ENGINEERING TOMORROW...TODAY

WHITE PAPER

UK SHALE GAS PROCESSING: PART TWO

Author(s): Matthew Last and Adrian Finn, Costain

First published: Hydrocarbon Engineering, May 2015

COSTAIN GROUP PLC Costain House, Vanwall Business Park, Maidenhead, Berkshire, SL6 4UB.
Tel: +44 (0) 1628 842444

UK SHALE GAS PROCESSING: Part Two

Matthew Last and Adrian Finn, Costain, UK, discuss processing technology for UK shale gas.

Sunset over Durdle Door.

Many shales produce gas containing acid gases such as hydrogen sulfide and CO_2 as well as other sulfur compounds (e.g. COS, CS_2, mercaptans). US shale gas contains a wide range of CO_2 levels, from under 1 mol% to 8 – 10 mol%, while H_2S levels range from <100 – 750 ppmv.

H_2S must be almost totally removed from natural gas due to its toxicity, whereas CO_2 levels need only be reduced to meet sales gas specifications (unless further downstream processing such as cryogenic nitrogen rejection requires greater removal to avoid freezing). Components need to be determined accurately to select, size and design the most

Figure 1. BG Tunisia Hannibal gas treatment plant.

Figure 2. E.ON Connah's Quay gas treatment plant.

Table 1. NTS specifications[4]

Hydrogen sulfide	≤5 mg/m^3
Total sulfur	≤50 mg/m^3
Hydrogen	≤0.1% (molar)
Oxygen	≤0.001% (molar)
Hydrocarbon dewpoint	≤-2 °C at any pressure up to 85 barg
Water dewpoint	≤-10 °C at 85 barg
Wobbe number (real gross dry)	In the range 47.20 to 51.41 MJ/m^3
Carbon dioxide	≤2.5% (molar)
Radioactivity	≤5 Becquerels/g

suitable process technology, especially as some sulfur contaminants can have a very large effect on the acid gas removal duty even if present in very small quantities. There are increased environmental and safety risks, and costs, for sulfur removal which will translate into an increased sales gas price. It may be appropriate to allow sulfur compounds to slip through the acid gas removal unit to be removed downstream and this evaluation needs good understanding of process technologies to arrive at an optimal design.

The most popular process for removal of moderate levels of acid gas from natural gas uses an amine solvent, which absorbs the acid gas chemically in a contacting column and releases the acid gas in a thermal regeneration step. The main design considerations influencing plant performance include the lean amine temperature, the solvent concentration and circulation rate, and the column design. Commodity solvents are available alongside various proprietary formulations. These are mainly methyl diethanolamine (MDEA) based formulations with activators/enhancers, which offer reduced regeneration energy, high solution strength (so lower circulation rate), lower corrosivity and high resistance to amine degradation. A process that can operate robustly across a range of compositions can offer long term cost benefits.

A plant upgrade project by Costain for BG Tunisia included revamp of a large acid gas removal system using enhanced MDEA. For higher acid gas removal levels physical solvents can reduce processing costs but care is required in managing the heavier hydrocarbons absorbed by the solvent.

Dehydration and hydrocarbon dewpointing

Water must be removed from natural gas to avoid problems in gas transmission systems, such as corrosion and blockage through hydrate formation as well as to avoid freezing issues. Extracted shale gas is saturated with water. As shown in Table 1, the required water dewpoint for UK NTS transmission is less than -10°C. A number of dehydration technologies can achieve this specification and the most widely used methods are discussed.

Glycol dehydration is widely used for removing water from natural gas streams. It is economical for a wide range of plant capacities (typically from 100 million ft^3/d upwards, though no plant capacity is too small). Water is absorbed from the gas by glycol solvent, most commonly triethylene glycol (TEG), in a high pressure contactor. TEG is usually chosen for its high thermal stability, its ability to be regenerated with a high purity, and low capital and operating costs. An efficient upstream scrubber should be installed to remove contaminants which could cause glycol foaming and to ensure no liquid hydrocarbons are carried over. The rich solvent is then regenerated in a distillation process. The purity at which the lean solvent enters the contactor dictates the dehydration performance. A feature of glycol plants is their very high turndown capabilities.[1]

Costain's experience includes TEG dehydration units to achieve a water dewpoint of -10°C all the way to enhanced TEG dehydration technology to achieve -80°C water dewpoint at a major UK gas processing plant upstream of cryogenic NGL extraction.

Adsorption can be used with a fixed bed of molecular sieve or silica gel. While the capital cost for an adsorption based plant tends to be higher than for a glycol unit at larger capacities, it can easily handle variations in duty and is very reliable in operation. Molecular sieve can simultaneously adsorb water and sulphur compounds. Silica gel offers larger adsorption capacities, can be regenerated at lower temperatures, and importantly can be used for hydrocarbon dewpointing in the same step so as to simplify overall gas processing. Silica gel cannot achieve the very low water dewpoint that molecular sieve can, but is normally adequate for water dewpointing and hydrocarbon dewpointing. Costain has employed this technology for gas dewpointing on several major gas processing plants.

Costain used molecular sieves to remove water simultaneously with sulfur species at the 200 million ft^3/d E.ON Connah's Quay Gas Treatment Plant, UK, with water being removed to less than 1 ppm, H_2S to less than 1 ppm and total sulfur from 35 ppm to less than 8 ppm.[2] Costain also designed and built a silica gel dewpointing unit as part of the Centrica York gas treatment project, based at Easington, a COMAH Tier 1 site.

A third method is cooling of the gas to remove water by condensation. This can be by Joule Thomson (adiabatic) expansion, turboexpanders or mechanical refrigeration. This method is also capable of removing heavy hydrocarbons to meet hydrocarbon dewpoint. To avoid hydrate formation, either monoethylene glycol (MEG) or methanol is injected, so whilst condensation is a well proven and inexpensive process the introduction of additional fluids into the plant increases complexity. Selection between MEG and methanol must consider performance and required amounts, cost, losses (methanol being more volatile), corrosion suppression and regeneration, especially the ability to avoid salt problems in thermal regeneration.

Costain is providing a Joule Thomson based dewpointing plant as part of a Freon replacement project in the UK.

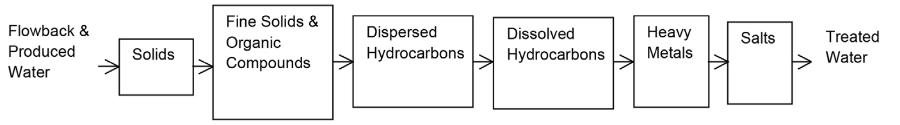

Figure 3. Water treatment removal steps.

Figure 4. Water treatment facility delivered by Costain for GDF Suez gas storage facility, Stublach.

Heating value adjustment

There can be large variations in the nitrogen content of shale gas. In Poland, exploratory wells have produced very high nitrogen content gas. Where sales gas is too lean (low calorific value and/or Wobbe index), gas blending would be the most cost effective option. Propane injection offers a straightforward alternative. Costain installed propane injection facilities on the first Grain LNG terminal in the UK for this purpose.

Excessive nitrogen content can be reduced by nitrogen rejection. For all bar very small flowrates, the most cost effective technology is cryogenic processing, otherwise pressure swing adsorption (PSA) and membrane technology are alternatives. In cryogenic processing, a pure nitrogen vent stream is produced by distillation. This is a critical difference to other technologies in being environmentally acceptable. Costain has utilised cryogenic nitrogen rejection technology on many projects including on the E.ON gas treatment plant, Connah's Quay UK where the feed gas nitrogen content is reduced to less than 5%.

Water processing

The major differentiator in shale gas processing compared to conventional gas processing is the large volume of water used in the fracking process, with each well requiring between 10 000 - 30 000 m^3 of water.[3] Provision of fresh water depends on the local situation and may be from public water supply or recycled/reused waters. It may also be taken from surface water or groundwater if sustainable and permitted by the relevant environmental regulator.

Fracking fluid is normally approximately 90% water, 8% proppant (normally sand) and 1 - 2% chemical additives including hydrochloric acid for pH control, glutaraldehyde as a bactericide, guar gum as a gelling agent and other petroleum based surfactants.[3] Once fracking has taken place, 15 - 80% of this fluid flows out of the well, termed 'flowback water'. The remainder will return with the shale gas flow over the life of the well, referred to as 'produced water'. The handling of this water is a major consideration for any shale gas project. Both the flowback and produced water will contain rock particles, various dissolved salts and quantities of naturally occurring radioactive material. The water can either be treated for reuse in future fracking operations at the well site or for return to domestic and industrial use. Such quantity of water requiring treatment facilities is clearly a cost and potential environmental burden.

To reduce demands on local transport infrastructure it would be desirable to install water storage and treatment facilities at the well site rather than transporting offsite via road tanker. When fracking is completed any residual liquids and solids could be sent to a waste treatment and disposal facility. In the US, flowback and produced water are commonly stored at the well site in open pits. This potentially threatens surface water contamination (e.g. during heavy rain) and risks volatile organic compounds (VOCs) escaping to atmosphere. In the UK, regulations exclude use of open pits and operators will need to store and contain these fluids (with storage vessels) before treatment.

The basic steps for onsite water treatment are shown in Figure 3.

For each removal step, there are specific technologies which offer differing benefits in cost, operation, flexibility and maintenance. Some processes combine multiple removal steps so reducing the plant footprint. For example, hydrocyclones and degassing can remove fine solids and dispersed hydrocarbons. Biological processes, often used for dissolved hydrocarbons, work best with steady feed flowrates (which for shale gas would require a large storage vessel to buffer the varying water flowrates from the wells). Alternative options would be UV and membrane based technologies which are not as sensitive to varying flowrates.

Costain's experience in water processing and management includes long term frameworks to maintain and improve standards in water quality at strategic UK sites. Costain engineered new produced water treatment facilities for an overall upgrade project for the whole Dukhan onshore oil field, Qatar. These utilised multiple sets of parallel hydrocyclones followed by degasser vessels to achieve 'best in class' produced water quality with good tolerance to flowrate changes, easy modularisation and very low maintenance. More recently, Costain also upgraded the produced water unit at ENI's gas plant in Pakistan, which processes gas from the onshore Bhit gas field. Here a new three phase separator was installed in series with the existing flash drum to improve the level of hydrocarbon separation from the water phase.

Conclusion

Natural gas will continue to play an important role as the cleanest fossil fuel. Demand is forecasted to rise significantly worldwide. Shale gas has transformed the gas business in the US and had a major influence on the country's economy. Its exploitation can provide security of supply and energy independence, which is highly attractive in areas that rely on imports, such as Europe.

This article has summarised the processing steps and technologies to be considered for optimisation and cost reduction of shale gas processing. Process selection and plant design will be considered based on feed specifications and variability, overall processing efficiency and the meeting of safety and environmental and regulations by experienced gas processing design, engineering and construction specialists. Early engagement with stakeholders via feasibility and conceptual design studies will be a key part in developing a successful shale gas industry in the UK.

References

1. *FINN, A.J. and TOMLINSON, T.R., 'A case for dehydration', Hydrocarbon Engineering, December 2007.*
2. *SPENCER, M., 'Demonstrating the Benefits of Integrated Adsorber Design', Presented at Eighth GPA GCC Chapter Technical Conference, Bahrain, 24 May 2000.*
3. *Department of Energy and Climate Change, 'Fracking UK Shale: Water', February 2014, (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/277211/Water.pdf).*

Acknowledgements

The authors would like to thank colleagues at Costain, especially Terry Tomlinson for reviewing the paper and Danmi Lee for preparing much of the material.