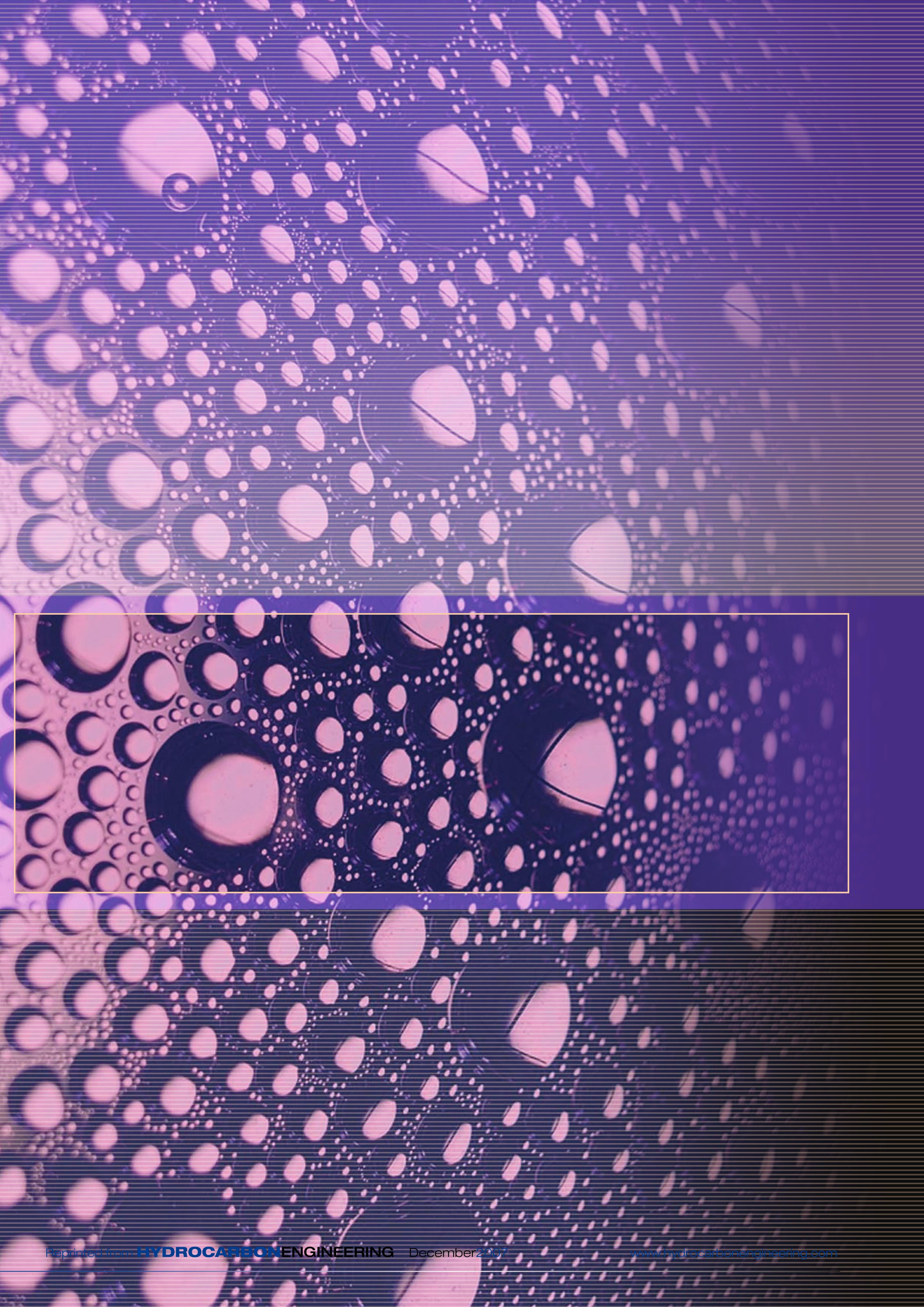

A case for dehydration

Adrian Finn and Terry Tomlinson, Costain Oil, Gas & Process Ltd, UK, discuss process technology to meet water and hydrocarbon dew point specifications on natural gas storage installations.

By 2010, the UK will depend on imports for nearly half of its gas supply. By 2020, this figure could be as much as 90%.[1] The availability of good quality gas from the North Sea and Irish Sea has historically meant there was little justification for gas storage in the UK as peak demand could be relatively easily met even on the coldest day. Consequently, the UK currently only has enough gas storage for 4% of annual consumption, a fraction of what is typical in Europe. At the end of 2006 three storage facilities were operational in the UK, with one under construction and several undergoing planning permission.[2] Rapidly increasing imports means there is a need for increased gas storage capacity to provide strategic reserves.[3]

Gas storage facilities open up important commercial opportunities as low cost gas from the national transmission system (NTS) can be injected in summer months into either depleted hydrocarbon reservoirs or purpose built salt caverns and withdrawn and routed into the NTS in winter when gas price and demand is high. Depleted gas reservoirs are cost effective as they offer greater storage capacity (and economies of scale) and the existing gas processing and distribution system can be used. The Rough gas field was converted to a storage facility in 1985. It can store up to 3100 million m^3 of gas and is of major strategic importance to the UK. Underground salt caverns are also appropriate as the cavern walls are essentially impermeable, though the cost and time for leaching the salt out can be significant. Salt caverns are important, in that by being smaller than hydrocarbon reservoirs they are easier to fill and empty so are better for meeting short term gas price fluctuations.

Stored gas will be saturated with water at the reservoir temperature and pressure. If obtained from a depleted hydrocarbon reservoir it will also contain heavier hydrocarbons. The presence of water and heavier hydrocarbons will cause the gas to be outside the gas quality specifications for water dew point and potentially hydrocarbon dew point (so storage in depleted gas reservoirs can require more gas processing).

This article discusses selection of the most appropriate processing technology for gas storage installations in terms of meeting the NTS dew point specifications.

Dehydration

Dehydration is required as water can cause several problems with gas transmission systems, including pipeline corrosion, erosion and instrument measurement errors. A water dew point of less than -10 ˚C is specified to ensure free water cannot form.

There are three principal methods of dehydrating natural gas to transmission system specification. Selection of the optimum depends on several factors:

- Absorption using glycol.
- Adsorption with solid dessicants.
- Condensation using refrigeration with methanol or glycol injection.

There are other dehydration technologies that are not so well proven in commercial applications. These include semi permeable membranes and technologies that rely on swirling the gas to achieve temperature reduction and condensation of both water and hydrocarbons. Commercial operating experience is limited with these technologies and there would be uncertainty over their performance and reliability for a gas storage facility. Furthermore they rely on pressure reduction to operate and would lead to increased sales gas compression costs. Figure 1 provides a decision chart for the selection of gas dehydration processes, which shows the relevant technologies for meeting gas transportation requirements.[4]

Absorption by glycol dehydration

Glycol dehydration is the most widely used method to dehydrate natural gas and represents a simple, proven and relatively low cost option. It relies on absorbing the water content of the gas into a solvent at relatively high pressure and low temperature and then regenerating the solvent to release the water at relatively low pressure and high temperature. Triethylene glycol (TEG) is the most appropriate solvent because it has high thermal stability and physical properties resulting in low capital and operating costs for plants. Plant capacities range from less than 100 MMSCFD to over 1000 MMSCFD.

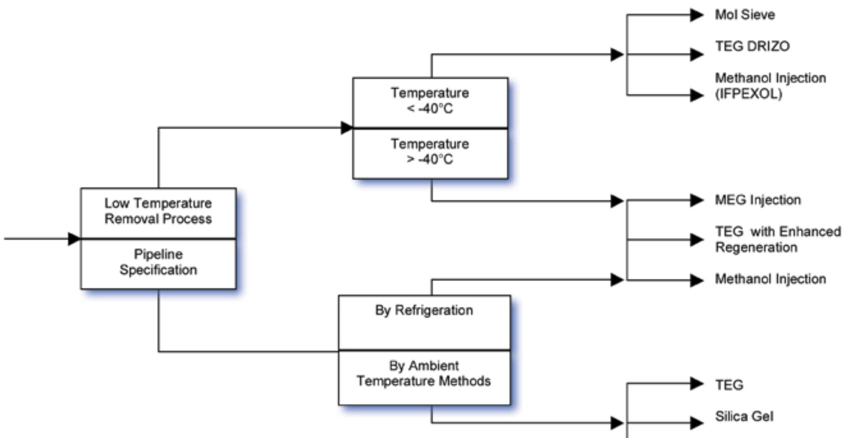

Figure 1. Process selection chart for gas dehydration.

The reduction in water dew point of the treated gas is dictated by the lean TEG concentration used in the absorber and hence the design of the regeneration system. A conventional regeneration system cannot achieve lower TEG water content than approximately 1.4 wt.% without exceeding a regeneration temperature of over 200 ˚C at atmospheric pressure. Higher temperatures would result in TEG degradation. However, the use of stripping gas to further reduce TEG

Figure 2. Teesside Gas Processing Plant Train 1 DRIZO Unit.

water content is simple and well established. In warm climates or downstream of acid gas removal systems, stripping gas is normally needed to meet -10 ˚C water dew point, but the basic TEG regeneration system is adequate for the UK.

Costain's experience includes major TEG dehydration facilities, including stripping gas regeneration and more sophisticated TEG regeneration systems. These plants have proved to have excellent reliability and can cater for a wide range of varying feed gas conditions. Glycol plants have very high turndown with low energy consumption. The large number of experienced designers and fabricators mean that standard designs can be procured at competitive cost. The only real concern tends to come with feed gas contaminants, especially heavier hydrocarbons, which can cause glycol foaming in the absorber and consequent loss of performance. This can be alleviated by use of an anti-foaming agent, but the behaviour of these agents can be difficult to predict and can even worsen performance. Removal of potential offending contaminants upstream of the glycol absorption system is the best approach.

If the feed gas contains BTX components then the fact these are absorbed into the TEG (and released with the water waste stream from the TEG regenerator) becomes an important environmental issue. BTX components are carcinogenic and cannot be released into the atmosphere. Relatively simple solutions have been developed to avoid the release of BTX and for any project this issue requires assessment against best available technology (BAT) requirements. The 'DRIZO' technology used on the px Teesside Gas Processing Plant (TGPP), and shown in Figure 2, features BTX recovery.

Adsorption

Three main types of solid dessicant are well proven for dehydration:

- Silica gel.
- Activated alumina.
- Molecular sieve.

Water is removed from the natural gas by physical adsorption on a fixed bed of adsorbent. The water is subsequently desorbed by thermal regeneration using dry gas at elevated temperature (i.e. temperature swing adsorption (TSA), as distinct from pressure swing adsorption (PSA), which relies on reduced pressure for regeneration).

Silica gel is a pure form of silicon dioxide that has a high affinity for water and requires a relatively small heat load for regeneration. It offers the ability to meet both hydrocarbon and water dew point specifications in one process system, which is highly beneficial compared to either alumina or molecular sieve.

Different grades of molecular sieve allow adsorption of different contaminants and sulfur compounds, as well as water, can be removed to very low levels. The applicability of molecular sieve for dehydration can therefore depend on the presence, or absence, of sulfur compounds.

Condensation by refrigeration

Natural gas can be cooled so that sufficient water is condensed to meet the water dew point specification. This approach is also suitable for removing heavier hydrocarbons so that hydrocarbon dew point can also be attained. Either pressure reduction (Joule-Thomson or turbo-expansion) or mechanical refrigeration can be used for cooling. To prevent the formation of hydrates and ice, either glycol or methanol is injected.

Glycol (normally mono ethylene glycol (MEG)) injection is simple, well proven and inexpensive. The MEG depresses the freezing point so that hydrates or ice cannot form at the temperatures required to meet dew point specifications (typically -15 - -20 ˚C). The MEG and condensed water/hydrocarbons mixture has high viscosity and needs to be heated to ensure good separation. Even then, uncertainty in composition and the extent of hydrocarbon absorption in the MEG may cause operational difficulties unless process design has accounted for the full range of potential operating conditions. The presence of salt can also be a difficulty with MEG regeneration and can cause operating problems unless it is removed.

In the UK, methanol has been favoured for offshore hydrate inhibition because it flows more easily than MEG, is more effective and reliable and leads to a smaller onshore slugcatcher. However, methanol is more difficult to regenerate than MEG, which leads to a larger and more costly regeneration system and increased energy and operating costs.

In comparing methanol against MEG, whilst methanol is cheaper than MEG because of its volatility, more is lost into the natural gas. Very good thermodynamic property prediction methods are needed to assess methanol distribution between vapour and liquid phases due to methanol's polar nature.

Hydrocarbon removal

If the gas storage facility is a depleted gas reservoir then some indigenous gas will initially be left in the reservoir to maintain pressure, known as 'cushion gas'. When stored gas is drawn out, heavier hydrocarbons in the 'cushion gas' could cause the withdrawn gas to be

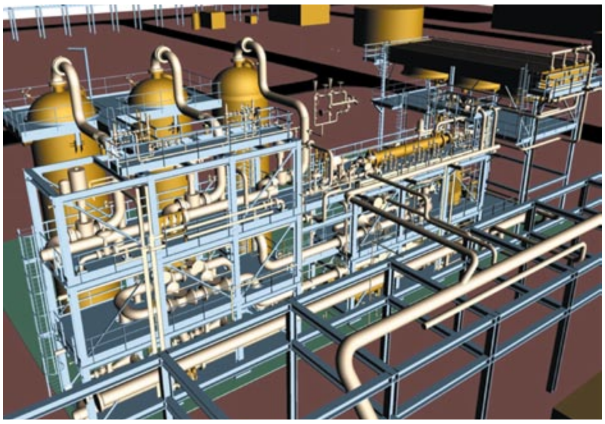

Figure 3. 385 MMSCFD silica gel plant supplied by Costain to the Rashid Petroleum Co., Idku, Egypt.

outside the hydrocarbon dew point specification.

The processes normally used to remove heavier hydrocarbons are adsorption and low temperature removal via condensation. Absorption with 'lean oil' has been used for years to remove heavier hydrocarbons from natural gas but is relatively expensive (both in terms of capital and operating cost), especially for storage installations that only need a very small proportion of the heavier hydrocarbons to be removed to meet dew point specification.

Adsorption

Silica gel offers the ability to meet both hydrocarbon and water dew point specification in one process system. Silica gel can remove pentane and heavier hydrocarbons with 100% removal of octanes and heavier, which means it is highly effective in removing the components that influence hydrocarbon dew point. Figure 3 shows a 385 MMSCFD silica gel plant supplied by Costain to the Rashid Petroleum Co., Idku, Egypt for both water and hydrocarbon dew pointing.

As with any adsorption system the silica gel bed is specified to operate for a specific time, at which point it is taken offline and thermally regenerated. A freshly regenerated bed is then put online. Beds can be operated in parallel to maximise efficiency with changing feed gas conditions.[5] This was an important aspect in the use of silica gel on the Rough Storage facility, the UK's major gas storage installation, because the mixing of injected gas (from the NTS) and the indigenous Rough reservoir gas would result in an uncertain gas composition that would change over time.[6] It was identified that retrograde condensation would mean a conventional refrigeration process (operating at -23 ˚C) might not be as effective and reliable as a silica gel system. For any depleted reservoir storage facility similar concerns over variability of gas composition would tend to apply.

The disadvantages of a silica gel adsorption system arise from the need to regenerate, by heating not only the silica gel bed to a suitable temperature (approximately 250 ˚C) to drive off contaminants but also the vessel and pipework too. This requires a relatively large heater, usually a fired heater, which incurs large capital and operating costs. Internal insulation of the adsorber vessels may be justified to reduce heater and fuel gas costs. The need for at least two and possibly more large, high pressure adsorber vessels also makes for a relatively high capital cost. Therefore whilst silica gel provides a simple, reliable and flexible process facility, which requires little operator attention, it can come at a relatively high cost.

Condensation at reduced temperature

The most common method for hydrocarbon dew point control has been cooling, condensing and separation of heavier hydrocarbons. The necessary refrigeration may come from Joule-Thomson expansion, turbo expansion or mechanical refrigeration.

Though both Joule-Thomson expansion and turbo-expansion are common processes for condensing heavier hydrocarbons, they both result in pressure drop. For gas storage installations, this would mean increased sales gas compression and relatively high capital and operating cost. Turbo expanders do not turndown efficiently and could not normally be justified for dew pointing.

Mechanical refrigeration using a conventional packaged refrigeration system is a low cost solution for gas chilling. Pressure drop is minimal. As discussed earlier, to avoid freezing, glycol or methanol injection is used. Refrigeration systems do require greater operator attention and maintenance than a silica gel system. The gas composition may also dictate the need to chill below -20 ˚C, which may restrict the choice of hydrate inhibitor to methanol and can lead to larger volumes of unstable condensate than with adsorption.

As condensate needs processing to meet vapour pressure specification, the capital cost of processing, plus storage and export to consumers, should be included in any process evaluation and selection studies.

Conclusion

Any gas storage project should evaluate process options to ensure the selected technology and plant configuration is optimal for the particular site and gas conditions. This evaluation can have an important influence on project economics and feasibility. Costain Oil, Gas & Process has developed the experience and capability to perform such technology assessments from evaluations on a range of projects over recent years.

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