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Process simulation and assessment of a back-up condensate stabilization unit

Nejat Rahmanian [a,*], Ilmi Bin Ilias [b], Khashayar Nasrifar [c,1]

[a] School of Engineering, Faculty of Engineering and Informatics, University of Bradford, BD7 1DP, UK
[b] Chemical Engineering Department, Universiti Teknologi PETRONAS, 31750 Tronoh, Malaysia
[c] Department of Chemical and Petrochemical Engineering, University of Nizwa, Oman

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ABSTRACT

A simulation was conducted using Aspen HYSYS® software for an industrial scale condensate stabilization unit and the results of the product composition from the simulation were compared with the plant data. The results were also compared to the results obtained using PRO/II software. The results show that the simulation is in good agreement with the plant data, especially for medium range hydrocarbons. For hydrocarbons lighter than C_5, the simulation results over predict the plant data while for hydrocarbons heavier than C_9 this trend is reversed. The influences of steam temperature and pressure, as well as feed conditions (flow rate, temperature and pressure) for the product specification (RVP and sulphur content) were also investigated. It was reported that the operating conditions gave rise to the production of off-specification condensate and it was also found that the unit could be utilized within 40–110% of its normal throughput without altering equipment sizing and by the operating parameters.

1. Introduction

Condensate stabilisation refers to stripping of light hydrocarbons (methane and ethane) and removal of acidic components from a liquid hydrocarbon to meet the marketing standards. Hydrocarbon condensates recovered from a natural gas, especially in remote offshore platforms, sometimes do not undergo further processing but are simply stabilized for blending with crude oil streams and then exported as crude oil. For the case of raw condensate, there are no strict specific requirements for the product other than the process specifications. In general, the process of increasing the amount of intermediates (C_3 to C_5) and heavy fractions (C_{6+}) in the condensate is called condensate stabilization (Mokhatab et al., 2006). The hydrocarbon condensate stabilization is also required to minimize the hydrocarbon losses from the storage tank (Benoy and Kale, 2010). This process is performed because a vapour phase must not be produced upon flashing in the atmospheric storage tank. Besides, the purpose of this process is to separate light hydrocarbon gases such as methane and ethane from the heavier hydrocarbon components such as propane and the others. Heavier components can be used for oil refinery cracking processes which allow the production of light products such as Liquefied Petroleum Gas (LPG) and gasoline (Gary, and Handwerk, 2001). Nevertheless, the stabilized liquid has some vapour pressure specifications as it is transferred into pipelines (Mokhatab et al., 2006) and therefore the raw condensate must be processed at certain pressure and temperature so as not to allow to release of light gas in the condensate export pipeline or tanker.

In general, condensate stabilization accomplishes several goals, the foremost of which are:

a) To increase the recovery of methane-ethane and LPG products.
b) To lower the vapour pressure of the condensate which makes it more suitable for blending and reducing the evaporation losses while the product is stored or shipped.
c) To sweeten the raw liquid entering the downstream plant (if any) by removing the acid gases such as hydrogen sulphide and carbon dioxide contents in order to meet the required specifications.
d) To maintain the purity and molecular weight of the lean absorption oil free of certain components such as pentanes and heavier hydrocarbons.

The vapour pressure of condensate is measured by the Reid

* Corresponding author.
E-mail address: n.rahmanian@bradford.ac.uk (N. Rahmanian).
[1] Present address: Department of Chemical Engineering, Shiraz University of Technology, Shiraz, Iran.

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Vapour Pressure (RVP) test, (ASTM D323-99a, 2012). The impact of RVP is often referred to as the gasoline volatility. RVP can also be estimated without performing the actual test by using an algorithm (Esparragoza et al., 1992; Benoy and Kale, 2010; www.intertech.com). In this study, RVP has been set as a criterion for off-spec conditions of the product - that is, a maximum of 10 psia in summer and 12 psia in winter. In actual plant conditions, any condensate produced from this range is called off-spec product and is sent to an off-specification storage tank for temporary storage and further processing at a suitable time. The off-spec tank has the capacity to store 24 h off-spec production.

Process simulation software packages are extensively used nowadays to estimate the product efficiency and enhance the performance of the system by optimizing operating parameters (Bao et al., 2002; Šoóš et al., 2003; Ye et al., 2009; Peters et al., 2011; Lastari et al., 2012; Tavan et al., 2013). There have been few simulating software packages such as Aspen Plus®, Aspen HYSYS® and PRO/II® for use in the oil and gas industries. For example, the hydrogen production with steam methane reforming in a fluidized bed membrane has been simulated by Aspen Plus (Ye et al., 2009). This simulation demonstrates considerable responses against the change in pressure, temperature, steam-to-carbon ratio and permeates the side partial pressure of the reactor. Besides, the result was compared with a pilot scale experimental study and not at real industrial scale. Carbon dioxide capture by MEA absorbent was studied and simulated by Aspen Plus and Aspen HYSYS® (ErikØi, 2012). Aspen ® was also used to simulate azeotropic separation of ethane and CO_2 using reactive absorption (Tavan and Hosseini,Hysys 2013).

PRO/II® is a commercial process simulator widely used in the oil, gas and petroleum industries (Liao et al., 2001; Lee et al., 2011, Kim et al., 2014), for instance, in the production of methanol from natural gas, CO_2 absorption has been simulated for a FPSO (floating production, storage, off-loading) system (Kim et al., 2014). In another example, the CO_2 reforming of methane has been modelled with PRO/II® to consider the effect of Ni-based catalyst (Lee et al., 2011). The conversion of CH_4 versus the change in concentration of H_2O and CO_2 has been studied and the Ni/MgO was chosen as a desirable catalyst in order to produce synthesis gas; the result of modelling was validated by experimental data not plant data.

The objective of this study is: i) to find the right operational window and optimum conditions for a current operational BCSU in terms of producing on-specification product and ii) to compare the simulation software packages PRO/II® and Aspen HYSYS® for this specific unit operation.

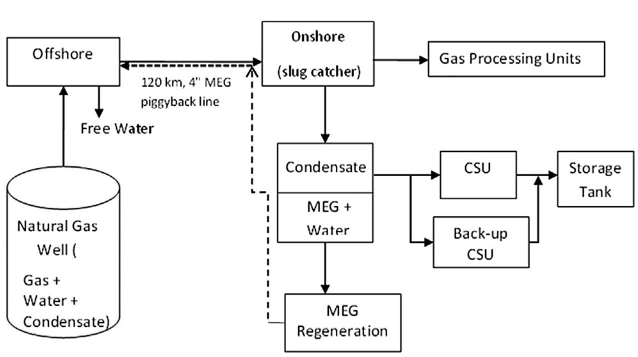

Fig. 1. Block flow Diagram of the gas plant including Condensate Stabilization Unit and Back-up Condensate Stabilisation Unit (Behbehani and Atashrouz, 2011).

1.1. Block flow diagram of condensate stabilization unit

Fig. 1 shows the block flow diagram of a gas plant consisting of a Condensate Stabilization Unit (CSU) and a back-up CSU (BCSU) located at Asaluyeh port in the southern part of Iran. BCSU in this plant is the subject of this study.

Firstly, reservoir fluids which consist of gas, water and condensate are produced and primarily processed at the offshore platforms. Then, some free water is removed from the mixture and the rest is transported to the on-shore plant. The transportation of the treated reservoir fluids is transported through a 32 inch pipeline about 120 km from the off-shore processing platform plant to the on-shore plant. In the presence of water, the gas mixture can form gas hydrates, which hampers the smooth flow of gas in the pipeline. Hence, monoethylene glycol (MEG) is injected via a 4 inch piggy backline to the exit stream from the offshore platform in order to prevent the formation of gas hydrates (see Fig. 1).

Once the gas mixture arrives at the onshore plant, it will be separated into two streams; a gas stream and a liquid stream in the slug catcher. The gas stream is transferred to the gas plant and the liquid stream that consists of condensate, MEG and water is further separated to form a condensate stream and a mixture of MEG and water stream. The mixture of MEG and water is treated in the MEG regeneration unit where MEG is recycled to the off-shore via a 4 inch piggy back line. Then the condensate stream is fed to the CSU. A BCSU is designed to run the plant during CSU failure. After treating in CSU or BCSU, the stabilized condensate is transferred to storage tanks for exporting purposes to local plants or overseas.

1.2. Process description of BCSU

The BCSU process is similar to stage separation utilizing the equilibrium principles between vapour and condensate phases. Equilibrium vaporization occurs when the vapour and condensate phases are in equilibrium at the temperature and pressure of separation (Mokhatab et al., 2006).

Fig. 2 shows a typical flash vaporization process for condensate stabilization with the same concept as BCSU in this study. The main feed which is a condensate produced from the inlet separator (slug catcher) passes through a heat exchanger and then enters the high-pressure (HP) flash tank where the pressure is maintained at 600 psia. A pressure drop of 300 psia helps flash of large amounts of light ends which are discharged as sour gas stream after recompression. The sour gas can be sent to further units or recycled into a reservoir for enhanced oil recovery purposes. After that, the bottom liquid from the HP tank enters the middle pressure (MP) flash tank where the additional methane and ethane are released. Then, the bottom product re-enters the low-pressure (LP) tank and they are fed to a condensate stripper for purification before transferring to

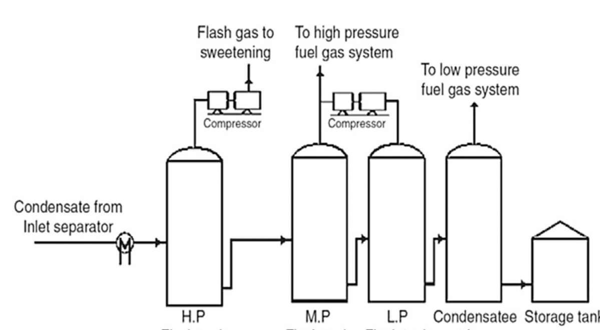

Fig. 2. Flash vaporization method (Mokhatab et al., 2006).