The Solution to Coldbox Freezing

Dr Tobias Eckardt, Dr Margaret Greene, Dr William Dolan, and Justin Pan, (BASF), and Stephen Holmes, Stephen Hughes, and Kevin Cunning (Kinder Morgan), outline how they addressed heavy hydrocarbon freezing while boosting yield at the Elba Island LNG Facility.

LNG is produced by cooling natural gas to -160˚C. Prior to cooling to these low temperatures, impurities must be removed from the gas to ensure proper performance of the downstream liquefaction process. A standard pre-treatment line-up consists of an acid gas removal unit (AGRU), a molecular sieve dehydration unit to remove water to <0.1 ppm, and a mercury removal unit. It was not until the first baseload LNG plants in the US processing lean gas started up in the mid-2010s and began to experience freezing in the cryogenic heat exchangers that this typical pre-treatment approach was questioned. Only now, more than six years since the first mega scale LNG plant was built on the US Gulf Coast and 88 million tpy of capacity later,[1] the industry has acknowledged and started to address the freezing problem, which reduces LNG throughput throughout the region.

The freezing of coldboxes in US LNG plants is due to traces of heavy hydrocarbons (HHCs) in otherwise lean natural gas, which are not removed prior to the cold section of the plant. Depending

on the plant design, HHC freezing can occur as far upstream as the gas/gas heat exchanger upstream of the turboexpander. However, it is more common for the freezing to occur in the coldbox. US LNG plants have addressed the HHC freezing problem by reducing throughput or completely shutting down the trains to warm up the coldbox to derime. This process leads to flaring of natural gas and excess energy consumption due to warming and cooling of the coldbox. Another option is to run the coldbox at higher temperatures, which allows the facility to produce LNG continuously, but less efficiently. Even though the gas still meets LNG specifications, these mitigation practices also lead to plugging of heat exchanger filters in the sub-cooler skid on LNG tankers. Again, freezing causes cooling circuit shutdown and leads to more loss of LNG through boil off gas. Every plant must take a different approach to solve the problem of HHC freezing, but each approach adds complexity to operations and reduces the efficiency of LNG production.

Rather than sacrificing LNG production, BASF recommends removing the trace HHCs in the pre-treatment section of the plant. BASF has decades of experience producing and installing adsorbents for HHC and water removal from natural gas using temperature swing adsorption (TSA) technology. BASF Sorbead® aluminosilicate gel adsorbents are installed in some of the largest gas processing facilities in the world processing crude well gas to pipeline specifications.[2] BASF has leveraged this experience to bring a new technology, Durasorb™, to the LNG industry. Durasorb technology has been qualified by Shell, Exxon, and other gas majors, and has been implemented in a greenfield and brownfield plant. In this paper, BASF and the plant operator, Kinder Morgan, will detail the implementation of Durasorb as a drop-in solution to coldbox freezing at the Elba Island LNG Facility.

Table 1. Feed gas to Elba Island, on dry basis

Component	Envelope
O_2	–
N_2	0.31 – 0.50%
CO_2	0.10 – 1.20%
CH_4	93.55 – 96.65%
C_2H_6	2.65 – 4.51%
C_3H_8	0.10 – 0.29%
iC_4H_{10}	30 – 395 ppm
nC_4H_{10}	50 – 470 ppm
C5's	7.5 – 300 ppm
C6+*	32 –240 ppm
BTEX	2 – 55 ppm
*including C8	3 – 42 ppm
*including C9+	5 – 38 ppm

Problem identification and solution implementation

The ten 0.25 million tpy trains at the Elba Island Facility were started up over the course of 11 months from September 2019 to August 2020. The facility is fed from the US natural gas pipeline grid and employs Shell MMLS liquefaction technology. The pre-treatment line-up consists of an AGRU and dehydration unit. A simplified block diagram of the plant layout is shown in Figure 1. The dehydration unit consists of two towers, operating between 75 – 95˚F (24 – 35˚C), 730 psia (50 bar), on a 1440-minute cycle.

Because the pre-treatment line-up was not designed to remove trace HHCs, and these components are not efficiently removed in the liquefaction section of the plant, freezing of C8+ and BTX occurs in the cryogenic heat exchanger. The freezing of HHCs in the cold section requires plant operations to halt production for 1 – 2 days every 2 – 3 months on all 10 LNG trains. This workaround increases operational complexity, utilises personnel resources, and reduces annual LNG production.

In 2021, Kinder Morgan engineers began seeking a permanent solution to HHC freezing and reached out to natural gas experts in BASF. Together, three potential solutions were discussed:

1. Install a heavy hydrocarbon removal unit (HRU) upstream of the AGRU to process the full 400 million ft^3/d of gas coming into the facility. This meets the HCC removal specifications for the entire plant, but requires the most cost and time, and has a single point of failure.

2. Install a third adsorber tower in each train. This meets HHC removal specifications for the individual train, but requires a high cost, time, and large plot space.

3. Replace the existing adsorbent material with Durasorb and utilise the current capabilities of the facility. This option has no CAPEX, a short time frame, and can be executed during a scheduled outage, but has limited benzene removal.

Understanding the capabilities and limitations of the current equipment at the facility was pivotal in predicting the performance of the unit if option 3 was chosen. Key pieces of equipment to understand when considering this option are the regeneration gas heater, cooler, and compressor capabilities.

Option 1 would implement well-established HRU technology, which would utilise aluminosilicate gel material in a short cycle temperature swing adsorption (TSA) unit. This option would require significant CAPEX and time but would solve the problem for the whole plant and meet a benzene specification of <0.5 ppm. Option 2 would utilise the current infrastructure but add a third adsorption tower to each train. This option would provide more HHC removal, but also

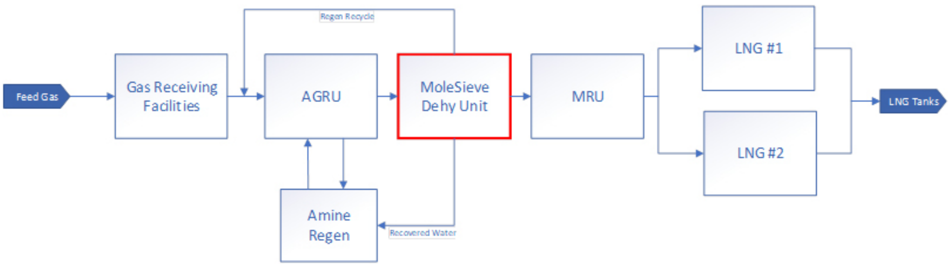

Figure 1. Elba Island LNG plant layout. Molecular sieve unit, highlighted with a red box, is the scope of this paper.

require CAPEX and time, and the facility did not have the plot space. Option 3, implementing Durasorb as a drop-in solution, is the simplest option, using the existing infrastructure of the plant, but is expected to remove the least amount of HHCs prior to the cold gas separator.

Durasorb technology combines the performance of an HRU for HHC removal and a dehydration unit for water removal to cryogenic specifications. The main challenge with combining HRU and dehydration technology is the lifetime of molecular sieves. In an HRU, BASF utilises aluminosilicate gel materials, which are robust and can withstand upwards of 10 000 cycles in a lifetime. On the other hand, molecular sieves are required to achieve very low water specifications but are not robust materials and can only withstand 1200 – 1500 cycles in a lifetime. Combining aluminosilicate gel materials,[3] which are the most well-suited materials for adsorption of heavy hydrocarbons (C8+, BTX), and molecular sieves in the same unit requires the molecular sieve materials to match the lifetime of the aluminosilicate gel materials.[4] Durasorb technology utilises a proprietary bed design that necessitates most of the bed to be filled with the more robust aluminosilicate gel material and a small section of the bottom of the bed with molecular sieve (Figure 2). This approach protects the molecular sieve from HHCs and most of the water, which allows the molecular sieve to last longer and be cycled more frequently.[5]

In early 2022, Kinder Morgan decided to move forward with a trial of option 3, which was the quickest to implement and required no CAPEX. This option also provided Kinder Morgan with a side-by-side comparison, replacing molecular sieve with BASF's Durasorb material in two of 10 trains. Initial analysis also showed there was ample regen gas, which would allow for cycle time optimisation and performance improvement. Since the implementation in July and August 2022, BASF and Kinder Morgan have worked together to monitor and optimise the performance of the Durasorb trains.

Performance

LNG trains at the Elba Island Facility include a moisture analyser and online GC measuring C6+ and benzene concentration. Upon start up with Durasorb technology, the LNG trains were processing 38 million ft^3/d of gas and removing water to LNG specifications. Although removing water is of utmost importance, the goal of this project was to address the freezing problem, which is caused by benzene and C8+ components. As shown in the Figure 3, feed gas composition includes ~7 ppmv of benzene and ~150-200 ppmv of C6+. Comparing C6+ inlet and outlet GC data shows removal of about 30-40 ppmv of C6+. Further analysis and manipulation of the data indicates that the removed C6+ are C8+ components.

As a known freezing impurity, the removal of benzene was also monitored. Inlet and outlet GC data are shown in Figure 4. The data shows benzene removal from an average of 7 ppm inlet to undetectable levels at the outlet. Benzene continues to be removed over many cycles and has been consistent since startup of the Durasorb trains.

In addition to GC data, regeneration separator liquid volume was monitored to confirm heavy hydrocarbon removal performance of the adsorber beds.

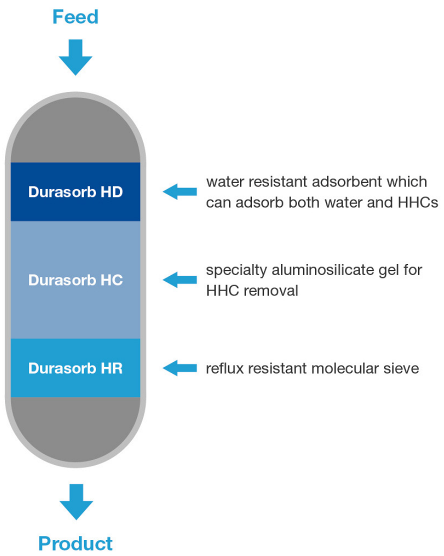

Figure 2. Durasorb bed design.

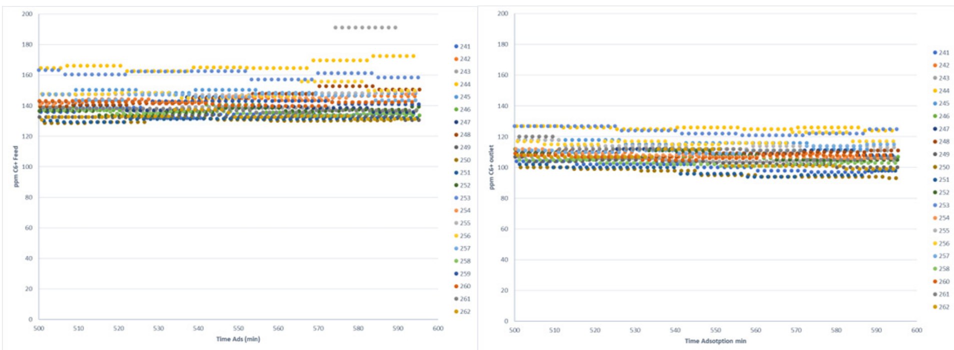

Figure 3. Left: Inlet gas composition shows an average C6+ concentration of 148 ppm. Data points represent C6+ concentration for each cycle over time. Cycles 241-262 are representative of all cycles. Right: Outlet gas composition shows an average C6+ concentration of about 110 ppm.

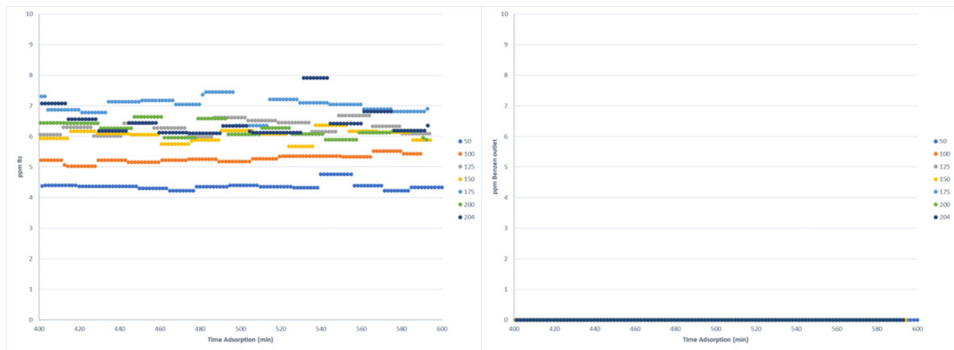

Figure 4. Left: Inlet gas benzene concentration. Right: Outlet gas benzene concentration.

Data collection and optimisation

Based on data provided by Kinder Morgan, BASF recommended reducing cycle time from 720 min. to 590 min. Shorter cycle time allows the unit to remove more HHCs, taking a deeper cut of C8+ and benzene. As shown in Figure 5, benzene breakthrough occurs at 770 mins., therefore, ending the adsorption time sooner than 770 mins. ensures complete benzene removal. Running the unit to breakthrough gave BASF and Kinder Morgan additional data for benzene adsorption, confirming BASF's simulation model, and showed that occasional breakthrough of benzene does not lead to permanent increase in coldbox dp.

A result of the Durasorb technology achieving the desired performance of removing HHCs and water is the presence of HHCs in the regen liquids normally routed back to the AGRU. Due to the scale of each LNG train at the Elba Island Facility, operations can dispose of the contaminated liquid stream and make up water losses at a negligible cost, rather than recycling back to the AGRU. For greenfield projects or retrofits of larger LNG trains, a three-phase separator represents the most desirable solution for the regeneration condensate to facilitate separate handling mechanisms for the water and hydrocarbon streams. Alternative liquid handling solutions can also be considered depending on the plant line-up and operational needs. Recycling the regeneration condensate back to the front of the AGRU may be possible depending on the amount of hydrocarbon liquids removed.

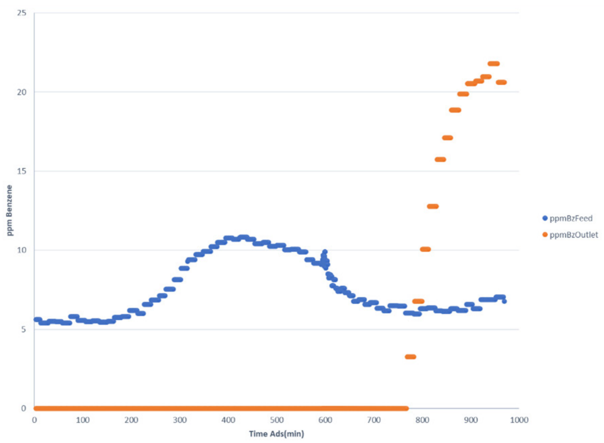

Figure 5. Feed gas inlet and outlet benzene concentration, showing benzene breakthrough for one cycle.

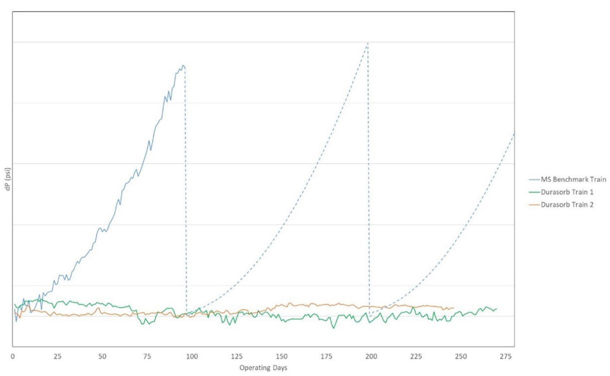

Figure 6. Pressure drop in coldbox for molecular sieve benchmark train and Durasorb trains. Dotted lines represent projected deriming events for MS trains.

Results

As of the date of paper submission (28 June 2023), the two Durasorb trains at the Elba Island Facility continue to remove water and HHCs to the levels described in this paper. Most importantly, the pressure drop in the coldbox remains flat and natural gas has been processed through these trains on a continuous basis, without requiring shutdown for deriming. Figure 6 shows how the pressure drop in the Durasorb trains remains steady, as the pressure drop in the molecular sieve trains continues to increase until shutdown and deriming are required. Durasorb trains have run for over 330 days and eliminated three deriming events that would have required a production stoppage. The Durasorb trains continue to run well, with no indication of solids build up, and plant data indicates that the expected four-year lifetime will be achieved.

Conclusions and next steps

BASF worked with Kinder Morgan to identify a solution to coldbox freezing that would have the desired impact in the shortest amount of time. BASF and Kinder Morgan worked together to implement Durasorb technology in two out of 10 trains at the Elba Island LNG Facility. The two trains operating with Durasorb materials are removing HHCs and water and preventing deriming events.

Implementation of Durasorb has increased uptime at the Elba Island Facility. Kinder Morgan has been pleased with both the performance of the Durasorb technology and the support provided by BASF. With that, Kinder Morgan has decided to replace existing molecular sieves with Durasorb technology in three additional trains this year, bringing the total Durasorb trains at Elba Island to five. In addition, Kinder Morgan is planning a full 10 train upgrade project, which will utilise Durasorb to remove heavy hydrocarbons and allow the gas to by-pass the cold gas separator. Bypassing the cold gas separator allows operations to run at higher pressure throughout the process and keep the gas above critical. This process change, along with auxiliary equipment upgrades, is expected to reduce the frequency of outages and flaring emissions associated with deriming and increase production throughput at the Elba Island Facility.[6] **LNG**

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Note

This article is based on a paper presented at LNG2023. It has been published with the approval of the LNG2023 Conference.