NEW CHALLENGES FOR UK NATURAL GAS

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ABSTRACT

The United Kingdom's self-sufficiency in natural gas has rapidly declined and for the first time the UK has become a net importer of natural gas. Dependence on imported natural gas is set to increase significantly. Some forecasts show the UK may need to import up to 40% of supplies by 2010 and up to 90% by 2020. Winter gas prices are now a factor of 10 higher than 4 years ago and this is seriously impacting big industrial consumers such as ammonia producers and power generators.

At present, the main projected increase in imported gas is from Norway, mainly via the Langeled pipeline which landfalls in north-east England (carrying gas from the giant Ormen-Lange development by 2007/8) and from Europe via the existing Zeebrugge-Bacton Interconnector and the Balgzand-Bacton pipeline (operational by 2007). The latter two lines will link the UK with the European gas grid and may open up potential supply sources from the Former Soviet Union (FSU).

Several LNG import terminal projects have been undertaken. The first to be completed is on the Isle of Grain near London, which commenced LNG imports during 2005. Two further LNG import terminals, Dragon and South Hook, are under construction at Milford Haven in Wales but will not be fully operational form some years. A further potential development is the upgrade of the former LNG import terminal at Canvey Island, near London. It is estimated that the LNG from these terminals could supply around 25% of the UK's overall gas demand by 2020.

Imported natural gas and LNG will both be of varying quality. A recent report (1) commissioned by the DTI, OFGEM (Office of Gas & Electricity Markets) and the Health & Safety Executive (HSE) highlighted that imported gas or LNG is likely to have a higher Wobbe Index (WI) range than currently acceptable in the UK National Transmission System (NTS). The allowable WI range for the UK, as set out in the Gas Safety Management Regulations (GSMR), is between 47.20 and 51.41 MJ/Sm^3.

In addition to gas quality issues from imports, depletion of existing offshore UK gas fields and a drop in the number of new UK gas field developments has led to evaluation of more marginal (lower quality) gas fields that would need special treatment and processing facilities to meet NTS specifications.

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HISTORICAL DEVELOPMENT

The first natural gas to be produced from the southern North Sea, in the 1960s, required relatively little processing (high in methane content). Simple MEG based dehydration processes, with mechanical or Joule-Thomson (JT) refrigeration, were sufficient for gas to meet NTS specifications.

Large-scale production of gas from the northern North Sea began in the 1970s via terminals at St. Fergus in northern Scotland, via the FLAGS pipeline system and later the SAGE pipeline. This gas required extraction of NGLs and removal of CO_2 and H_2S. The processes used included cryogenic ethane extraction to supply NGL feedstock to the Shell/ExxonMobil Fife ethylene plant, Mossmorran. In 1992 Costain completed a third NGL fractionation train at Mossmorran to increase total plant capacity to 15,000 tonne/day of propane, butanes and condensate as well as ethane. Recent major gas supplies, notably from the Norwegian Statfjord field and the Heimdal gas field via the Vesterled pipeline, have ensured the long-term viability of the St. Fergus gas plants and the Fife ethylene plant.

The 1970s also saw the strategic building of several “peak-shaving” LNG storage facilities to provide security of supply during extreme winter demand by liquefying natural gas for up to approximately 270 days a year. Plant capacity is typically 400 tonnes per day in 2 trains. The expander-based liquefaction facility built by Costain at the Isle of Grain has now been converted to a 3.3 million tonnes per annum (tpa) LNG import terminal.

In the 1980s, Irish Sea gas fields were developed and presented several challenges including the presence of H_2S, but more importantly, high nitrogen content. Initially, nitrogen-rich gas was blended with gas of higher calorific value and passed to the NTS, but this became increasingly difficult. Eventually, deployment of large-scale cryogenic nitrogen removal facilities became essential.

North Morecambe gas, from the Irish Sea, and processed by Hydrocarbon Resources Limited (HRL) at Barrow contains approximately 8% (mol.) nitrogen. For this site, Costain developed and patented in the late 1980s an integrated cryogenic nitrogen rejection process that uses a pre-fractionation column upstream of a heat-pumped fractionation column. This process solution gave minimal power consumption, the lowest capital cost and the lowest overall project cost.

Further development in the Irish Sea included the Liverpool Bay development, which passes gas to the Point of Ayr terminal, north Wales, to remove acid gases. Some exported gas is used at the adjacent 1400 MW Connah’s Quay power station, operated by PowerGen (now E.On). To allow flexibility of power plant operation, a Nitrogen Rejection Unit (NRU) was designed and built by Costain to process 200 million scfd of gas of 8 to 11% (mol.) to NTS specification (2). An integrated three-column process was used to provide excellent flexibility. A high reliability sales gas compression system was installed based on the use of electric drives for cost and environmental reasons.

In the early 1990s, Costain designed and built the 800 million scfd Teesside Gas Processing Plant for Enron (now operated by px Ltd.) in North East of England (3). The development at Teesside represented the fourth area to receive gas after south-east England, northern Scotland and north-west England. North Sea gas is supplied via the 2 billion scfd CATS pipeline system and has a relatively high liquids content. Train 1 is capable of producing about 900 tonne/day of NGL using only JT expansion and passes the bulk of the dewpointed gas to the 1875 MW Teesside Power Plant, the world’s largest integrated combined cycle gas-fired power plant. Train 2 was designed as a more sophisticated turbo-expander plant to recover higher levels of NGL (over 1000 tonne/day), whilst exporting high pressure sales gas to the NTS. Uniquely in the UK, the flexibility of the Train 2 plant allows plant operation to respond to market demand for liquid fuels, thereby maximising revenues.

RECENT TRENDS

A new gas processing terminal constructed by Costain at Barrow, is designed to process 130 million scfd of gas from the Rivers Fields in the Irish Sea. This project was technically challenging due to the high acid gas content and high mercaptans levels in the natural gas feed. Many solvents used for acid gas removal are degraded by trace sulphur compounds and usually become ineffective at meeting treated gas organic sulphur specifications.

The H_2S level in the treated gas had to be reduced to less than 1 ppmv and the total organic sulphur content to less than 8 ppmv. The treated gas is passed to existing HRL gas conditioning facilities that include the HRL nitrogen rejection plant.

Only a limited number of acid gas removal technologies are feasible for this duty and very few references exist worldwide for major gas processing applications handling high level of relatively heavy mercaptans. A thorough review of appropriate gas sweetening technologies was therefore undertaken with solvent suppliers and detailed property prediction procedures were assessed. Off-design cases were evaluated and design sensitivity studies performed in liaison with both Burlington Resources and the selected technology supplier, Shell Global Solutions (SGS).

The sulphur-rich gas from solvent regeneration is fed to a sulphuric acid production plant. Although sulphuric acid has essentially negligible value in the UK, this approach was preferred to the use of a Claus plant (that would produce sulphur), due to high capital cost and the low return on investment due to the low value of sulphur.

NEW CHALLENGES

Gas producers are currently considering the development of low WI gas fields in the southern North Sea that previously has not been economic. These gas fields typically have high CO_2 content, as well as high nitrogen content.

Recent study work by Costain has looked specifically at offshore application of existing bulk CO_2 removal technologies (4) so as to treat gas prior to pipelining it to shore. The more simple process technologies, particularly membrane-based separation, tend to be more suited to large-scale offshore applications where space, weight and reliability are of high importance. Work is ongoing to identify the viability of high CO_2 marginal developments and the particular technology needs to make offshore removal viable.

All CO_2 removal projects must consider CO_2 disposal or “sequestration”, as disposal to the atmosphere is not acceptable. Where the removed CO_2 can be economically transported, it may be feasible to use it for enhanced oil recovery (EOR). Alternatively the CO_2 must be sequestered into a depleted reservoir or the seabed. The high oil recovery levels historically achieved offshore UK and Norway means that EOR is difficult to justify in the North Sea though evaluations have been undertaken due to the current high price of oil (5,6).

IMPORTED NATURAL GAS

The quality of imported gas varies according to its country of origin. Norwegian gas, imported via St. Fergus (or soon to be imported at Easington) typically has a WI range above normal NTS specification, whereas Dutch gas, imported via the Bacton Interconnector would typically have a relatively low WI.

Gas blending to maintain NTS specification is the simplest option to cater for off-specification gas. For example, at St. Fergus, Norwegian gas imported via the Vesterled pipeline is rich but will generally be blended offshore. Although the maximum WI is marginally outside NTS specification (max around 52 MJ/Sm^3) it is predicted to fall over time. By 2010 it is expected that the gas supplied via the Vesterled pipeline will always be within NTS WI specification.

By contrast, Norwegian gas imported via the Langeled pipeline will also be of high WI, but gas blending is likely to become more problematic over time as the amount of gas imported from the Ormen-Lange field increases. As a result, nitrogen ballasting to reduce WI may be required at the Langeled import terminal at Easington (1).

The only nitrogen generation plant in the UK that has operated for rich gas ballasting was supplied by Costain to Total at their St. Fergus gas terminal in the mid 1980s. To improve N_2 recovery, this plant used a proprietary modification to Costain's standard cryogenic N_2 generator. The high-purity nitrogen generator was designed and developed by Costain over 40 years ago and Costain has continued to develop improved process schemes for increased nitrogen recovery and reduced utility costs.

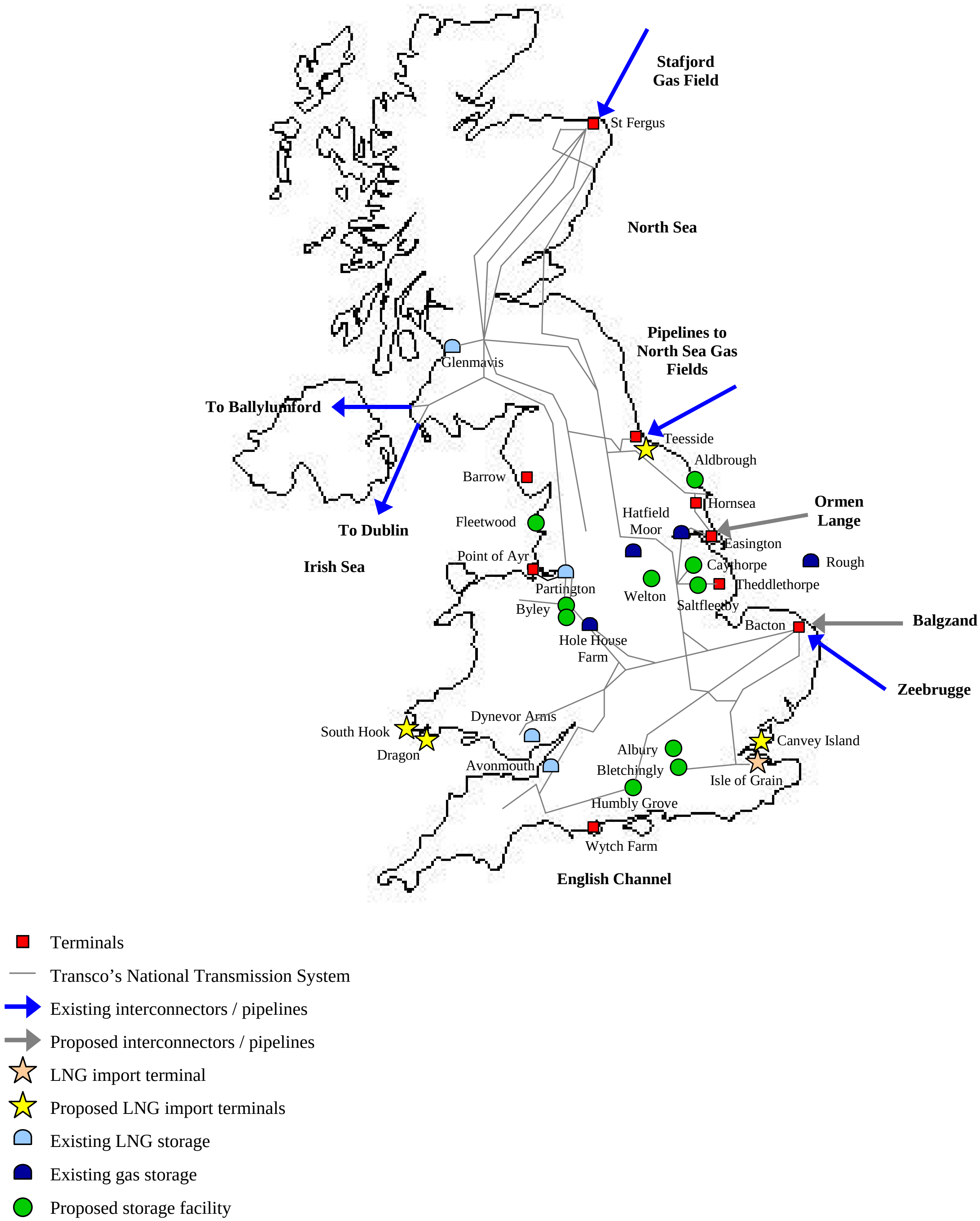

Figure 1 - Britain's Gas Infrastructure and Proposed Improvements

IMPORTED LNG

Imported LNG brings with it both quality and distribution challenges. As gas distribution changes from northern North Sea production to southern-based import terminals and pipelines, strengthening of the gas transmission system is required. The two new LNG import terminals in Wales necessitate the building of new cross-country pipelines and compression stations to deliver the gas into the existing grid. In addition, as the UK becomes more dependant on imported gas, new gas storage facilities are being proposed and built onshore using both depleted gas fields and salt caverns to increase the strategic reserve of gas supplies for harsh winters.

During the natural gas liquefaction process, heavier hydrocarbons such as pentanes plus are removed to prevent freeze-up in the downstream cryogenic sections, whilst lighter hydrocarbons such as ethane, propane and butane are liquefied along with methane. These lighter hydrocarbons contribute to the higher CV and thus the higher WI. During LNG transportation there is also a tendency for the WI to increase as lighter components (methane and nitrogen) boil-off - making LNG heavier over time and over longer transportation distances. Therefore, imported LNG specification varies greatly from country to country. Most potential LNG supplies have a WI in the range 51 to 54 MJ/Sm^3 and above UK limits. Because of this, new LNG terminals will generally require further processing of rich gas, or will need to blend it with air or lean gas to reduce its WI.

Table 1 – UK NTS Gas Specification

Specification	**Unit**	**Limit**
Wobbe Index	MJ/sm^3	47.20-51.41
Nitrogen	mol%	5 (max)
Carbon dioxide	mol%	2 (max)
Nitrogen and carbon dioxide (inert content)	mol%	7 (max)
Oxygen	ppmv	10 (max)
Hydrogen sulphide	mg/sm^3	5 (max)
Total sulphur	ppmv	50 (max)

Regasified LNG can be blended with NTS gas to meet its WI specification, but this can restrict its transportation capacity on a thermal basis. Blending with air is a cheaper option, but at present this is not viable in the UK because the oxygen specification (10ppmv) set by the gas transporter, National Grid (formerly Transco), would easily be exceeded. Another possibility is the extraction of heavy hydrocarbons from the regasified LNG, although this reduces gas volumetric flow. Unless there is a local market for the extracted LPG, this product has no economic value. Stripping out natural gas liquids (NGLs) at source would also lower the WI of the produced LNG, but the economics of this option are only favourable for large LNG train capacities. For example, QatarGas II uses an NGL removal system for its two 7.8million tpa trains destined for the South Hook (ExxonMobil/Qatar Petroleum) import terminal at Milford Haven.

Nitrogen ballasting is generally the preferred method for derichment of natural gas. The gaseous nitrogen can be absorbed in the export LNG stream in a re-condenser vessel prior to the LNG send-out pumps and vaporizers (Figure 2). Normally gaseous nitrogen is compressed to high pressure and then injected into the export gas header. Injection at low pressure into the re-condenser can be advantageous.

At present N_2 ballasting facilities have been installed at the Grain terminal. Selection of the optimum scheme for WI reduction at other locations depends on a number of factors including: feed specification and its variability; local market for LPG; response to demand fluctuations and overall process efficiency and availability.

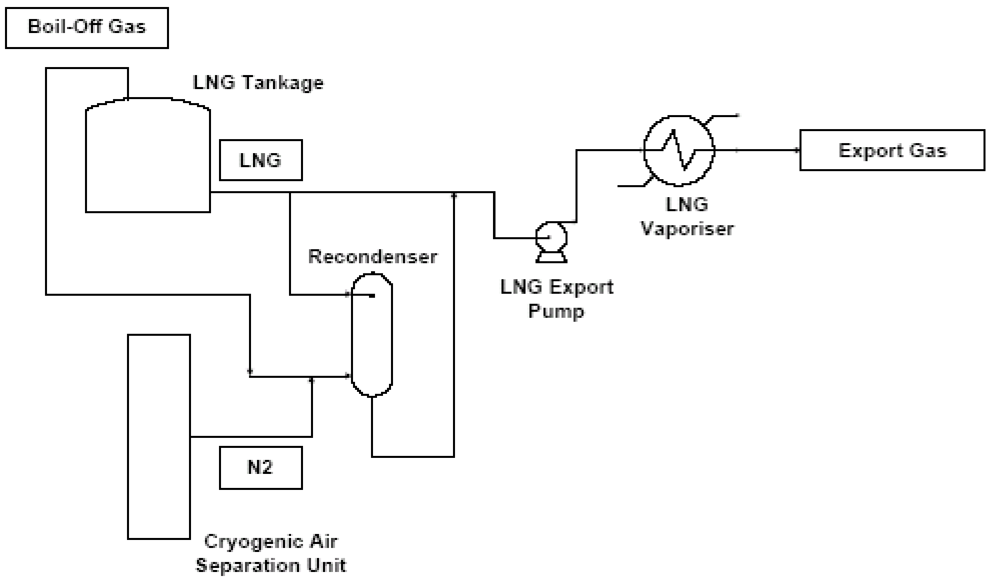

Figure 2 - Schematic Flow Diagram for Nitrogen Ballasting

As LNG quality varies considerably from country to country, the design basis for a nitrogen ballasting plant would vary depending on from where the supplier obtains LNG. With the developing LNG spot market, greater flexibility in terms of nitrogen generation plant and nitrogen supply configuration is likely to be required at import terminals.

Costain's experience is that the most effective design of nitrogen ballasting plant will generally be multi-train units with the capacity for gas or liquids production. This approach allows a high degree of plant flexibility when responding to changing operating scenarios and the need to cover a range of terminal send-out rates and unloading scenarios. The capacity range of particular interest for nitrogen ballasting plants is 100 to 500 tonnes per day.

NITROGEN REJECTION

The design of a nitrogen rejection plant must consider the most cost-effective overall facility including for feed compression, pre-treatment, nitrogen removal and product gas compression. There is a range of processes for nitrogen removal from natural gas. An integrated approach to overall facility design is required, as the lowest cost nitrogen rejection plant does not necessarily lead to the most cost-effective overall facility when feed and product compression are taken into account.

The pre-treatment facilities required for nitrogen rejection plants are essentially similar to those required for conventional gas processing and include removal of carbon dioxide, sulphur, water and hydrocarbon dewpoint control. Deeper removal may be required to avoid freezing at the cryogenic temperatures in the Nitrogen Rejection Unit. Removal of heavy hydrocarbons (aromatics in particular) is conventional practice on low temperature gas plants and many systems have been installed using lean oil absorption, adsorption and partial condensation.

For small gas flowrates, of below 50 million scfd, Pressure Swing Adsorption (PSA) and semi-permeable membranes may be considered. However, for large flowrates, where there is a need to separate nitrogen/methane to an appropriate purity and high methane recovery, PSA requires relatively high power consumption and capital cost. The only process technology that is economic for large flowrates is cryogenic distillation. The power consumption required by a cryogenic unit is not excessive compared to the power consumption that would be required just to deliver gas to the pipeline system.

CRYOGENIC NITROGEN REJECTION

Process selection and optimisation for cryogenic nitrogen rejection is essentially balancing the cryogenic process efficiency, flowsheet complexity and cost against the cost of compression. The machinery configuration needs to be carefully addressed to minimise power consumption.

The key parameter for process cycle selection is nitrogen content. Feed pressure, flowrate and contaminant levels are also of importance but it is the nitrogen content, which essentially dictates the cryogenic cycle.

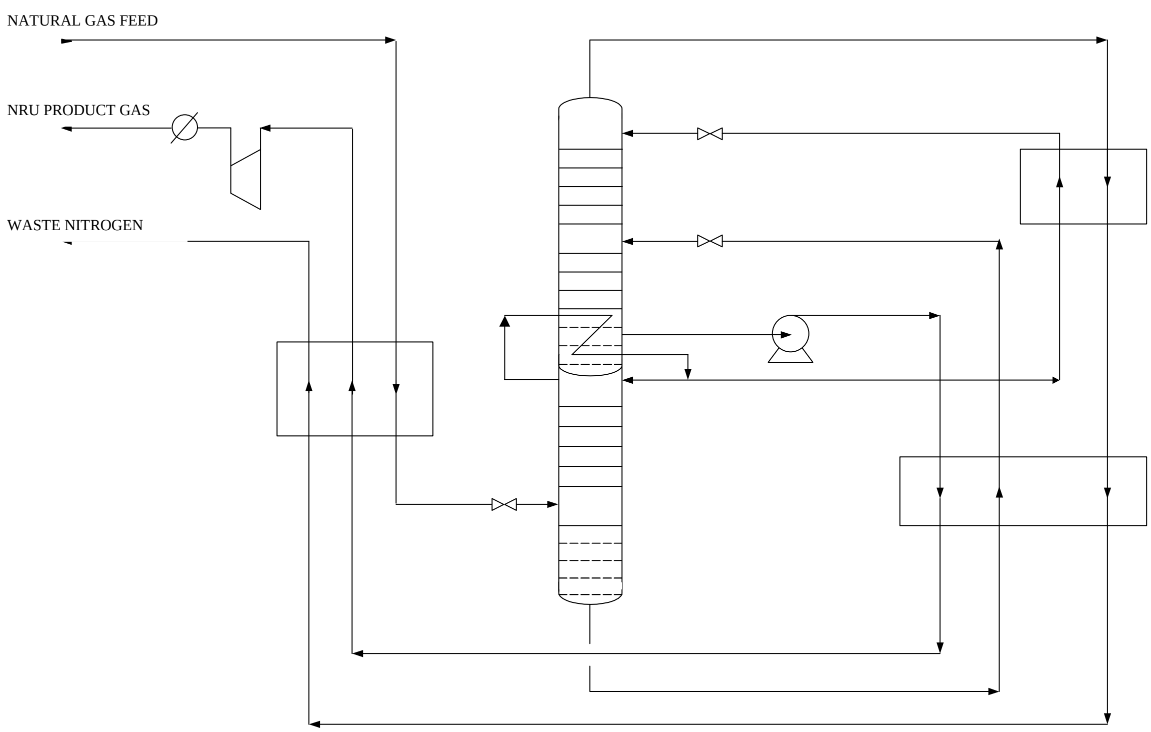

Figure3 - Schematic Flow Diagram for Nitrogen Removal Unit

Because of the dominant impact of product compression on total plant cost, the cryogenic cycle must be highly efficient. For nitrogen rejection units these issues are well understood, which usually makes the choice of process cycle relatively straightforward.

The capital cost and power consumption of the nitrogen rejection process is influenced by the feed flowrate and feed gas nitrogen content and it is conventional to bypass a portion of feed gas around the cryogenic process to reduce cost. This means that the nitrogen level in the NRU product hydrocarbon stream must be reduced below the overall sales gas specification so that the blended export gas is on specification.

The rejected nitrogen stream usually contains a small quantity of hydrocarbon (predominantly methane). The hydrocarbon content of the nitrogen vent stream is dictated by environmental and economic criteria and is typically set at about 0.5 mol.%. The economic optimum methane level in the vent stream is derived from a relatively straightforward evaluation of revenue loss against capital and operating costs. Depending on local environmental regulations this stream will be vented, re-injected or incinerated. A typical removal unit schematic is shown in Figure 3. For a feed gas nitrogen content of 7-20% N_2 an upstream column would be used to increase the nitrogen level to the downstream fractionation system. This may consist of an integrated double fractionation column process or, in more modern plants, a single fractionation column. As experience in nitrogen rejection plant design grows, plant designs are becoming simpler and less power-intensive and nitrogen rejection is becoming more widespread.

LPG EXTRACTION

Where infrastructure exists to transport and use LPG products and an LNG import terminal anticipates rich LNG, WI reduction using extraction of LPG from LNG at the import terminal may be economically attractive (Figure 4). LPG extraction is of particular interest where local refineries could process and utilise the propane, butane and natural gasoline fractions.

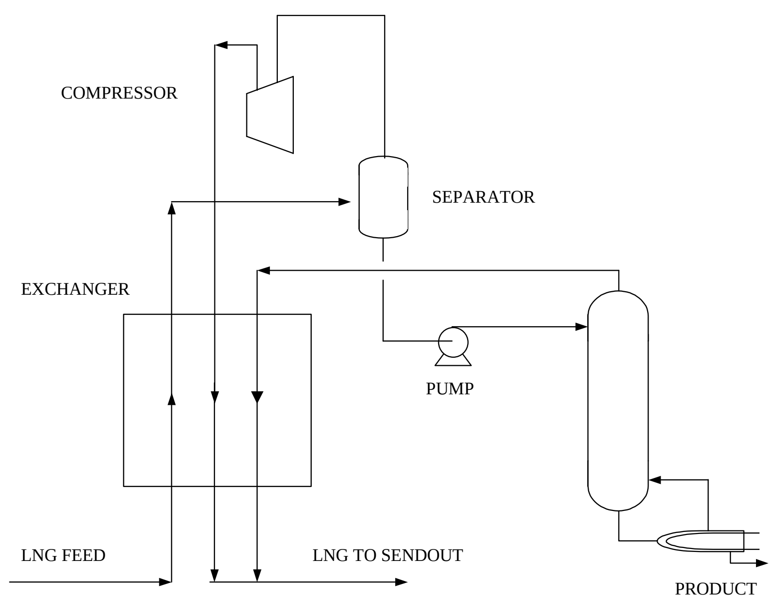

Figure 4 – Compressor Based LPG Extraction Scheme

A number of processes are available for LPG extraction. Schemes typically include warming and partial vaporisation of the LNG send-out stream at low pressure followed by distillation of the liquid fraction. The low-pressure vapour stream is then compressed and condensed against the LNG feed stream prior to pumping to send out pressure. This type of scheme typically needs both significant mechanical and heat energy for compression and reboiler heat duty respectively. The requirement for vapour compression also limits flexibility when responding to changes in throughput.

To address this problem, one of the major energy companies and Costain have cooperated on the development of a process scheme for LPG recovery that offers greater simplicity and flexibility than existing schemes. This scheme allows high recovery of LPG from the LNG export scheme without the need for compression of the column overheads stream. All of the energy input required for separation is used as heating or pumping power, which makes possible a high degree of integration with other process systems.

CONCLUSIONS

- UK's dependence on imported natural gas and LNG is set to increase dramatically over the coming years.
- Many potential sources of imported LNG will require further processing to reduce WI and meet NTS specification.
- New domestic gas prospects are likely to be of lower quality and may require new processing schemes.
- Blending with air is cheaper than other process options, but this is not viable in the UK because of a low oxygen specification set by National Grid.
- UK may be disadvantaged when procuring LNG on the international market because of its narrow range of WI compared to other European countries.
- The selection of the optimum gas processing scheme requires consideration of a number of factors, including: feed specification and its variability; process integration options; local market for LPG; response to demand fluctuations and overall process efficiency.

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