PEMEX BURGOS GAS PROCESSING COMPLEX OPERATING AND DESIGN RECOMMENDATIONS

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ABSTRACT

Beginning in 2001, Petróleos Mexicanos (Pemex) has installed six gas processing trains at its Burgos Gas Processing Complex located in northern Mexico. Four of the six trains have been in service for two or more years. The last two trains were brought on-line in late 2008 and in early 2009. Each 200 MMSCFD train contains a cryogenic section based on the same process and general physical design, and is capable of 99% propane recovery. Ethane recovery capability is not included in any of the trains.

Pemex has accumulated several years of very successful operating experience with the four cryogenic processing trains currently in service. Many of the "lessons learned" from the operation of the first two trains have resulted in improvements in the subsequent trains. Several of these designs improvements are discussed.

It is hoped that plant operators/owners and process design engineers will both benefit from Pemex's accumulated experience by including the key design features and the "lessons learned" in their own designs.

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BACKGROUND INFORMATION

Project Background

The Burgos Gas Processing Complex (Complejo Procesador de Gas Burgos, CPG Burgos) in Reynosa, Tamaulipas, Mexico currently processes 1.2 billion standard cubic feet per day (BSCFD) of sweet wet gas for recovery of propane and heavier hydrocarbon liquids. This complex is composed of six cryogenic plants, each with a processing capacity of 200 MMSCFD. This project began in the summer of 2001, and the sixth plant was placed in operation during the first quarter of 2009.

A partnership between ICA Fluor (ICAF), a Mexican-owned corporation, Linde Process Plants, and Ortloff Engineers was formed to design and construct the plants. Ortloff provided the process design for the Single Column Overhead REcycle (SCORE) cryogenic plants. Linde provided the detailed engineering and fabrication of the 200 MMSCFD modular plants. ICAF provided all of the on-site construction, installation, DCS programming, SIS system, utility systems, inlet gas conditioning systems, and firewater system. All three companies provided commissioning and startup assistance for all six plants.

Figure 1 – Pemex CPG Burgos Plant 1

Operations Background

Pemex is a state owned oil and gas company. Pemex Gas y Petroquímica Básica (PGPB) is the subsidiary that operates the gas processing facilities. PGPB has several cryogenic plants in the southern part of Mexico. These facilities include three Gas Subcooled Process (GSP) retrofit plants designed by Ortloff in the Cactus and Ciudad Pemex gas processing complexes located in the states of Chiapas and Tabasco. Although Pemex has a lean oil plant in the Reynosa area (which will eventually be shut down when the new cryogenic NGL recovery plants are put in service), PGPB did not have any cryogenic plants in the northern part of the country until the plants in Reynosa were built.

The Pemex personnel in the Reynosa area did not have any operating experience with turbo-expander plants, so PGPB temporarily transferred some of the engineers and operators from the facilities in the Cactus plants to assist with the commissioning, startup, and operation of the new plants. Although these personnel changes helped during critical times, the lack of experience made the startup of the first two plants challenging. These challenges will be discussed in the "Startup Experience" section of this paper.

For the commissioning of the third and fourth plants, PGPB brought in engineers and operators from the Reynosa lean oil plant. The new personnel first went through all the technology training and then worked for some time in Plants 1 and 2. The engineers and operators that started up the first two plants transferred to the new plants for commissioning and startup. The two years of operating experience in Plants 1 and 2 made the startup of Plants 3 and 4 much easier. The same approach was used in Plants 5 and 6.

Plant Construction and Startup Timeline

The schedule for the installation of the plants was fairly aggressive. Six plants were designed, built, and installed in less than eight years. The plants have been built and installed in pairs, with the construction of the first pair beginning during the summer of 2001 and the commissioning completed during the summer of 2003. Construction for the second pair of plants began in the summer of 2004, and those plants were commissioned in 2006. The construction of the third pair of plants began in January of 2007, and commissioning occurred during the winter of 2008-2009.

The premise that allowed this "fast track" schedule was that all six plants would be identical. As we all know, "identical" is practically impossible. This is especially true in the case of the Reynosa plants, since the plants in each pair of plants are laid out as mirror images of each other. Other changes were made (discussed later in the paper) as Pemex and the startup team encountered problems and operating difficulties during the commissioning, startup, and operation of the earlier plants.

Process Overview

Each of the plants is designed to process 200 MMSCFD of sweet wet gas using Ortloff's patented SCORE process technology [1]. The plants recover over 99% of the propane and essentially all of the butanes and heavier hydrocarbons in the feed gas. Each plant has inlet separation, dehydration, a cryogenic plant, residue gas compression, and a debutanizer tower. The complex also has the capability to process condensate in four of the six plants.

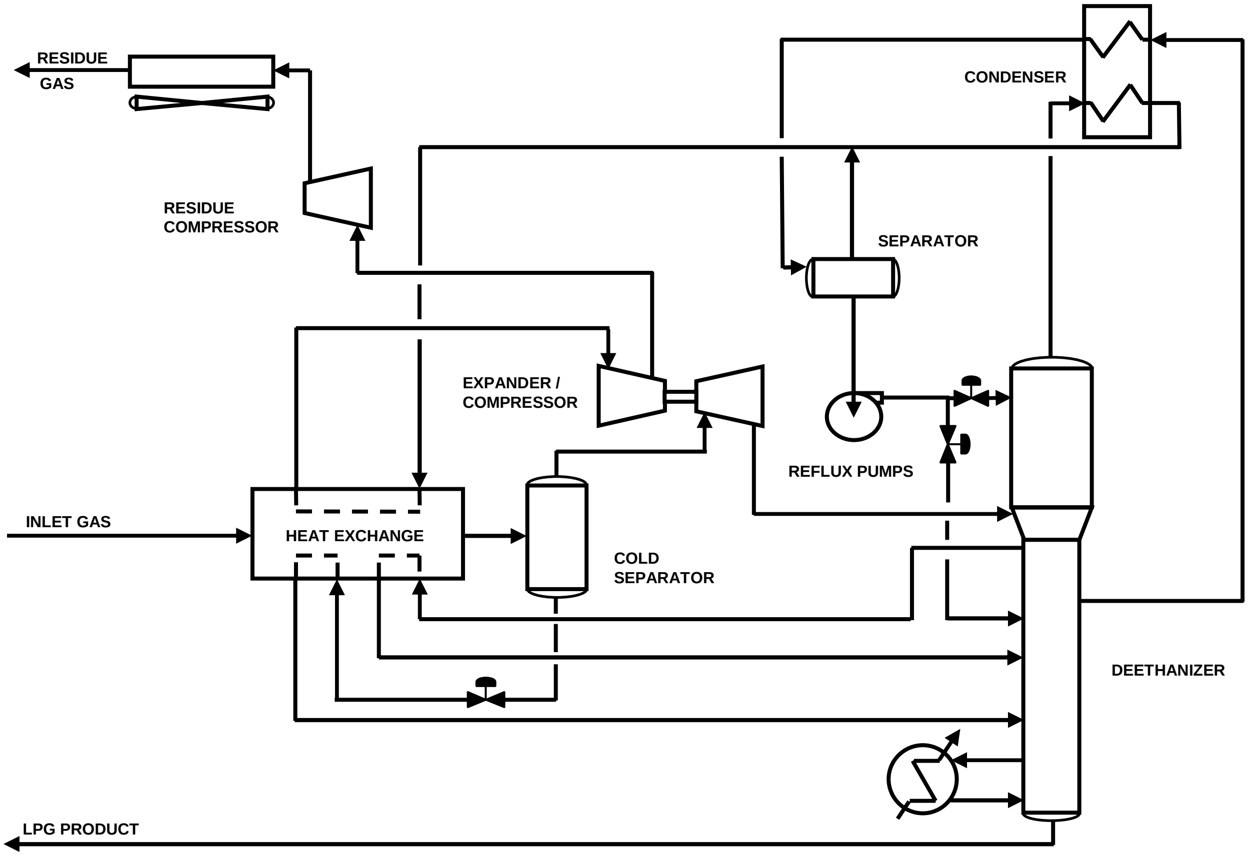

Figure 2 – SCORE Process Flow Diagram

In the SCORE process, the gas from the outlet of the dehydrators is cooled by heat exchange with the residue gas, the cold separator liquids, and the side reboiler stream, then enters the cold separator. The vapors from the cold separator are work-expanded to provide cooling for the process. The 2-phase expander outlet stream is fed to the tower at the bottom of the top (absorber) section. The liquid from the cold separator is used to provide cooling to the inlet gas and is then fed to the tower in the bottom (stripper) section.

The SCORE process has a side vapor draw below the expander feed tray. This vapor draw is the vapor coming up from the bottom section of the tower, and contains methane and ethane that can be used as reflux to absorb the heavy hydrocarbons from the expander vapors. The vapor draw is partially condensed as it is cooled by the tower overhead stream, then fed to a reflux accumulator to separate liquid for reflux to the absorber and stripper sections of the tower.

The SCORE process also has a side liquid draw below the expander feed point that is used to provide inlet gas cooling. The side liquid draw is similar to a side reboiler, except that the liquids are returned to the tower several stages below the draw stage.

The residue gas compression for each plant consists of two Solar Taurus Model 70 turbines coupled with two-stage Dresser-Datum compressors. The two stage compressors were selected to decrease the fuel gas consumption (part of the process guarantees). Each pair of plants shares a common spare compressor. This five compressor arrangement has proven to be very practical during startup, maintenance, and normal operation.

The gas processing complex is located about 20 miles southwest of the city of Reynosa on Highway 40 (or Highway to Monterrey). Due to this remote location, there is not sufficient raw or potable water for use in the plants, precluding the use of a cooling tower. Instead, air coolers are used for compressor interstage and after coolers, debutanizer condenser, and product coolers.

Since water is scarce, there is no makeup water to allow using steam as the heating medium. Instead, the plants use hot oil as the heating medium for all reboilers and feed heaters. The hot oil loop includes a surge tank, charge pumps, process pumps, and waste heat recovery units on the gas turbine exhausts.

EVOLUTION OF THE PLANT DESIGN

Key Design Features

The SCORE process design has provided a steady product recovery of over 99% since the plants were put in operation six years ago. The success of the plant operations can be attributed to the following key design features.

- *Plot plan, equipment, and piping layout*
  As mentioned earlier, the plants are modularized to reduce construction and assembly time. The equipment modules are arranged in three structures. Each structure contains either three or four platform levels. The inlet separation and dehydration equipment is installed in one structure and the cryogenic plant equipment is installed in a second. The debutanizer auxiliary equipment, along with the hot oil and fuel gas equipment, is installed in the third structure.

  All of the rotating equipment throughout the plant is installed at ground level and laid out so that operators have easy access for maintenance of this equipment. Access for most of the instrumentation and valves is also adequate. The expander and flare knock-out drum each have their own modules for their auxiliary equipment.

- *Residue Gas Compression*
  As mentioned previously, each plant has two residue gas compressors, with a common spare for each pair of trains. The compressors are two-stage with aerial interstage coolers and after coolers. This arrangement has proven to be very practical for operations and maintenance and has provided very reliable plant operation.

Figure 3 – Waste Heat Recovery Units on Gas Turbine Exhaust

- *Free-draining from heat exchangers to accumulators and separators*
  All of the heat exchangers in the plant are located in the upper level platforms. The inlet gas exchangers are installed above the cold separator, and the reflux condensers for both the deethanizer and debutanizer are installed above their respective reflux drums. This allows for free-draining of the condensed liquids in the process streams to eliminate the potential for high pressure drop or liquid slugging.

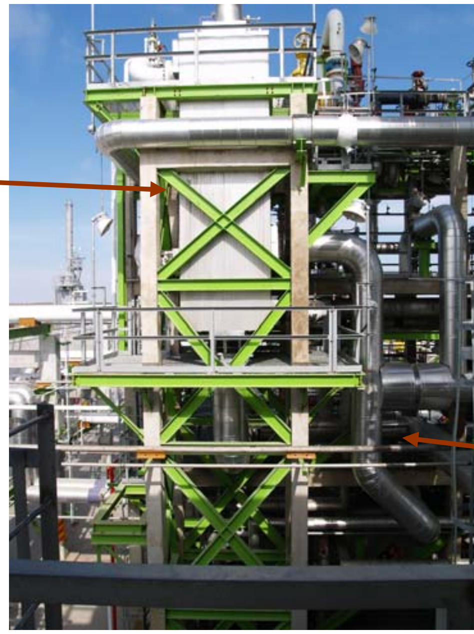

Figure 4 – SCORE Process Structure

- *Inlet Gas Exchangers Bypass Line*
  Under certain conditions in the SCORE process, recovery can be improved by increasing the inlet temperature to the expander. For this reason, a bypass line with a remotely operated valve has been provided to bypass inlet gas around the gas/gas and gas/liquid exchangers upstream of the cold separator. This bypass became an essential operating feature during the colder weather when, due to having more than 5 km of above-ground inlet gas lines, the inlet gas temperature would fall significantly below the design inlet gas temperature. This drop in temperature caused colder temperatures throughout the plant. Although colder temperatures usually improve recovery, the propane recovery of the SCORE process is already 99+%. The colder inlet gas temperature caused excessive condensation of ethane from the inlet gas, making it difficult to strip the ethane from the liquids to meet the product specifications and to maintain stable control.

Equipment Design Improvements

Pemex operations personnel identified several problems with the first two plants. These concerns were taken into consideration for the subsequent plants, and the following improvements were made.

- *Side Liquid Draw*
  In the first two plants, the side liquid draw line to the side reboiler did not have block valves upstream of the strainers or control valves. This meant that every time the strainer

got plugged or dirty, the propane recovery would decrease and the plant had to be shut down and depressured to clean or replace the strainer. For Plants 3 and 4, block valves were added so that the strainer could be cleaned while the plant remained in operation. Plants 5 and 6 were equipped with block valves and dual 100% parallel strainers, allowing the plants to remain in operation and the side reboilers in service when it is necessary to clean the strainers.

- *Strainers*
  As a result of the difficulties encountered during the operation of the first four plants, Pemex requested that parallel dual strainers and block valves be installed throughout the plant upstream of platefin heat exchangers. This improvement allows for more reliable plant operation because it adds the flexibility of cleaning the strainers for critical pieces of equipment without bypassing the equipment or shutting down the plant.

- *Dryout Lines*
  Proper dryout procedure is critical for startup of a cryogenic plant, as discussed later in the "Startup Experience" section of this paper. For the SCORE process, it is imperative that the reflux section of the deethanizer be as dry as possible. The entire reflux system is essentially in a closed loop with the column, so there is no path to use during dryout unless dryout piping is added during the design phase of the project. One possible path for dryout gas flow is from the reflux pump case drains to the flare. In Plants 1 and 2, the dryout gas was routed to flare using temporary hose connections. For the subsequent plants, these lines were hard-piped and additional dryout lines were installed.

- *Methanol Injection Points*
  Any introduction of moisture into a cryogenic plant can cause hydrate formation. The injection of methanol into the process can be used to eliminate or remove the hydrates. This topic will also be discussed in the "Startup Experience" section of this paper. The most likely point for hydrate formation is in the reflux condenser, but hydrates have also been observed in the gas/liquids exchanger. Since the Pemex operations personnel did not have cryogenic plant operation experience, they did not realize how important these injection points were when they reviewed the P&IDs for Plants 1 and 2. Once they operated Plants 1 and 2 for a few months, they realized that additional injection points would be useful, and these were added to the other plants. All the methanol lines were hard-piped in the subsequent plants.

- *Pressure Differential Transmitters*
  In Plants 1 and 2, the pressure drop across the platefin exchanger inlet strainers in the gas/gas exchangers were only indicated locally. The plant engineers and operators realized how important it is to have the pressure drop indication in the DCS across the strainers and across the strainer and exchanger, and asked to have both readings in the DCS. In Plants 3 through 6, the operators now have the ability to monitor either the strainer or both the strainer and exchanger for all the gas/gas exchangers by simply closing and opening valves. In Plants 5 and 6, this feature was also added to the side reboiler.

- *Regeneration Gas Heater Wind Buffers*
  There are two prevailing wind directions at the plant site, from the north and from the south. During the commissioning of the regeneration gas heater in Plant 1, these winds caused two problems. The pilot kept going out, and the flame scanners could not detect the flame all of the time. These problems caused the regeneration gas heater to shut down continually on flame failure. Wind buffers were installed around the heater to resolve the problem.

- *Regeneration Gas Heater*
  Pemex has experienced recurring problems on Plants 1 through 4 during startup of the regeneration gas heater, due to the inability of a differential pressure switch to detect whether there was adequate purge flow prior to allowing pilot ignition. Because the heater box offers little resistance to flow, the dP through the heater is very low. Any delays in restarting the regeneration gas heater could potentially require a reduction in inlet gas flow (or even shutdown of the plant), since a cryogenic plant cannot operate without a serviceable inlet gas dehydration system. The solution, implemented on Plants 5 and 6, was to change from sensing blower dP to blower flow.

- *Inlet Separation*
  During startup of Plants 1 and 2, it became clear that additional inlet separation was needed to protect the plants from the increased liquids brought in with the inlet gas during pipeline pigging operations. Severe plant disruption occurred and additional operator attention was needed whenever the pipeline was pigged. For Plants 3 and 4, an additional 3-phase separator was added at the plant battery limits upstream of the individual plant inlet separator. For Plants 5 and 6, the inlet separators were increased in size, in addition to having the battery limits 3-phase separator.

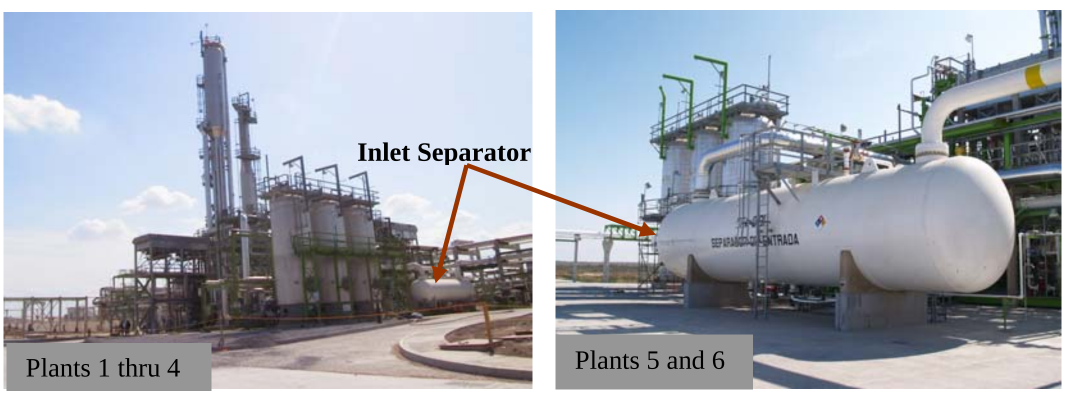

Figure 5 - Additional Inlet Separation

- *Expander/Compressor Seal Gas*
  Plants 1 through 4 suffered a number of expander shutdowns due to failure of the seal gas supply regulators. Redundant seal gas regulators were added to Plant 5 and 6 to prevent this problem. For future plants in the Reynosa area, the addition of a seal gas heater (or possibly insulation and heat tracing of the seal gas supply line) will be considered. While the seal gas supply source temperature is adequate, a combination of long uninsulated supply lines, low flow, low ambient temperatures, and pressure let-down ultimately resulted in undesirably low seal gas temperatures at the machines.

Instrumentation and Control Improvements

Pemex Operations personnel also discovered several problems with the instruments and controls in the early plants. These issues were identified and corrected in the subsequent plant designs.

- *Faulty Valve Positioners*
  During startup of Plants 1 and 2, a number of valve positioner failures occurred. The effects of these failures were not considered during the design stage. While none of the failures created a safety concern, they did understandably cause significant process upsets. One of the failures was on the inlet gas valve feeding the gas/liquid exchanger. The valve was specified as a "fail open" valve, but the positioner failed with full output, causing the valve to close completely. The valve is controlled by a flow controller with a split-range output. The output also goes to the inlet gas valve feeding the gas/gas exchanger. When the valve to the gas/liquid exchanger closed, the loss of flow caused the controller to start closing the valve to the gas/gas exchanger to try and force more inlet gas to the gas/liquid exchanger. Because the valve to the gas/gas exchanger has a minimum stop to prevent it from closing completely, an automatic plant shutdown was avoided, allowing time to investigate the problem. Of course, the plant did have to be shut down eventually to replace the faulty positioner. For Plants 3 through 6, a minimum stop was included on both valves.

- *Magnetic Level Measurements*
  A magnetic-type level measurement has been used successfully for control and local indication on the deethanizer reflux accumulator, but not without learning a couple of lessons. First, the float must be specified to have a minimum specific gravity (SG) of less than the expected minimum SG of the process fluid to allow for process variations. For example, a mixture of ethane and methane with an SG of 0.46 would be expected in the outlet of a deethanizer condenser under normal operating conditions. However, the float needs to be specified for an SG of 0.4 or less in order to float under all conditions. Second, the lower sensing line to the vessel must be well insulated to prevent unstable level measurement due to vaporization in the sensing line.

- *Deethanizer Reflux Flow Measurement*
  The flow measurements for the deethanizer reflux flow are typical orifice plate and dP transmitter installations, with the transmitter installed below the process line. However, the initial installation produced unreliable and inaccurate measurements. It was determined that vapor pockets in the uninsulated tubing to the dP transmitter were causing the problem. The problem was corrected by eliminating the numerous bends in the tubing to provide a vertical tubing run that is as straight as practical to prevent "vapor lock" in the sensing lines.

- *Dehydrator Outlet Dewpoint Shut Down*
  Plants 1 through 4 included a plant shutdown initiated by high dewpoint measurement in the dehydrator outlet line. Dewpoint measurements can be unreliable. This shutdown has been bypassed since startup because it caused several nuisance shutdowns. The high dewpoint shutdown was eliminated for Plants 5 and 6. High and High-High moisture alarms are sufficient.

- *Level Transmitters*
  Some problems have been experienced with the level transmitters for the cold separator and deethanizer reflux accumulator. Each vessel has two separate and independent level measurements, one for control and one for shutdown. The shutdown level instrument for Plants 1 and 2 used dP transmitters with electrically heated process tubing, and with the transmitters mounted above the process taps. While this works for typical cryogenic liquids, it did not work with the liquids in these vessels. For this type of installation to work, the heat input from the electric tracing must be enough to keep the entire fluid vaporized. Because the liquids are not a single component, we suspect the heavier components were not vaporized, creating an opposing level in the low pressure transmitter sensing line. For Plants 3 through 6, dP transmitters with factory-filled tubing and seals were used with some, not total, success.

Safety Improvements

As operating experience was gained on the earlier trains, some additional safeguards were added to the plants.

- *Additional Shutdowns*
  Two additional shutdown inputs were added for Plants 5 and 6, inlet gas high flow and deethanizer high pressure, as a result of a transmitter failure on Plant 1. The expander vanes and Joule-Thomson (J-T) valve are controlled from a pressure measurement on the suction to the residue gas compressors. When this transmitter failed, the control system fully opened both the expander vanes and the J-T valve, causing significant flaring of the excess gas to occur. The additional shutdown inputs were added as a precaution.

- *Additional Shutdown Valves*
  As part of the improvements made for safety, Plants 5 and 6 added shutdown valves to the following equipment items:

  1. Liquid outlet from the inlet separator
  2. Liquid outlet from the inlet filter/separators
  3. Regeneration gas supply to the regeneration gas heater
  4. Liquid outlet from the cold separator
  5. Light Naphtha product to storage
  6. LPG product to storage

STARTUP EXPERIENCE

Construction Debris Issues

In the petrochemical industry, some processes are able to tolerate limited amounts of construction debris, dirt, or water left in the piping from the construction phase of the project. However, any process that includes platefin heat exchangers will not tolerate any such solid materials. Due to extreme operating temperatures, a cryogenic NGL recovery plant also cannot tolerate the introduction of water that can cause hydrates to form.

During the startup of Plants 1 and 2, one of the major problems the startup group encountered was debris, such as welding dams and masking tape, left in the process piping. The following were the symptoms observed throughout the plant:

- The temperatures around the side reboiler did not match plant simulation.
- The deethanizer differential pressure and temperature readings oscillated.
- The propane recovery was below the design value.

In order to confirm suspicions that the strainers and exchangers were plugged with debris, a pressure profile was taken from the plant inlet to the deethanizer bottoms. A differential pressure reading of 1 kg/cm2 across the side reboiler and no differential pressure across any of the exchanger inlet strainers confirmed that there was some type of obstruction in the exchanger.

Once it was clear that there was an obstruction, methanol was injected into the side reboiler to make sure that the obstruction was not caused by hydrate formation. The methanol injection did not alleviate the problem. The next step was to open and inspect all the exchanger inlet strainers. When this was done, a large quantity of masking tape, welding dams, and other debris were found in the piping upstream of every exchanger. Although most of these strainers had collapsed, trash only entered the gas/gas exchanger. A procedure from the exchanger vendor for back-puffing platefin exchangers was followed to clean out this exchanger. This procedure called for pressurizing the exchanger and using rupture disks to blow the debris out through the exchanger inlet nozzle by back-flow when the rupture disk blew. The strainers had to be opened and cleaned several times to rid the plant of the debris.

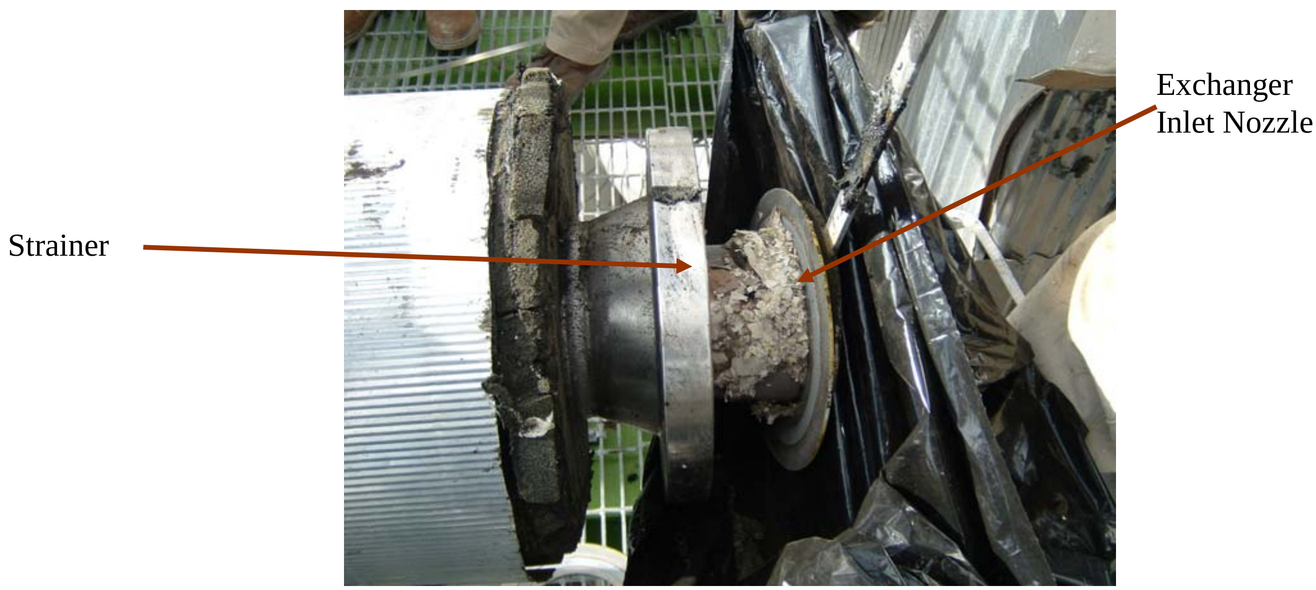

Figure 6 – Plugged Exchanger Inlet Strainer

A simulation using the operating data was developed in an attempt to match the observed plant performance. The largest discrepancies were in the propane recovery (observed was lower than in the simulation) and the side reboiler outlet temperature (observed was far lower than the simulation) as shown in Table 1. The bypass valve around the exchanger was opened to try to alleviate some of the liquid buildup, but there was no improvement in the temperature reading. This led the startup team to conclude that the side reboiler inlet line was obstructed with debris and spill-over was occurring on the draw tray in the tower, causing the oscillating temperatures throughout the tower.

Table 1 - Simulation vs. Observed Temperatures

Temperatures in °F	Simulation	Observed
Deethanizer Overhead	-84.0	-81.0 to -83.0
Side Reboiler Outlet	-55.4	-69.2
Deethanizer Bed #2	-38.5	-36.4 to -34.0
Deethanizer Bed #3	-14.5	-11.0 to -12.8
Deethanizer Bed # 4	70.0	65.0 to 68.0
Propane Recovery, %	99.6	96.0 – 98.0

Although the temperature readings around the side reboiler improved after cleaning the strainers several more times, the tower differential pressure and temperature readings continued to oscillate. The simulation was updated to attempt to match the plant performance better. A match of the observed propane recovery level could only be achieved when the number of theoretical stages in the column simulation was reduced in both the top and bottom sections of the column.

Based on the information from the simulations and the large amount of debris previously found in the piping, the Ortloff personnel on-site concluded that debris had also entered the column and was plugging the distributors and possibly obstructing flow in the packing. The startup group decided to open the column for inspection and if necessary to clean it out. Large quantities of debris were subsequently found in the distributor trays, chimney trays, and on top of the packing (see Figure 7), and the plant was restarted after the debris was removed from these locations.

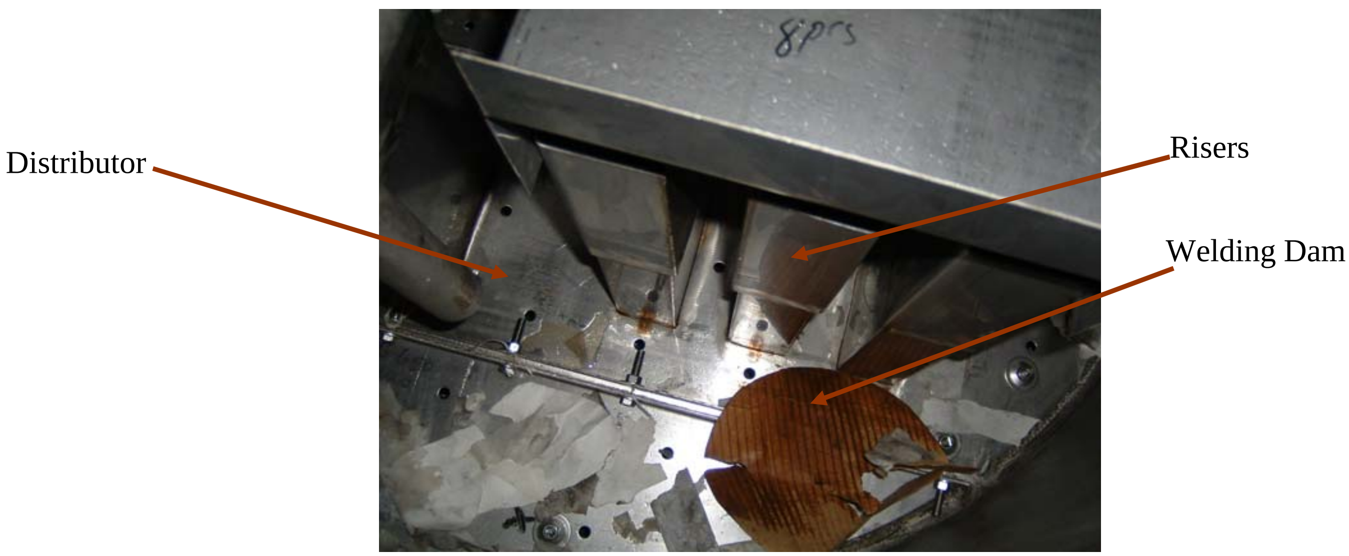

Figure 7 – Top Deethanizer Distributor

Once the piping, exchangers and tower were cleaned, the simulation used for the startup conditions was updated using the operating data. All temperature, flow, and pressure readings were matched and the propane recovery level now matched the observed values.

During dryout and initial operation of Plants 1 and 2, some control valves with small openings in the trim became plugged and damaged by particulates, particularly the J-T valve. The damage to this valve caused considerable delays during dryout and startup. The J-T valve has a noise reduction trim which is an excellent strainer for particulates. However, it allowed the smaller particles to pass through the cage and damage the balanced plug and seals. This damage resulted in leakage through the closed valve and unreliable operation (sticking, jerky movement). For Plants 5 and 6, a strainer was installed directly upstream of the J-T valve, inside of the J-T valve isolation valves, so it can be isolated, removed, and cleaned without depressuring the plant.

Similar problems were also encountered with the inlet separator and inlet filter/separator drain valves. In this case, the damage was due to the very small port sizes. For Plants 5 and 6, parallel Y-type strainers with individual block valves were provided. A dP transmitter to the DCS was provided to indicate strainer dP and alarm on high differential pressure.

The problems caused by the debris left in the piping were not as severe in Plants 3 and 4, and were nonexistent in Plants 5 and 6. In Plants 3 and 4, the materials (tape and vapor dams) used for welding were changed, which somewhat alleviated the problem. Welding dams and tape were still found in the strainers and piping, but none of the strainers collapsed, so the integrity of the exchangers was not affected. In Plants 5 and 6, the welding material was changed again, there was additional training on welding procedures, and the process piping was thoroughly cleaned before it was installed. The stainless steel piping in Plants 3 through 6 was pressure washed using R.O. water and all off-module piping was carefully inspected before installation. Polyethylene pigs were used in Plants 5 and 6 to clean all off-module piping, which eliminated essentially 100% of the debris that would otherwise have entered the exchangers and column from this piping. The strainers in Plants 5 and 6 were inspected after startup and there were no traces of any construction debris.

Hydrate Formation Issues

Another problem encountered during startup was hydrate formation. This problem is not unique to any one plant, but is quite common throughout the industry. There are two main causes for hydrate formation:

- The first is failure to complete the plant dryout procedures. Once the plant is built and ready to start up, most operating companies are eager to introduce the wet process gas and begin making product, so the dryout flow is stopped prematurely and the plant is put in operation. As a result, hydrates are likely to form in the sections of the plant where the dryout gas flow was low.

- The second is poor dehydrator performance. This problem can be caused by dehydrator design errors, inlet separation sizing errors, and changes in water content in the inlet gas. Another common issue is the malfunction of the dehydrator switching valves. When these valves do not close completely, gas bypasses the dehydrator being regenerated and only partial regeneration is achieved.

Hydrates will form if the plant is not completely dried or if water is introduced into the process because of dehydrator breakthrough. Methanol injection is commonly used to suppress any hydrates that may form when the plant is put in operation. However, methanol injection can actually make the hydrate formation worse.

In the Reynosa plants, the dryout of the first three plants was interrupted and restarted due to other problems encountered during plant startup. Because it was imperative (due to schedule issues) to put the plants in operation once the debris was removed from the exchangers and the column, the dryout procedure was cut short and the required dewpoint readings were never achieved.

The schedule allowed a more thorough dryout of Plant 4. According to the Pemex operations personnel, a great improvement in the Plant 4 operations (as compared to the other three plants) has been observed. Plant 4 does not have problems with hydrates forming in the reflux condenser or in the side reboiler. This improvement has led the operations personnel to create a more detailed dryout procedure which includes a schedule for switching flow through the different dryout paths and flaring points until a -60°C dewpoint is achieved at all locations.

A problem with gas dehydration system capacity was also encountered in Plant 1 and 2. This problem has been attributed to the ratio between mole sieve and silica gel in the dehydrators. The problem was solved by increasing the quantity of mole sieve and by changing the type of mole sieve. The same change was made in the subsequent plants. It was possible to accomplish this change by simply adding the mole sieve, since the dehydrator vessels had extra capacity.

After encountering these problems in the Reynosa plants, a simulation which included the addition of methanol to the process was developed to allow studying the behavior of water and methanol in the SCORE process. It was concluded that the temperature in the column overhead was too cold for the water and methanol to leave with the gas, and the temperature at the bottom of the column was too hot for the water to leave with the liquid product. The simulation showed that the methanol is distilled to some extent and that the water left with the side vapor draw and went through the reflux condenser. This behavior creates a cycle of methanol injection and hydrate formation. The solution for the hydrate formation at this point is to warm up or "derime" the plant. This can be achieved in several ways. At Reynosa, the tower pressure is increased, the expander speed is decreased, and the J-T valve is partially opened. The plant operates in this mode for 6-12 hours, at temperatures warm enough to allow the methanol and water to leave through the column overhead.

Engineering Training for Simulation vs. Field Operations

After operating the SCORE plants for several years, the Pemex operations personnel requested that more extensive training on simulations vs. field operations be prepared. The main objective for the course was to teach the Pemex process engineers and lead operators learn how to optimize the plant operations during off-design conditions.

Although the case where the expander is out of service and the plant operates in J-T mode was part of the original design package, this mode of operation was also reviewed. The simulation output was compared with actual operating data and the engineers were satisfied with the agreement between the simulation results and the actual plant data. Other simulations included cold inlet gas, problems with the reflux scheme, flooding in the tower, and side reboiler problems. For each case, a plant pressure, temperature and flow profile was created. The simulation output included the tower pressure, temperature profiles, and stream analysis so that the plant engineering staff could compare plant operating data with the simulation output for several possible causes of low propane recovery. Although a process simulator cannot replace sound engineering judgment, simulators can be used as a tool to train engineers and operators and thus enhance plant operations.

CONCLUSIONS

The circumstances in the Burgos Gas Processing Complex were unique. The six plants in the complex were "identical" and the construction of each pair immediately followed the startup of the last pair of plants. These circumstances allowed the plant operations personnel and the project team to take advantage of the lessons learned and actually apply this experience in the next pair of plants.

This valuable experience is clearly seen in the progression of the startup in all six plants. From the time wet inlet gas was first introduced into the plants, it took approximately three months to get to the point where Plant 1 and 2 were ready for their performance test. In Plant 3 and 4, this period of time was reduced from 3 months to 3 weeks. For Plant 6, wet inlet gas was introduced early in February of this year, and the performance test took place 48 hours later. This great improvement was only possible because all the project participants were truly committed to excellence.

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