achieve a suitable level of separation. Any produced solid material is also normally found in this layer.

8.2. FIELD DEVELOPMENT

One of the fundamental decisions to be made during field development is whether to develop the discovered field as an oil or gas field. This has a large impact on:

(i) the sales contract

(ii) the field development philosophy and any measures taken for improving the reservoir recovery efficiency and

(iii) the production facilities.

The design and operation of the production facilities influences the (relative) recovery of oil and gas. In virtually all cases, the production facilities will be designed to maximise the recovery of (hydrocarbon) liquids since their sale is normally more profitable than gas. However, more complex facilities are usually required to recover a higher proportion of liquids; resulting in a trade off between increased capital expenditure, (possibly) reduced operating cost and increased revenue.

8.2.1 Oil Fields

The production from oil fields build up rapidly as more wells are drilled and brought onto production. The oil field is then produced at a maximum (plateau) for the next few years. This rate is determined by the capacity of the production facility. The oil production then gradually decreases until the income from the oil production no longer pays for the field operating expenses (Figure 2). The field is then ready for abandonment.

The plateau oil production rate will be determined by the individual well rates, and the numbers of wells to be drilled; not to mention the geology, reservoir fluid properties etc. The length of the production plateau and the decline will also be a function of the reservoir size and the recovery mechanism.

Oil fields will typically produce a much larger volume of water than oil. Hence, oil/water separation typically occurs near to the production well to minimise unnecessary expense in the pumping of large volumes of water over large distances. In particular, offshore separation will be employed in the case of offshore fields; while wellhead separation (at the sea floor, and disposal into an injection well) is now being developed for subsea wells. Offshore operations are thus becoming more similar to land operations, where piping and pipeline costs are minimised by:
(i) local separation and disposal of the bulk of the produced water

(ii) oil (with a relatively low water content) being sent to a central gathering station for final water separation treatment.

![Figure 2
Oil field production](image)

Large volumes of sales quality crude oil have to be piped to the coastal export terminal via a pipeline where it can become part of the world crude oil trade. This is particularly true for onshore oil fields where the only economic means of transporting significant volumes is by pipeline, though smaller volumes are sometimes transported by train/barge or road. Offshore, the choice between a pipeline and local storage near the platform together with a shuttle tanker to transport the crude oil directly to the refinery or to the export terminal will be determined by the economics of the two scenarios. If a dedicated pipeline to the coast can not be justified, then the presence of existing infrastructure - i.e. a nearby pipeline - with sufficient available capacity to transport that projected volumes is the key factor. The increasing density of the pipeline transport network in the North Sea is illustrated in Figure 3.

Gas export is normally only possible when the volumes are sufficient to make building of a dedicated pipeline economic. Thus, the available pipeline infrastructure is even more important in the case of produced gas since there are no storage alternatives - it has to be exported, used or otherwise disposed of at the same time as it is produced. Many oil developments will use (part of) the gas as a fuel to power the platform and facilities. However, the changes in the volumes of produced fluids from the wells (table 3), imply that there may be excess gas early in the life of the project available for export, while the platform becomes gas-short later on in the project lifetime. The installation of a gas pipeline allows the field to export gas in the early years while importing gas to power platform equipment in late project life. This is particularly attractive if the operators own a nearby field with surplus gas. All these factors have a large impact on the design of the platform facilities.
Any remaining gas has to be disposed of by flaring, venting (releasing to the atmosphere without combustion) or underground disposal. Reduction in the emitted (flared and vented) gas has become a governmental objective with the imposition of a carbon tax in some countries. Further, company management has encouraged the development of many innovative facility designs/field development options to achieve this.

As mentioned earlier, large volumes of water are “co-produced” with the oil. Frequently large volumes of water are injected into the reservoir to increase the oil recovery by “sweeping” the oil from the injection to the production well, and by maintaining the down-hole reservoir pressure.

This requires facilities to:

(i) extract large volumes of water from a surface (sea or river) or underground source (dedicated water production wells),

(ii) remove solids (filtration) and (corrosive) oxygen to the specified levels and

(iii) inject the water into a dedicated injection well.

8.2.2 Gas Fields
The development of a hydrocarbon resource such as a gas field implies that, unlike oilfields, the produced fluid will be mainly gas accompanied by small volumes of water and condensate (sometimes called “natural gasoline” or natural gas liquids
(NGL). Offshore separation is normally employed with the (small volumes of) water being disposed of to the sea and the gas/condensate being exported to the coast via multiphase pipelines. Advances in control engineering (automation, data transmission, infra red gas detectors etc.) mean that (small and mature) fields can now be run on a “not-normally-manned” basis with the consequent reduction in operating expense and manpower employed.

A new type of field that is being developed in the North Sea is the High Temperature, High Pressure Gas Condensate field. These fields produce (relatively) much larger volumes of condensate compared to gas fields. They also exhibit unusually large changes in wellhead pressures and fluid compositions as the reservoir depletes.

8.3. FIELD DEVELOPMENT EXAMPLES

The majority of offshore production platforms are supported by steel jackets which are held in place on the sea bottom by steel piles (see Figure 4 and 5, a large, integrated steel jacket platform). These welded pipe structures provide a support for various prefabricated modules, e.g. accommodation, power facilities etc. (see section 5 - ‘Platform Functions’ for a more detailed discussion).

Figure 4
Types of offshore platforms

Figure 5
A large steel jacket platform
Concrete gravity platforms depend on their large weight to hold them in place on the sea bed. The Brent D platform weighs over 200,000 tons, but is also capable of storing 1,000,000 barrels of oil; so as well as avoiding the need for piling, it provides local crude storage capacity for transfer at regular intervals to the shuttle tankers.

An offshore storage buoy or storage tanker would be required if this integral storage was not available within the platform construction. Offshore loading is illustrated in Figure 6.

**Figure 6**
Offshore loading

Fixed platforms become uneconomic as the water depth increases and floating platforms are attached - either tethered (anchored) over subsea production wells or more rigidly held in place by tensioned cables. The most recent developments to exploit the smaller hydrocarbon reservoirs currently being developed, can be found in the combination of subsea wells drilled from one or more drilling centres, with a FPSO (Floating Production Storage and Offtake) vessel. The FPSO hosts all the normal platform functions such as production separation and water injection equipment. As discussed earlier, gas export requires a pipeline while oil export can be by pipeline or shuttle tanker. Figure 7 illustrates a typical example of this type of development. An FPSO is not the only option for this type of development - depending on the reserves, location etc., a fixed platform can play host to the production facilities (Figure 8) for the subsea wells.

### 8.4. PRODUCTION PLATFORM FUNCTIONS

Production platforms perform a multitude of functions as listed below. All functions may be carried out in one large platform - as in the case of integrated platforms illustrated in Figure 5. Alternatively they may be split into a series of separate platforms - each with one or more of the following functions - connected by a bridge so that personnel and equipment can move easily between them. Figure 9 illustrates a typical organisation of the following modules.
Figure 7
A subsea FPSO development

Figure 8
A host platform connected to several subsea fields
1. Drilling derrick with wellheads situated directly underneath
2. Drilling support module such as drilling mud preparation
3. Process equipment where oil, gas and water are separated and treated to sales or end-user specifications
4. Export and (sometimes import of) sales quality crude oil and gas
4a. Compression module where gas is compressed to the required pressure for export or own use (gas lift, gas injection or power generation). Excess gas is flared via the flare boom
4b. Oil export module which house the pumps for exporting the crude to pipeline, local (floating) storage or shuttle tanker
4c. Water Injection module consisting of filtration, deoxygenation, chlorination, and high pressure injection pumps
5. Platform utilities such as power generation (frequently gas turbines but standby diesel power in the case that the gas supply is unavailable)
6. Accommodation / life support for the personnel manning the platform. For safety reasons, this is normally situated as far as possible from the process/compression/wellhead areas.
7. Control room, the hub of the platform’s operation. Safety and loss control systems are monitored here, as is the fiscal metering that accurately measures the volumes of crude oil exported.
8. Maintenance workshops, communications, cranes to lift supplies and equipment onto the platform from supply vessels, transport (helicopters) etc.

The chosen Reservoir Oil Recovery Mechanism and associated artificial lift used to increase the energy available to lift fluids from the downhole to the surface will have a significant impact on the required (platform) services (Table 1).
### 8.5. PRODUCTION PHILOSOPHIES

The process plant capacity is set by the number of production wells and the well production rates (determined by reservoir permeability, fluid properties, and pressure thickness of the pay zone, well design, individual well reserves etc.) and the field production philosophy. These differ between oil and gas fields:

#### 8.5.1 Separation Objectives
The complete separation process system is designed to produce on specification export fluids. The actual values will depend on the specific (crude oil or gas) properties and the transport route (Table 2).

#### 8.5.2 Oilfields
Oilfields are produced at maximum plateau rates dictated by the facility design for as long as possible. The (oil) production rate will then decline usually accompanied by increasing water production until the minimum economic rate is reached. This is the point at which operating expenses are no longer paid for by the oil income (Figure 2 and Table 3).

---

**Table 1**
Scale and type of platform services depend on recovery mechanism.

<table>
<thead>
<tr>
<th>Recovery Mechanism</th>
<th>Process</th>
<th>Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>Primary Recovery</td>
<td>Natural Flow</td>
<td>No extra platform services</td>
</tr>
<tr>
<td>Artificial Lift</td>
<td>Gas Lift</td>
<td>Extra Gas Compression</td>
</tr>
<tr>
<td></td>
<td>ESP*</td>
<td>Extra Electrical Power Generation</td>
</tr>
<tr>
<td>Secondary Recovery</td>
<td>Water Flood</td>
<td>Water Injection Facilities</td>
</tr>
<tr>
<td></td>
<td>Pressure Maintenance</td>
<td>Water Injection Facilities</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Extra Electrical Power Generation</td>
</tr>
<tr>
<td>Tertiary Recovery</td>
<td>Steam, Carbon Dioxide, Miscible Gas, Chemical etc.</td>
<td>Dedicated, Specialised Facilities</td>
</tr>
</tbody>
</table>

* ESP - Electric Submersible Pump
<table>
<thead>
<tr>
<th>PRODUCT</th>
<th>PROPERTY</th>
<th>SPECIFICATION</th>
</tr>
</thead>
<tbody>
<tr>
<td>CRUDE OIL</td>
<td>Vapour pressure</td>
<td>&lt; 16 psi at 25°C *</td>
</tr>
<tr>
<td></td>
<td>Water content</td>
<td>&lt; 0.5% wt</td>
</tr>
<tr>
<td></td>
<td>Salt content</td>
<td>&lt; 70 g/m3</td>
</tr>
<tr>
<td></td>
<td>Temperature</td>
<td>&lt; 40°C</td>
</tr>
<tr>
<td></td>
<td>Pressure</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>~ atmospheric for tanker export or pipeline operating pressure</td>
</tr>
<tr>
<td></td>
<td></td>
<td>* Higher values allowed pipeline export</td>
</tr>
<tr>
<td>GAS</td>
<td>Calorific value</td>
<td>~ specified limits</td>
</tr>
<tr>
<td></td>
<td>Liquids</td>
<td>- none</td>
</tr>
<tr>
<td></td>
<td>Hydrocarbon dewpoint</td>
<td>&lt; -3°C</td>
</tr>
<tr>
<td></td>
<td>Water dewpoint</td>
<td>&lt; -8°C in NW Europe</td>
</tr>
<tr>
<td></td>
<td>Carbon dioxide</td>
<td>&lt; 3% wt</td>
</tr>
<tr>
<td></td>
<td>Hydrogen sulphide</td>
<td>&lt; 4 ppm</td>
</tr>
<tr>
<td></td>
<td>Temperature</td>
<td>&lt; 40°C</td>
</tr>
<tr>
<td></td>
<td>Pressure</td>
<td>~ pipeline operating value</td>
</tr>
<tr>
<td></td>
<td></td>
<td>* varies with ambient conditions e.g. 0°C in sub-tropical areas, -20°C in Canada</td>
</tr>
<tr>
<td>WATER</td>
<td>Dispersed oil</td>
<td>&lt; 40 ppm for marine discharge in N.W. Europe,</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&lt; 32 ppm in Gulf of Mexico</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fluid</th>
<th>Phase</th>
<th>Early</th>
<th>Mid-Life</th>
<th>Mature</th>
<th>Abandonment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil (bopd)</td>
<td></td>
<td>100k</td>
<td>100k</td>
<td>30k</td>
<td>10k</td>
</tr>
<tr>
<td>Gas (MM scf/d)</td>
<td></td>
<td>100</td>
<td>100</td>
<td>30</td>
<td>10</td>
</tr>
<tr>
<td>Water (bwpd)</td>
<td></td>
<td>&lt;500</td>
<td>30k</td>
<td>100k</td>
<td>&gt;100k</td>
</tr>
<tr>
<td>Water cut</td>
<td></td>
<td>&lt;0.5%</td>
<td>30%</td>
<td>77%</td>
<td>&gt;90%</td>
</tr>
</tbody>
</table>

The gas associated with the oil production must be used at the time of production - whether for export, fuel, lift gas, re-injection or flared. If the opportunity for pipeline export does not exist, then projects frequently have excess gas early in their early/mid lives, while they are short of gas in the later, decline phase.

8.5.3 Gas Fields
The pattern of gas usage tends to be seasonal i.e. with periods of high and low demand:

(i) Winter peak in N.W. Europe, Northern USA and Canada, here space heating uses a large proportion of the gas.
(ii) Summer peak in Southern U.S.A. where air conditioning is the major user.

(iii) Constant demand when industry is the main user (e.g. Aluminium Smelting) or when supplying a Liquefied Natural Gas Plant.

A typical nomination contract in N.W. Europe will specify both a total yearly production and a minimum production rate at the end of the winter period.

The composition of any produced water will change significantly during the field life time. Initially it will be (fresh) condensed water vapour that was originally present in the gas phase in the reservoir. Later on, (liquid) formation water will start to be produced from the reservoir - resulting in a gradual increase in salinity until the formation water value is reached if large scale water production occurs. Frequently, the easiest export route for any liquid hydrocarbons (condensate) recovered during the separation process is to spike (inject) them back into the gas export pipeline for later recovery at a central, onshore facility.

A typical production profile is illustrated in Figure 10 and Table 4.

Figure 10
A typical gas field production profile

Table 4
Typical changes in production rates during the lifetime of a typical southern North Sea gas field

<table>
<thead>
<tr>
<th>Phase</th>
<th>Fluid</th>
<th>Early</th>
<th>Mid-Life</th>
<th>Declining</th>
<th>Abandonment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas (MMsft³/d)</td>
<td>500</td>
<td>500</td>
<td>50</td>
<td>20</td>
<td></td>
</tr>
<tr>
<td>Condensate (bpd)</td>
<td>5000</td>
<td>5000</td>
<td>5000</td>
<td>200</td>
<td></td>
</tr>
<tr>
<td>Water (bwpd)</td>
<td>250</td>
<td>500</td>
<td>500</td>
<td>200</td>
<td></td>
</tr>
</tbody>
</table>
8.6. BASIC PROCESSING SCHEME

The building blocks of a simplified processing scheme are shown in Figure 11. The reservoir fluids are produced to surface at the wellhead followed by separation into the oil, gas and water phases. Each phase is then treated individually to reach the sales specification.

(i) The oil content of the produced water is reduced to a level suitable for disposal. Any recovered oil is passed to the final stages of oil treatment.

(ii) The separated gas is treated to sales specification by reducing its water and liquid hydrocarbon content. The recovered liquid hydrocarbons are “spiked” into the crude oil stream if it is being transported by pipeline. Alternatively, it may be added to the sales gas pipeline, followed by onshore separation. The gas may be sold, used for power generation, gas lift, injection back into the reservoir with any excess being flared.

(iii) The crude oil is transported by pipeline or tanker (sea, road, or rail) after being treated to the appropriate specifications. The latter option requires larger, local storage than when transport is by pipeline.

6.1 Processing Conditions
The process equipment design and the materials of construction are determined by:
**Fluid Quality**
Wellhead pressure and temperature of the produced reservoir fluid. These change dramatically over the lifetime of the field - see table 3 and module 10, section 10.2.

**Fluid Properties**
The properties of the crude oil are analysed in the laboratory, and phase equilibria (“PVT”) properties are determined. This aspect is discussed in detail in the Reservoir Engineering part of this course. Hydrocarbon mixtures can be classified into five main types based on these phase equilibria properties as summarised in Table 5.

<table>
<thead>
<tr>
<th>Field Development type</th>
<th>Low Shrinkage Oil</th>
<th>High Shrinkage Oil</th>
<th>Retrograde Condensate</th>
<th>Wet Gas</th>
<th>Dry Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stabilised crude density</td>
<td>&lt; 30°API</td>
<td>30° &lt; API &lt; 50°</td>
<td>API &lt; 60°</td>
<td>API &gt; 50°</td>
<td>API &gt; 50°</td>
</tr>
<tr>
<td>Gas Oil Ratio (scf/STB)</td>
<td>&lt; 500</td>
<td>500 &lt; GOR &lt; 8,000</td>
<td>&lt; 70,000</td>
<td>&lt; 100,000</td>
<td>&gt; 100,000</td>
</tr>
<tr>
<td>Comments</td>
<td>Broad phase envelope with high proportion of heavy hydrocarbons</td>
<td>Narrow phase envelope with few heavy hydrocarbons</td>
<td>Even more lighter and fewer heavier hydrocarbons</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The hydrocarbon fluid properties along with the wellhead pressures determine the number of separation stages and the process conditions under which the oil/gas/water separation is carried out. Many of the stabilised crude oils produced by the different North Sea fields have similar properties. These are summarised in Table 6.

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Specific Gravity</td>
<td>0.84 g/cm</td>
</tr>
<tr>
<td></td>
<td>36° API in oilfield units</td>
</tr>
<tr>
<td>Viscosity</td>
<td>4 cSt at 50° C</td>
</tr>
<tr>
<td>Sulphur content</td>
<td>&lt; 1.0 % wt</td>
</tr>
<tr>
<td>Gas Oil Ratio</td>
<td>1000 scf/stb</td>
</tr>
<tr>
<td>Crude Oil Composition</td>
<td>50% wt paraffins</td>
</tr>
<tr>
<td></td>
<td>30% wt napthenes</td>
</tr>
<tr>
<td></td>
<td>20% wt aromatics</td>
</tr>
<tr>
<td>Wax</td>
<td>variable, but often low (&lt;5%)</td>
</tr>
<tr>
<td>Asphaltenes</td>
<td>variable, but usually low (&lt;2%)</td>
</tr>
<tr>
<td>Gas Composition</td>
<td>&gt; 80% methane</td>
</tr>
</tbody>
</table>

Carbon Dioxide and Hydrogen Sulphide in the gas phase are also normally low.
The similarity of the crudes developed from the many fields means that they can be piped to the coastal terminal in a “common carrier” pipeline. The lower the specific gravity (the higher the API gravity), the greater the market value of the crude due to the increased yield in high value, refinery products. Economics thus dictate that denser, more viscous, lower API gravity crudes - such as that produced by the Alba field - are transferred to shore via a shuttle tanker, even when a “common carrier” pipeline with sufficient free capacity is available. This is to protect the value of the other crude streams using the pipeline.

8.6.2 Process Plant Metallurgy
Maximum producing wellhead temperature and pressures along with the presence of corrosive components (e.g. carbon dioxide, hydrogen sulphide, saline formation waters) determine the specification (metallurgy) of the process equipment. Process conditions can be modified so that a more economical construction metallurgy can be chosen viz:

(i) Inlet temperatures can be reduced by cooling in a heat exchanger (seawater is available in large quantities as a cheap, cooling medium for offshore operations)

(ii) Pressures can be reduced by use of a choke

(iii) Corrosivity can be reduced by the injection of corrosion inhibitors. These are a mixture of chemicals injected into the process stream at a low dosage level which coat the metal surfaces, reducing their susceptibility to corrosive attack.

8.6.3 Separators
Separators form the heart of the production process. There are two basic types:

(i) Gravity separators which depend on the density difference between the phases to be separated

(ii) Centrifugal separators in which the effect of gravity is enhanced by spinning the fluids at a high velocity

Gravity separators are essentially large cylindrical pressure vessels up to 5m in diameter and 20m long. They are used in either 2-phase (liquid/gas) separation, or 3-phase (water/oil/gas separation). They are normally mounted in a series of 2, 3 or even 4 separators (figure 12) with inlet and outlet under pressure control. They be mounted either vertically or horizontally.
Gravity separators (see figure 14) consist of an:

(i) Inlet section with momentum breaker/inlet deflector to rapidly change the inlet liquid velocity; hence helping disengage free gas.

(ii) Gravity settling section, typically sized so that:

(a) 2-phase separators: sufficient gas phase residence time such that liquid droplets of 100 µm will separate from the gas.

(b) 3-phase separators: as for 2-phase separators plus sufficient oil phase residence time such that 500 µm water droplets will settle into the water phase. The separated water phase will typically contain 500 ppm dispersed oil, hence requiring further treatment before disposal.

The above criteria are based on settling theory (see section 8.7); alternatively, experiment may be carried out to measure the rate of oil/water separation. Typical results for such a settling experiment are shown in Figure 13 - the initially produced intimate oil and water mixture (emulsion) separates into a lower, "clean" (or low oil content) water layer and an upper, "dry" (or low water content) oil layer with a (more persistent) emulsion layer in-between.

(iii) Gas outlet with mist extractor. One design of which is a wire pad of finely woven stainless steel wire wrapped in a cylinder. It is designed to remove liquid droplets between 10mm and 100µm. These droplets impinge on the wire, coalesce and flow down in to the liquid phase. Efficient operation depends on operating with the correct gas velocity:

(a) too high gas velocity - liquid drops “eroded” from wire and is re-entrained.

(b) too low liquid velocity - liquid drops drift past mesh without impinging.

A gas scrubber is employed if larger droplets (up to 500µm) have to be removed since a mist eliminator would flood with this level of liquid loading.

(iv) Liquid outlet under level control to evacuate liquid or separate oil and water phase (2/3-phase separation operation, respectively). The outlet is usually equipped with a vortex breaker to prevent re-entrainment of gas.
8.6.3.1 Horizontal Separators (Figure 14)
These are most suited to separation of large volumes of gas from liquid. Their advantages/disadvantages compared to vertical separators are:

(i) Larger interface area gives better foam/emulsion handling characterisation

(ii) Can be modularised, but require larger surface area

(iii) Solids removal is less efficient and requires a more complex jet wash system

(iv) Lower surge capacity i.e. reduced ability to deal with uneven, inlet flow

8.6.3.2 Vertical Separators (Figure 15)
These are most suited for separation of gas from large volumes of liquid. Compared to horizontal separators they are:

(i) Good for uneven, surging inlet flow due to their greater height

(ii) The oil/gas and oil/water interface level control is less critical for the same reason

(iii) However, they do tend to be larger than their horizontal equivalent for the same separation capacity
8.6.4 Operational Production Problems with Gravity Separators

The process equipment used in platform operations is designed to achieve the required product specifications using standard chemical engineering design procedures. However, a number of operational problems referred to above can be encountered if allowance is not made for the fact that we are not dealing with “pure” fluids. The complex mixture that makes up the produced hydrocarbon contains many minor components that cause:

8.6.4.1 Foaming:
Presence of semi stable gas bubbles at the oil/gas surface that prevent the gas disengaging quickly and cleanly from the liquid surface. A de-foaming chemical (surfactant) is injected at a low concentration to overcome this problem; coupled with the use of a mist eliminator which will remove liquid droplets from in the size range 10-100µm.

8.6.4.2 Solids
Low concentrations of solids are frequently produced to surface with the well fluids. They may be present in a low concentration but represent a large absolute solid volumes given the large volumes of produced fluid. These solids range from “fines” - (micron) sized clay particles which can flow through the formation pore throat structure - to individual sand grains / larger “lumps” of failed formation which can be produced from weak or unconsolidated formations. These solids collect in the base.
of the separators where they reduce the separator performance (shorter residence time) and can lead to corrosion since the fluid is stagnant. They have to be regularly removed. Water jets are mounted at the bottom of the tank - the jetting action resuspends the solids followed by transport to a holding tank for ultimate disposal. Alternatively, manual removal of the solid deposit is required.

Several other solid phases can form in the gravity separators and the other components of the production system. These include:

(i) **Scale**
By the mixing of incompatible waters (e.g. barium sulphate from mixing sea water (sulphate source) and produced water (source of barium), or due to pressure/temperature changes (e.g. to calcium carbonate scale)). The point of deposition can be controlled by the addition of scale ‘inhibitors’.

(ii) **Wax**
Cooling of the crude oil can result in its paraffin content precipitating as a solid wax. This is avoided by preventing the crude cooling below the wax cloudpoint temperature; while the temperature at which deposition occurs can be controlled to some extent by the use of wax inhibitors.

(iii) **Asphaltenes**
Pressure reduction below the bubble point and the consequent loss of the more volatile components can lead to the precipitation of asphaltenes from some crude oils.

8.6.4.3 Emulsion
Momentum breakers and corrugated plate settling packs are installed internally in the separator to promote oil droplet coalescence and separation. However, emulsion separation may not be sufficiently complete within the residence time available in the primary separator. This depends on the chemical properties of the crude oil/water system (see section 6.3) and the time/rate of shear that the fluids have been subjected to during the production process. Frequently used, practical solutions include the addition of heat (viscosity reduction) or emulsion breaking chemicals together with acceptance of reduced oil and water quality being passed to the subsequent separation stages. Reverse emulsion breakers can be employed for treating water-in-oil emulsions.

8.6.4.4 Surging Flow
The primary separator provides pressure control on all three (gas/oil/water) outlets. It controls residence time via the oil/water level controls. Production wells frequently do not produce fluid at a constant even flow rate. This is due to the length and topology of the production tubing and flow lines. These problems are accentuated by incorrectly set gas lift (well heading) as well as the long flow lines associated with subsea wells. The separation system must be capable of dealing with the resulting high, instantaneous feed rates which can cause the levels to increase above their normal, operating values. The control system needs to be suitably adjusted to deal with this.
8.6.4.5 Production Chemicals
In addition to those already discussed, other production chemicals used include biocides, corrosion inhibitors. Fig 16 is a typical example of where they might be used in an oil/gas/water separation system.

8.6.4.6 Miscellaneous Processes and Comments
An *fresh* water wash may be required to reduce the salt content in the crude oil to the specification value if the formation water has a high salt content. This involves mixing the crude with the water followed by subsequent separation.

The main separation train may be twinned (i.e. two separation trains of equal capacity) to increase the reliability (uptime) of the separation facility. In addition a smaller test separator will almost always be installed to allow individual well rates to be measured as part of the field monitoring programme.

8.7. HORIZONTAL SEPARATOR SIZING BASICS

The liquid droplets will settle at a velocity determined by equating the gravity force on the drop with the drag force caused by its relative motion to the fluid continuous phase. Typical trajectories of the settling liquid droplets are shown in Figure 17. This assumes that the internals of the separator have been designed so that turbulence effects are minimised e.g. by use of inlet deflectors/momentum breakers, vortex breakers on the outlet.
### 8.7.1 Gas Capacity

Separators are typically designed to allow liquid droplets larger than 100µ to settle from the gas phase to the liquid interface. The maximum allowable gas velocity ($V_g$) which achieves this separation may be calculated by the Souder-Brown equation:

$$ V_g = k \left( \frac{p_l - p_g}{p_g} \right) $$

where
- \( p_l \) = liquid density
- \( p_g \) = gas density
- \( k \) = constant

The constant \( k \) is related to the diameter of the droplet to be separated, the gas viscosity as well as the densities of the liquid and gas phases. Calculation of the constant \( k \) is complicated by the fact that the settling flow regime is not laminar, and qualitative calculations are beyond the scope of this text. However, suitable correlation’s can be found in the Chemical Engineering literature (e.g. Arnold and Stewart, in section 8.11).

The minimum area required for gas flow ($A_g$) is then:

$$ A_g = \frac{Q_g}{V_g} $$

where \( Q_g \) is the specified maximum gas flow.

### 8.7.2 Liquid Capacity

The separation velocity ($V$) of one liquid from another is described by Stokes Law:
\[
v = \frac{K d^2 (\rho_d - \rho_c)}{\mu_c}
\]

where

- \(d\) = minimum specified droplet size to be separated
- \(\rho_d\) = density discontinuous phase
- \(\rho_c\) = density continuous phase
- \(\mu_c\) = viscosity of continuous phase
- \(K\) = a constant

Also, the required droplet separation time is given by:

\[
\text{Required droplet separation time} = \frac{\text{vertical height of continuous phase}}{\text{separation velocity}}
\]

The separation of water droplets from oil is normally more difficult than oil from water since oil is normally more viscous than water. If no other information is available, field experience indicates that if 500µm water droplets are removed from the oil, the resulting oil-in-water content will typically be 2000 ppm or less. Similar arguments apply to the calculation of the constant \(K\) as was discussed for gas capacity. These calculations, along with the specified liquid flow rates, allow the area required for liquid flow to be specified.

An alternative approach is to base the separation requirements on emulsion separation tests which specify a required separation time (Section 6.3 and Figure 13). Separators are typically run 50-75% liquid full, so knowledge of the design liquid flow rates and the required residence times allow the separator length and diameter to be calculated. An increased separator diameter is required to compensate for surging flow as well as allowing sufficient volume to give an adequate response time between high/low level alarms before the high/low level trip leads to a shut down. An additional 30-60 seconds hold-up volume is typically specified. The resulting performance of a typical three stage separation process is summarised in Table 7.

<table>
<thead>
<tr>
<th>Separator Stage</th>
<th>Water Residence Time (min)</th>
<th>Oil Residence Time (min)</th>
<th>Target Water in Oil (%vol)</th>
<th>Target Oil in Water (ppm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1st</td>
<td>4</td>
<td>2</td>
<td>2</td>
<td>2000</td>
</tr>
<tr>
<td>2nd</td>
<td>&gt;6</td>
<td>4</td>
<td>1</td>
<td>400</td>
</tr>
<tr>
<td>3rd</td>
<td>&gt;8</td>
<td>6</td>
<td>0.25</td>
<td>100</td>
</tr>
</tbody>
</table>

Table 7
Performance targets for typical 3-stage separation system
8.8. TEST SEPARATOR

The production from each well has to be regularly measured accurately as part of the field’s well surveillance programme. Accurate three phase flow meters have only recently become available, so traditionally a small three phase separator (the test separator) has been used for this purpose. Here, the well production is split into its constituent phases (oil/water/gas); the flow rates of each measured separately with conventional orifice meters. The oil and water flows recombined for further processing.

Multi phase flow meters are now becoming reliable. This is reducing the need to install a test separator (platform space and weight saving) as well as the need to install a second (test) pipeline in subsea field developments between the manifold and the host facility (module 10, figure 7).

8.9. COMPRESSORS

The gas liberated from the produced fluids must be delivered to the export pipeline at the specified pressure. It is flashed from the produced liquid at a variety of pressures during the production process - so economically achieving this export pressure requires a number of gas compressors rather than one large one. Minimising the compression power requirements while maximising the liquid recovery (determined by the thermodynamics of the produced fluids), will dictate that the gas from each oil separation stage is compressed to the operating pressure of the previous stage. This is schematically illustrated in Figure 19.
The action of the compressor performing work on the gas being compressed raises its temperature considerably (the “bicycle pump effect”). Minimisation of the compressor power requirements together with maximising of the liquid recovery (which condenses on cooling the gas) dictates the use of interstage coolers, as shown. Offshore, sea water is used for this cooling duty.

An example of the combined result of the above effects is illustrated in Table 8.

<table>
<thead>
<tr>
<th>Separator Pressure (bar)</th>
<th>Oil Production (m³)</th>
<th>Compression Power *(kw)</th>
</tr>
</thead>
<tbody>
<tr>
<td>80, 5</td>
<td>1300</td>
<td>640</td>
</tr>
<tr>
<td>80, 30, 5</td>
<td>1315</td>
<td>370</td>
</tr>
<tr>
<td>80, 30, 12, 5</td>
<td>1321</td>
<td>295</td>
</tr>
</tbody>
</table>

*Omission of compressor interstage coolers increases this by 50%

The prime mover or engine chosen to power the compressor depends on the compressor’s location and the power required. Gas turbines, diesel engines and electric motors are all frequently employed.

Centrifugal and positive displacement reciprocating compressors are both commonly used in oil field applications. Both compressor types are susceptible to damage by liquid droplets, hence the presence of the liquid knockout vessels prior to each compressor.
Centrifugal compressors are large, complex machines that contain internals that rotate at high velocities. They are much more difficult to install and maintain than crude oil or water pumps. One of the critical areas in compressor design is to ensure that a recycle valve is included which opens to prevent compressor “surge”. This occurs when the feed rate is insufficient to allow the compressor to reach its design discharge pressure.

The subsequent treatment dehydration etc. of the gas to achieve export specifications once it has been compressed is similar to that described in gas field operations. (Section 8.10).

8.10. OIL EXPORT

The volume of oil being exported has to be measured to the highest accuracy - since not only does it define the project product and cashflow, but also involves both fiscal (tax/royalty etc.) and intercompany transfer (e.g. to a “common carrier” pipeline) aspects.

Turbine flow meters - which involve the measurement of the number of times that the flowing oil revolves a paddle or turbine placed in the oil flow path - have a high, intrinsic accuracy and are normally used for this purpose. However, they have to be calibrated - or “proved” at regular intervals. A bank - say 5 to 10 - of smaller capacity turbine flow meters are used rather than a single, large meter. The calibration process is illustrated in Figure 20. The flow rate as measured by the turbine flow meter is compared with that calculated from the time for a sphere to be displaced between two detectors and the volume between these detectors.
Oil export depends on efficient pipeline operation. The pipeline requires regular cleaning by a “pig”. This removes settled sand, stagnant water collected at low points (for corrosion prevention), wax deposits etc. The “pig” may be in the form of a sphere to displace fluids or a cylinder with brushes to scrape the inside surface of the line. Alternatively it may have “intelligence” in that it can inspect the pipeline condition.
and record the results for later replay. The “intelligent” pig uses similar techniques as employed for well (tubing) condition monitoring {mechanical arms to “feel” for corrosion pits and grooves, acoustic wall thickness measurement devices etc.}. As an aid to recovery, they often carry a transmitter so that their position can be pinpointed if they become stuck in the pipeline.

The pig is “launched” into the pipeline using a pig launcher (see Figure 21). This is an oversize barrel with end closure, pressure gauge and venting/purging system to allow any hydrocarbons present in the “launcher” to be depressurised/disposed of in a safe manner. Opening of any pressurised lines which could potentially contain hydrocarbons is a hazardous operation which requires proper attention to safety and environmental aspects.

A pig “signaller” is built into the launcher. This confirms the successful launch of the pig into the pipeline. A duplicate pig “signaller” and “launcher” is installed at the receiving end of the pipeline to record the arrival of the pig and to allow its safe removal from the pipeline.

### 8.11. GAS HANDLING

Similar process units are used in oil field gas handling as are used in gas fields. In both cases the objective is to maximise the recovery of liquid Natural Gas Liquids or NGL’s (mainly hydrocarbons with a chain of four or five carbon atoms). This is achieved in oil fields by multi-stage separation and (gas) compression - as discussed in the previous chapter. Single stage separation, with optional gas compression and processing as dictated by the producing wellhead pressure and gas composition respectively, is the norm for gas fields. Figure 22 illustrates typical gas field facilities.

#### 8.11.1 Increasing NGL Recovery

The increased NGL yield, and reduction in the water content, is achieved by cooling the gas. The equipment used is:
(i) **Refrigeration to between -30°C and -40°C** using a conventional refrigeration plant. (Freon and Propane as refrigeration agents, respectively).

(ii) **Joule-Thomson expansion** - the gas will be cooled when its pressure is reduced by flowing through a throttle or choke (isenthalpic conditions). This process is favoured when there is a large pressure drop between wellhead and pipeline operating pressures. The gas may require compression back to the export pipeline operating pressure subsequent to the separation of the condensed liquids.

(iii) **Turbo Expansion** - this involves extracting energy from the gas by getting it to do work e.g. powering a compressor or generating electricity while its pressure is being reduced. This achieves a lower temperature than for Joule Thomson expansion e.g. Shell’s St. Fergus gas plant cools the gas to -99°C using two-stage turbo expansion.

(iv) **Processing of Chilled Liquids**
Glycol is added prior to cooling the gas so that any condensed water does not form (solid) ice or hydrates (see Section 10.3.2). The cool water/glycol/liquid hydrocarbon mixture is lead to a three-phase separator where the water/glycol mixture is removed from the bottom while the hydrocarbon liquid (middle layer) is pumped to a distillation column (see Section 10.2 on NGL Stabilisation for further details). Adjustment of the distillation conditions (number of trays, bottom temperature, pressure etc.) allows ethane, propane and butane to be recovered separately e.g. for use as a chemical feed stock. The (denser) NGL’s are recovered from the column bottom. Cryogenic distillation conditions (<-50°C) are necessary if recovery of substantial volumes of ethane is desired.

---

**Figure 22**
Schematic gas field facility system

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8.11.2 NGL Stabilisation
The separated NGL has a high vapour pressure due to dissolved, volatile gasses (methane, ethane etc.). It is not suitable for storage in a tank or onward transport to customers. The vapour pressure is reduced by heating the NGL to progressively higher temperature and allowing the gas to “flash-off” at constant pressure (Figure 23) {See section on PVT properties in Reservoir Engineering module} The same process can be carried out more efficiently in a distillation column. The column consists of a number of trays containing bubble caps (Figure 24) which forces the gas rising upwards into intimate contact with the liquid on the tray, ensuring they come to equilibrium. The higher trays are operated at a progressively lower temperature than the lower trays. Hence the liquid undergoes a series of multiple flashes at increasing temperature and constant pressure as it trickles down the column from the top tray to the bottom tray. Any water that is present will tend to concentrate at the tray operating at just below its boiling point under the column operating pressure. A separator may be installed on this tray and the water drawn off for disposal.

Unstabilised NGL

Low Temperature Separator

Intermediate Temperature Separator

High Temperature Separator

Stabilised NGL Storage

Cooler

Heater

Figure 23
Process scheme for NGL stabilisation via multiple flashes at constant pressure and increasing temperature

Packing material is frequently used as an alternative to distillation trays. These ensure that the liquid and gas come into equilibrium by providing a large surface area with which the upcoming gas and the downward flowing liquid can brought into equilibrium. There are many proprietary types of packing - some examples are illustrated in Figure 25.

8.11.3 Gas Dehydration
Produced Natural gas is saturated with water vapour under the prevailing downhole, reservoir conditions. Production to the surface and subsequent processing normally involves a progressive reduction in the gas temperature (and pressure). The equilibrium water content of the gas phase decreases as the temperature drops or the pressure increases, resulting in the separation of the liquid water. (Figure 26). Water presents as vapour in the gas phase does not present a problem to the gas facility operation - unlike liquid or solid water (ice):
Liquid water accumulates at pipeline low points, reducing well capacity and accelerating corrosion. It also forms solid hydrates (see Section 10.3.2) which, similar to ice, can plug lines, valves etc.
The saturated water content of natural gas under various conditions of temperature and pressure can be derived from Figure 26. The **Dew Point** is the temperature at a given pressure, at which the gas is saturated with water vapour, and any further reductions in temperature will cause the water to begin to condense. Thus, if the water content of a gas stream is known, its **Dew Point** can be derived from Figure 26.

![Figure 26](image)

**Dew point of natural gas.** (adapted from Gas Processors Suppliers Association, Engineering Data Book, 10th. Edition)
8.11.3.1 Dew Point Depression
Dew Point Depression is the number of degrees that the dew point (or water condensation temperature) has to be lowered by the dehydration process e.g. a 80°F Dew Point Depression for a gas at 100°F and 1000 psi would require the removal \( \{60 - 4.5 = \} \) 55.5 lbs water/MM ft³ gas and implies that liquid water condensation would not occur above 20°F (at 1000 psi) or even -10°F if the pressure was reduced to 200 psi.

8.11.3.2 Hydrates
Hydrates are solid materials which form from light hydrocarbons and liquid water. The light, hydrocarbon molecule is embedded in the solid water crystalline lattice, which makes up the majority of the compound’s composition. Viz:

\[
\begin{align*}
\text{Methane} & \quad \text{CH}_4 \cdot 7\text{H}_2\text{O} \\
\text{Ethane} & \quad \text{C}_2\text{H}_6 \cdot 8\text{H}_2\text{O}
\end{align*}
\]

Figure 26 shows that they are formed above the normal freezing point of water and indicates the maximum temperature at which they are encountered.

One solution to preventing operational problems from hydrate formation is to add an (expensive) inhibitor e.g. methanol to the gas stream or to reduce the water content of the gas such that liquid water cannot form under the full range of operating conditions. Water vapour removal is achieved by:

(I) Refrigeration or cooling (see section 10.1)

(ii) Continuous absorption in a liquid desiccant (e.g. glycol)

(iii) Batch absorption by a solid desiccant (e.g. silica gel)

8.11.4 Continuous Dehydration Process
The process scheme for counter current absorption in a (packed) column using a liquid desiccant such as (triethylene) glycol is shown in Figure 27. The wet gas enters the contactor column at the bottom while the “lean” (low water content) glycol is pumped in at the top. The glycol trickling down the column is brought into intimate contact with the gas bubbling upwards. The water vapour is absorbed by the glycol since the partial pressure of water in the gas phase is greater than its partial pressure in the liquid (glycol) phase. The lower the water content of the “lean” glycol, the lower the resulting dew point temperature and water content of the gas phase.
The “rich” glycol/water mixture is drawn off from the bottom of the contactor tower. The absorbed water vapour dramatically lowers the mixture’s boiling point, so that the glycol may be regenerated by boiling in a distillation column. It works in a similar manner to those described earlier in section 10.2; except that a condenser (cooler) is placed at the top of the columns. The temperature of the condenser is adjusted so that the glycol condenses and is returned as column reflux, while the water vapour passes through it as a gas. The “lean” glycol is drawn from the bottom of the still and can now be used to treat further more wet gas. The water content of the “lean” glycol can be further reduced by gas stripping. This involves bubbling a gas through the lean glycol - either in the regeneration column itself or, if higher purity glycol is required, in a separate small column prior to the gas being passed to the main, regeneration column. Low pressure (say 50 psi at 60°F) gas is used since increasing its temperature to column operating temperatures will increase its water carrying capacity from, say, 250 to 100,000 lbs/MMscf.

Triethylene glycol can typically achieve a dew point depression of 55°C by operating the glycol reboiler at 205°C. This can be increased to 85°C by use of gas stripping. Further reductions in the dewpoint e.g. to -100°C for gas destined for a cryogenic liquefied natural gas plant, require use of a solid desiccant.

8.10.5 Batch Dehydration Process
Very low dew points, such as those required for cryogenic LNG plants where a water vapour concentration of less than 1ppm is required, can only be achieved with solid bed dehydration systems such as illustrated in Figure 28. It consists of:

(i) two or more desiccant filled contactor vessels,

(ii) a heater to supply hot, regeneration gas,

(iii) a cooler, to condense water from the used regeneration gas, together with a separator.

The solid desiccant (e.g. silica gel, alumina gel, molecular sieve etc.) has a very large specific surface area. This allows it to absorb water from the (wet) gas passing...
downwards through the contactor at low near ambient temperatures (30º - 40ºC). Once the entire bed has become saturated with water, the inlet (wet) gas is switched to a second tower containing fresh absorbent. The saturated (spent) tower is then regenerated by passing heated (260º - 350ºC) gas through it. The water absorbed by the solid dessicant is vaporised into the hot gas stream. Cooling of this hot, wet gas reduces the water saturation level and liquid water is recovered from the separator. A hot tower will not work efficiently. The dessicant bed needs to be cooled - by passing cool inlet gas - to its operating temperature (30º - 40ºC) before it will work efficiently. The “fresh” tower is then available for operation when the tower currently in use becomes saturated with water vapour. The towers are typically sized so that they work on an 8-hour adsorption cycle followed by regeneration through six hours heating and two hours cooling.

**Figure 28**
*Schematic flow diagram for solid bed dehydration*

---

**8.10.6 Acid Gas Treating**

Natural gas frequently contains other contaminants than those discussed to date. These include carbon dioxide (CO₂), hydrogen sulphide (H₂S) and other sulphur compounds such as mercaptans. Since these materials form acidic solutions when dissolved in water, they are known as acid gasses. These compounds are undesirable since they:

(i) **Cause corrosion**

e.g. CO₂ is corrosive in the presence of liquid water at a partial pressure (=total pressure * mole% of CO₂) of 30 psi. H₂S can lead to sulphide stress cracking and hydrogen embrittlement of many metals at partial pressures as low as 0.05 psi
(ii) **reduce the heating value of the gas and**, 

(iii) in the case of H\textsubscript{2}S, can be **poisonous** in quite low concentrations (H\textsubscript{2}S has a distinct odour at 0.15 ppm, exposure to 100 ppm H\textsubscript{2}S leads to drowsiness after 15 minutes while 500 ppm causes sufficiently severe breathing problems after 5 minutes that prompt the requirement of artificial respiration. Unfortunately, H\textsubscript{2}S cannot be smelt at these lethal concentrations.

The maximum allowable CO\textsubscript{2} and H\textsubscript{2}S concentrations are normally specified in the gas sales contract - typical values are 3% and 4 ppm respectively. Low concentrations of H\textsubscript{2}S may be removed by solid absorbents (e.g. iron oxide, zinc oxide) which are replaced when the bed is spent. Higher concentrations of H\textsubscript{2}S as well as CO\textsubscript{2} are removed in solvent extraction process similar to a glycol dehydration unit (section 10.4 and figure 26).

The extraction unit consists of two parts - an adsorption column in which the acidic gas to be treated is fed in at the bottom and the liquid solvent is added at the top. The column internals - trays or packing - ensure that there is intimate contact between the two phases and the process conditions adjusted so that the CO\textsubscript{2} / H\textsubscript{2}S concentrations are reduced to specification levels.

One class of solvents used for treating acid gasses are alkaline liquids that reversibly react with the acidic gases H\textsubscript{2}S and CO\textsubscript{2} e.g. mono-ethanolamine.

\[
\begin{align*}
2 \text{RNH}_2 + \text{H}_2\text{S} & \underset{\text{heat}}{\overset{\text{heat}}{\rightleftharpoons}} (\text{RNH}_3)_2 \text{S} \\
(\text{RNH}_3)_2 \text{S} + \text{H}_2\text{S} & \underset{\text{heat}}{\overset{\text{heat}}{\rightarrow}} 2(\text{RNH}_3)\text{HS} \\
2 \text{RNH}_2 + \text{CO}_2 & \underset{\text{heat}}{\overset{\text{heat}}{\rightleftharpoons}} \text{RNHCOONH}_3 \text{R}
\end{align*}
\]

An alternative is a physical solvent e.g. Sulfinol in which one can dissolve large quantities of CO\textsubscript{2} and H\textsubscript{2}S at low temperature; while releasing them again at high temperatures. Thus, in both cases, a solvent “rich” in absorbed CO\textsubscript{2} and H\textsubscript{2}S is recovered from the bottom of the adsorption column and transferred to the regeneration column, where heat liberates the absorbed CO\textsubscript{2} or H\textsubscript{2}S. The regenerated solvent is used again. The gasses are vented or flared {H\textsubscript{2}S being converted to sulphur dioxide (SO\textsubscript{2})}. However, there are normally strict environmental constraints on the quantities of H\textsubscript{2}S and SO\textsubscript{2} that can be released into the environment; while the emission of CO\textsubscript{2} attracts a tax penalty in some countries. Alternatives are:

(i) Injection into an underground disposal reservoir

(ii) Conversion of the H\textsubscript{2}S into solid sulphur which can be sold to the chemical industry. The Claus process is frequently used - this involves the oxidation of part of the H\textsubscript{2}S to SO\textsubscript{2}; followed by conversion to sulphur by reaction with further H\textsubscript{2}S.

\[
\begin{align*}
2 \text{H}_2\text{S} + 3 \text{O}_2 & \rightarrow 2 \text{SO}_2 + 2\text{H}_2\text{O} \\
\text{SO}_2 + 2\text{H}_2\text{S} & \rightarrow 3\text{S} + 2\text{H}_2\text{O}
\end{align*}
\]
8.12 FURTHER READING

Arnold K and Stewart M. "Surface Production Operations"
Published by Gulf publishing Company

Kennedy J "Oil and Gas Pipeline Fundamentals"
Published by Penwell Books, 1993
ISBN 0-87814-390-4