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AFA WORKSHOP ON Process Waste Heat Boilers Integrity and Reliability

Hotel Sharq Village & SPA

Qatar: 01 - 03 December 2014

Papers





Program



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DAY 1 – Monday: December 01, 2014

08:30 – 09:30 Registration

09:30 – 10:00 Welcome Address

10:00 – 11:15 KBR's Improved Design for
Waste Heat Boilers in Ammonia
Plant

Umesh Jain,
Chief Technical Advisor,
KBR Inc., USA

11:15 – 11:45 Networking Coffee / Tea

11:45 – 12:30 Failure of the New RG Waste
Heat Boiler of Ammonia 5 at
Qafco

Marco van Graefschepe,
Head of Ammonia 5,
QAFCO, Qatar

12:30 – 13:15 Lessons Learned from FERTIL-1:
Waste Heat Boiler Operation

Ali AL Hosani,
Ammonia-1 Process Engineer,
FERTIL, UAE

13:15 – 14:00 Technical Assessment of SAFCO-
4 Synthesis Loop Waste Heat
Boiler-II Leakage

Ekambaram Manavalan,

Inspection Manager

Abdulrahman Al Johani,

Inspection Engineer,
SAFCO, Saudi Arabia

14:00

Networking Lunch



DAY 2 – Tuesday: December 02, 2014

- 09:30 – 10:30 Technical and Economic Feasibility Assessment for a CHP System with ORC Technology
David Alonso,
CEO, DVA Global Energy Services, Spain
- 10:30 – 11:15 Ammonia Synloop Waste Heat Boiler Failure in Ammonia Plant III.
Hossam Naiem
Abu-Qir Fertilizer Co., Egypt
- 11:15 – 11:30 **Networking Coffee / Tea**
- 11:30 – 13:15 Primary Waste Heat Boiler Failure Analysis Repair Methodology and Replacement
Ahmed Al-Mulhim,
Process Engineer,
ALBAYRONI, Saudi Arabia
- 13:15 – 14:00 Summary of History of Waste Heat Boiler in Ammonia IV (E 3205)- PIC
Mohammad Folad,
Planning Engineer, PIC, Kuwait
- 14:00 **Networking Lunch**

DAY 3 – Wednesday: December 03, 2014

09:30 – 10:15 Waste heat recovery in fertilizer industry: OCP case study
Hamid Mazouz, Researcher
Abdelaaziz ben el bou,
Production Manager,
OCP SA, Morocco

10:15 – 11:00 Replacing of Waste Heat Boiler in Sulphuric Acid Plant
Ibrahim Makhamreh,
Plant Manager, JPMC, Jordan

11:00 – 11:30 Networking Coffee / Tea

11:30 – 12:15 Gas side corrosion of stack gas heat recovery economizer in oil-fired high pressure steam boiler
Osama Khalil,
Chemical Supervisor,
APC – Jordan

12:15 **Closing**

13:00 Networking Lunch



Arab Fertilizer Association

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DAY 1 Monday: December 01, 2014



KBR's Improved Design for Waste Heat Boilers in Ammonia Plant

**Umesh Jain
Chief Technical Advisor
KBR Inc.
USA**

KBR's Improved Design for Waste Heat Boilers in Ammonia Plant

Umesh Jain, KBR, Inc.

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1.0 Introduction

More than 150 ammonia plants worldwide use reformed gas waste heat boilers featuring bayonet style tube bundles. Legacy Kellogg (KBR) plants built from the 1960s to the 1980s typically have three shells numbered as 101-CA, 101-CB & 102-C. 101-CA and CB are bayonet, water tube boilers and 102-C is a fixed tube sheet, fire-tube boiler. Although the bayonet technology was highly successful and credible in that timeline, it has become obsolete. KBR has been offering single shell one pass floating head technology since the mid-1980s, which has been highly successful in numerous ammonia plants.

A review of on-stream factors of plants having bayonet boilers reveals that such aging boilers may contribute significantly to loss of production. Severe process conditions and inevitable transient operations lead to failure of these boilers. Smooth and reliable performance of these boilers is a pre-requisite for profitable operation of ammonia plants. Mechanical failures prevent optimum operations and require excessive maintenance.

KBR's water tube boiler with a floating head provides an opportunity to replace multiple existing exchangers with a single shell. This provides reliable, sustained operation proven in numerous grass-roots KBR plants built since the mid-1980's. Ammonia plants built prior to that time need to compete with the newer ones, and upgrading their boiler technology will enhance plant on-stream factor significantly. KBR has developed a cost effective execution solution, and plants with bayonet boilers are either implementing or considering this solution.

Modern natural gas-based, efficient ammonia plants produce high flows of high pressure steam using innovative heat integration. Such integration requires supplying boiler feed water and collecting of steam from the frontend and Ammonia Synthesis loop located far from each other. A simple, robust, low-cost and user friendly system for generating steam from waste heat is needed in the Synthesis loop to ensure profitable ammonia operations.

The unique KBR steam system provides a simple, user friendly and low-cost arrangement. The KBR ammonia synthesis loop uses two shell & tube exchangers in this demanding steam generation service. This is preferred compared to other complex mechanical designs including those with integral drums. The common steam drum approach is proven to be very user friendly as there are no routine operation and maintenance needs associated with each steam drum, e.g. level control, drum water analysis, chemical dosing and individual drum blow-down requirements. This system, proven in numerous KBR plants, is also very user friendly during operational transients as the operator has fewer things to manage such as only one drum level.

The paper discusses reliability issues associated with Reformed gas boilers and Synthesis loop boilers, compares different technologies and describes the retrofit execution.

2.0 Front End Waste Heat Boilers

Many legacy Kellogg (KBR) plants built prior to 1990s are producing 30% – 80% more than the nameplate ammonia production capacity. In every case no upgrade has been done to the

existing waste heat boilers, 101-CA/CB. Operating at increased capacity increases the heat flux across exchanger tubes, increases the vaporization rate, and reduces the residence time in the steam drum, which leads to increased rate of tube failure.

Refer to Figure 1: The Secondary Reformer, 103-D effluent gas enters the shell through a distributor pipe with perforations for uniform distribution of gas. The gas at around 1,000°C flows upwards heating water in tubes, and the cooled process gas then goes to the Secondary Waste Heat Boiler, 102-C, for further HP Steam Generation.

Boiler Feed Water (BFW) from the elevated Steam Drum, 101-F, flows through one downcomer into the water chamber where it enters the top of the inner tubes of 101-CA/CB and flows down. At the bottom of the inner tubes water flows up into the annular space between outer and inner tubes. High Pressure steam and BFW at ~105 bar (g) rise in the annular space to the steam chamber and then to the steam drum through two risers.

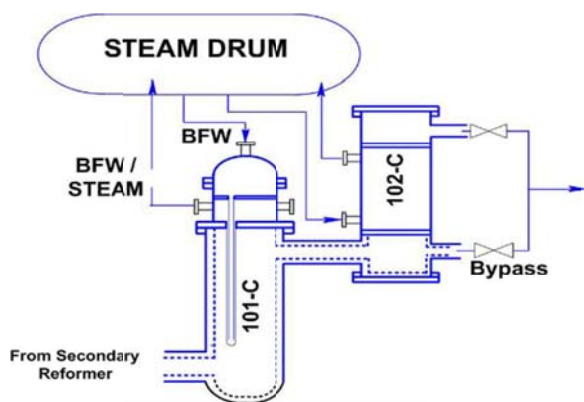


Figure: 1 – Legacy Kellogg Waste Heat Boilers

LEGACY KELLOGG DESIGN

The legacy Kellogg waste heat boiler is protected by a water jacket on the outside and a single layer of refractory on the inside. The

metal shell is designed for about 200 °C. The refractory also has a metal liner. The exchanger baffle diameter and the inside diameter of the metal liners are carefully selected so that at operating temperatures a reasonably tight seal is formed. This tight seal avoids gas by-passing the heat transfer area.

Each exchanger, 101-CA/CB, has multiple tubes to transfer the required duty. The inner tubes (bayonet) are 1" (25.4 mm) and are open at both ends. The outer tubes, referred to as scabbards, are 2" (50.8 mm) in diameter and are closed at the bottom.

To keep bayonet and scabbard (inner and outer) tubes separated by a somewhat uniform distance, nail-like projections are welded to the outside of bayonets.

Nameplate design of these exchangers was with a BFW to steam ratio of 10. With increased plant rate and higher heat transfer duty this ratio reduces to seven or less. Refer to Figure 2.

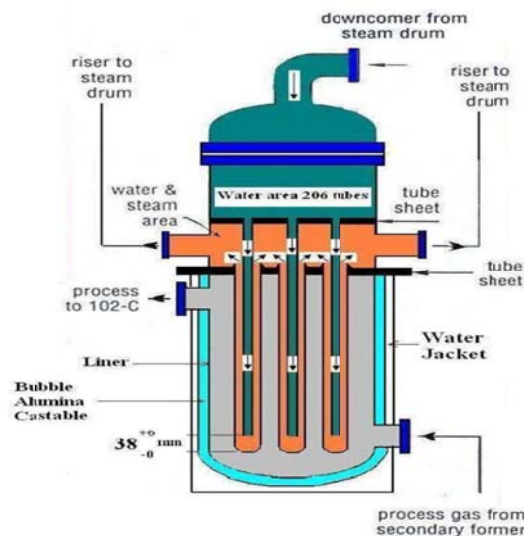


Figure: 2 – Bayonet Style Waste Heat Boilers, 101-CA/CB

PAST ISSUES WITH LEGACY KELLOGG DESIGN

1. Metal liner – During operation the metal liner warps and gets out of shape. When the exchanger tube bundle is to be pulled it does not come out easily as the exchanger baffle binds with the liner. In some cases the metal liner is forcibly removed with the tube bundle.

2. Nails on the outside of the bayonets – Nails or spacers disrupt the flow pattern and can create hot spots. The clearance between the spacers and scabbard increases with use. This causes the nails to rub against scabbard more vigorously. This rubbing removes the protective magnetite layer and leads to tube failure by corrosion.

3. Deposits at the bottom of the scabbards – BFW and steam change direction at the bottom of the scabbards. Any debris will deposit at the bottom and form scale leading to hot spots and higher rates of failure.

HOW ARE WASTE HEAT BOILER PROBLEMS SOLVED TODAY?

All ammonia producers strive for greater reliability and many achieve four years between a plant turnaround. Major ammonia producers are striving for six years between plant turnaround. As a corporate policy, spare tube bundles are maintained or the ammonia plant participates in a spare parts sharing pool with other plants. At a regular interval, approximately every four or six years, 101-CA/CB tube bundles are replaced. No effort is made to analyze problems or improve on the design.

One east European ammonia producer has an excellent plant workshop where they fabricate their own tube bundles.

In extreme cases some have replaced their bayonet Waste Heat Boilers with a Fire-tube style exchanger. This is an expensive solution, made without cost benefit analysis and without considering legitimate low cost options. Fire-tube boilers have their own set of pluses and minuses.

LOW COST (BUT INCOMPLETE) SOLUTION

Replacing the existing 101-CA/CB shells with dual layer refractory and no metal liner will help expedite removal of the tube bundle. The tube bundle is replaced with new and improved design with upgraded materials.

The new in-kind replacement design cannot address debris deposits at the bottom of the scabbard tubes. The new design cannot address the issue of disturbances caused by spacers. Thus, this upgrade will not increase the expected life of the bundle. However, removal and insertion of the bundle will be much faster, thus greatly reducing downtime on the failure of a bundle.

Replacing the shell with a refractory lined upgrade could be done in an extended turnaround. Due to heavier weight, the structural steel may need to be modified. If this change is done, 102-C should be replaced with the current design that is more reliable.

CURRENT DESIGN: A TOTAL SOLUTION

In newer plants, KBR has maintained the good aspects of the legacy 101-CA/CB design. Features like the proven design of the refractory lining and water jacketing on the outside are maintained.

The new design is also based on natural thermosyphon. The BFW from the elevated Steam Drum, 101-F is taken through the exchanger, and HP Steam plus BFW are returned to the drum like the legacy design.

In the new design, all three Waste Heat Boilers, 101-CA/CB and 102-C, are replaced with one exchanger. The High Temperature Shift inlet temperature is controlled with a bypass on the exchanger.

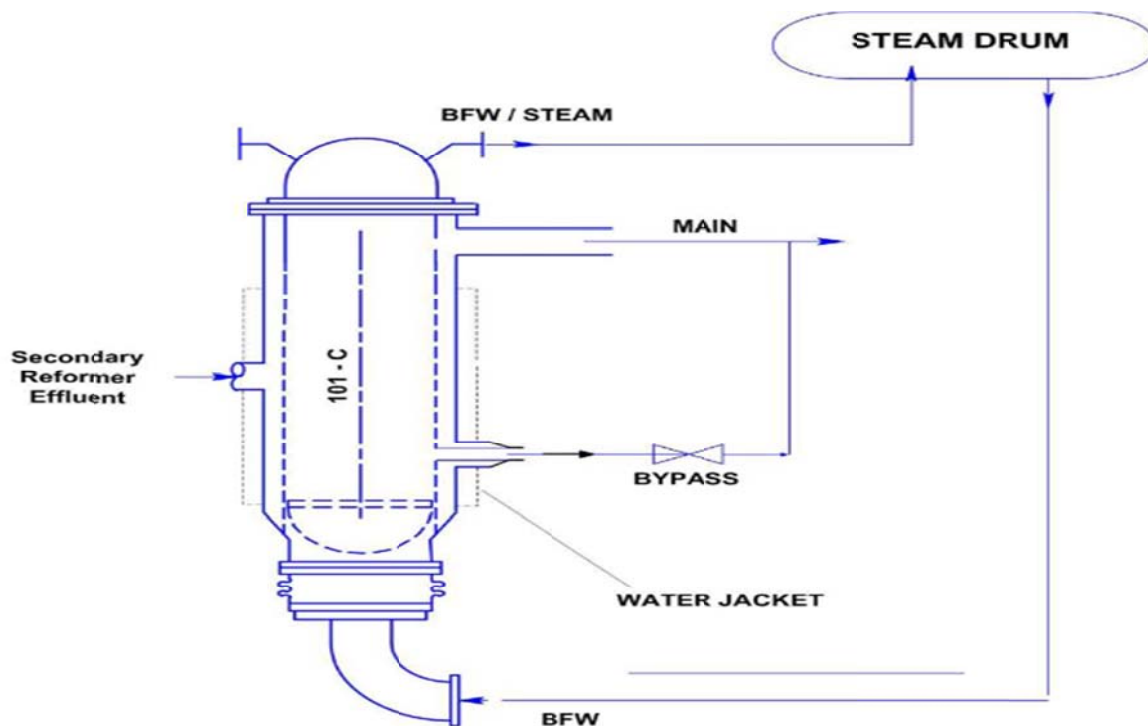


Figure: 3 – KBR Water-tube Waste Heat Boiler

WATER TUBE BOILER DESCRIPTION

The exchanger shell in the current KBR design has dual layer refractory. The inner layer is for heat conservation and outer layer for erosion protection. There is no metal liner in this design. The exchanger baffle diameter and the inside diameter of the refractory are set such that they form a tight seal at operating conditions. At ambient conditions there is enough clearance between the refractory and baffles that the tube bundle comes out easily.

BFW from the elevated Steam Drum, 101-F, flows to the bottom of the exchanger and up through the tubes. Secondary Effluent gas at around 1,000 °C enters shell side of the exchanger through an inlet gas distributor. The inlet gas distributor is a special proprietary KBR design. The gas distributor avoids direct impingement of the hot gases on the tubes.

REPLACING BAYONET EXCHANGERS WITH KBR FLOATING HEAD EXCHANGER

All three exchangers are replaced with new one floating head exchanger. The new exchanger (101-C) is designed for the higher duty required for increased capacity. Almost all legacy Kellogg Secondary Reformers, 103-D, have two outlets, one for each 101-Cs. These Secondary Reformer outlets are combined together with one water jacketed transfer line which sends hot reformed gases to the new heat exchanger.

The new exchanger is installed outside the existing structure and parallel to the Secondary Reformer. Since the new exchanger (101-C) is on a new foundation, it is installed while the plant is in operation.

High pressure boiler feed water lines to and from the drum require modifications, and proper

piping stress analysis is necessary to assure reliable upgrade.

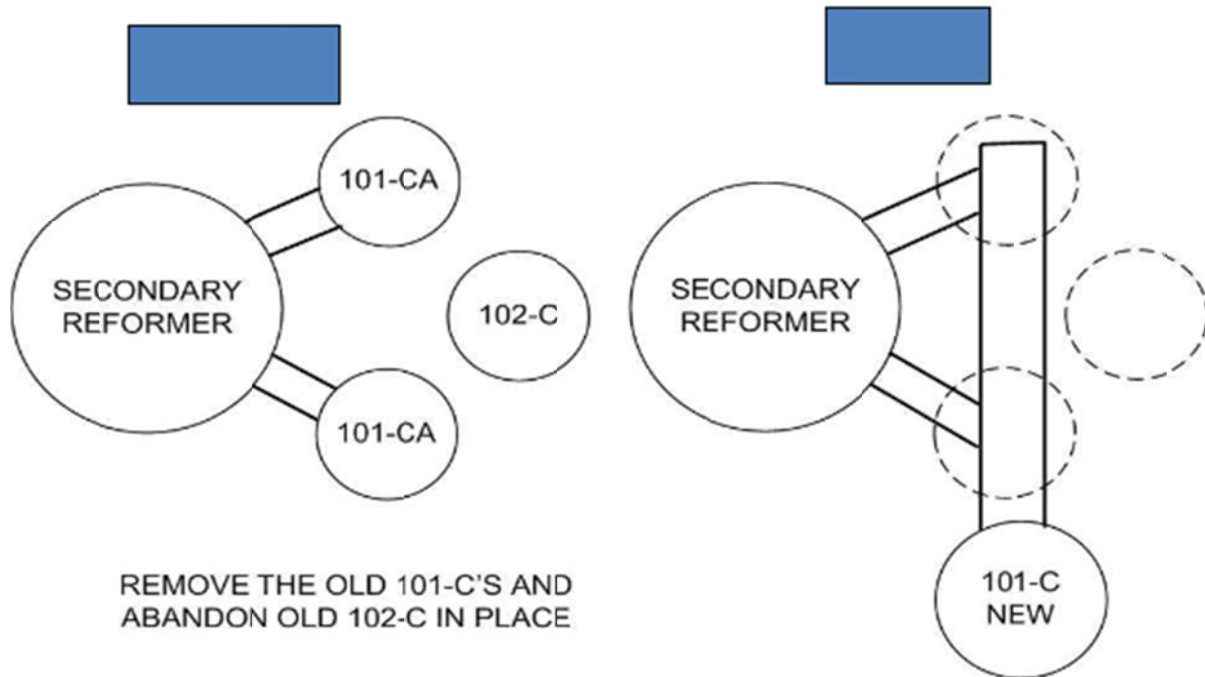


Figure: 4 – Replacing Bayonet Exchangers with New Floating Head Exchanger

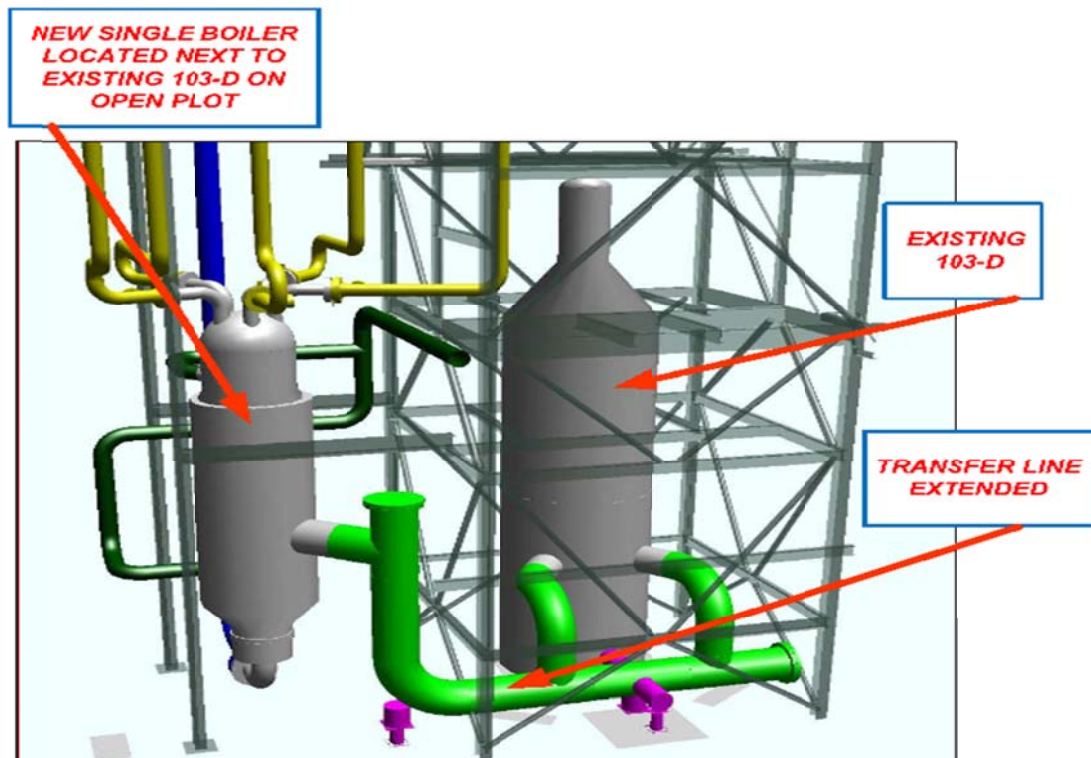


Figure: 5 – Replacing Bayonet Exchangers with New KBR Floating Head Exchanger

BFW QUALITY

No matter how good the design, one still must pay close attention to the Boiler Feed Water quality. The main conclusion of P. Orphanides and R. Michel in their 2008 paper was: “Keep your boiler surfaces clean and you will not suffer damage.”

3.0 Synthesis Loop Waste Heat Boilers

With HP steam generated in the synthesis loop since the late 1980's, different steam system configurations have emerged in the ammonia industry as various technology providers reconfigured the steam system of the plant. Considering the significant distance between the syn-loop waste heat boiler and the steam drum of the front-end, most plants have a separate steam drum for the synthesis loop. Some configurations have used synthesis loop waste heat boilers with their integral steam drums as vendor designed items while others provided separate drum in the synthesis loop. While following this approach where the syn-loop has two separate ammonia converters with multiple boilers, plants may also have more than one HP steam drum in the synthesis loop.

KBR has used a different approach in integrating the steam system in modern energy efficient ammonia plants. While producing high pressure steam in the syn-loop, KBR uses only one common high pressure steam drum, located near the reforming section, for the ammonia plant. The common HP steam drum is located close to the secondary reformer waste heat boiler to support thermo syphon water circulation. BFW and steam from the boilers located at the exit of HT shift converter and ammonia converter, flow into this common, steam drum. The deaerated

BFW is preheated and then split between the two heat recovery trains – one recovers heat in the frontend exit of the HT shift converter and other recovers heat in the synthesis loop exit of the ammonia converter. Steam is produced in the HP drum by force feeding two-phase steam plus BFW mixture from these two trains as seen in FIGURE-1.

Several different configurations are used by other licensors. For example, the front-end may have a dedicated secondary reformer waste heat boiler with a piggy back HP steam drum that is integrated with the boiler downstream of the HT shift. The synthesis loop uses vendor designed vertical boilers with integral HP steam drums in such plants. Where plants have a second ammonia converter in series, two such vertical boilers with their dedicated drums are used as seen in FIGURE-2.

SYNTHESIS LOOP WASTE HEAT BOILER

Rather than using a complex waste heat boiler, KBR uses two shell and tube exchangers in series (see FIGURE-3) in the syn-loop to generate high pressure steam. These exchangers use a removable U-tube configuration having special details where water is placed inside the tubes. This configuration is more tolerant to transient operating conditions in this severe service, thus provides high reliability. Other configurations including fixed tube-sheet designs or inverted U tubes with hot gas inside having an integral steam drum are more prone to failure as seen in operating plants. A portion of the boiler feed water required in the common steam drum is fed through this exchanger to the common steam drum. A significant portion of water is vaporized and the two-phase stream of steam plus water is routed to the common steam

drum following a specially executed robust piping arrangement that has no restriction on its length.

The unique KBR steam system provides a simple, user friendly and low-cost arrangement. KBR uses two shell & tube exchangers in this demanding operating service of the syn-loop. This is preferred compared to other complex mechanical designs including those with integral drums. The common steam drum approach is proven to be very user friendly as there are no routine operation and maintenance needs in the synthesis loop as typically associated with each steam drum, e.g. level control, drum water analysis, chemical dosing and individual drum blow-down requirements. This system, proven in numerous KBR plants, is also very user friendly during operational transients as the operator has fewer things to manage such as only one drum level .

Due to its unique features, compared to other complex designs, this exchanger arrangement in KBR plants is relatively more forgiving to possible transients in the water treatment regime and to process upset conditions usually seen over the life cycle of ammonia plants. High reliability of this system contributes to the exceptionally high on-stream factor of KBR ammonia plants. This simple compact waste heat boiler with fewer associated system items (e.g. no level control) in the steam system assists in reducing installed cost of KBR ammonia plants.

CONCLUSION

Maximum recovery of process waste heat for producing high pressure steam is required in modern, efficient ammonia plants. This requires a system to supply HP BFW and to collect HP steam from heat exchangers located all over the plant. Although several complex systems are used in industry, including vendor designs with separate steam drums, HP steam generation systems in KBR ammonia plants provide simple, robust, low cost and user friendly systems that ensures profitable ammonia operations.

FIGURE-1: SINGLE DRUM KBR STEAM SYSTEM

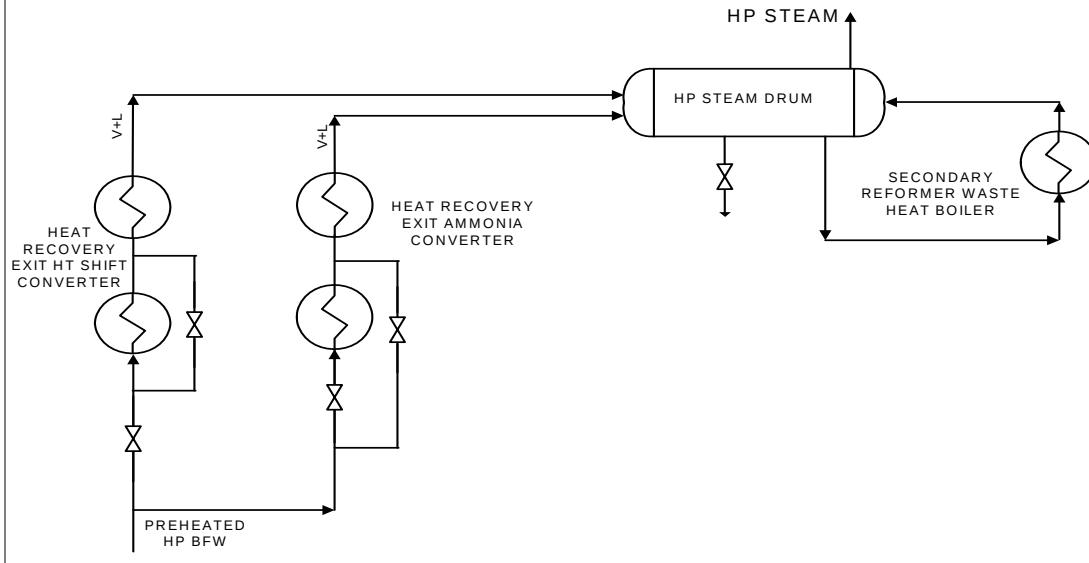


FIGURE-2: MULTIPLE DRUM STEAM SYSTEM

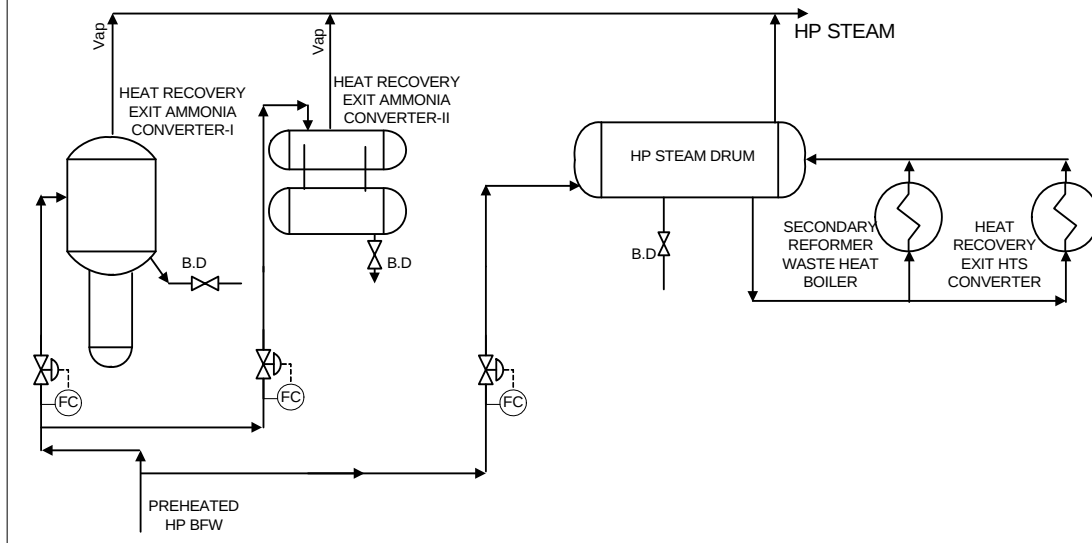




FIGURE-3: Ammonia Converter exit waste heat boiler

References

1. Mahesh Gandhi, Shashi Singh & Robert Burlingame, KBR Inc. (Houston) 'Enhance Ammonia Plant Reliability by Replacing Aging Bayonet Type Boilers with KBR's Floating Head Waste Heat Boiler' – N₂+Syngas Conference 2014
2. Shashi Singh, KBR Inc. (Houston) 'User Friendly High Pressure Steam Generation System Contributes to High Reliability of KBR Ammonia Plants' – Asian N₂+Syngas Conference 2013



Failure of the New RG Waste Heat Boiler of Ammonia 5 at Qafco

Marco van Graefschepe
Head of Ammonia 5
QAFCO
Qatar

AFA Process Waste Heat Boilers workshop Dec. 1-3, 2014 Doha, QATAR

Failure of the new RG Waste Heat Boiler of Ammonia 5 at Qafco

Qafco's Ammonia 5 plant is one of the 2 new ammonia plants at Qafco, that came with the Qafco 5 and 6 major expansion project, increasing Qafco's Urea and Ammonia capacities by 1.6 and 2.8 million Metric Tons (MT) per year respectively. The new plants are located at the new site for Qafco 5 and 6 at about 3 km west of the old site of Qafco 1 to 4 plants and were commissioned from 2011 to 2012.

On Sept. 9th 2011 the RG Waste Heat Boiler of Qafco's Ammonia 5 plant experienced a major leaking of boiler water to the process side, only shortly after commissioning and start-up of the new plant. Two tubes were found ruptured and almost half of the tubes showed cracks in the tube to tube sheet welds at inlet side.

Inspection, analysis and repair took more than 4 months, after which the plant was restarted and operated at reduced plant load and lower HP steam pressure.

Only about 2 weeks later, when the plant experienced a shut down, again leaking of the WHB was observed. This time the main damage was at the outlet tube sheet, especially the tube sheet itself showed severe cracks in the base material.

The plant could be restarted after 3 months. But again after 2 weeks leaking of the WHB was observed and the plant was stopped. Few tube leaks were found at the inlet tube sheet. After a 1 month repair period the plant was started and the WHB didn't fail anymore until its replacement during the scheduled Warranty Shut down in Februari 2014.

This article describes the process observations and root causes of the failures

Marco van Graefschep

Qatar Fertilizer Company (Qafco)

Failure of the new waste heat boiler E0308

The Qafco Ammonia 5 plant primary reformer furnace was lit for the first time on August 16th 2011 and the front-end reached stable operation on August 26th. During the start up activities the primary reformer experienced 4 process trips. Synthesis convertor reduction started on August 27th at 80% plant load and was completed on Sept. 4th. First liquid ammonia production was achieved on Sept. 1st. Plant load reached 100% on Sept. 4th.

On the evening of September 8th 2011 the plant was running stable with normal process conditions at approximately 100% load. At around 20:30hrs, during his routine plant survey, one of the field operators observed a small fire from E0309 (HP-steam super heater) channel flange. He immediately informed the shift supervisor and DCS operator via the radio.

The fire was put-off shortly after by operational staff using a trolley mounted dry chemical powder extinguisher. It was observed that process gas was leaking from E0309 channel flange (process gas temperature was 370 deg C). Nitrogen and steam was applied with hoses on the leak spot in order to dilute the leaking gas. Meanwhile key people from Contractor and Company were contacted and briefed about the leakage and fire. Upon arrival of this key personnel, the situation of the leakage was reviewed and it was jointly decided to shut down the plant and attend to the leak. Shutdown activities started at 23:30hrs on September 8th and at 04.00hrs September 9th primary reformer shut down was completed.

Plant shutdown:

Decision to shutdown the plant was taken at 23:30hrs on the September 8th due to fire discovered at E-0309 flange channel cover. The various sections were systematically taken out of operation as follows:

- From 23.30hrs to 02.30 hrs plant load was reduced from 100% to 60%
- At 02:30hrs plant back-end was taken out of operation
- At 03:10hrs methanator & CO₂-removal system (including LTG/LTS) were taken out of operation.
- At 3.30hrs front-end plant load was reduced to 30%
- At 03:38hrs remaining process air to secondary reformer was cut-off
- At 03:43hrs the primary reformer shutdown was initiated from DCS after observation of heavy steam/gas leak and loud sound from temperature control valve TV03175 (process gas bypass of HP-steam super heater E0309). (Figure 1). This observation is significant to the analysis of the failure of the waste heat boiler (E0308).
- The full plant shut down was completed without any automatic trip initiation.



Figure 1: Leaking Process gas bypass valve of E0309

First visual observations with respect to waste heat boiler E0308:

- While preparing steam superheater E0309 for inspection, the primary reformer loop was fully depressurized on September 12th evening. In parallel, the HP-steam circuit (consisting of steam drum V0301 and the 3 waste heat boilers E0308, E0410 and E0801) was pressurized with nitrogen to purge the system and keep it under inert media as the shutdown was estimated to last for a longer period.
- During this activity, drop wise water leakage was observed from TV03175 bonnet (E0309 bypass valve) and E0308 gas side outlet compartment drain. Based on these observations, HP Waste heat boiler (E0308) upstream and down stream side manholes were opened and heavy leakage was observed from some the E0308 tubes from both sides.
- On September 14th, when E0308 could be entered for first time after cooling down, the following observations were made:

Heavy water leakage was observed from 2 tube-tube sheet joints at the inlet tube sheet (Figure 2). The process gas bypass (center pipe) was found slightly deformed at the inlet tube sheet (also Figure 2).



Figure 2: Heavy water leakage was observed at the inlet tube sheet

Most of the ferrules were found in damaged condition. Debris of ferrules and refractory was found at E0308 inlet compartment (Figure 3).



Figure 3: Most of the ferrules were found damaged and debris of ferrules and refractory was found at the entrance in front of the tube sheet.

Also broken ferrule pieces went through the pipes to the outlet compartment and water had traveled from E0308 to E0309. (Figure 4)



Figure 4: Water and debris was found at the outlet compartment

Analysis of process parameters before/during/after the fire incident

After above observations on E0308, the relevant process parameters were collected and analyzed to understand at what stage in time this major leaking had occurred and if any operational abnormality could explain for this failure to happen.

Based upon first analysis of trends it became clear that major leakage had occurred during the shut down around 3.40hr, after the process air was cut off. Several significant parameters show a sharp change here.

From the further analysis no indications were found which could give a reason for the failure as such. All parameters were moving as per process requirement and expectation. No abnormal temperatures or pressures were observed which could have put the boiler under too high stress and which could lead to this failure.

Following were the main observations during the shut down taken around the “E0308 failure” (referring to the time around 03.40hrs)

- 1) **Waste heat boiler E0308 inlet temperature (Figure 6 and Table 1):** Before the failure, the waste heat boiler inlet temperature increased from 896 deg C (03:20hrs) to 996 deg C (03:39hrs), due to increasing primary reformer outlet temperature. After that, this temperature came down suddenly to 965 deg C (03:40hrs) and dropped further to 365 deg C (03:41hrs) and reached 241 deg C (03:42hrs) (Figure 7 and Table 1). Note that there are actually 4 thermo couples measuring at approximately 1,4m distance from E0308 inlet tubesheet (TI03171 and TX03177/A/B/C) (Figure 5). Almost sure the observed temperature drop (Figure 7 and Table 1) is caused by the boiler water spraying under high force out of the leaking tubes.

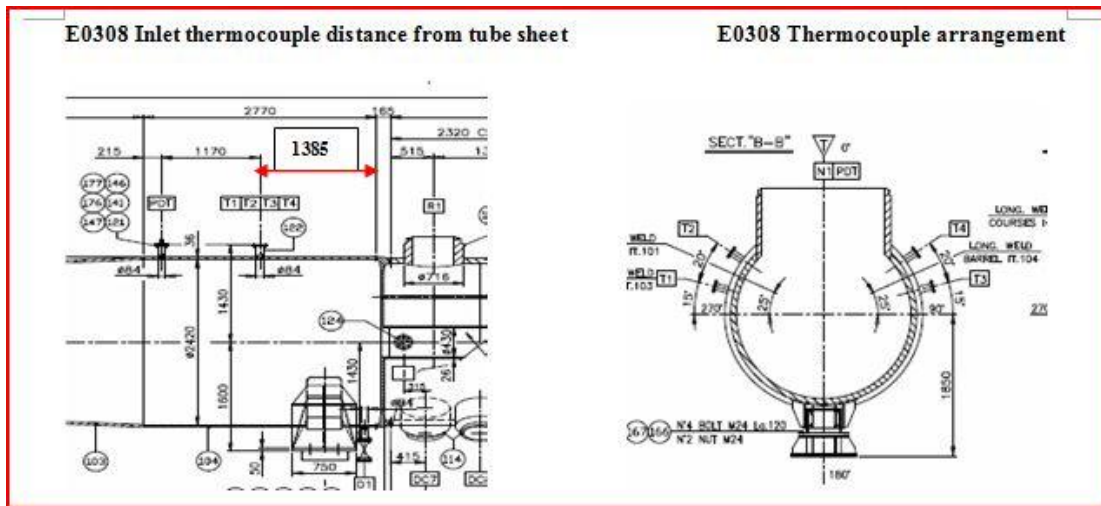


Figure 5: Thermo couple locations at the E0308 inlet side

Later analysis of operational data revealed that 1 of the thermo couples (TI03171) during 2 earlier front-end trips showed a sudden drop for several minutes. Most likely some extent of leaking was already present at that time and water was spraying on this specific temperature element (Figure 6).

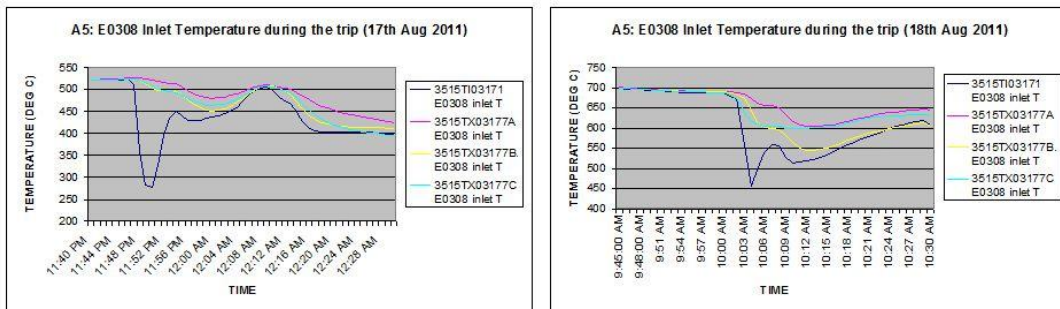


Figure 6: One of the inlet thermo couples inlet E0308 showing temporarily a drop in temperature.

- 2) **V0301 (steam drum) Level (Figure 7 and Table 1):** Before the moment of the major failure the level and pressure of the steam drum were still normal. From the moment of failure, the level of the steam drum came down from 52.42% (03:39hrs) to 30.26% (03:43hrs) but stayed above the trip value. Also the boiler feed water flow rate to V0301 increased from 88 T/hr to 193 T/h in same time and reached a maximum of 324 T/hr around 03.50 hrs.
- 3) **E0308 (WHB) outlet temperature (Figure 7 and Table 1):** The outlet temperature of E0308 came down from 436 deg C (03:39hrs) to 250 deg C (03:42hrs). Note that this outlet temperature at this point of time is higher than the inlet temperature of the WHB!
- 4) **Reformer system pressure (Figure 7 and Table 1):** the front-end pressure measured at the high temperature shift converter R0401 increased from 2060 kPaG to 2770 kPaG. Almost sure due to sudden vaporization of the leaking BFW water from the WHB entering the process side.
- 5) **Leakage from SSH E0309 gas bypass valve TV03175:** One of the field operators observed a heavy steam/gas leak and loud sound coming from temperature control valve TV03175 (process gas bypass of steam super heater E0309), which lead to the decision to initiate shut down of the primary reformer. This leakage from the flange bonnet seems to have occurred when above mentioned sudden front-end pressure increase happened due to the BFW entering the system, as it was discovered at the same time. Note that it was found later that the bonnet gasket was damaged and that the bonnet joint bolts were loose i.e. not properly tightened.

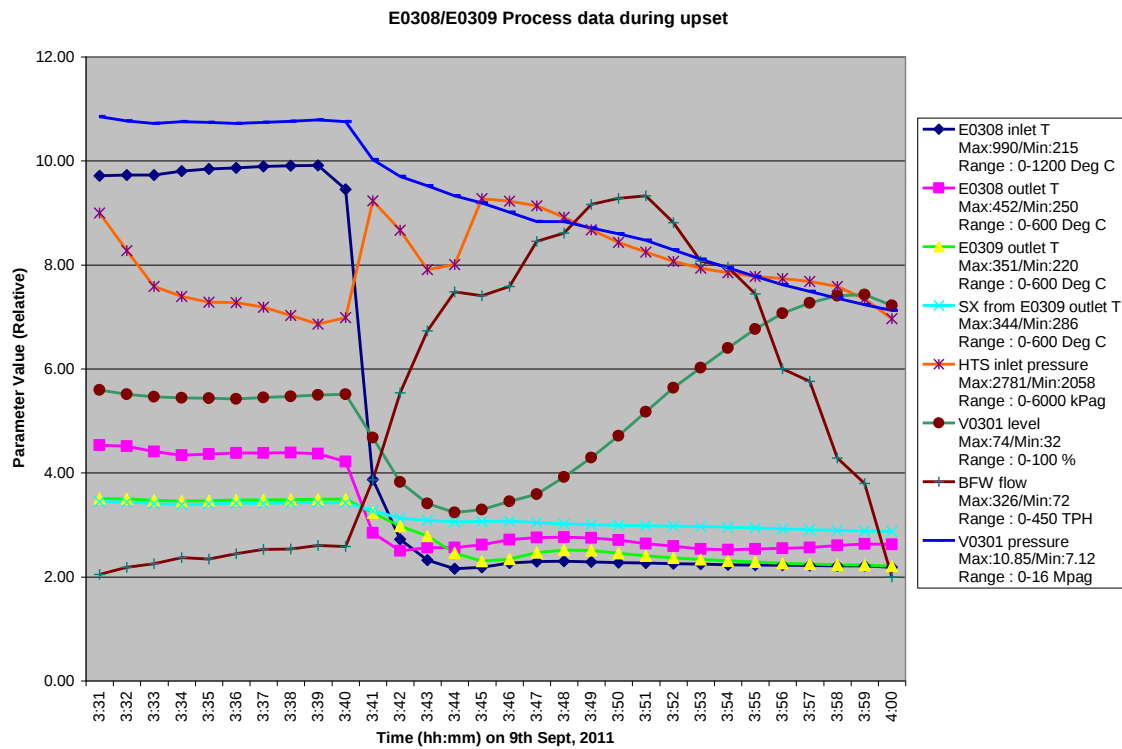


Figure 7: Main process parameters around time of E0308 failure

Date	Time	E0308 inlet T Max:990/Min:215 Range : 0-1200 Deg C	E0308 outlet T Max:452/Min:250 Range : 0-600 Deg C	E0309 outlet T Max:351/Min:220 Range : 0-600 Deg C	SX from E0309 outlet T Max:344/Min:286 Range : 0-600 Deg C	HTS inlet pressure Max:2781/Min:2058 Range : 0-6000 kPag	V0301 level Max:74/Min:32 Range : 0-100 %	BFW flow Max:326/Min:72 Range : 0-450 TPH	V0301 pressure Max:10.85/Min:7.12 Range : 0-16 Mpag
9/9/2011	3:31	9.71	4.53	3.51	3.45	9.00	5.60	2.05	10.85
9/9/2011	3:32	9.73	4.51	3.50	3.44	8.27	5.51	2.19	10.77
9/9/2011	3:33	9.73	4.41	3.47	3.41	7.59	5.46	2.25	10.72
9/9/2011	3:34	9.80	4.34	3.46	3.39	7.39	5.44	2.37	10.75
9/9/2011	3:35	9.85	4.36	3.47	3.41	7.28	5.44	2.34	10.74
9/9/2011	3:36	9.86	4.38	3.48	3.42	7.28	5.42	2.45	10.72
9/9/2011	3:37	9.89	4.38	3.48	3.41	7.18	5.45	2.53	10.74
9/9/2011	3:38	9.90	4.39	3.48	3.42	7.03	5.47	2.53	10.76
9/9/2011	3:39	9.92	4.37	3.49	3.42	6.86	5.50	2.60	10.79
9/9/2011	3:40	9.45	4.22	3.49	3.43	6.99	5.51	2.58	10.75
9/9/2011	3:41	3.87	2.84	3.23	3.27	9.23	4.68	3.87	10.02
9/9/2011	3:42	2.72	2.50	2.98	3.13	8.67	3.83	5.54	9.70
9/9/2011	3:43	2.32	2.56	2.78	3.09	7.91	3.41	6.73	9.52
9/9/2011	3:44	2.16	2.56	2.46	3.06	8.00	3.24	7.48	9.33
9/9/2011	3:45	2.18	2.62	2.30	3.07	9.27	3.29	7.40	9.19
9/9/2011	3:46	2.27	2.72	2.34	3.07	9.22	3.45	7.58	9.01
9/9/2011	3:47	2.29	2.75	2.46	3.05	9.13	3.59	8.45	8.83
9/9/2011	3:48	2.30	2.77	2.51	3.02	8.92	3.92	8.61	8.83
9/9/2011	3:49	2.29	2.75	2.51	3.00	8.67	4.29	9.16	8.71
9/9/2011	3:50	2.28	2.71	2.45	2.99	8.43	4.71	9.28	8.60
9/9/2011	3:51	2.26	2.64	2.40	2.98	8.25	5.17	9.32	8.47
9/9/2011	3:52	2.25	2.59	2.36	2.98	8.07	5.64	8.81	8.29
9/9/2011	3:53	2.24	2.53	2.33	2.97	7.94	6.02	8.07	8.11
9/9/2011	3:54	2.23	2.52	2.31	2.96	7.84	6.40	7.96	7.94
9/9/2011	3:55	2.23	2.54	2.29	2.94	7.78	6.77	7.44	7.78
9/9/2011	3:56	2.22	2.55	2.26	2.92	7.73	7.07	6.00	7.62
9/9/2011	3:57	2.22	2.56	2.24	2.91	7.68	7.27	5.76	7.49
9/9/2011	3:58	2.21	2.60	2.24	2.89	7.58	7.41	4.29	7.36
9/9/2011	3:59	2.21	2.63	2.22	2.88	7.35	7.43	3.80	7.23
9/9/2011	4:00	2.19	2.63	2.20	2.87	6.96	7.22	2.00	7.12

Table 1: Main process parameters around time of E0308 failure

6) **R0401 (HTS convertor) temperature profile behavior around the time of E0308 failure (Figure 8 and Table 2):**

- R0401 catalyst bed temperatures were decreasing after the E0308 failure. R0401 inlet temperature dropped from 347 deg C (03:40hrs) to 143 deg C (04:35hrs).
- One hour after the failure, 7 out of 8 catalyst bed temperatures indicated a temperature of around 145 deg C. All these catalyst bed temperatures had come down gradually from a range from 350 to 420 deg C to this 145 deg C.
- Up to this instant, the outlet temperature of R0401 was always higher than the inlet temperature. At 04:37hrs the outlet temperature came down dramatically from 229 deg C at 04:37hrs to 149 deg C at 04:42hrs (about 80 deg C within five minutes). This may indicate an amount of water which has entered the catalyst bed.
- The temperature at the outlet of R0401 increased again after that but at 04:54hrs dropped back to slightly below R0401 inlet temperature. This most likely indicated that the water after entering the catalyst bed had further settled.

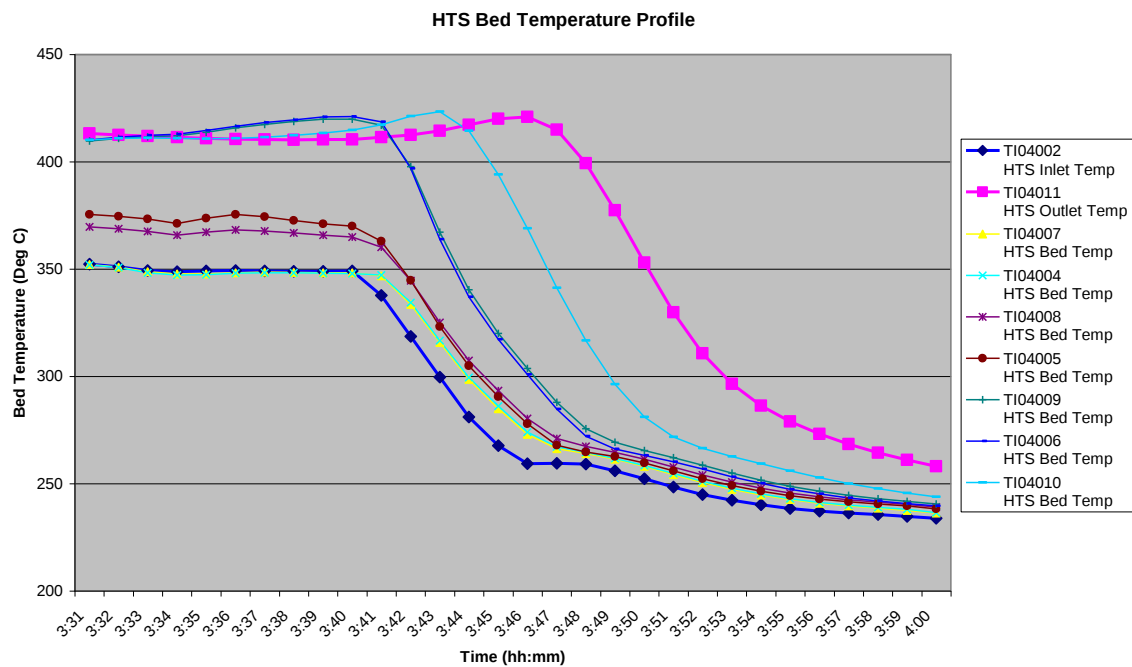


Figure 8: HTS catalyst bed temperatures behavior around time of E0308 failure

Time	TI04002 HTS Inlet Temp	TI04011 HTS Outlet Temp	TI04007 HTS Bed Temp	TI04004 HTS Bed Temp	TI04008 HTS Bed Temp	TI04005 HTS Bed Temp	TI04009 HTS Bed Temp	TI04006 HTS Bed Temp	TI04010 HTS Bed Temp	POI04001
3:31	352.34	413.22	352.11	352	369.65	375.52	409.6	410.26	410.22	8.91
3:32	351.01	412.53	350.84	350.65	368.85	374.57	410.82	411.44	410.83	7.6
3:33	349.31	411.89	348.85	348.28	367.58	373.26	411.64	412.26	411.1	10
3:34	348.83	411.39	347.75	347.17	365.75	371.28	412.13	412.85	410.93	9.87
3:35	349.07	410.86	347.77	347.37	367.2	373.75	413.7	414.57	410.73	8.49
3:36	349.29	410.55	348.27	348.1	368.18	375.41	415.72	416.56	410.94	8.44
3:37	349.06	410.37	348.51	348.31	367.75	374.41	417.29	418.16	411.49	9.29
3:38	348.91	410.25	348.48	348.16	366.79	372.68	418.74	419.56	412.32	9.81
3:39	348.95	410.32	348.26	348.07	365.73	371.13	419.85	420.79	413.39	8.99
3:40	349.05	410.43	348.21	347.92	364.88	370	419.84	421.1	414.69	22.75
3:41	337.76	411.44	346.76	347.14	360.17	362.94	417.09	418.68	417.19	40.5
3:42	318.58	412.48	333.55	334.35	344.53	344.68	397.79	396.84	421.18	67.81
3:43	299.72	414.4	315.8	316.6	325.01	323.18	367.16	363.91	423.26	56.32
3:44	280.98	417.13	298.59	299.45	307.38	304.93	340.38	337.08	414.3	44.24
3:45	267.79	419.98	284.97	286.13	293.35	290.61	320.05	317.24	394.11	31.67
3:46	259.27	420.85	272.97	274.05	280.43	277.86	303.77	300.92	368.92	38
3:47	259.41	415	266.33	267.16	271.05	267.82	287.93	284.77	341.25	35.17
3:48	259.08	399.35	263.97	264.48	267.4	264.75	275.57	272.09	316.63	35.71
3:49	255.91	377.29	261.32	261.81	264.58	262.65	269.25	266.06	296.32	35.07
3:50	252.21	353.06	257.99	258.44	261.35	259.58	265.5	263.14	281.1	33.92
3:51	248.38	329.74	254.2	254.73	257.7	255.97	262.02	260.17	271.76	33.98
3:52	244.99	310.66	250.56	251.09	253.96	252.3	258.55	256.78	266.47	33.1
3:53	242.25	296.52	247.39	247.88	250.66	249.18	254.92	253.23	262.65	31.89
3:54	240.12	286.36	244.82	245.21	247.93	246.53	251.64	250.09	259.28	30.23
3:55	238.46	278.94	242.58	243.04	245.64	244.37	248.79	247.45	255.99	29.13
3:56	237.25	273.16	240.83	241.22	243.83	242.73	246.49	245.21	252.81	27.35
3:57	236.4	268.44	239.61	240.05	242.48	241.5	244.55	243.42	250.05	25.6
3:58	235.69	264.44	238.65	238.98	241.43	240.52	243.02	242	247.71	24.62
3:59	234.68	261.02	237.59	237.99	240.35	239.58	241.81	240.77	245.68	20.11
4:00	233.81	258.02	236.4	236.57	239.1	238.28	240.58	239.63	243.84	16.12

Table 2: HTS catalyst bed temperatures behavior around time of E0308 failure

Operational staff reported at a later point in time that a considerable amount of water had been drained downstream of R0401, upstream of R0403 (LTG).

Also water was drained from the process gas side inlet - and outlet compartments of 2nd waste heat boiler E0410, located directly downstream of R0401.

When the E0309 tube bundle was pulled out from its shell, pieces of ferrule and refractory material were found. Therefore it was suspected that debris consisting of ferrule and refractory material also had reached the top layer of the catalyst bed of R0401.

While taking samples from the top layer indeed this debris was found. Analysis results of samples taken from the catalyst top layer indicated phosphate depositing from the boiler feed water, so confirming also that water had entered the vessel. Based upon further tests on the catalyst it was decided to take out all the catalyst and replace it with a full new charge that was available as spare.

Above findings clearly evidence the leaking of the waste heat boiler.

During the shut down the combination of operational parameters pointing together towards a leaking waste heat boiler was not immediately recognized as such.

Main reason was that the alarm management system had not been optimized yet, the DCS-operators were still flooded with alarms of different priorities.

Also the plant was just for a few days in normal operation so there was still little experience with the behavior of the new running plant.

Nobody expected a leaking waste heat boiler in a new plant just after start-up.

The incident happened in the weekend, supervision at night shift was limited.

After bringing the plant to shutdown the focus was on E-0309, to prepare for inspection and repair. Earlier after the shut down, when opening the 2 drains at the inlet and outlet chambers of E0308 only little water came out (due to plugging of the drains with debris from refractory and ferrules as was found later). All together this resulted in the fact that the leak of the waste heat boilers, was only discovered some days after the shutting down the plant for E0309.

Observations and root cause analysis

Observations and analysis

During first observations two tubes were found ruptured and almost half of the tubes showed cracks in the tube to tube sheet welds.

Further inspection, analysis and repair took more than 4 months, after which the plant was restarted and operated with relieved conditions for the WHB: at reduced plant load and with lower HP steam pressure.

Failure mode was found to be brittle fracture in HAZ of welds repaired before operation, due to high residual stresses and high hardness.

Root cause

The root cause for these high residual stresses and high hardness is most likely not a single one. After extensive analysis, the following were found to be the most likely root causes:

- The relative complex design of the WHB (although following ASME code): the chosen materials, the length, the thin tube sheet combined with thick shell/bypass pipe) and the local PWHT requirement in work shop (which made it difficult to control the temperature equally)
- The lack of proper control of manual repairs on site, before in operation (several defects like excess/lack of penetration, lack of fusion, carburization and root undercut, which are very difficult to detect or undetectable with UT, especially on the tube side)

The damage refractory and broken ferrules were considered to be a result of the tube failure, not the cause, most likely broken due to high water/steam pressure impact. Ceramic ferrules have high thermal resistance but are mechanically less strong (sensitive in case of rapid quenching water/steam force and when no proper decoupling between rigid and flexible elements).

Lessons learnt:

Choose more conservative design, with more easy to control PWHT (if possible furnace PWHT)
Choose metal alloy i/o ceramic ferrules for this application of high temperature/pressure with relative thin tube sheet (and where there is always a chance of leaking tube sooner or later)

Second and Third failure of the waste heat boiler

Second failure and root cause

Only about 2 weeks later, when the plant experienced a shut down, for the second time leaking of the WHB was observed. When the drain on the outlet compartment was opened to check for a possible leak, water was coming out. After opening in- and outlet man ways, the findings were at the outlet tube sheet, especially the tube sheet itself showed severe cracks in the base material (Figure 9 and 10). The plant was restarted 3 months after failure.

This 2nd failure of the WHB was found to be due to stress corrosion in areas around welded tube plugs with high remaining stresses and local (phosphate) deposition in crevices.



Figure 9 and 10: Cracks in outlet tube sheet

Third failure and root cause

After 2 weeks of operation increased flow of boiler feed water to the steam drum was observed and confirmed leaking of the RG WHB again. This time a few leaking tubes were found at the inlet tube sheet. Root cause here was found to be insufficient stress relieve of few repair welds on earlier repaired tubes (which were in a difficult to reach area of the tube sheet)

Plant was restarted after 1 month repair and since then WHB E0308 has not leaked anymore. The unit was replaced by one of different design during the warranty shutdown in Febr. 2014. Ammonia 5 plant is now operating at 105% of its design capacity.



Lessons Learned from FERTIL-1

Waste Heat Boiler Operation

Ali AL HOSANI

Ammonia-1 Process Engineer

FERTIL

UAE

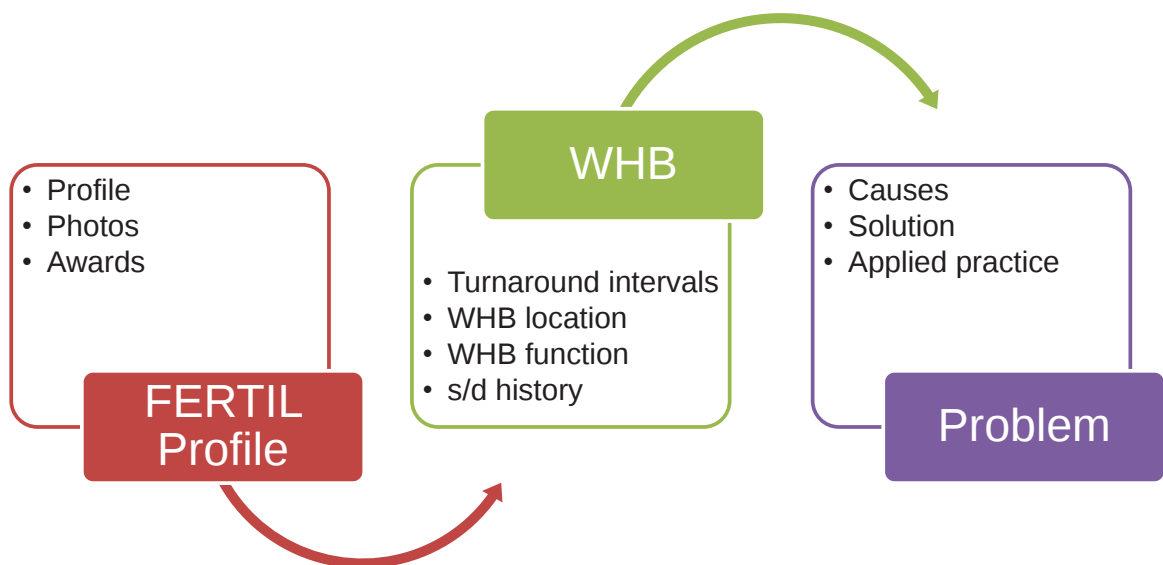
Lessons Learned from FERTIL-1 Waste Heat Boiler Operation

Presented in : AFA Workshop
Waste Heat boiler Reliability and Integrity
1-3 Dec. 2014 , Qatar

Presenter:

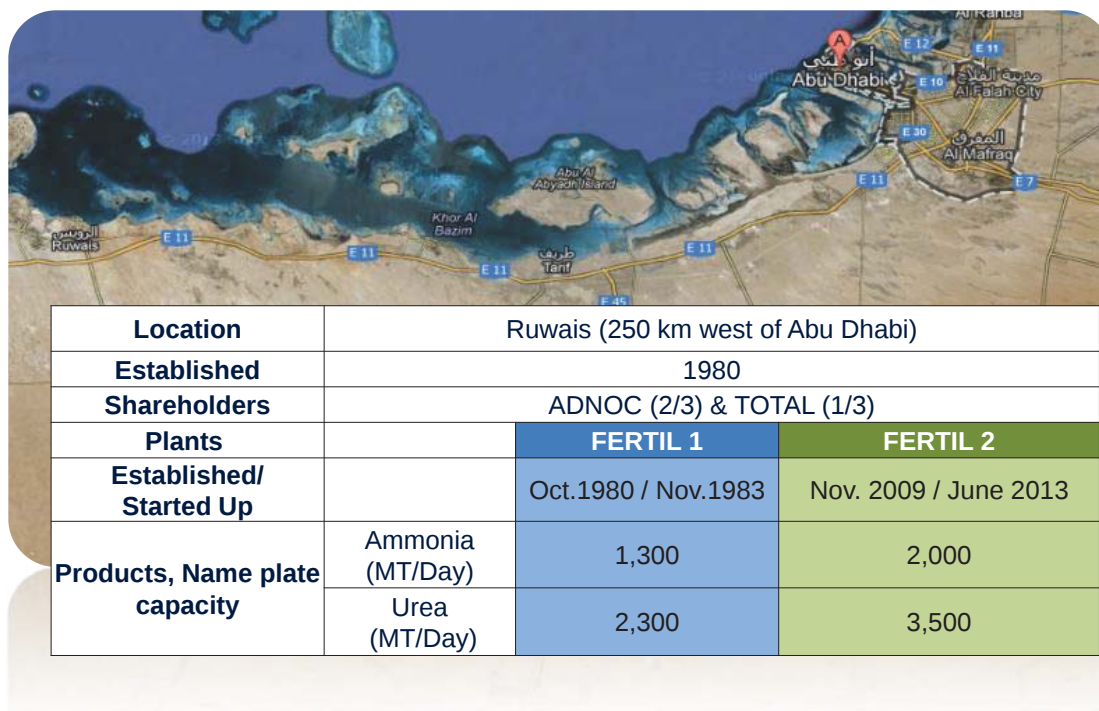
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Content



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FERTIL's Profile



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Plants Photo



FERTIL-1



FERTIL-2



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FERTIL's Awards

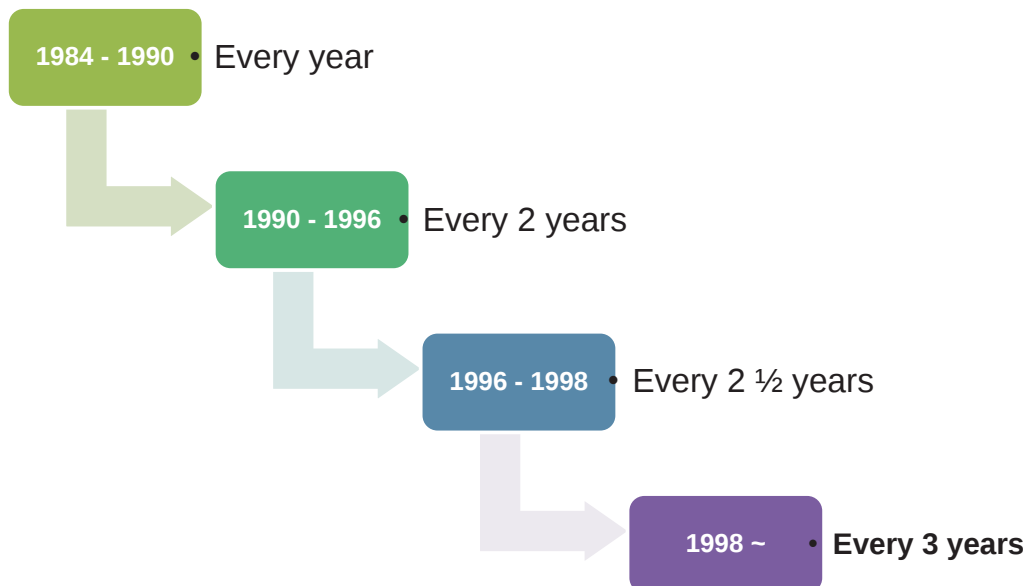


- ✓ Several Awards in ADNOC HSE Performance
- ✓ Occupational Health & Safety certification OHSAS 18001
- ✓ Several Awards of Royal Society for the Prevention of Accidents (RoSPA) including Sector Award
- ✓ Environmental Quality Certification ISO 14001
- ✓ 12 Years without Lost time Incident (LTI) award
- ✓ ISO 9001 for Quality Management System
- ✓ Dubai Quality Appreciation Program Award for industrial sector
- ✓ Sheikh Khalifa Excellence Award for industrial sector
- ✓ ISO 50001 for Energy management system



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Background Turnaround Intervals



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Background

FERTIL-1 WHB function



1

- cools reformed gas to the temperature required for CO conversion in the HTSC

2

- produces high-pressure (HP) steam by using available process heat from Secondary Reformer

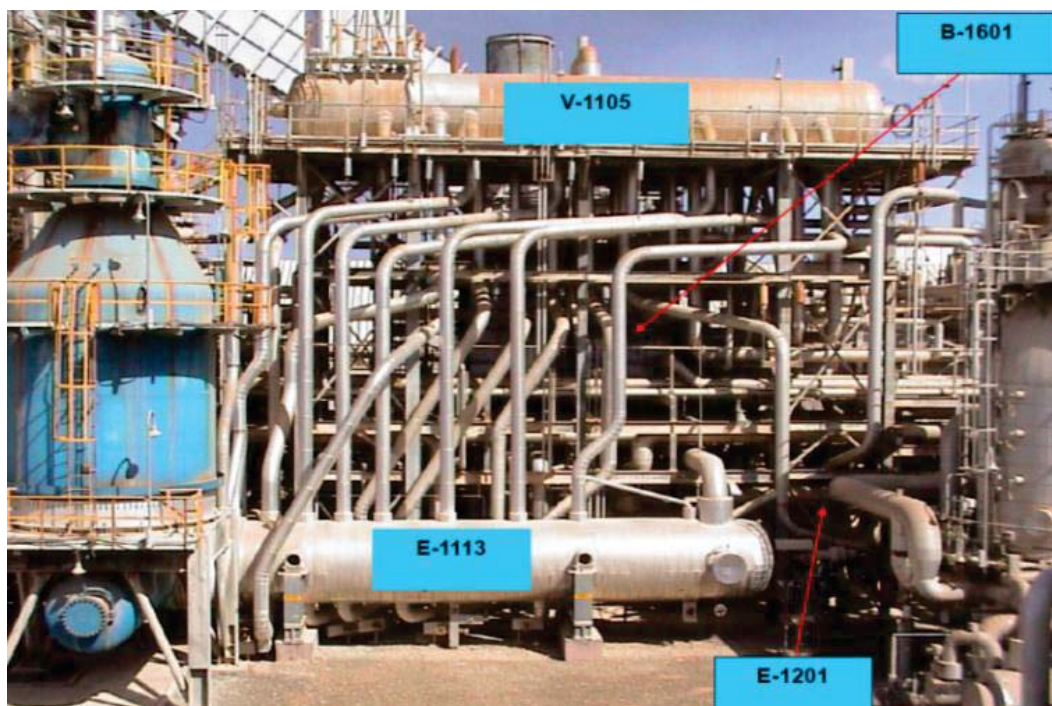
3

- produces about 170 t/h of HP steam at the present load.

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Background

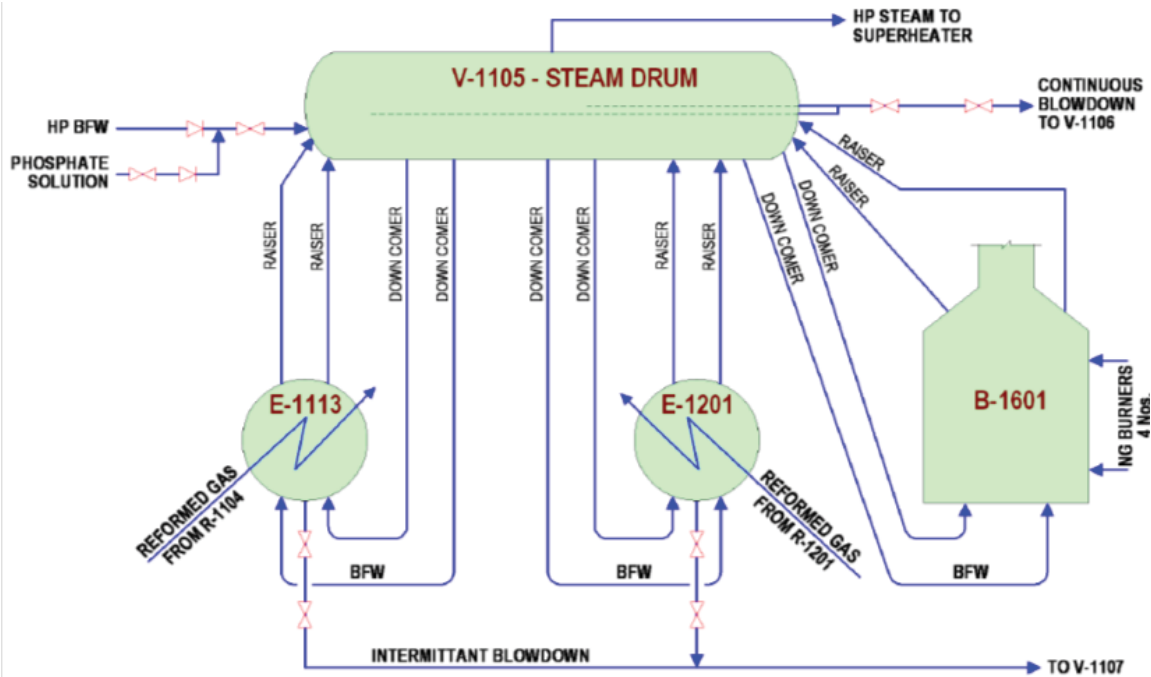
FERTIL-1 WHB Location



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Background

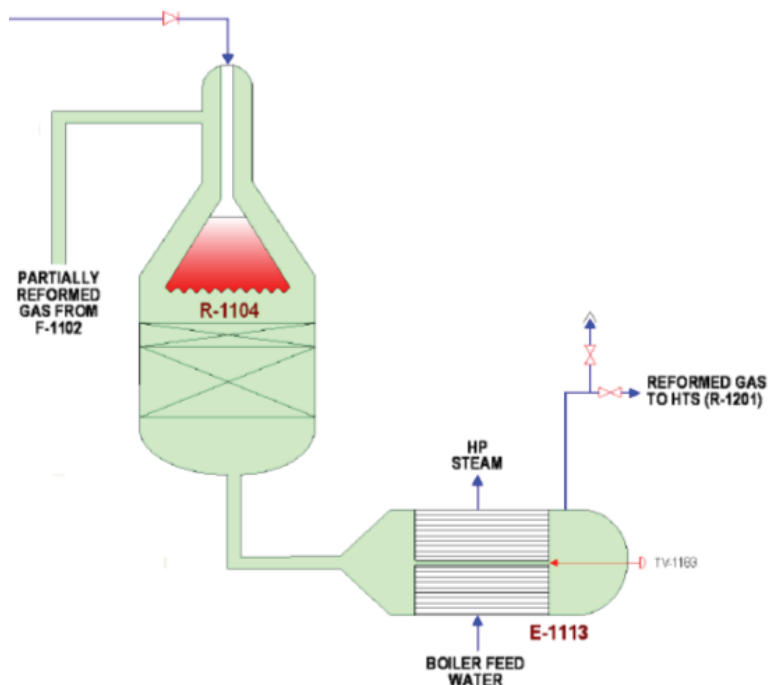
HP Steam Generation



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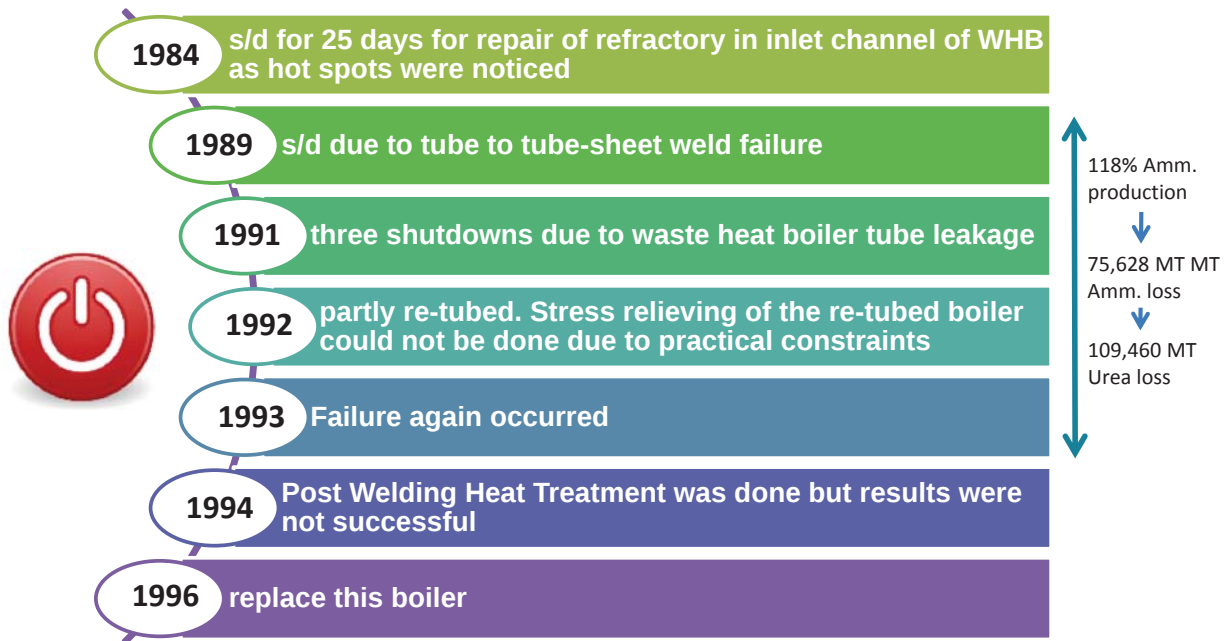
Background

WHB and Secondary Reformer



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WHB History



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Causes of Failure



After an investigation by Borsig, the causes of the frequent boiler failures were identified as:

1. High heat flux near the hot end of the boiler and suspected lower than required circulation ratio resulting in steam blanketing
2. Suspected lapses in the BFW quality



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Action Taken



1. In the design of the new boiler, the previous factors were given due consideration
 - some design parameters were changed.
 - the new boiler is larger in size.
 - Some additional down comers and risers added.
2. the BFW quality was improved and providing on line analyzer, conductivity and Na-meters enhanced better monitoring.
3. BFW conductivity is now maintained at less than $0.2\mu\text{S}/\text{cm}^2$ as compared to $1.0\mu\text{S}/\text{cm}^2$.



The new boiler is performing satisfactory till date



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Objectives and Applied Practices



A general action plan was made in 1996 to meet the following objectives:



Improve Availability and Reliability by analyzing all shutdown causes and determine remedial action

Maximize the through-put of the plant by identifying the plant load limitation and define remedial action

Sustain the plant integrity

Elaboration of Standard Operations Procedures and check-lists

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Thank You

Technical Assessment of SAFCO-4 Synthesis Loop Waste Heat Boiler-II

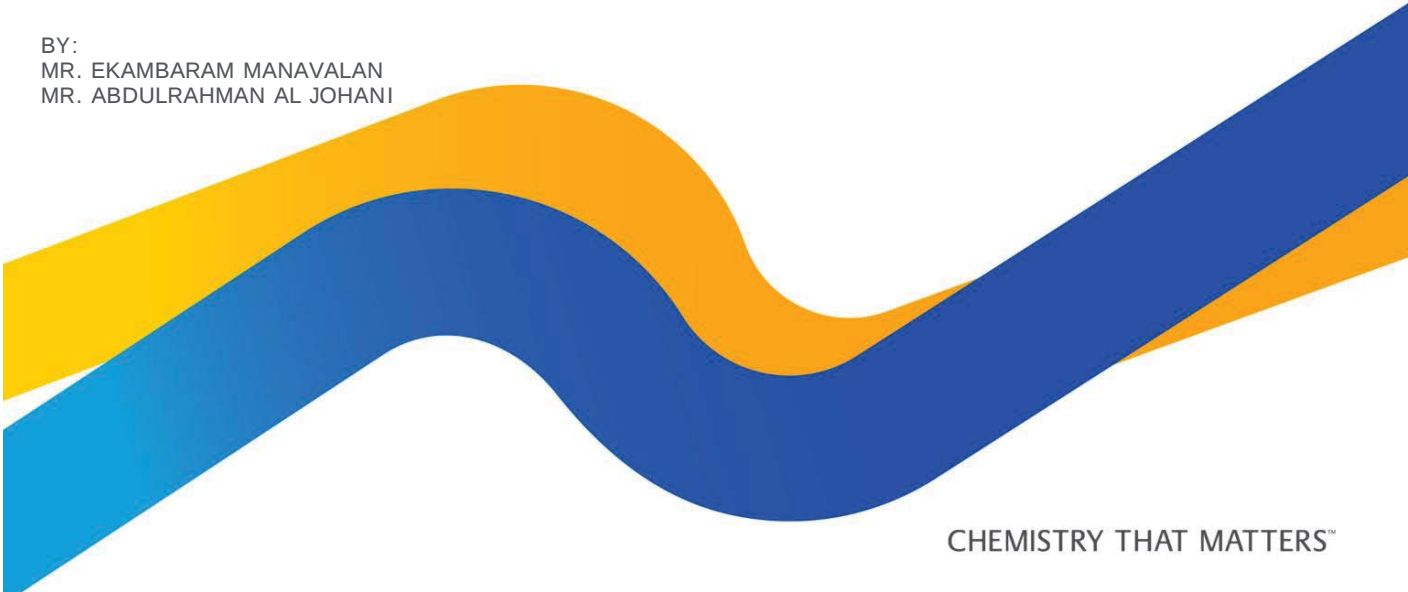
Ekambaram Manavalan
Inspection Manager

Abdulrahman Al Johani
Inspection Engineer

SAFCO
Saudi Arabia

TECHNICAL ASSESSMENT OF SAFCO-4 SYNTHESIS LOOP WASTE HEAT BOILER-II LEAKAGE

BY:
MR. EKAMBARAM MANAVALAN
MR. ABDULRAHMAN AL JOHANI

A large decorative wavy line in blue and orange spans across the middle of the page.

CHEMISTRY THAT MATTERS™

BACKGROUND

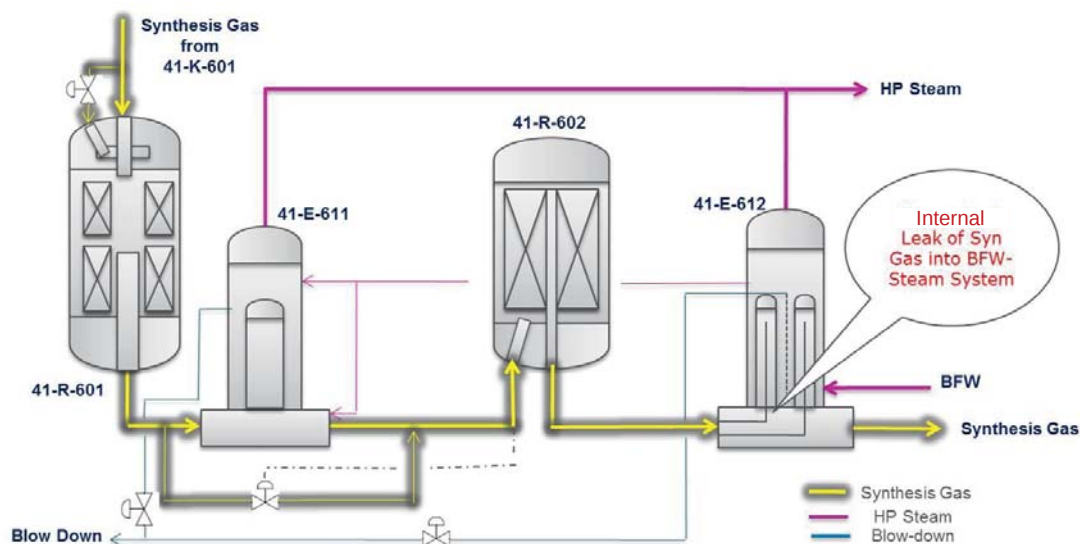
- Saudi Arabian Fertilizer Company (SAFCO), an affiliate of Saudi Arabian Basic Industries Corporation (SABIC) is the first petrochemical company in Kingdom of Saudi Arabia.
- SAFCO is one of the leading producers of Ammonia and Urea in the world with annual production capacity of around 2.3 million tons of Ammonia and 2.6 million tons of Urea.
- In our SAFCO-4 Ammonia plant back end Synthesis loop waste heat boiler # 2, tube leak was observed within 6 years of service. Premature failure of this critical Equipment is a great concern.
- This presentation explain the problem history, Equipment details, technical assessment, mitigation, inspections and repairs carried after leak to operate the Equipment without affecting the Safety and integrity.

HISTORY

- SAFCO-4 Ammonia plant Synthesis loop waste heat boiler#2 (41-E-612) was commissioned during 2006 and performing satisfactorily till January 2012. (Process Licensor: Uhde; Equipment manufacturer: OLMi, Italy)
- During January 2012, Ammonia plant tripped due to power failure. After the plant start-up, higher conductivity was reported from condensate blow down. Minor tube leakage was confirmed by process analysis.
- Equipment was in operation in same leak condition with close monitoring until April 2012.
- During April 2012 Turnaround, Equipment was internally inspected and leak was attended. There was no further leak until July 2013.
- Higher conductivity again reported during July 2013. Process evaluation confirmed tube leakage. Equipment was in operation with leak condition with close monitoring until January 2014.
- Equipment was internally inspected and leak was attended during January 2014 shutdown. There is no further leak and Equipment is now performing satisfactorily.

No. 2

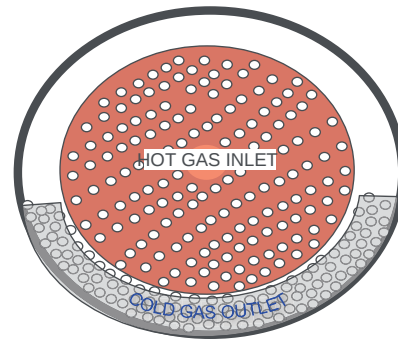
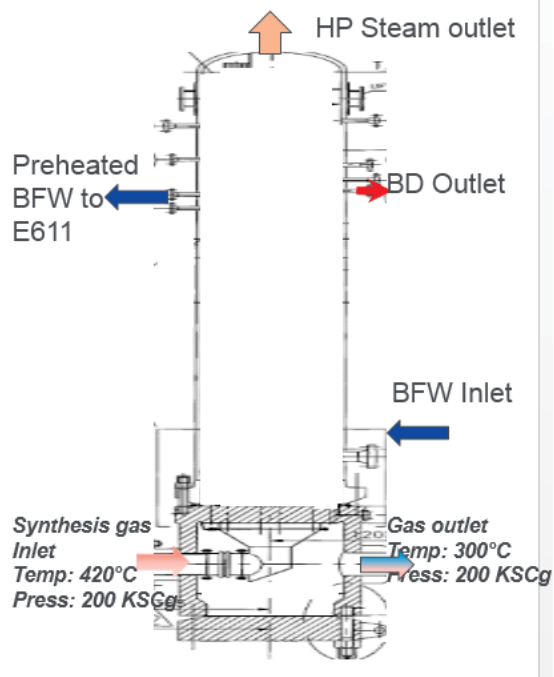
PROCESS DESCRIPTION



- Partially converted synthesis gas (~21% Ammonia & 48% H₂ and rest N₂, CH₄ & Ar) at pressure of ~200 Kg/cm²g and temperature ~ 420°C from converter II enters 41E612 waste heat boiler-II tube side.
- Preheated BFW from BFW preheaters enters the shell side of 41E612 boiler at ~125 Kg/cm²g, a part of BFW converts to HP steam after cooling the synthesis gas and rest directed to waste heat boiler-I (41E611) for cooling synthesis gas coming from converter I.

No. 3

EQUIPMENT SCHEMATIC



Equipment size: 1360mm shell ID x 10152mm overall length

No. 4

MATERIAL OF CONSTRUCTION

- Shell / Head: 20 MnMoNi 4.5 (~ ASTM A553)
- Internal Barrel: ~ ASTM A515 Gr 70
- Tube: ~ Alloy steel 2 ¼ Cr-1 Mo; Total tubes: 290 U, Size: 30mm O.D x 3.2 mm thick.
- Tube sheet: ~ Alloy steel 2 ¼ Cr-1 Mo, Weld overlay with Inconel 600.
- Channel: ~ Alloy steel 2 ¼ Cr-1 Mo
- Gas guide plate : ~ SS 321
- False Tube sheet: ~ SS 321
- Ferrule: ~ SS 304

No. 5

IMPACT OF THE LEAK

Process Upsets	Impact	Mitigation Action	Elimination action
High conductivity / Ammonia in turbine condensate going to Utility	- Higher ionic load on mixed bed polisher leading to lower cycle time and production - More waste generation (sustainability)	- Arrange Ammonia removal unit - Arrange draining facility for contaminated turbine condensate - Import polish water from SF3 & IBB - Reduce plant load	- Inspect & Repair leaking tube. - Replace the boiler during next TA2015.
Presence of H2 and inert in steam	- H2 in the condenser ejector & de-aerator vents (Safety concern) - Vacuum disturbance	- Measure explosive on platforms / working area - Restrict hot jobs in plant area - Line up spare ejector to maintain vacuum	

No. 6

INSPECTION FINDINGS & REPAIR DONE DURING 2012

- Shell side hydro test revealed one tube leaking from tube in-bore welding due to circumferential crack on the weld.
- Total no of tubes: 290-U tubes (580 single length).
- Tube inspection by Eddy Current Testing (by Delta test) were done for 368 out 580 tubes and the test result was found satisfactory without any wall loss or any abnormality. ECT could not be performed for 144 tubes due to fouling of false tube sheet gas guide plate and 68 tubes due to weld protrusion.
- Tube in-bore welding UT inspection (by Olmi) was done for accessible 394 tube welds and the test result was satisfactory except for 1 leaky tube and 2 additional tube welds which was found with weld liner indication. Inspection could not be performed for 179 tube welds due to fouling of false tube sheet gas guide plate and 7 tubes due to weld protrusion.
- 3 tubes (one leaking tube and 2 tubes having weld linear indication) were plugged.
- Boroscopic inspection from shell side nozzles revealed that there was no corrosion of tubes outer surface.

No. 7

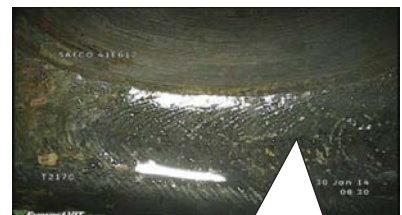
INSPECTION SCOPE DURING 2014

- Perform visual / DPT inspection of channel head internals, gas inlet chamber, expansion bellow, ferrules, tube- sheet weld overlay and, nozzle welds.
- Shell side hydro test at design pressure
- Remove all ferrules for tube inspection.
- Modification of false tube sheet guide plate for full assess of tube inspection.
- 100% Tube inspection by Eddy Current Testing (using modified probe to assess inaccessible tubes which were not tested during 2012).
- 100% Tube in-bore welding UT inspection (after modification of false tube sheet guide plate for full assess of tube inspection).
- 100% Boroscopic inspection of tubes in-bore welding.
- Tubes plugging for leaky tubes as per approved procedure provided by Uhde/OLMI
- Additional sensitive pneumatic leak test to detect minute tube leak.

No. 8

INSPECTION FINDINGS & REPAIR DONE DURING 2014

- Shell side hydro test revealed one tube leaking from tube in-bore welding due to circumferential crack on the weld.
- Tube inspection by Eddy Current Testing (by Delta test) were done for all tubes (except the 3 tubes which were plugged during 2012). Result was found satisfactory without any tube wall loss or any abnormality.
- Tube in-bore welding UT inspection (by Olmi) was done for all tubes. In-bore weld of one leaky tube was found crack along the weld axis and in-bore welds of 5 other tubes revealed linear indication. All defects were in cold side of the tube sheet.
- 6 tubes (one leaking tube and 5 tubes with welding linear indication) were plugged.
- Boroscopic inspection from shell side nozzles revealed that there was no corrosion of tubes outer surface.
- Total tubes plugged so far: 9.



Longitudinal Crack in in-bore weld

No. 9

CONCLUSION

- Original fabrication defect (which was not detectable) propagated during service due to plant upsets is considered as the main cause for the tube weld failure.
- During the procurement of new Equipment, more focus shall be given to avoid any fabrication defect by increasing the scope of NDT and quality checks.

DAY 2: Tuesday December 02, 2014



Technical and Economic Feasibility Assessment for a CHP System with

David Alonso
CEO
DVA Global Energy Services
Spain



Technical and Economic Feasibility Assessment for a CHP System with ORC Technology



1. Objective of the study
2. Energy demand profiles
3. CHP base configuration
4. Improvements to basic CHP configuration
5. Selection of CHP systems
6. Sensitivity analysis

1. **Objective of the study**
2. Energy demand profiles
3. CHP base configuration
4. Improvements to basic CHP configuration
5. Selection of CHP systems
6. Sensitivity analysis

Objective

- A feasibility study is performed for assessing the profitability of a new CHP (Combined Heat and Power) plant, for energy supply to an oil refining site:
 - ✓ Power generation technology: gas turbine.
 - ✓ Electrical power limit 50 MW (legislation)
 - ✓ GT Exhaust gases are used to:
 - Replace two furnaces generating process thermal oil.
 - Produce cooling water in an absorption refrigeration system, to replace mechanical chilled.
- Study of the performance of an organic Rankine cycle (ORC) for additional power generation.
- Feasibility of different modifications (maximum profitability of cogeneration).

1. Objective of the study
2. **Energy demand profiles**
3. CHP base configuration
4. Improvements to basic CHP configuration
5. Selection of CHP systems
6. Sensitivity analysis

Hot oil demand

Hot oil currently generated by 2 furnaces:

- **Furnace B8401**

Duty: 27 MWe

Inlet temperature: 260°C

Outlet temperature: 320°C

Hot oil flow: 700 t/h

- **Furnace B401N**

Duty: 41 MWe

Inlet temperature: 260°C

Outlet temperature: 320°C

Hot oil flow: 1049 t/h

Cooling water demand

Process air currently requires cooling water generated by chillers:

✓ Fenol II Line

- Cooling power: 921 kW
- Chilled water (20% ethylene glycol): 170 m³/h
- Inlet chilled water: 5°C
- Outlet chilled water: 0°C

✓ Fenol III Line

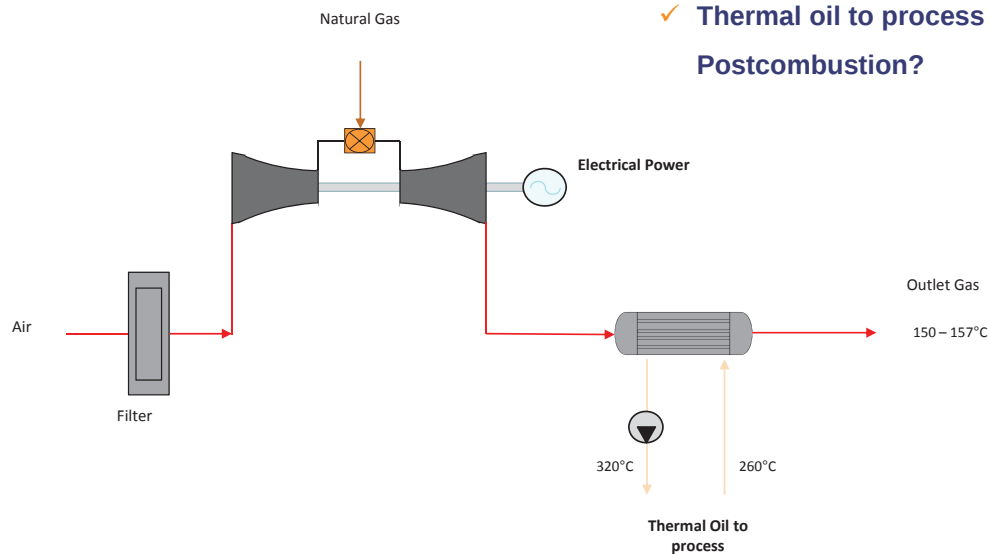
- Cooling power: 1.354 kW
- Chilled water (20% ethylene glycol): 250 m³/h
- Outlet chilled water: 0°C
- Inlet chilled water: 5°C

Total Cooling Power: 2.275 kW

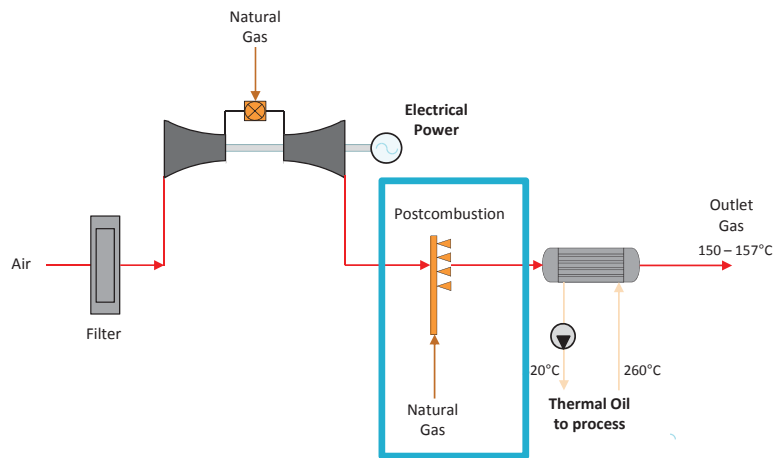
Electricity

- Cogeneration NO designed in base on electricity demand of the site
- Sell all the electricity to the grid and purchase 100% electricity demand
- Maximum electrical power : 50 MW (legislation)
- Legislative framework beneficial: bonus on sale price of the electric energy to the grid

1. Objective of the study
2. Energy demand profiles
3. **CHP base configuration**
4. Improvements to basic CHP configuration
5. Selection of CHP systems
6. Sensitivity analysis

GT + HRS

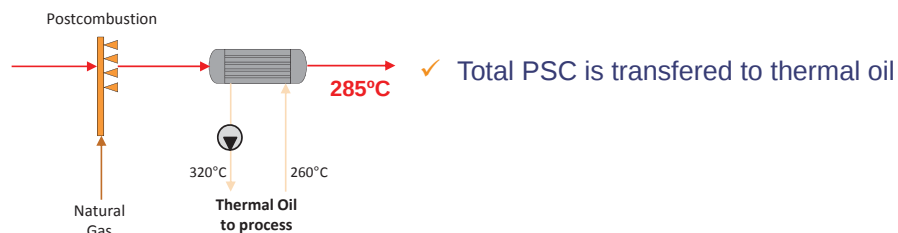
GT + HRSG + PSC



- ✓ **PSC to increase hot oil production**
- ✓ **Gases temperature limit after combustion: 800°C**

POSTCOMBSUTION?

- **Objetive** : Increase hot oil production
- **Advantage**: Increase **EEE**



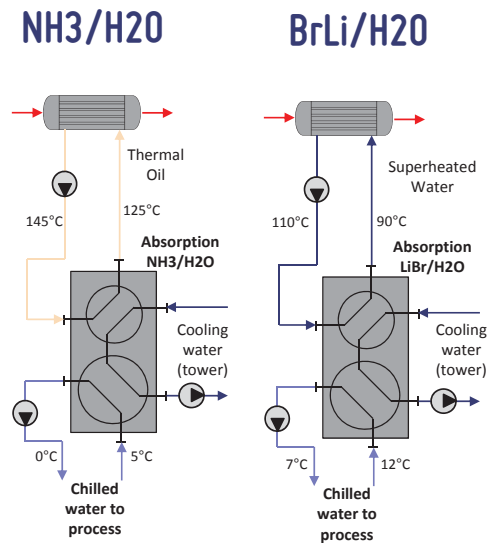
- ✓ For larger sizes selected gas turbines meet both furnaces demand: operative benefit
- **Disadvantages**: It requires a design of gas/oil heat exchanger according to the rules provided for process furnaces (40-50% cost overrun)

Economical evaluation PBT: beneficial. PSC reduces 1 -1,5 años el PBT

1. Objective of the study
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 - 4.1 Cooling Absorption System (CAS) and Organic Rankine Cycle (ORC)
 - 4.2 GT Air Inlet Cooling (GTAIC)
5. Selection of CHP systems
6. Sensitivity analysis

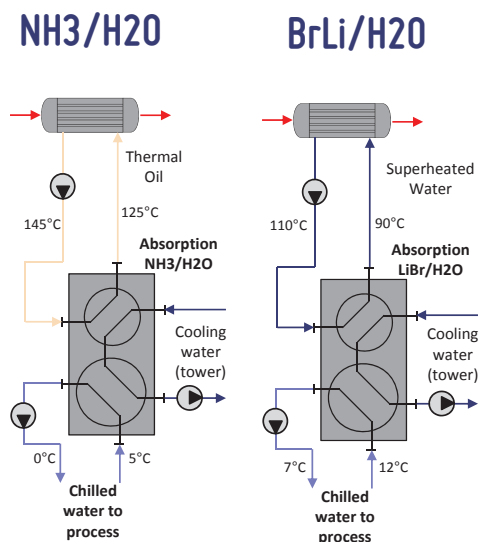
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4.1A Cooling Absorption System (CAS)



- ✓ Include an oil/gases exchanger to feed cooling absorption system
- ✓ Chilled water generated by absorption system is used to supply the cooling process
- ✓ Chilled water temperature required 0/5°C (supply /return)
- ✓ Both BrLi/H2O and NH3/H2O CAS have been considered to refrigerate water, with different options for CAS thermal feeding: low pressure steam, superheated water and thermal oil

4.1A Cooling Absorption System (CAS)

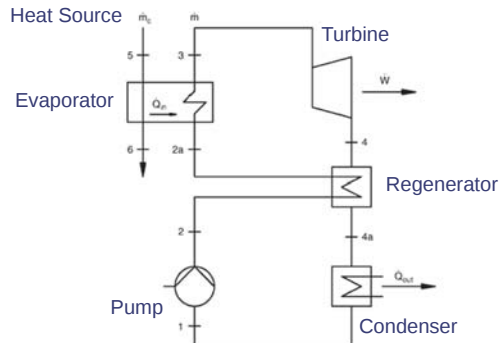


Main differences NH3/H2O vs BrLi/H2O CAS

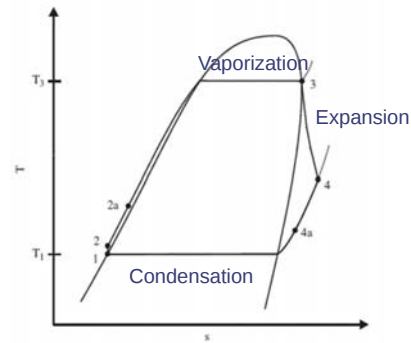
- ✓ **Cooling demand**
 - **Brli:** partial replacement cooling demand, water is cooled to 7°C
 - **NH3:** total replacement cooling demand, water is cooled to 0°C
- ✓ **NH3/H2O CAS** requires higher temperature of thermal feeding

4.1B Organic Rankine Cycle (ORC)

- Cycle power generates electricity from heat source medium or low temperature (300-180°C)
- Organic fluid: low vaporization temperature and pressure, expansion outside of biphasic zone
- Variety of cycles: simple, regenerated supercritical



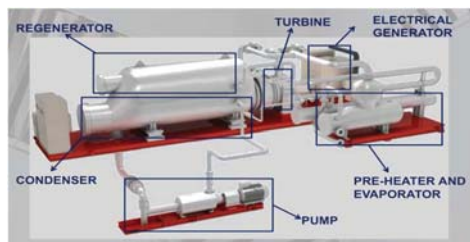
ORC cycle



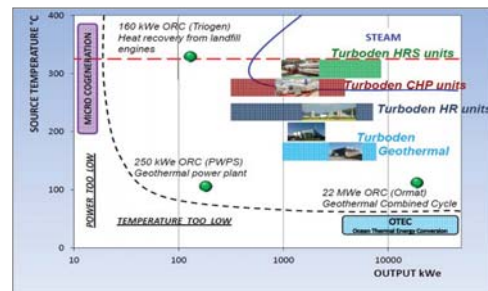
4.1B Organic Rankine Cycle (ORC)

ORC typologies

- **CHP** Thermal source **300°C**. Generates electricity and water to **90°C**
Gross electrical efficiency: **19%**
- **HR** Thermal source **300-240°C**. Only electricity. Gross electrical efficiency : **22% - 17%**
- **HRS** Thermal source **310°C**. Only electricity. Gross electrical efficiency : **24,5%**



Feeding the evaporator: Heat oil, hot water or saturated steam



ORC produces electricity from waste heat

Options:

- ✓ Two stages evaporator
 - ✓ Step 1 Feed: heat oil (300-240°C)
 - ✓ Step 2 Feed: hot water (155°C)
- ✓ Use of higher temperature range of the thermal source

4.1 Cooling Absorption System (CAS) and Organic Rankine Cycle (ORC)

ORC and absorption system integration

Study of several configurations of gas recovery system:

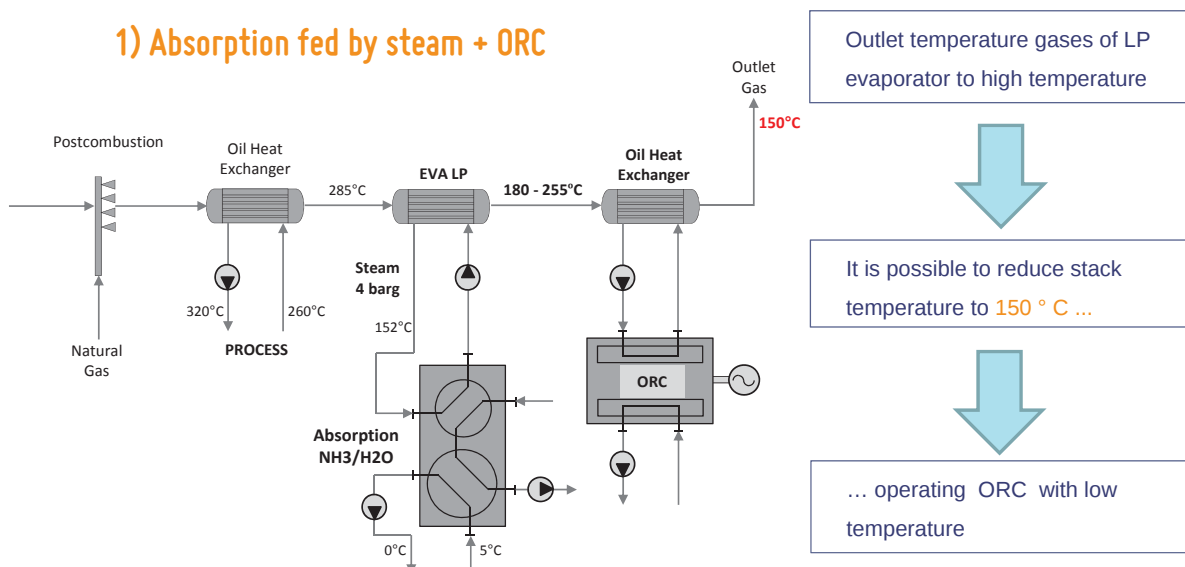
- 1) Absorption fed by steam + ORC
- 2) Absorption fed by superheated water + ORC
- 3) ORC + Absorption fed by hot oil
- 4) ORC with double stage evaporator

4.1 Cooling Absorption System (CAS) and Organic Rankine Cycle (ORC)

ORC and CAS integration

Study of several configurations of gas recovery system.

1) Absorption fed by steam + ORC

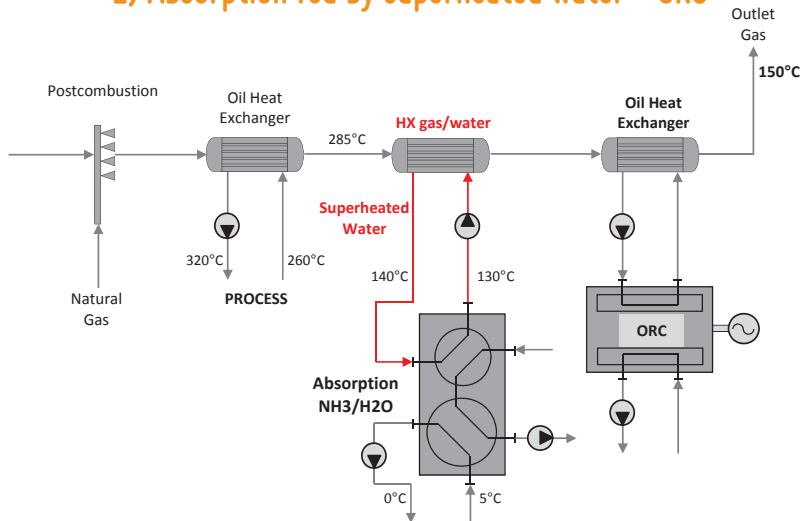


4.1 Cooling Absorption System (CAS) and Organic Rankine Cycle (ORC)

ORC and CAS integration

Study of several configurations of gas recovery system.

2) Absorption fed by superheated water + ORC



Changes

Absorption is fed with superheated water instead of steam.

Advantages

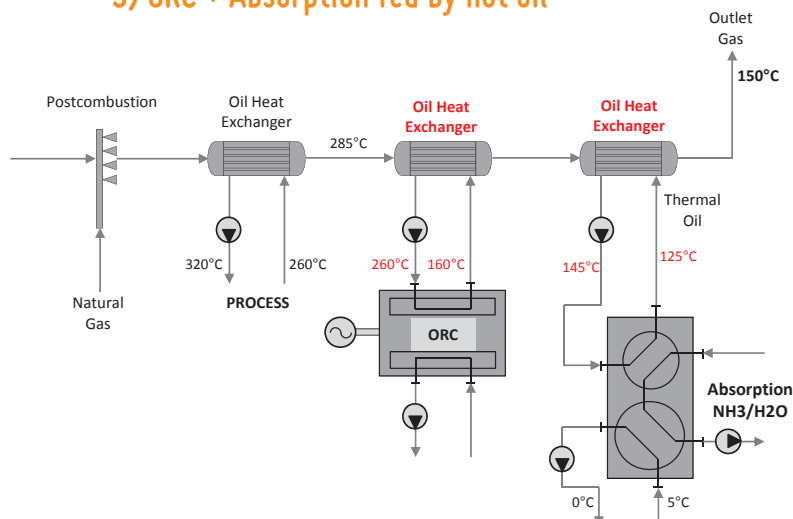
Lower cost of gas/superheated-H₂O exchanger due to the lack of evaporator.

4.1 Cooling Absorption System (CAS) and Organic Rankine Cycle (ORC)

ORC and CAS integration

Study of several configurations of gas recovery system.

3) ORC + Absorption fed by hot oil



Changes:

- Inverted order between absorption and ORC.
- Heat oil instead of superheated water for absorption.

Advantages:

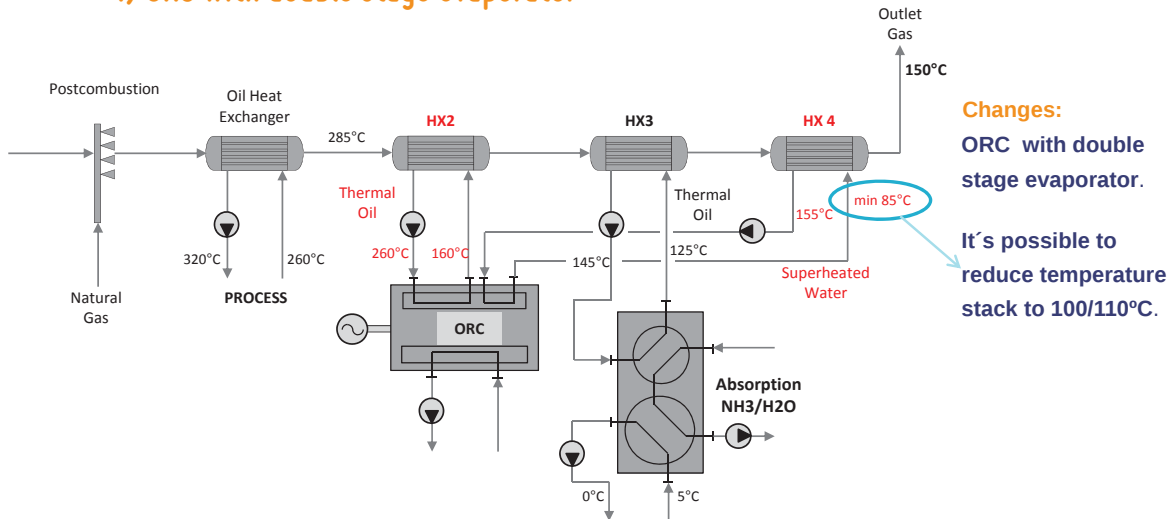
- Increase ORC efficiency (higher temperature thermal source)

4.1 Cooling Absorption System (CAS) and Organic Rankine Cycle (ORC)

ORC and CAS integration

Study of several configurations of gas recovery system.

4) ORC with double stage evaporator

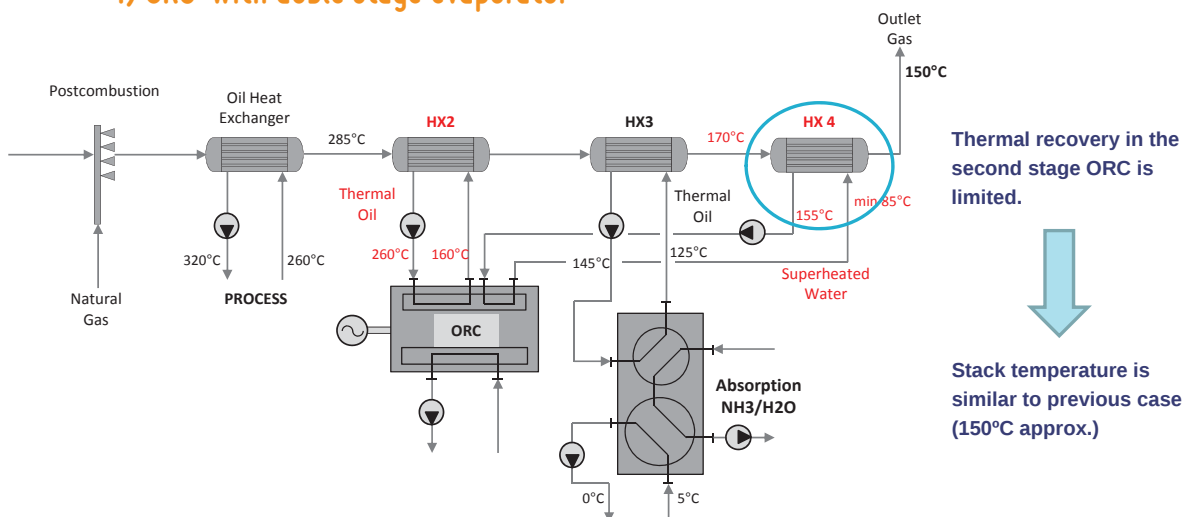


4.1 Cooling Absorption System (CAS) and Organic Rankine Cycle (ORC)

ORC and CAS integration

Study of several configurations of gas recovery system.

4) ORC with double stage evaporator

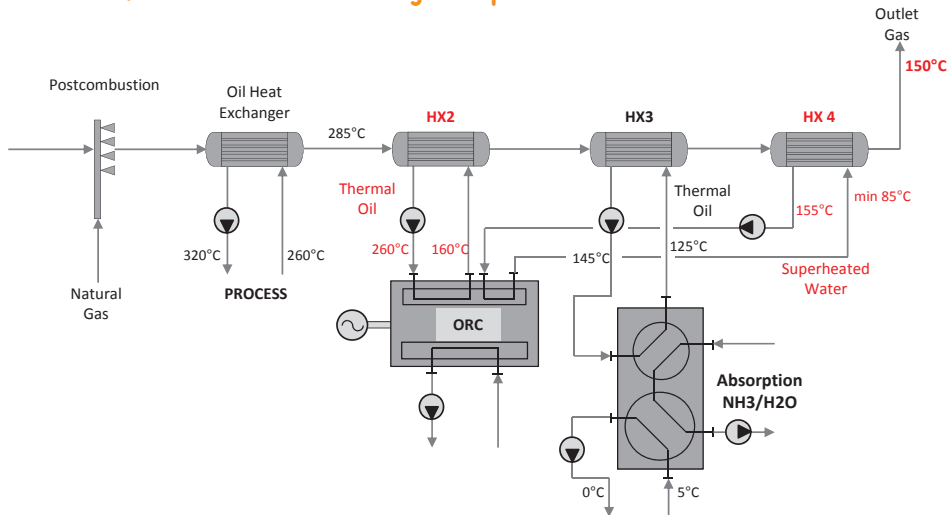


4.1 Cooling Absorption System (CAS) and Organic Rankine Cycle (ORC)

ORC and CAS integration

Study of several configurations of gas recovery system.

4) ORC with double stage evaporator



Conclusions:

NO advantages

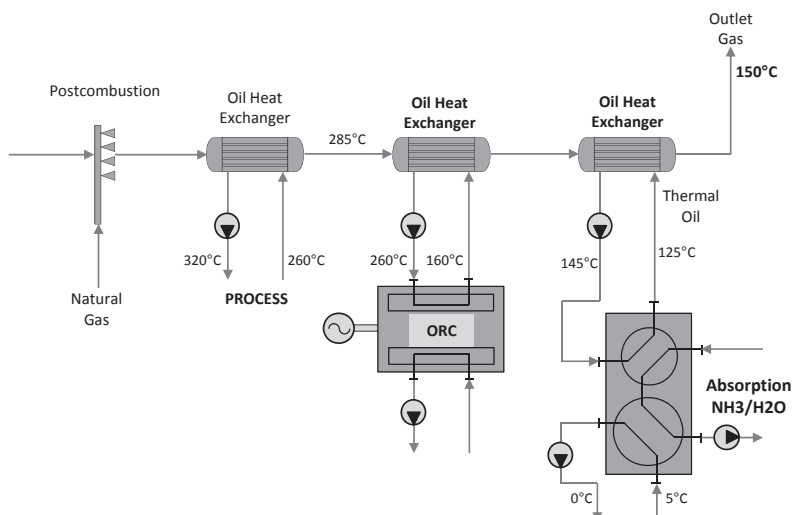
Disadvantages:

Higher cost of ORC

4.1 Cooling Absorption System (CAS) and Organic Rankine Cycle (ORC)

ORC and CAS integration

Final configuration: ORC single stage + absorption heat fed by hot oil



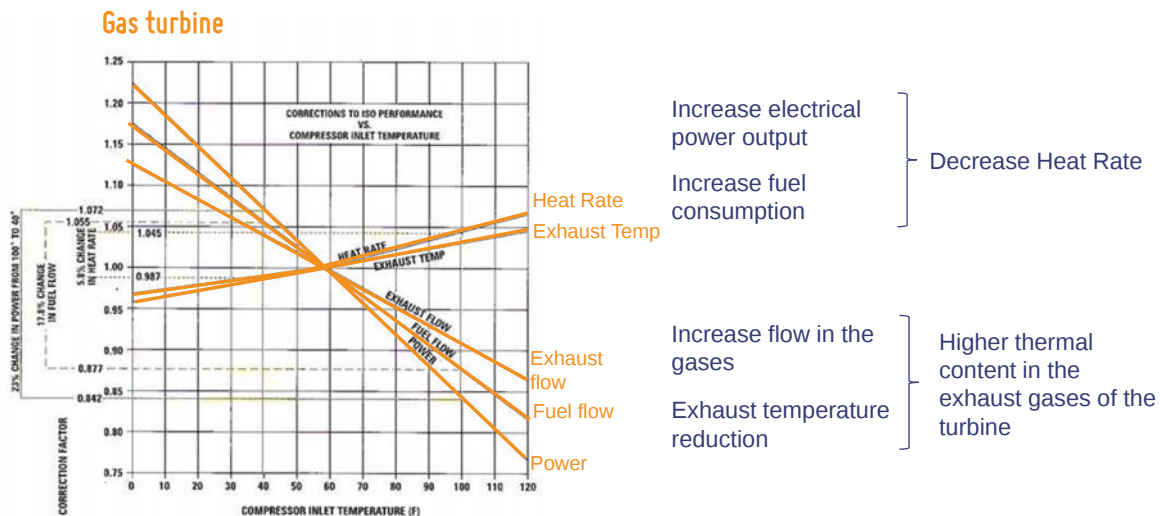
Advantage

- Use thermal oil for absorption implies:
 - **Lower costs compared to steam (not evaporator).**
- ORC before absorption:
 - **Supplying 100% cooling demand.**
 - **More efficiently ORC.**

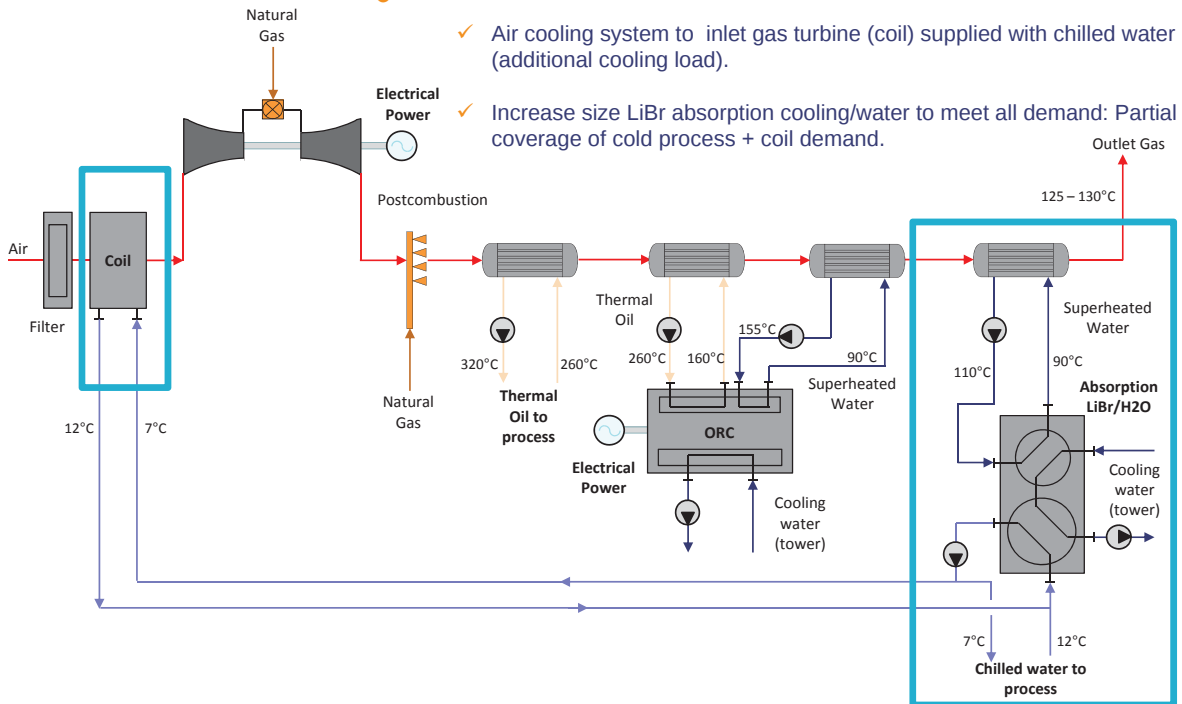
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4.2 GT air inlet cooling (GTAIC)

- GTAIC is included in the proposed configuration of the CHP system with BrLi-H₂O Absorption, to compensate GT electrical output decrease during summer season.
- A study of GT cooling power requirement is carried out, as a function of yearly variable ambient temperature.

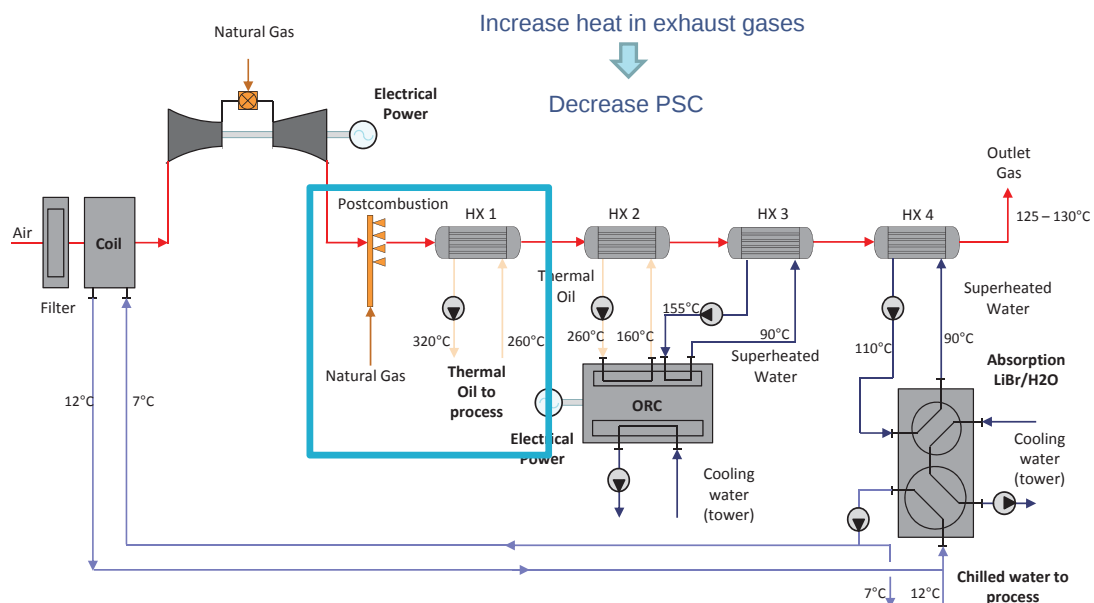


4.2 GT air inlet cooling (GTAIC)



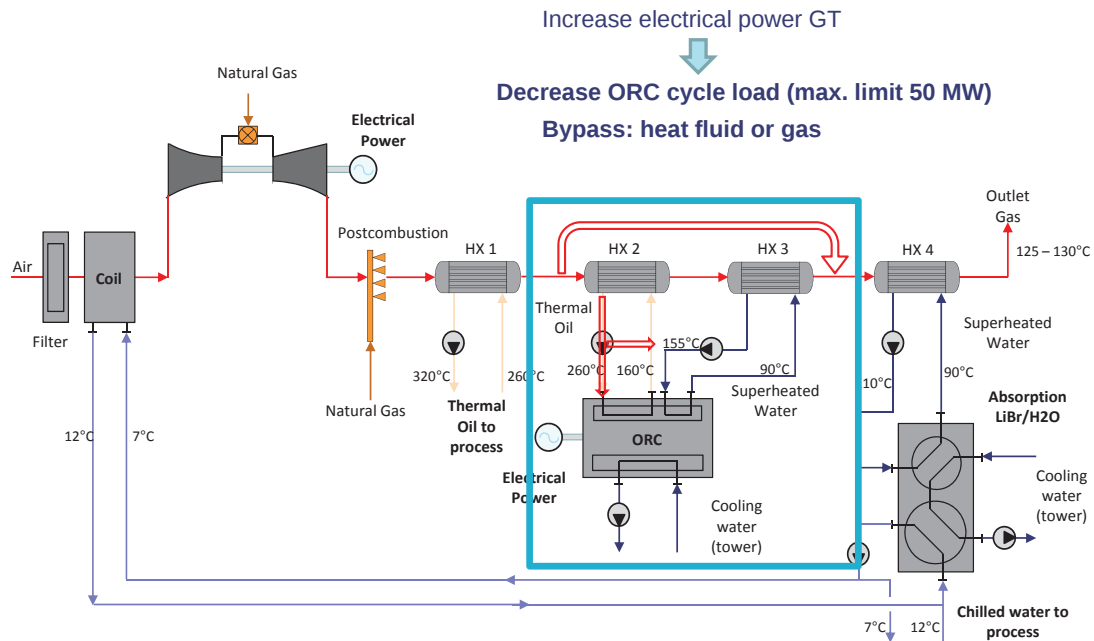
4.2 GT air inlet cooling (GTAIC)

Effects: 1.- OSC and hot oil exchanger

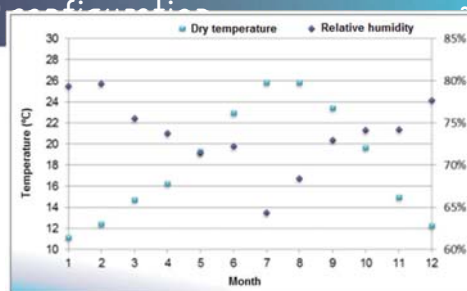
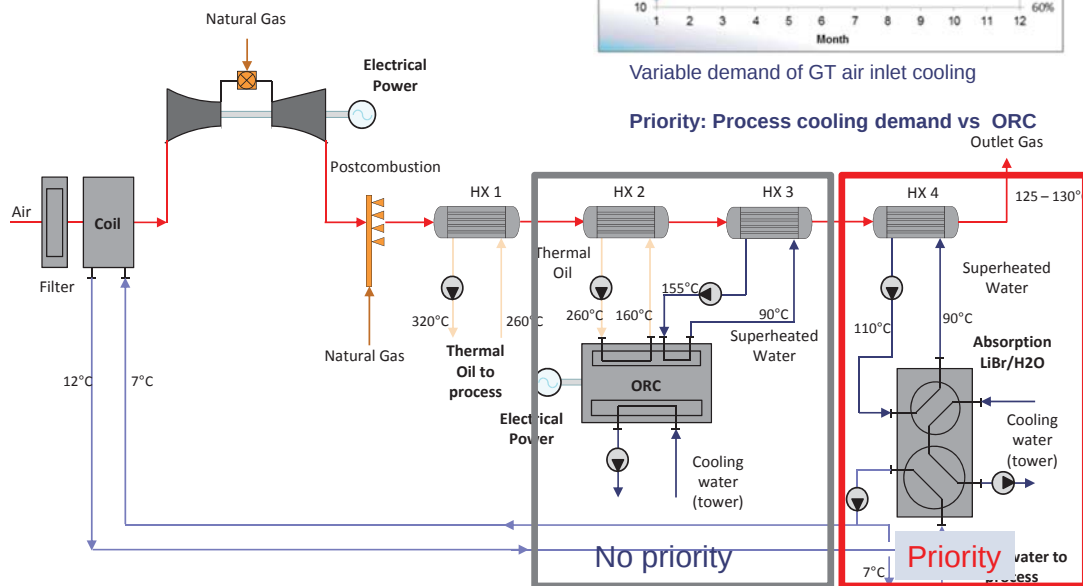


4.2 GT air inlet cooling (GTAIC)

Effects: 2. ORC cycle

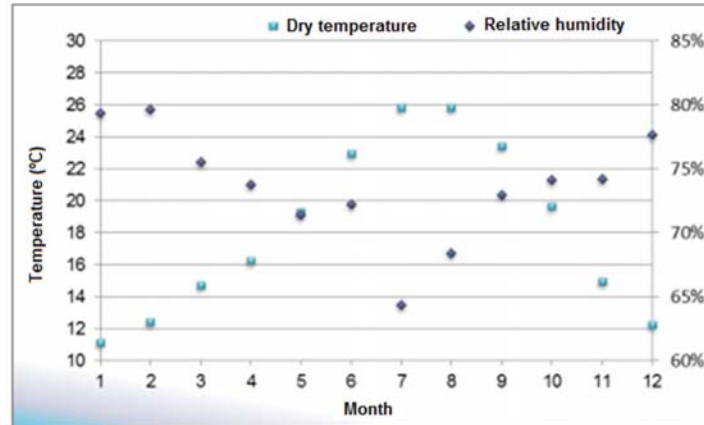


4.2 GT air inlet cooling (GTAIC)

Effects: Absorption LiBr-H₂O

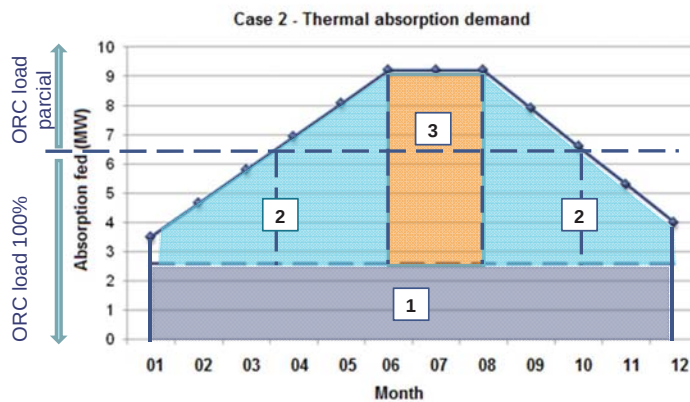
4.2 GT air inlet cooling (GTAIC)

Mensual base study: Air temperature and humidity



4.2 GT air inlet cooling (GTAIC)

Monthly base study



Thermal absorption demand:

• **Constant** part

1 Partial coverage of the cold process

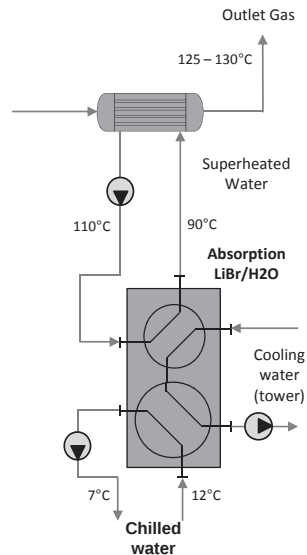
• **Part Load** (air cooling GT)

2 Part Load absorption (T_{amb} moderate)

3 Absorption at full load (high T_{amb})
ORC works part-load

4.2 GT air inlet cooling (GTAIC)

Cooling capacity absorption



PRELIMINARY STUDY:

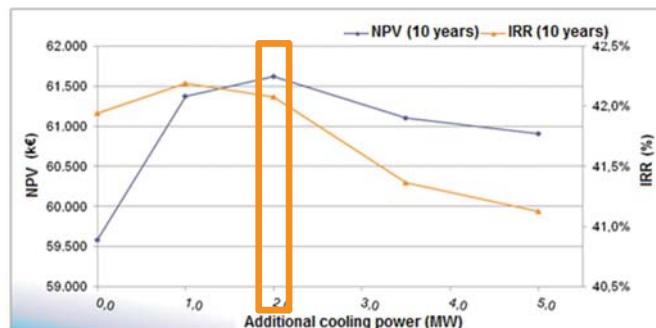
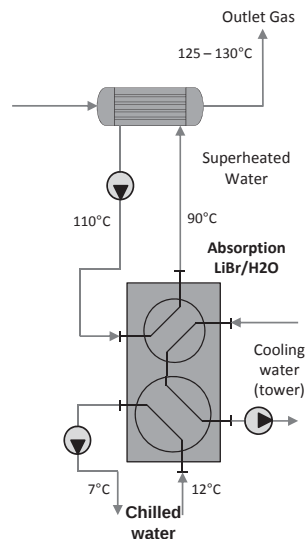
Define CAS capacity to cool air inlet to GT

Analysis 4 GT (from 40 to 47 MW).

Cooling to process + Cooling to air
1,8 MW + ? MW

4.2 GT air inlet cooling (GTAIC)

Cooling capacity absorption: additional cooling power between 1 y 5 MW



* 0 MW additional cooling

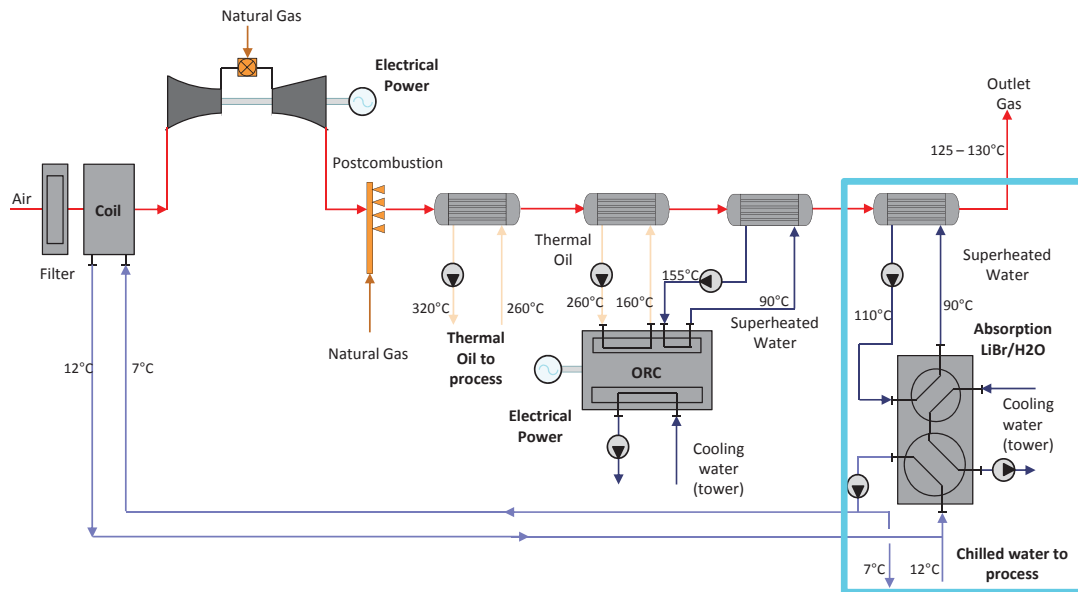
- ✓ Maximum values of IRR and NPV for 1 and 2 MW
- ✓ NPV reaches maximum for 2 MW

Cooling to process + Cooling to air
1,8 MW + ? MW

4.2 GT air inlet cooling (GTAIC)

Conclusions

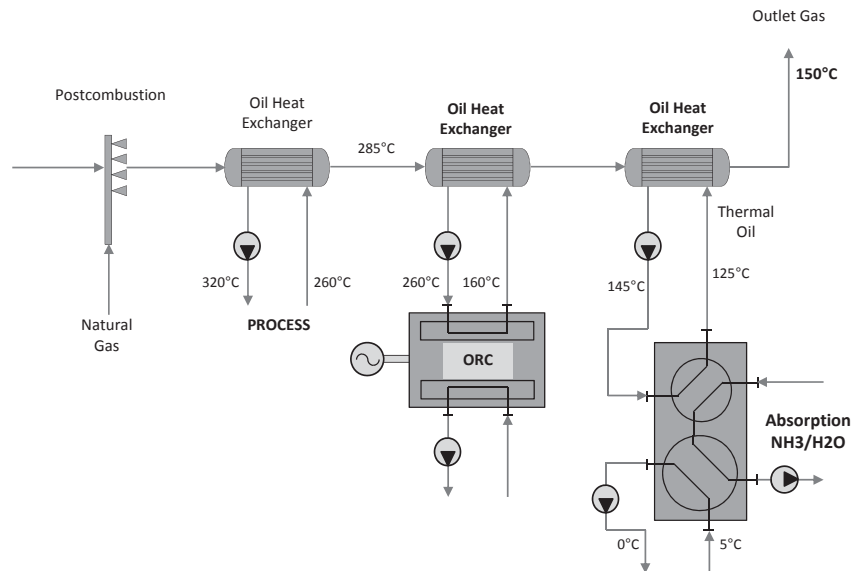
Power absorption refrigerating equipment: 1,8 MW + 2 MW
(Process) (cooling air admission)



1. Objective of the study
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Summary studied configuration

1) BASE CONFIGURATION (NH₃ Abs): GT + PSC + HO exchanger + ORC + NH₃ Cooling



Commercially available GT

- First selection of commercially available GT
 - ✓ Generate electricity at 50 Hz
 - ✓ Nominal electric power from **15 MW to 50 MW**
 - ✓ Results: **41 turbines** considered in the study

Gas Turbine Model	Power (MW)	Exhaust temperature (°C)	Air flow rate (t/h)	Heat Rate (kJ PCIKWh)	Heat Rate (adim)
Solar Titan 130-20500S	15.002	497	176	10.226	2.841
Hitachi H15	15.086	546	188	11.257	3.127
GE LM1800e Low Power	16.575	486	217	10.545	2.929
GE LM1800e High Power	17.725	494	224	10.418	2.894
Kawasaki GPB1800	18.045	533	211	10.576	2.938
Siemens SGT-100-A2	19.065	389	348	10.663	2.968
Solar Titan 250-T30000S	21.730	463	241	9.283	2.573
GE LM2500PE (1)	21.822	529	246	10.133	2.815
Siemens SGT-400	24.630	542	278	10.513	2.920
P-W FTB Swift Pac 30	25.048	463	296	9.543	2.651
GE S371 PA	26.589	483	444	12.580	3.494
P-W FTB Swift Pac 30	27.555	480	307	9.437	2.621
RR RB211-G RT62	27.697	504	330	10.132	2.814
GE LM2500 PV	29.276	521	312	9.685	2.690
RR RB211-GT RT62	29.401	504	339	9.975	2.771
GE LM2500 PR	29.846	528	314	9.704	2.696
GE LM2500 PV	30.340	500	299	9.033	2.509
Siemens SGT-700	31.280	528	332	9.901	2.759
Hitachi H25	31.820	557	341	10.329	2.869
Siemens SGT-700-33	32.215	538	330	9.764	2.712
RR RB211 GT RT61	32.435	511	335	9.418	2.616
GE LM2500 PD (G4)	32.606	528	324	9.388	2.611
GE LM2500 RC (G4)	32.835	524	326	9.376	2.604
GE LM2500 RA (G4)	33.337	524	326	9.234	2.555
Siemens SGT-750	35.925	462	403	9.295	2.582
GE 6581B (1)	42.088	546	524	11.228	3.119
GE 6581B	42.100	546	524	11.183	3.106
GE LM6000 PD	42.751	452	450	8.687	2.413
GE LM6000 PF	42.751	452	450	8.687	2.413
GE 6591 C	42.950	568	423	9.885	2.746
GE LM6000 PC	43.498	451	456	8.656	2.404
GE LM6000 PC	43.517	451	459	8.666	2.407
Siemens SGT-800	47.000	544	463	9.590	2.664
GE LM6000 PF SPRINT 15	47.093	447	471	8.715	2.421
GE LM6000 PC SPRINT	47.179	448	468	8.684	2.412
GE LM6000 PC SPRINT	47.182	448	471	8.690	2.414
GE LM6000 PD SPRINT	47.333	447	471	8.672	2.409
GE LM6000 PF SPRINT 25	47.958	450	472	8.659	2.405
GE LM6000 PH	48.717	475	497	8.778	2.438
Siemens SGT-900	49.500	514	620	10.946	3.041
GE LM6000 PH SPRINT	51.039	471	503	8.774	2.437



5.2 Preliminary energy assessment

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Preliminary analysis

- Define more attractive GT
 - Previous simulations of 41 turbines
 - Main selection criteria: EEE cogeneration
 - Priority: GT with low NOx combustion

Performance gas turbine						Cogeneration data			
Gas Turbine Model	Power (MW)		Heat Rate (Btu/kWh)	Heat Rate (kJ/kWh)	Heat Rate (adim)	Electricity (MW)	Combustible (MW PCI)	Useful heat (MW)	EEE
Solar Titan 130-20500S	15,002	497	176	10,226	2,841	15,556	59,301	32,443	66.8%
Hitachi H15	15,086	546	188	11,257	3,127	15,733	62,115	34,357	65.1%
GE LM1800e Low Power	16,575	486	217	10,545	2,929	17,446	69,872	38,984	65.1%
GE LM1800e High Power	17,725	494	224	10,418	2,894	18,651	72,742	40,100	66.2%
Kawasaki GPB1800	18,045	533	211	10,576	2,938	18,870	70,640	38,026	66.5%
Siemens SGT 500 A2	19,065	369	348	10,683	2,968	20,930	103,508	59,803	56.6%
Solar Titan 250-T30000S	21,730	463	241	9,263	2,573	22,787	81,326	42,812	67.5%
GE LM2500PE (*)	21,822	529	246	10,133	2,815	22,918	82,283	43,610	67.1%
Siemens SGT-600	24,630	542	279	10,513	2,920	25,981	94,450	48,875	64.7%
P-W FTS Swift Pac 30	25,048	463	296	9,543	2,651	26,531	97,611	51,587	65.8%
GE S371 PA	26,589	483	444	12,580	3,494	29,217	134,092	72,364	54.4%
P-W FTS Swift Pac 30	27,555	480	307	9,437	2,621	29,123	102,972	53,342	66.6%
RR RB211-G RT62	27,697	504	330	10,132	2,814	29,443	108,516	57,011	65.2%
GE LM2500 PK	29,276	521	312	9,685	2,690	30,882	105,998	54,139	67.8%
RR RB211-GT RT62	29,401	504	339	9,975	2,771	31,216	112,864	58,447	65.1%
GE LM2500 PR	29,846	528	314	9,704	2,696	31,468	107,176	54,458	67.8%
GE LM2500 PV	30,340	500	299	9,033	2,509	31,846	104,196	52,065	68.1%
Siemens SGT-700	31,200	528	332	9,901	2,750	32,961	114,065	57,338	65.8%
Hitachi H25	31,820	557	341	10,329	2,869	33,651	117,225	58,766	64.8%
Siemens SGT-700-33	32,215	538	330	9,764	2,712	33,942	114,428	57,011	66.8%
RR RB211 GT RT61	32,435	511	335	9,418	2,616	34,218	115,148	57,809	67.2%
GE LM2500 RD (G4)	32,606	526	324	9,388	2,611	34,305	112,898	56,054	67.8%
GE LM2500 RC (G4)	32,835	524	326	9,376	2,604	34,550	113,671	56,373	67.1%
GE LM2500 RA (G4)	33,337	524	326	9,234	2,565	35,052	113,664	56,373	68.1%
Siemens SGT-750	35,925	462	403	9,295	2,582	38,212	135,379	68,657	64.7%
GE 6581B (*)	42,088	546	524	11,228	3,118	45,326	157,160	72,364	59.1%
GE 6581B	42,100	546	524	11,183	3,106	45,347	156,671	72,364	59.9%
GE LM6000 PD	42,751	452	450	8,687	2,413	45,425	148,332	72,364	66.9%
GE LM6000 PF	42,751	452	450	8,687	2,413	45,425	148,332	72,364	66.9%
GE 6591 C	42,950	568	423	9,885	2,746	45,439	148,641	71,848	66.0%
GE LM6000 PC	43,498	451	456	8,656	2,404	46,219	149,590	72,364	66.9%
GE LM6000 PC	43,517	451	459	8,666	2,407	46,261	149,600	72,364	66.9%
Siemens SGT-800	47,000	544	463	8,590	2,664	49,775	156,367	72,364	65.5%
GE LM6000 PF SPRINT 15	47,093	447	471	8,715	2,421	49,930	158,816	72,364	63.1%
GE LM6000 PC SPRINT	47,179	448	468	8,684	2,412	49,992	158,623	72,364	63.9%
GE LM6000 PC SPRINT	47,182	448	471	8,690	2,414	50,019	158,556	72,364	64.0%
GE LM6000 PD SPRINT	47,333	447	471	8,672	2,409	50,170	158,831	72,364	64.0%
GE LM6000 PF SPRINT 25	47,958	450	472	8,659	2,405	50,802	158,670	72,364	64.1%
GE LM6000 PH	48,717	475	497	8,778	2,438	51,755	157,927	72,364	66.8%
Siemens SGT-900	49,500	514	620	10,946	3,041	53,489	174,768	72,364	56.1%
GE LM6000 PH SPRINT	51,039	471	503	8,774	2,437	54,123	163,805	72,364	64.9%



5.2 Preliminary energy assessment

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Results

- 11 selected turbines to analyse in depth

Performance gas turbine						Cogeneration data				
Ref	Gas Turbine Model	Power (MW)	Exhaust temperature (°C)	Air flow rate (t/h)	Heat Rate (kJ PC/kWh)	Heat Rate (adim)	Electricity (MW)	Combustible (MW PCI)	Useful heat (MW)	EEE
1	Solar Titan 130-20500S	15,002	497	176	10,226	2,841	15,556	59,301	32,443	66.9%
	Hitachi H15	15,086	546	188	11,257	3,127	15,733	62,115	34,357	65.7%
	GE LM1800e Low Power	16,575	486	217	10,545	2,929	17,446	69,872	38,984	65.7%
	GE LM1800e High Power	17,725	494	224	10,418	2,894	18,651	72,742	40,100	66.2%
	Kawasaki GPB1800	18,045	533	211	10,576	2,938	18,870	70,640	38,026	66.5%
	Siemens SGT-500-A2	19,065	369	348	10,683	2,968	20,930	103,508	59,803	56.6%
	Solar Titan 250-T30000S	21,730	463	241	9,263	2,573	22,787	81,326	42,812	67.5%
	GE LM2500PE (*)	21,822	529	246	10,133	2,815	22,918	82,283	43,610	67.1%
	Siemens SGT-600	24,630	542	279	10,513	2,920	25,981	94,450	48,875	64.7%
	P-W FTS Swift Pac 30	25,048	463	296	9,543	2,651	26,531	97,611	51,587	65.8%
	GE S371 PA	26,589	483	444	12,580	3,494	29,217	134,092	72,364	54.4%
2	P-W FTS Swift Pac 30	27,555	480	307	9,437	2,621	29,123	102,972	53,342	66.6%
	RR RB211-G RT62	27,697	504	330	10,132	2,814	29,443	108,516	57,011	65.2%
	GE LM2500 PK	29,276	521	312	9,685	2,690	30,882	105,998	54,139	67.4%
	RR RB211-GT RT62	29,401	504	339	9,975	2,771	31,216	112,864	58,447	65.1%
	GE LM2500 PR	29,846	528	314	9,704	2,696	31,468	107,176	54,458	67.8%
	GE LM2500 PV	30,340	500	299	9,033	2,509	31,846	104,196	52,065	68.1%
	Siemens SGT-700	31,200	528	332	9,901	2,750	32,961	114,065	57,338	65.8%
	Hitachi H25	31,820	557	341	10,329	2,869	33,651	117,225	58,766	64.8%
	Siemens SGT-700-33	32,215	538	330	9,764	2,712	33,942	114,428	57,011	66.8%
	RR RB211 GT RT61	32,435	511	335	9,418	2,616	34,218	115,148	57,809	67.2%
	GE LM2500 RD (G4)	32,606	526	324	9,388	2,611	34,305	112,898	56,054	67.8%
3	GE LM2500 RC (G4)	32,835	524	326	9,376	2,604	34,550	113,671	56,373	67.1%
	GE LM2500 RA (G4)	33,337	524	326	9,234	2,565	35,052	113,664	56,373	68.1%
	Siemens SGT-750	35,925	462	403	9,295	2,582	38,212	135,379	68,657	64.7%
	GE 6581B (*)	42,088	546	524	11,228	3,118	45,326	157,160	72,364	59.1%
	GE 6581B	42,100	546	524	11,183	3,106	45,347	156,671	72,364	59.9%
	GE LM6000 PD	42,751	452	450	8,687	2,413	45,425	148,332	72,364	66.9%
	GE LM6000 PF	42,751	452	450	8,687	2,413	45,425	148,332	72,364	66.9%
	GE 6591 C	42,950	568	423	9,885	2,746	45,439	148,641	71,848	66.0%
	GE LM6000 PC	43,498	451	456	8,656	2,404	46,219	149,590	72,364	66.9%
	GE LM6000 PC	43,517	451	459	8,666	2,407	46,261	149,600	72,364	66.9%
	Siemens SGT-800	47,000	544	463	8,590	2,664	49,775	156,367	72,364	65.5%
4	GE LM6000 PF SPRINT 15	47,093	447	471	8,715	2,421	49,930	158,816	72,364	63.1%
	GE LM6000 PC SPRINT	47,179	448	468	8,684	2,412	49,992	158,623	72,364	63.9%
	GE LM6000 PC SPRINT	47,182	448	471	8,690	2,414	50,019	158,556	72,364	64.0%
	GE LM6000 PD SPRINT	47,333	447	471	8,672	2,409	50,170	158,831	72,364	64.0%
	GE LM6000 PF SPRINT 25	47,958	450	472	8,659	2,405	50,802	158,670	72,364	64.1%
	GE LM6000 PH	48,717	475	497	8,778	2,438	51,755	157,927	72,364	66.8%
	Siemens SGT-900	49,500	514	620	10,946	3,041	53,489	174,768	72,364	56.1%
	GE LM6000 PH SPRINT	51,039	471	503	8,774	2,437	54,123	163,805	72,364	64.9%
	Solar Titan 130-20500S	15,002	497	176	10,226	2,841	15,556	59,301	32,443	66.9%
	Hitachi H15	15,086	546	188	11,257	3,127	15,733	62,115	34,357	65.7%



5.2 Preliminary energy assessment

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Results

- 11 selected turbines to analyse in depth

Ref	Performance gas turbine						Cogeneration data			
	Gas Turbine Model	Power (MW)	Exhaust temp (°C)	Air flow rate (t/h)	Heat Rate (kJ PCI/kWh)	Heat Rate (adim)	Electricity (MW)	Combustible (MW PCI)	Useful heat (MW)	EEE
1	Solar Titan 250-T30000S	21,730	463	241	9.263	2,573	22,787	81,326	42,812	67,5%
2	Siemens SGT-600	24,630	542	279	10.513	2,920	25,981	94,450	48,875	64,7%
3	GE LM2500 PR	29,846	528	314	9.704	2,696	31,468	107,176	54,458	67,4%
4	Siemens SGT-700	31,200	528	332	9.901	2,750	32,961	114,065	57,330	65,4%
5	GE LM2500 RD (G4)	32,606	526	324	9.398	2,611	34,305	112,898	56,054	67,8%
6	GE LM6000 PF	42,751	452	450	8.687	2,413	45,425	148,332	72,364	66,9%
7	Siemens SGT-800	47,000	544	463	9.590	2,664	49,775	156,367	72,364	65,5%
8	GE LM6000 PF SPRINT 25	47,958	450	472	8.659	2,405	50,802	159,670	72,364	64,1%
9	GE LM6000 PH	48,717	475	497	8.778	2,438	51,755	157,927	72,364	66,8%
10	GE LM6000 PH SPRINT	51,039	471	503	8.774	2,437	54,123	163,805	72,364	64,9%
11	GE 6581B	42,100	546	524	11.183	3,106	45,347	156,671	72,364	59,5%



5.2 Feasibility analysis

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Energy Results

Option		1	2	3	4	5	6	7	8	9	10	11
Power		21.23 MW	23.65 MW	29.19 MW	30.54 MW	31.69 MW	40.30 MW	46.52 MW	46.83 MW	47.13 MW	49.80 MW	42.27 MW
Gas turbine		Solar Titan 250 T30000S	Siemens SGT 600	GE LM2500 PR	Siemens SGT 700	GE LM2500 RD G4	GE LM6000 PF	Siemens SGT 800	GE LM6000 PF SPRINT	GE LM 6000PH	GE LM6000 PH SPRINT	GE PG 6581
Operation of the site	h	8.760	8.760	8.760	8.760	8.760	8.760	8.760	8.760	8.760	8.760	8.760
Operation of the cogeneration (CHP)	h	8.400	8.400	8.400	8.400	8.400	8.400	8.400	8.400	8.400	8.400	8.400
ELECTRICITY BALANCE												
Electricity of the gas turbine	MWh/year	169.714	187.824	232.268	242.348	251.983	319.351	370.079	372.380	374.934	396.715	332.002
ORC electricity	MWh/year	8.658	10.837	12.928	14.188	14.188	19.152	20.708	20.971	20.971	21.626	23.062
Generation in terminals	MWh/year	178.372	198.661	245.196	256.537	266.172	338.503	390.787	393.352	395.905	418.341	355.064
Electricity used for the CHP	MWh/year	4.454	4.967	5.738	6.017	6.055	7.600	8.234	8.267	8.298	8.571	7.819
Electricity exported	MWh/year	173.918	193.694	239.458	250.520	260.117	330.904	382.553	385.084	387.607	409.770	347.245
STEAM BALANCE / THERMAL OIL / WATER												
Thermal oil generated by the CHP	MWh/year	329.003	382.612	425.678	454.146	440.194	571.200	571.200	571.200	571.200	571.200	571.200
Water chiller exported by the CHP	m3/año	3.528.000	3.528.000	3.528.000	3.528.000	3.528.000	3.528.000	3.528.000	3.528.000	3.528.000	3.528.000	3.528.000
Cooling energy	MWh/year	19.110	19.110	19.110	19.110	19.110	19.110	19.110	19.110	19.110	19.110	19.110
Heat generated for absorption production	MWh/year	36.960	36.960	36.960	36.960	36.960	36.960	36.960	36.960	36.960	36.960	36.960
Heat for natural gas to furnaces	MWh/year	0	0	0	0	0	0	0	0	0	0	0
Air for services and instruments	m3/year	20.000	20.000	20.000	20.000	20.000	20.000	20.000	20.000	20.000	20.000	20.000
Useful heat (formula > 0°C)	MWh/year	348.592	402.200	445.267	473.735	459.782	590.789	590.780	590.789	590.789	590.789	590.789
Useful heat	MWh/year	365.963	419.572	462.638	491.106	477.154	608.160	608.152	608.160	608.160	608.160	608.160
FUEL BALANCE												
Gas turbine fuel	MWhPCI/year	453.718	579.793	645.700	690.295	684.272	807.475	1.019.332	927.444	946.260	1.000.222	1.065.271
Postcombusters fuel	MWhPCI/year	219.467	195.796	234.217	248.212	242.046	387.979	256.637	374.909	341.418	338.209	213.704
Total fuel	MWhPCI/year	673.184	775.589	879.917	938.507	926.318	1.195.454	1.275.968	1.302.353	1.287.678	1.338.431	1.278.976
Efficiency												
Electric efficiency		26,5%	25,6%	27,9%	27,3%	28,7%	28,3%	30,6%	30,2%	30,7%	31,3%	27,8%
Thermal efficiency		54,4%	54,1%	52,6%	52,3%	51,5%	50,9%	47,7%	46,7%	47,2%	45,4%	47,6%
EEE (> 0°C)		62,4%	60,4%	63,7%	62,2%	64,1%	62,8%	63,1%	60,9%	62,7%	61,3%	57,0%
EEE		66,9%	64,2%	67,0%	65,3%	67,2%	65,1%	65,1%	62,8%	64,7%	63,1%	58,9%
Total CO2	t/year	135.983	156.669	177.743	189.578	187.116	241.482	257.746	263.075	260.111	270.363	258.353
ENVIRONMENT												
Primary energy consumption of reference	MWhPCI/year	361.773	510.416	557.877	588.548	588.802	592.652	925.983	669.498	745.823	777.082	969.801
PES (Primary Energy Savings)	year	147.829	169.407	201.608	207.315	212.035	240.138	280.666	246.689	267.096	265.216	227.299
PESR (Primary Energy Savings Ratio)		41%	33%	36.1%	35%	36%	41%	30%	37%	36%	34%	23%
CO2 emission savings	t/year	29.861	34.220	40.725	41.878	42.831	48.508	56.694	49.831	53.953	53.574	45.914
CO2 associated to electricity generation	t/year	53.845	62.498	73.907	79.352	80.022	104.984	121.249	126.577	123.613	133.865	121.855
Total CO2	t/year	135.983	156.669	177.743	189.578	187.116	241.482	257.746	263.075	260.111	270.363	258.353

Energy Results

Option	1	2	3	4	5	6	7	8	9	10	11
Power	21.23 MW	23.65 MW	29.19 MW	30.54 MW	31.69 MW	40.30 MW	46.52 MW	46.83 MW	47.13 MW	49.80 MW	42.27 MW
Gas turbine	Solar Titan 250 T30000S	Siemens SGT 600	GE LM2500 PR	Siemens SGT 700	GE LM2500 RD G4	GE LM6000 PF	Siemens SGT 800	GE LM6000 PF SPRINT	GE LM 6000PH	GE LM6000 PH SPRINT	GE PG 6581

It is always covered the entire cooling process demand, for all selected turbines.

ELECTRICITY BALANCE											
Electricity of the gas turbine	MWh/year	169.714	187.824	232.268	242.348	251.983	319.351	370.079	372.380	374.934	396.715
ORC electricity	MWh/year	8.658	10.837	12.928	14.188	14.188	19.152	20.708	20.971	20.971	21.626
Generation in terminals	MWh/year	178.372	198.661	245.196	256.537	266.172	338.503	390.787	393.352	395.905	418.341
Electricity used for the CHP	MWh/year	4.454	4.967	5.738	6.017	6.055	7.600	8.234	8.267	8.298	8.571
Electricity exported	MWh/year	173.918	193.694	239.458	250.520	260.117	330.904	382.553	385.084	387.607	409.770

STEAM BALANCE / THERMAL OIL / WATER											
Thermal oil generated by the CHP	MWh/year	329.003	382.612	425.678	454.146	440.194	571.200	571.200	571.200	571.200	571.200
Water cooler exported by the CHP	m ³ /year	0.628.000	0.628.000	0.628.000	0.628.000	0.628.000	0.628.000	0.628.000	0.628.000	0.628.000	0.628.000
Cooling energy	MWh/year	19.110	19.110	19.110	19.110	19.110	19.110	19.110	19.110	19.110	19.110
Heat generated for absorption production	MWh/year	36.960	36.960	36.960	36.960	36.960	36.960	36.960	36.960	36.960	36.960
Heat for export not to forecast	MWh/year	0	0	0	0	0	0	0	0	0	0

Partial coverage of thermal oil demand for GT from 1 to 5, total from 6 to 10.

FUEL BALANCE											
Gas turbine fuel	MWh/PCI/year	453.718	579.793	645.700	690.295	684.272	807.475	1.019.332	927.444	946.260	1.000.222
Procombusters fuel	MWh/PCI/year	219.467	195.796	234.217	248.212	242.046	387.979	256.637	374.909	341.418	338.209

Different EEE, between 63% y 67%, and PES (primary energy savings), between 33% y 41%.

Electric efficiency		29.3%	29.0%	27.3%	27.3%	26.7%	26.3%	30.0%	30.2%	30.7%	27.8%
Thermal efficiency		54.4%	54.1%	52.6%	52.3%	51.5%	50.9%	47.7%	46.7%	47.2%	47.6%
EEE (> 0°C)		62.4%	60.4%	63.7%	62.2%	64.1%	62.8%	63.1%	60.9%	62.7%	61.3%
EEE		66.9%	64.2%	67.0%	65.3%	67.2%	65.1%	65.1%	62.8%	64.7%	63.1%
Total CO ₂	t/year	155.983	150.505	177.743	189.578	187.116	241.482	257.746	263.075	260.111	270.363
ENVIRONMENT											
Primary energy consumption of reference	MWh/PCI/year	361.773	510.416	557.877	588.548	588.802	592.652	925.983	669.498	745.823	777.082
PES (Primary Energy Savings)	year	147.829	169.407	201.608	207.315	212.035	240.138	280.666	246.689	267.096	265.216
PESR (Primary Energy Savings Ratio)		41%	33%	36.1%	35%	36%	41%	30%	37%	36%	23%
CO ₂ emission savings	t/year	29.861	34.220	40.725	41.878	42.831	48.508	56.694	49.831	53.953	53.574
CO ₂ associated to electricity generation	t/year	53.845	62.498	73.907	79.352	80.022	104.984	121.249	126.577	123.613	133.865
Total CO ₂	t/year	135.983	156.669	177.743	189.578	187.116	241.482	257.746	263.075	260.111	270.363

Economic Results

Option	1	2	3	4	5	6	7	8	9	10	11
Power	21.23 MW	23.64 MW	29.19 MW	30.53 MW	31.69 MW	40.30 MW	46.51 MW	46.83 MW	47.13 MW	49.80 MW	42.26 MW
Gas turbine	Solar Titan 250 T30000S	Siemens SGT 600	GE LM2500 PR	Siemens SGT 700	GE LM2500 RD G4	GE LM6000 PF	Siemens SGT 800	GE LM6000 PF SPRINT	GE LM 6000PH	GE LM6000 PH SPRINT	GE PG 6581

Total investment	k€										
Specific cost	k€/MW										

Income and cost of each GT and for 3 studies cases

INCOME	
Electricity exported	k€/year
Thermal oil heating	k€/year
Chilled water production	k€/year
Natural Gas heating	k€/year
Total income	k€/year

COSTS	
Natural Gas	k€/year
CO ₂ cost	k€/year
Air instruments cost	k€/year
Cooling water (tower) cost	k€/year
Electric toll cost	k€/year
O&M cost (variable)	k€/year
O&M cost (fixed) ¹⁾	k€/year
Total costs	k€/year

Fuel, electricity and utilities assessed with 10-year forecasts

¹⁾ Insurances included

Investment for each case

INVESTMENTS
Configuration
Gas turbine
Values in k€
MAIN EQUIPMENT
Gas turbine
Burner
Oil to process/gas heat exchanger
ORC
Absorption cooler
Coil
SECONDARY SYSTEMS
High voltage electricity and power transformers
Low voltage electricity
Outlet and bypass gasses
Gas combustible system
Piping system
Control and supervision system
Instrumentation and monitoring of emissions
CIVIL WORKS
ADDITIONAL SYSTEMS
TOTAL PHYSICAL INVESTMENT
ENGINEERING, CIVIL WORKS DIRECTOR, MANAGEMENT, LEGALIZATIONS
TOTAL INVESTMENT
Specific cost (k€/MW)

*Example: Results for cogeneration Modif 1 (BrLi Abs)

Financial scenary

- Period analysis: **10 years**
- Hours of operation of cogeneration: 24 hours/day
- Availability of cogeneration: 8400 hours/year
- Planned stops:
 - ✓ Stop hot parts (€ 1.5 million) and higher stop (€ 2.5 million)
 - ✓ Every four years, alternately
- Financing Method: **100% itself**
- Depreciation method: **linear to 10 years**
- Residual value: 4 times the cash flow last year

Financial Results

Option	1	2	3	4	5	6	7	8	9	10	11
Power	21,23 MW	23,64 MW	29,19 MW	30,53 MW	31,69 MW	40,30 MW	46,51 MW	46,83 MW	47,13 MW	49,80 MW	42,26 MW
Gas turbine	Solar Titan 250 T30000S	Siemens SGT 600	GE LM2500 PR	Siemens SGT 700	GE LM2500 RD G4	GE LM6000 PF	Siemens SGT 800	GE LM6000 PF SPRINT	GE LM 6000PH	GE LM6000 PH SPRINT	GE PG 6581
Total investment	k€	Investment from 25,6 to 41,3 MM€									
Specific cost	k€/MW										
INCOME											
Electricity exported	k€/year	Specific cost from 1,21 to 0,83 MM€ / MW									
Thermal oil heating	k€/year										
Chilled water production	k€/year										
Natural Gas heating	k€/year										
Total income	k€/year										
COSTS											
Natural Gas	k€/year	Net operating profit from 4,8 to 9,1 MM€ / year									
CO ₂ cost	k€/year										
Air instruments cost	k€/year										
Cooling water (tower) cost	k€/year										
Electric toll cost	k€/year	PBT very attractive for all turbines ranging analysed from 3,5 to 4,5 years									
O&M cost (variable)	k€/year										
O&M cost (fixed) ¹⁾	k€/year										
Total costs	k€/year										
RESULTS											
Operating profit year 2012 ²⁾	k€/year	High values of the IRR, from 30% to 39%									
Net profit for the year 2012	k€/year										
PBT	years										
IRR (10 years)											
NPV (10 years)	k€										

¹⁾ Insurances included²⁾ Profit before interest, taxes, depreciation and amortization

*Example: Results for base configuration

Selection of the best cases

Selection of the best two turbines for each configuration studied:

		BASE CONFIGURATION Abs NH3		Modification 1 Abs LiBr		Modification 2 GT Air Cooling	
		Siemens SGT 800	GELM6000 PH	Siemens SGT 800	GE LM6000 PH	Siemens SGT 800	GE LM6000 P
ENERGY RESULTS							
Electrical power	MW	46,52	47,13	47,05	47,69	48,9	45,6
Useful heat	MW	72,4	72,4	69,8	69,8	69,8	69,8
Total fuel	MW	151,9	153,3	151,9	153,3	154,8	148,3
REE		65,1%	64,7%	63,3%	63,0%	63,3%	64,4%
Electrical efficiency		30,6%	30,7%	31,0%	31,1%	31,6%	30,8%
Thermal efficiency		47,7%	47,2%	46,5%	46,1%	45,6%	47,6%
PES (percentage of primary energy savings)		30%	36%	30%	35%	29%	38%
CO2 savings	t/year	56.694	53.953	52.945	49.640	53.878	48.296
FINANCIAL RESULTS							
Total investment	k€	Very attractive results: Siemens SGT 800					
Specific cost	k€/MW						
Operating profit year 2012	k€/year						
Net profit for the year 2012	k€/year						
PBT	years						
IRR (10 years)							
NPV (10 years)	k€						

Very attractive results:

Siemens SGT 800,
GE LM6000 PH and GE LM6000 PF

- Attractive financial results:

IRR: 39 – 42%

PBT :

- Best turbines selected:

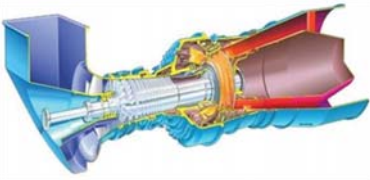
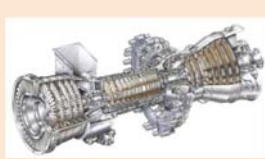
- ✓ Base Configuration
- ✓ Modif 1 (Abs LiBr)

Siemens SGT 800
&
GE LM6000 PH

- ✓ Modification 2
(GT Air cooling)

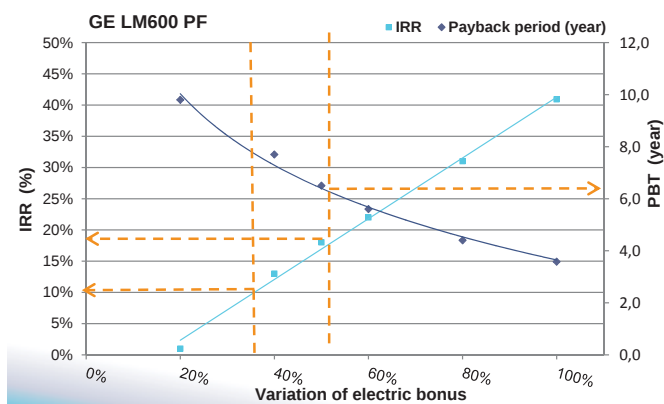
Siemens SGT 800
&
GE LM6000 PF

Summary of the selected turbines

Siemens SGT 800 (47,0 MW)	GE LM6000 PH (48,7 MW)	GE LM6000 PF (42,8 MW)
		
Results independent of the settings selected: NH3 or BrLi Abs or GT air cooling	Results valid for: ✓ Base Configuration (NH3-H2O Abs) ✓ Modif 1 (LiBr Abs)	Only for Modif 2 (GT Air Cooling)

Efectos de la reducción de los incentivos EE

- Study conducted on the basis of the incentives provided by the RD 661/07.
- Need to analyse the sensitivity of the results to reductions EE final prices



CONCLUSIONS

- 50% **reduction** on incentives not impair the profitability of projects:
 - ✓ PBT increases **from 3,5 to 6,5 years**.
 - ✓ IRR decreases **from 41% to 18%**.
- The minimum level of return (**IRR = 10%**) was achieved when the incentives take **35% of the current value**.

DVA Global Energy Services



Technical and Economic Feasibility Assessment for a CHP System with ORC Technology

Ammonia Synloop Waste Heat Boiler Failure Analysis Repair Methodology

**Hossam Naiem
Abu-Qir Fertilizer Co.
Egypt**

Ammonia Syn loop Waste Heat Boiler Failure In Ammonia Plant III

Prepared by
Eng Hossam Naiem

ABU QIR FERTILIZERS

Consists of three plants producing 6000 tpd
from nitrogen fertilizers



Abu Qir I

Abu Qir II

Abu Qir III

ABU QIR I



Ammonia plant
Urea plant

Producing 1150 tpd
Producing 1650 tpd

ABU QIR II



Ammonia plant
Nitric acid plant
Ammonium nitrates plant

Producing 1000 tpd
Producing 1800 tpd
Producing 2400 tpd

ABU QIR III



Ammonia plant
Urea plant

Producing 1200 tpd
Producing 2000 tpd

AMMONIA SHIPLOADING

Capital Investment

Fully covered by Company's own funds

Capacity 100000 tpy

Vessel Characteristic

Length : 150 m

Width: 21 m

Max Draft : 7.5 m

Capacity : 7000-11000 M.T

First Shipment 1990

ABSATRACT

- Waste heat boiler is located down stream of ammonia converter .
- Waste heat boiler showed an internal leakage from tube side to shell side after 4.5 years from commissioning.
- This report describes the case, how to detect the leakage and how to manage this problem, the possible causes and the final action.

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INTRODUCTION

- ▶ ABU QIR 3 plant was commissioned in October 1998, it consists of two main plants, ammonia plant with capacity 1200 ton and Urea plant with capacity 2000 ton. Granulated urea.
- ▶ After 4.5 years from start up the plant a gas leakage from tube side to shell side of synthesis loop waste heat boiler happened , and repeated for five times.

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INTRODUCTION

- ▶ The synthesis loop consists of :-
- ▶ 1- Ammonia converter with three beds Radial Flow
- ▶ 2- **Waste heat boiler**
- ▶ 3- Gas gas heat exchanger
- ▶ 4- Gas cooler
- ▶ 5- Cold exchanger
- ▶ 6- Loop chiller I & II
- ▶ 7- Separator
- ▶ 8- Flash drum

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Syntheses Loop Waste Heat Boiler Specifications:-

- The number of the tubes is 400- U-Tubes with 2 passes.
- The tube length is 5760 mm, tube outside diameter is 25 mm and tube wall thickness is 2.5 mm.
- The number of baffles is 26 and the boiler inside shell diameter is 1390 mm.

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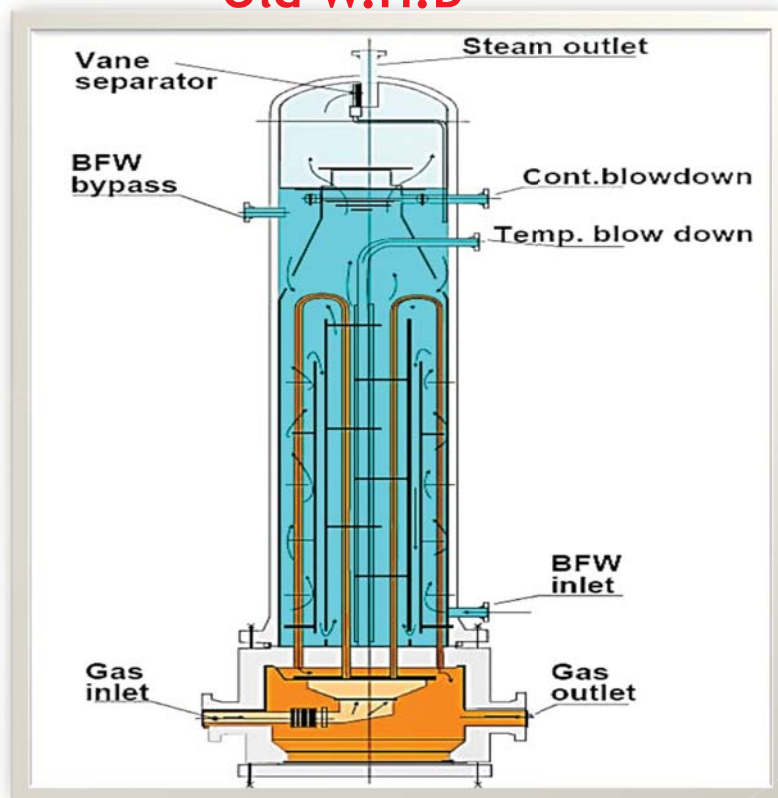
Material of Construction

- The tubes of the waste heat boiler are made of :
- (10 CrMo910), tube sheet is made of (12 CrMo910), the shell, head, and shell flange are made from (20 MnMoNi45).
- The waste heat boiler cools down the gases outlet ammonia converter from 465 °C to about 306 °C and generates saturated steam with 329 °C, the converted gases are introduced in the tube side at an operating pressure of 184.8 bars and the steam is generated in the shell at 125 bars absolute and temperature of 329 °C.

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Old W.H.B



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History of Internal leakage in W.H.B

The first leakage:-

It occurred in the morning shift on 6th march 2003, at this day the values of the PH, Cond. and ammonia of generated steam from W.H.B increased to dangerous limits:-

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History of Internal leakage in W.H.B

Tag Name		Conductivity		PH		NH ₃	
		Before Leakage	After Leakage	Before Leakage	After Leakage	Before Leakage	After Leakage
BFW		6.5	9.5	9.3	9.4	1.9	2.5
Steam Drum	Blow Down	6.6	6.8	9.1	9.3	----	1.2
	HP Steam	8.6	9.8	9.3	9.4	----	2.1
Waste Heat Boiler	Blow Down	6.9	72	9.1	10.3	----	100
	HP Steam	9.1	110	9.3	10.5	----	122
Package Boiler	Blow Down	5.8	8.6	9.1	9.2	-----	1.2
	HP Steam	7.7	10	9.3	9.5	-----	2.1

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History of Internal leakage in W.H.B condensate samples

Tag Name	Conductivity	PH	NH ₃
Ammonia Compressor 309	46	10	33
Synthesis Compressor 307	46.7	10	33
Process Air Compressor 302	47	10	33
CO ₂ Compressor 320	47	10	33
Generator 385	47	10	33

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History of Internal leakage in W.H.B

Tag Name	Conductivity	PH	NH ₃
Condensate tank 329D001	42	9.4	26
Condensate from Steam Drum 329D005	28	9.3	12
Condensate Return from Compressor	47	9.9	26

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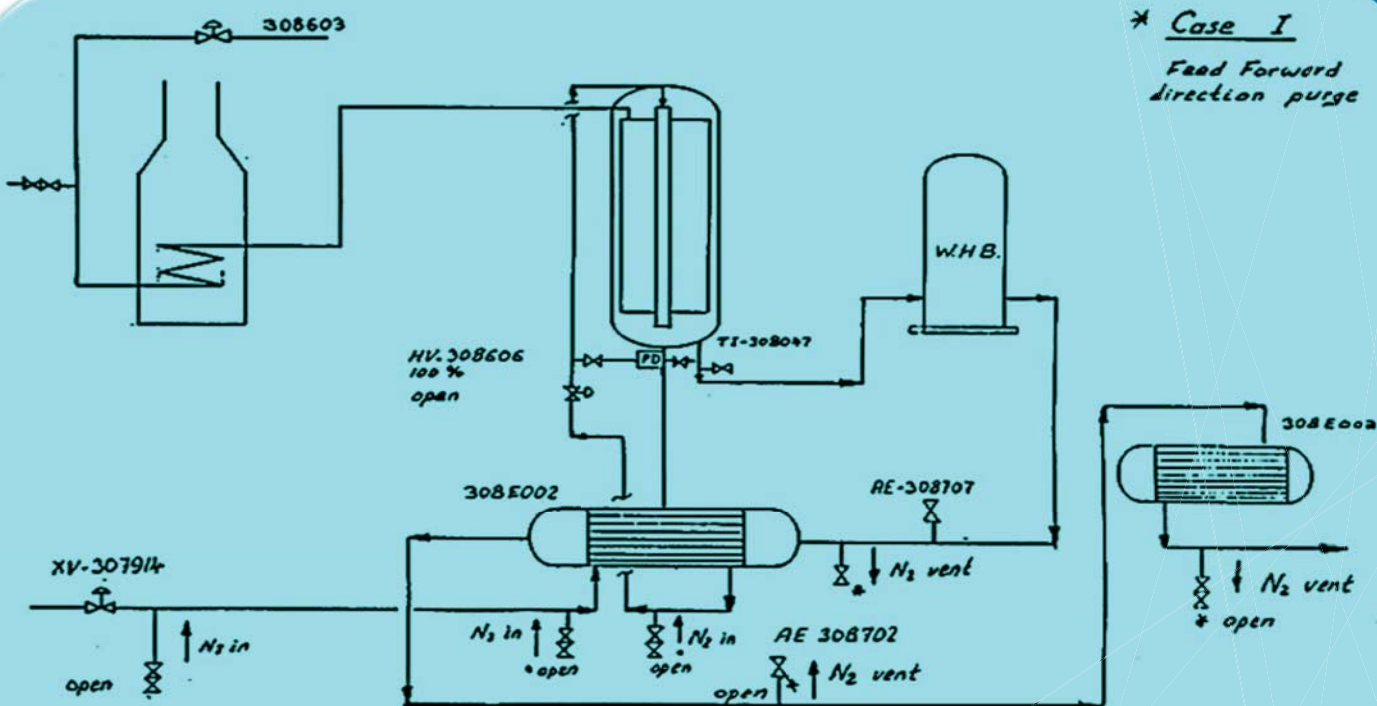
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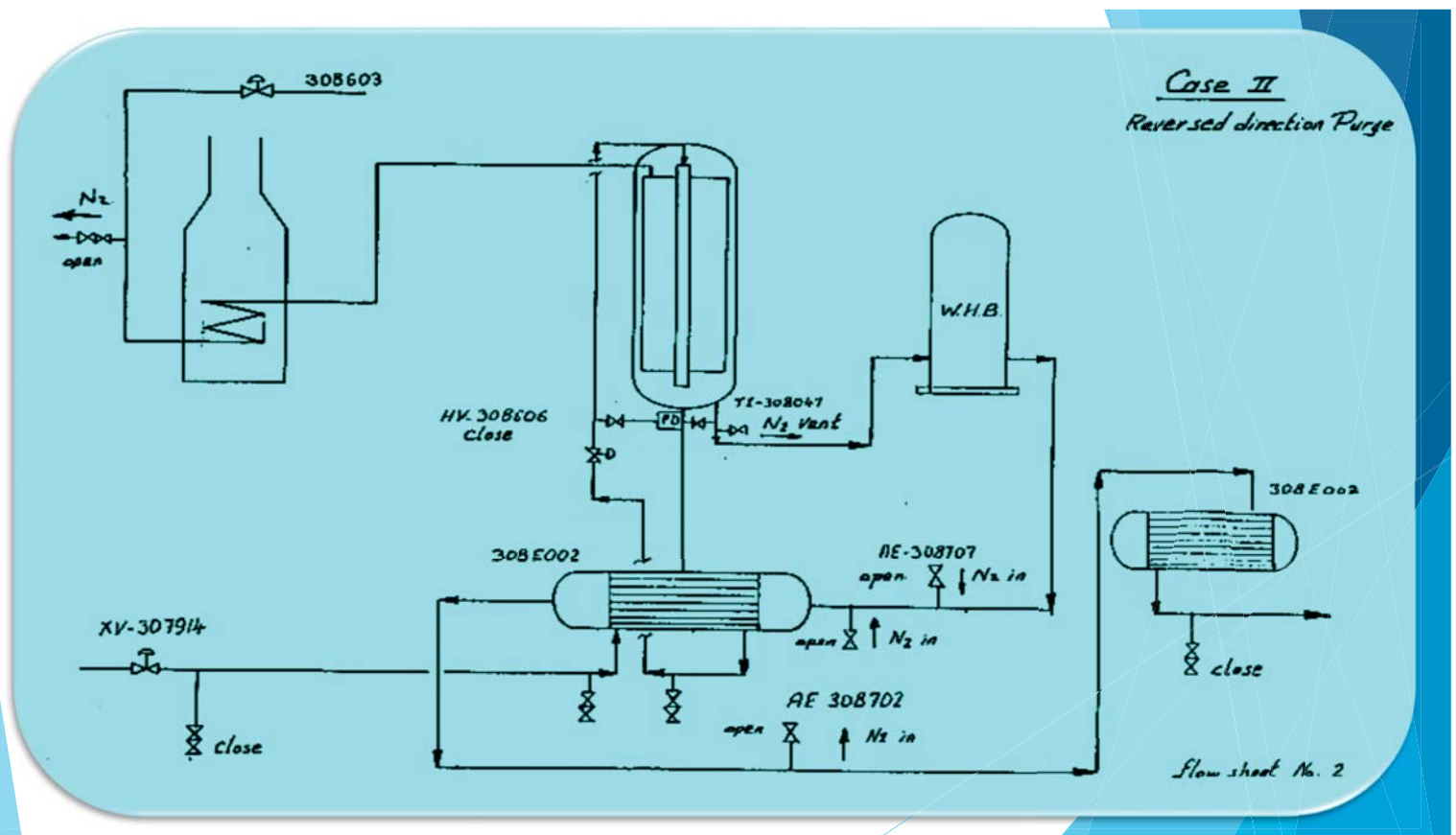
The steps of preparation to Repair the W.H.B

- 1) During shutdown of the synthesis loop , at 120 bar cooling down for Ammonia converter & W.H.B was done by opening Quench valves HV 308604 & 605 for about 4 hr. steam pressure was kept lower than synthesis loop pressure.
- 2) Depressurize the synthesis loop gradually, at 20 bar transfer NH_3 from ammonia separator & flash drum to ammonia storage tank, then continue decreasing Syn. loop pressure till 3 bars.
- 3) N_2 purge in the forward direction of gas flow and vent through the drain valves, the purge should have done first for about 8 hr. and samples should be taken every 1hr.

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The steps of preparation to Repair the W.H.B

7) During cutting the lower weld seal of waste heat Boiler:-

- Put N₂ hose on Ti-308049 (exit converter) and crack it open.
- Take samples from the drain of PDI-308206 (H₂ & NH₃) must be Nil.
- Exit N₂ will be from drains of start up heater.
- During cutting N₂ hose must be directed with small flow till the end of cut.

The steps of preparation to Repair the W.H.B

- The cutters and welders should wear special safety clothes.
- Cut about 3-4 Cm of the welding and take measurements for H₂ & NH₃.
- If the measurements are Ok open more than one N₂ hose and continue cutting to 30-40 Cm and stop for more measurements.
- Then continue cutting.
- Remove the internal expansion joint connected to the cone, and erect a blind flange inside the waste heat boiler on the gas header outlet the converter.
- Erect N₂ hose with PI indicator on the gas header outlet the converter to adjust the N₂ pressure at 0.3 bars inside Ammonia converter.



Repair Procedure:-

- ✚ Detecting the defected tubes in the waste heat boiler specially the hot inlet side by filling.
- ✚ Removing the ferrules of the failed tubes.
- ✚ Enlarging the Secondary tube sheet to insert the plugs.
- ✚ Insert the tube plugs up to the primary tube sheet.
- ✚ Preheating before welding and weld plugs to the primary tube sheet.
- ✚ Annealing for the welded plugs tube sheet.

Repair Procedure:-

- ✚ Make a rolling expanding for the plug to depth approximately 2/3 of the tube sheet thickness.
- ✚ Inspection for the welded plugs.
- ✚ Hydraulic test up to 120 bars and holding time for half an hour.
- ✚ Welding the cover of the enlarging part in the secondary tube sheet.
- ✚ Welding the cover of the outer diaphragm disk, N_2 flow must be opened with continuous measuring the explosion mixture.
- ✚ Pressure test must be done by filling the shell with deionate and increasing the pressure to 40 bars.

The Steps To Close The Waste Heat Boiler:-

- 1) Erect the cyclone.
- 2) Put N_2 hose at the point of PDI-308206 to protect Ammonia converter.
- 3) Remove the blind flange and erect the expansion joint.
- 4) Open the N_2 hose from gas-gas heat exchanger to the waste heat boiler and take analysis of H_2 & NH_3 .
- 5) When H_2 & NH_3 analysis approximately Nil. , then put the disk and crack open the N_2 from PDI-308206 and start welding with continuous H_2 & NH_3 analysis.

start	end	no. of plugged tubes
3/6/2003	3/13/2003	7
4/13/2003	4/17/2003	2
5/26/2003	5/31/2003	15
7/5/2003	7/8/2003	10
		total 34 tubes

***The waste heat boiler leaking repeated five times and total plugged tubes were 34 tubes from a total of (400) tubes

Inspection by Eddy Current (EC):-

1. Inspection of the tubes was limited to a length of 250 Cm above the tube sheet.
2. Most defected tubes were found in the area between 129 Cm and 193 Cm above the tube sheet (in the area between tube sheet and the first baffle).
3. The leakage was caused by reducing the thickness from outside.
4. 17% of the tubes were defected by reducing the average wall thickness more than 50%.
5. All defected tubes are located in the inner pass of the exchanger (hot gas entrance and boiling zone).
6. In the outer pass (cold gas outlet water preheated zone).....No defect was found.

Analysis of the problem and the expected reasons for the failure:-

- ✚ By Visual inspection by endoscope for the shell from the drain nozzles N 11 A/B, it was observed flakes of deposition from one side only at the tube sheet, which was magnetite deposits.
- ✚ The possible reasons for the tubes failure of the synthesis loop waste heat boiler is not very clear but most of the corrosion is found under the baffle plate of the hot side.
- ✚ The steam blanketing for inlet tubes led to drying and wetting for the outer surface of the tubes, natural recirculation and this phenomenon led to crack the passive layer (Fe_3O_4) and these continuous cycles led to loss the tube thickness and finally failure .
- ✚ Hot gas entrance due to inclination in the inlet tube.

Actions for prolong the life of the waste heat boiler

- 1) The pressure test was carried out at lower pressure than recommended (40 Bar) to save the weak tubes from leakage.
- 2) At any shut down or start up for the synthesis loop the pressure drop between tube side and shell side was restricted to keep it at lower as possible.
- 3) Increase the blow down rate to maximum.
- 4) Take complete analysis from N6 every week

The Decision for ordering a new waste heat boiler

With comparing production losses, money paid for the temporary shell, and the expected risk with adjustment , with the price of the new shell ,it was decided to order a new complete waste heat boiler with the new modification in the:-

- ✚ Hot gas inlet
- ✚ Number and height of the baffles of the inner pass

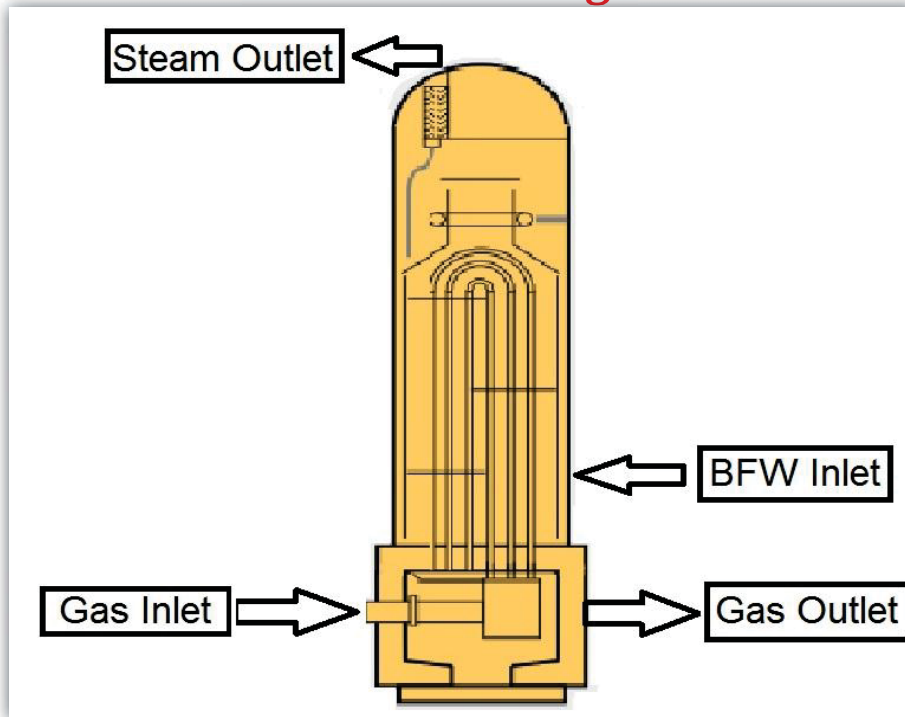
► The new W.H.B



The old W.H.B



New WHB Design



Procedures for changing waste heat boiler

- 1) N₂ purge in the normal direction of the gas flow about 8 hr.
- 2) N₂ purge in reverse direction also about 8 hr.
- 3) Cutting the weld seal in the gas inlet the waste heat boiler and also the gas line outlet
- 4) After the cutting, two flanges with N₂ hose were erected to gas gas heat exchanger inlet line and outlet converter line.

Procedure to clean the new waste heat boiler

Boiling Out

The first boiling out

A) Fill waste heat boiler with Boiler feed water to normal level (60%) and the vent of the waste heat boiler must be opened and add 2 lit. hydrazine.

B) Prepare the chemicals in a tank:-

- 1- 30 kg. of caustic soda with concentration of 50%
- 2- 21 kg. of tri-sodium orthophosphate -12H₂O with concentration of 97.5% 1.5 lit hydrazine

C) Inject the chemicals to waste heat boiler and then heat the water by using medium pressure steam.

The first boiling out

- D) Increase the temperature by 50 C/ hr.
- E) Adjust the pressure in waste heat boiler at 12 bar by closing the vent
- F) After 12 hr. the first boiling out is finished
- G) The steam must be close and drain the waste heat boiler from N11A/Band be sure that the vent is fully opened.
- H) After finishing the drain of waste heat boiler it must be pressurized by N2

Boiling Out W.H.B Analyses

Boiling Out W.H.B

Using Alkaline Trisodium phosphate

Sample from Tank of chemical additives

pH	%NaOH	N ₂ H ₄ mg/l	PO ₄ mg/l
13.1	1.6	140	3000

Sample from Rinsing WHB with BFW

pH	SiO ₂ mg/l	Cond µs/cm	Turbidity NTU	Fe ⁺ mg/l	KMnO ₄ Cons. (mg/l)
8.3	0.1	44	152	18	12

Boiling Out WHB at 12 bar (1st stage)

Date	Time	pH	Fe ⁺ mg/l	N ₂ H ₄ mg/l	KMnO ₄ Cons. (mg/l)	PO ₄ mg/l	TSS mg/l	Na ⁺ mg/l
30/9/2004	14:30	12.4	15	16	85	150	4.0	900
	18:30	12.4	10	12	90	170	—	
	24:00	12.3	8.0	12	100	190	4.0	

Sample after flushing with BFW

Date	Time	pH	Fe ⁺ mg/l	N ₂ H ₄ mg/l	KMnO ₄ Cons. (mg/l)	PO ₄ mg/l	Na ⁺ mg/l
1/10/2004	8:30	10.8	0.8	1.2	18	39	42.7

The second boiling out

- 1 - The same 4 steps in the first boiling out.
- 2 - Adjust the pressure in waste heat boiler at 16 bar by closing the vent and adjust the temp. at 200 C°.
- 3 - The vent of waste heat boiler opened fully every 30 min. for 5min.
- 4 - After 12 hr. the boiling out was finished
- 5 - The steam must be closed and drain the waste heat boiler from N11A/B. and be sure that the vent is fully opened.
- 6 - After finishing the drain of waste heat boiler it must be pressurized by N2 .

Boiling Out W.H.B Analysis

Boiling Out WHB at 16 bar (2nd stage)

Date	Time	pH	Fe, mg/l	N ₂ H ₄ mg/l	KMnO ₄ Cons. (mg/l)	PO ₄ mg/l	TSS mg/l	Na ⁺ mg/l
1/10/2004	10:45	12.2	0.6	25	127	290	2.0	1000

Flushing the waste heat boiler

- 1 - Open the waste heat boiler vent fully.
- 2 - Fill the waste heat boiler with boiler feed water and then drain it under N₂ pressure.
- 3 - Repeat the flushing of waste heat boiler and take analysis

Conclusion

- Since the waste heat boiler is one of the vital equipment in the ammonia plant, so it should be taken in consideration during design, precommissioning, and normal running of this equipment.
- During design, the number of baffles, its height and distribution at the evaporation zone should be carefully calculated to avoid the concentration of the heat load at a certain zone.
- Gas inlet pipe should be carefully treated in the design step to prevent heat localization.
- During precommissioning, the boiling out of the waste heat boiler should be carefully handled, cleaning and flushing with measuring the pH should confirm that the equipment is free from any chemicals that are used during the boiling out.

With our best wishes

Hosam Naiem

Primary Waste Heat Boiler Failure Analysis Repair Methodology and

Ahmed Al-Mulhim
ALBAYRONI
Saudi Arabia

PRIMARY WASTE HEAT BOILER

FAILURE ANALYSIS

REPAIR METHODOLOGY AND REPLACEMENT

ABSTRACT:

After eight years of trouble free operation, hot spots were noticed on the inlet channel of primary waste heat boiler of Ammonia Plant. Rightly diagnosed failure and timely shutdown helped in averting the serious consequences.

This expensive boiler is one of the most critical equipment because of its severe operating conditions, unique thin tube sheet design supplied by limited designers, difficult repair and long delivery period.

Here are discussed the failure analysis, repair methods adopted, post failure operating experience with couple of repeated failures, few design modifications in new boiler, removal/installation procedures and custom made alkali boil out procedure. Also briefed is the unique core tube philosophy conceived and adopted in this boiler on its own by ALBAYRONI.

INTRODUCTION:

Al Jubail Fertilizer Co. (ALBAYRONI) operates a 1000 MT/D nameplate capacity Kellogg design ammonia plant at Al-Jubail, Saudi Arabia. In ammonia plant, Primary waste heat boiler (101-C), located at the downstream of secondary reformer, is Borsig make, fire tube type horizontal exchanger. This boiler had been operating satisfactorily since commissioning in 1983 and no abnormality was observed in operation or regular inspection until 1990. As a first abnormality, the hot spot was noticed on the inlet channel in February 1991. No one knew then that, it was the beginning for a two-year long trouble full period for ALBAYRONI.

BOILER DETAILS:

The waste boiler was designed to cool reformed gas from 996°C to 371°C and produce high-pressure steam at 104 bara. The boiler is illustrated in Figure-1 and main specifications are furnished in Table-1.

The Shell is made of SA516 Gr 70 and tubes of SA 213 T12. The exchanger has an internal bypass tube with control valve at cold end to control the outlet temperature. The SA387 Gr 12 CI 2 tube-sheet is protected from erosion and collapse by 5mm thick incoloy 800H liner. The hot gas is directed into tubes through the refractory by incoloy 800H ferrules. SA387 Gr CI 2 alloy steel inlet channel is lined with two layers of refractory material, 96% bubbled alumina castable and 25% alumina insulating castable. The principal feature of this waste heat boiler is its thin reinforced tube sheets.

Another important feature of this waste heat boiler is its core tube design. The original boiler purchased in 1983 was without core tubes. But, during commissioning in 1983, repeated severe fouling was observed inside the tubes and the tubes at the cold end. This was attributed to the substantial velocity drop from hot end to cold end, which in turn was due to equivalent reduction in temperature. To overcome this problem, during commissioning stage only, in house developed and designed core tubes were inserted from cold end side to increase the velocity at cold ends. Process licensor as well as boiler manufacturer approved this modification. The core tubes were 6 meter long 1/2" SS304 sch.40 pipes.

INCIDENT:

Ammonia plant was running at 110% load. As usual, 101-C inlet temperature was conservatively maintained at 930-940 degC, much less than design fluid temperature 996 degC. On February 10, 1991, during the normal inspection, a hot spot was noticed on the inlet channel of Primary Waste Heat Boiler (101-C).

At the area of hot spot, the green pyro paint turned into white, indicating temperature in excess of 480°C. Thereafter, temperatures were regularly monitored by infrared pyrometer 'HEATSPY' and were found in the range of 520-590°C. Steam Cooling arrangement was provided to cool the hot spot area. Infrared thermography was also carried out to confirm the temperature and to determine the area of damage.

Based on the thermography results, the plant was shut down on February 23, 1991 to inspect and repair 101-C.

OBSERVATION:

On opening of manhole of inlet channel, following were observed.

- i A pool of water was found in channel, indicating the tube leakage. At hot spot area, bottom layer of refractory was totally missing and cracks were found on surrounding areas, towards shell.
- ii At bottom of the channel, the refractory was found completely broken disintegrated and soaked in water
- iii Near Hot Spot Area on the tube-sheet, incoloy 800H liner was completely damaged, ferrules in tubes were also damaged. Some ferrules were dislocated from their positions and found at bottom of the channel. Castable

covering the tube-sheet was completely damaged, thus exposing the tubesheet to hot gases. Cracks on tube-sheet were observed in both longitudinal and transverse directions. At some places, cracks were found throughout the thickness of the tube-sheet.

- iv Opposite to manhole and also on top side of channel cover, refractory was found broken and shrouds were exposed.
- v By-pass tube was found cracked at tip at both inlet and outlet channel ends. The incoloy 800H liner of by pass tube was also found cracked at one location.

FAILURE LOGIC :

A. Refractory and Tubesheet Failure :

It was established that the problem was initiated by the tube leak from the bottom row towards manhole side. The release of high-pressure boiler feed water caused erosion and thermal shocks to refractory. Due to complete failure of refractory, shell as well as tube-sheet, both of alloy steel and not compatible at 931°C, started cracking. Tube-sheet had completely cracked at some places and shell cracked up to the depth of 12mm.

Crazed pattern of cracks on tube-sheet indicate that it had been subjected to thermal fatigue, i.e. alternate heating and cooling cycles.

B. Tube Failure

Following are the frequently contributing factors for tube failures in similar service

1. Dry Out Phenomenon
2. Water Quality

1. The dry out phenomenon was ruled out because of following reasons:

- i. Generally, the dry out phenomenon would result in the failure of tubes in top rows. Whereas, in this case the tubes has failed only in bottom rows.
- ii. Although, coincidentally and emergency shutdown was faced only one month before this incident, no water loss or steam drum low level operation was observed during this emergency and also during normal operation.
- iii. In addition to 101-C, one gas fired water tube type auxiliary boiler and another fire tube type waste heat boiler are also connected to the same steam drum. And no abnormality was observed in any of these other two boilers.

2. Water Quality

Boiler Water quality was believed to be the most probable cause for following reasons.

- i. Most of the plant operators generally believe that the boiler feed water quality is controlled and monitored strictly within the specified limits in their plants. In spite of, the quality of water fed to the boilers has been frequently found to be a major contributory factor to many of such failures.
- ii. Boiler water irregularities can cause deposits, which get collected at bottom of the shell in a horizontal fire tube type waste heat boiler. This leads to an aggressive under deposit corrosion, especially in high heat flux areas, i.e. at tube inlet side. Failure in bottom row of tubes also explains this phenomenon.

Boiler manufacture also believed this to be the most probable reason. Later, it was known that similar failures are not unusual after several years of services.

To avoid under deposit corrosion problem, periodic chemical cleaning from waterside may be considered.

REPAIR WORK:

The tube sheet was very badly damaged by hot gases and cracked in both longitudinal and transeverse directions near hot spot area. At some places, grinding was carried out to find the depth of cracks, which were found throughout the thickness of the tube-sheet. Due to this it was decided to put a patch on tube-sheet covering 14 tubes and filler weld with the tube-sheet at both sides i.e. inlet and outlet side.

On inlet channel shell, depth of cracks were determined by Ultrasonic testing and found to be 12mm. The same was also repaired by complete grinding followed by welding. After welding, it was inspected by penetrant test and post-welding heat-treating (PWHT) was carried out.

After PWHT, in order to do Hydro test, boiler drum 101-CF and shell of 101-C were filled with water. With the head pressure of @1.5Kg/cm², patch welding at inlet and outlet channel over plugged tubes started leaking from heat affected zone.

After draining out water from shell side, gouging was carried out from leaking area followed by welding. Inspection by penetrants and PWHT was carried out.

After PWHT, leak test was carried out by air at 5.0psi. Further, it was leak tested by water at 30kg/cm² for 30 minutes. After leak test, refractory was replaced in bottom half and on the tube-sheet. Incoloy 800 liner was placed on tube-sheet and followed by curing of refractory.

POST REPAIR EXPERIENCE:

The significant difference between pre- and post failure operation was in boiler water control limits. For some parameters, the control limits were made stricter by following the VGB guidelines. These control limits are furnished in Table-2. However with the kind of damage this boiler material had suffered and the severe operating conditions it was undergoing, long run future reliability was very much in doubt. Early replacement was recommended.

Not unexpectedly, the failure repeated after five months of operation on 18 August 1991. This time extra cautious operating staff identified the failure immediately, thanks to the thermocouple located at the bottom of the inlet channel. This immediate symptom was sudden drop of @ 23-30 degC in inlet temperature, presumed as the result of water spillage at bottom side. This time, two tubes were found leaking, again in bottom rows of tubes but little away from first failure.

The plant was restarted with no further change in operating conditions. To our disappointment, the boiler failed within two months of operation on 07 October 1991, by displaying the same symptoms. This time, nine tubes had leaked in the bottom most row. Including this, total blocked tubes were now @7%. The tube failure layout is placed at Figure-2.

The plant load reduced to 100% and the inlet temperature was brought down to 900°C. With these changes, the boiler did not fail anymore till the replacement in January 1993.

NEW BOILER:

Right from the first failure observations; it was decided to order a new boiler at the earliest, based on the factual saying “A single failure can easily result in a profit loss equal to the total cost of the boiler”. Also important was that this specially designed boiler is supplied by very few fabricators and with long delivery time.

The same design and manufacturer were selected based on the following reasons.

1. This boiler has performed satisfactorily at least for eight years of operation.
2. More number of boilers, of same make and design, compared to the nearest competitor were operational with satisfactory performance.
3. The alternative design required many changes in down comer and riser piping with the common steam drum for other two boilers; it looked unwise to go for outright changes.

The new boiler was purchased with some, but not significant changes. The new and old boiler specifications are compared in Table-1.

REPLACEMENT AND CHEMICAL CLEANING:

This particular equipment is situated in a very congested layout. To replace this equipment, structures and high pressure pipe lines had to be cut and re welded.

The replacement job was completed within thirty-five days. These included the four days of chemical cleaning operation.

As described earlier, this boiler is part of a wide network of steam/ bfw pipelines and equipment's. The chemical cleaning of other equipment's/ piping was not required, rather preferred to avoid. To meet this requirement, the chemical cleaning of 101-C only was carried out by inserting the chemical circulation hoses into the riser openings of 101-C through steam drum manhole. The multiple outlets were taken from the blowdown valves available at the bottom of 101-C.

CONCLUSION:

Severe operating conditions and special design features provide little operational flexibilities and demand very strict water quality control. Statistically, failure frequency of such kind of waste heat boilers is high and post-repair life is very low. Inspection including tube thickness measurement in every turnaround is highly recommended. It is advisable to order the new boiler at the earliest as delivery of this boiler is very long and “A single failure can easily result in a profit loss equal to the total cost of the boiler”

ATTACHMENTS:

TABLE-1: 101-C SPECIFICATIONS

SL.#	PARAMETER	NEW 101-C		OLD 101-C	
		SHELL	TUBE	SHELL	TUBE
1	Fluid	BFW / Steam	Process Gas	BFW / Steam	Process Gas
2	Fluid Flow, Kg / Sec (100% Load)	558	41.76	558	41.76
3	Temp. In / Out, Deg. C	314 / 314	996 / 371	314 / 314	996 / 371
4	Operating Press., bar (E)	103	30.3	103	30.3
5	Circulation Ratio	12 : 1	-	12 : 1	-
6	Heat Duty, MM Kcal / Hr	51.5		51.5	
7	Surface Area, M2	461.3		472	
8	Design Pressure, Bar (E)	118	34	118	34
9	Design Temp., Deg. C	343	1010 In / 480 Out	343	1010 In / 480 Out
10	No. of Tubes	460		420	
11	Tube Length, MM	8,450		8,450	
12	Tube OD / THK, MM	38 / 5		42.4 / 4.5	
13	Tube Pitch, MM	51 / 91		56 / 96	
14	Shell OD / THK, MM	2206 / 96		2234 / 110	
15	Tube Material	SA 213 T 12		SA 213 T 12	
16	Shell Material	SA 302 GR C		SA 516 GR 70	
17	Tubesheet Material	SA 387 GR 12 CL 2		SA 387 GR 12 CL2	
	Inlet Channel			SA 387 GR 22 CL2	
	Outlet Channel			SA 387 GR 12 CL2	
18	Bypass Pipe, ID MM	252.4		265	
19	Core Tubes	2.65 M : 16 MM ϕ SS 2.0 M : 12 MM ϕ SS		21.3 MM OD SS, 6 M LONG	
20	Refractory for Inlet Channel	Petrolite D40K (Reinforced) / Plicast LW1 22 R/G (200 MM)		Plicast D40K / Plicast Petrolite (150 MM)	
21	Refractory for Tubesheet	Priblico 39K		Plicast Petrolite 39K	

TABLE-2: WATER QUALITY CONTROL LIMITS

PARAMETER	UNIT	NEW LIMITS	OLD LIMITS
A. BOILER FEED WATER :			
pH at 25 deg. C	-	9.0 - 9.6	8.8 - 9.2
SiO ₂	ppb	<10	-
N ₂ H ₄	ppb	20 - 100	>20
B. BOILER WATER :			
pH at 25 deg. C	-	9 - 10	9.2 - 9.9
Conductivity at 25 deg. C	us / cm	<50	<100
SiO ₂	ppb	<300	<1000
Phosphate as PO ₄	ppm	2 - 6	5 - 10

FIGURE-1: PRIMARY WASTE HEAT BOILER (101-C)

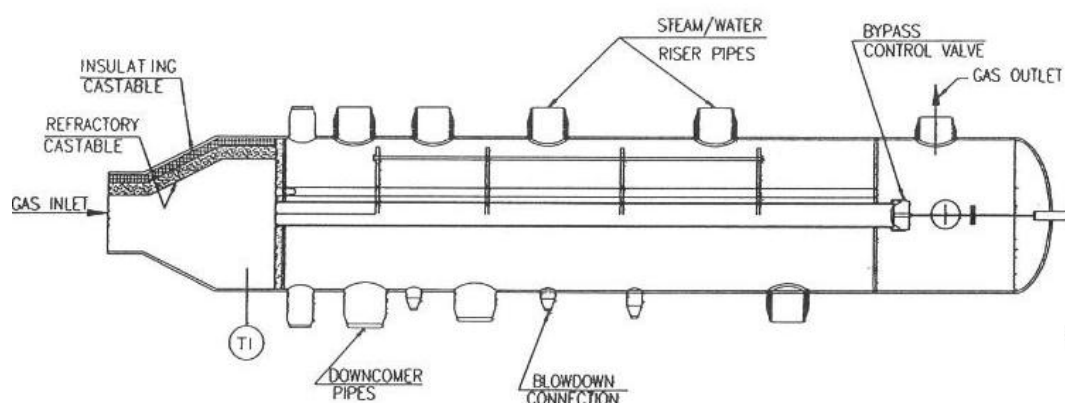
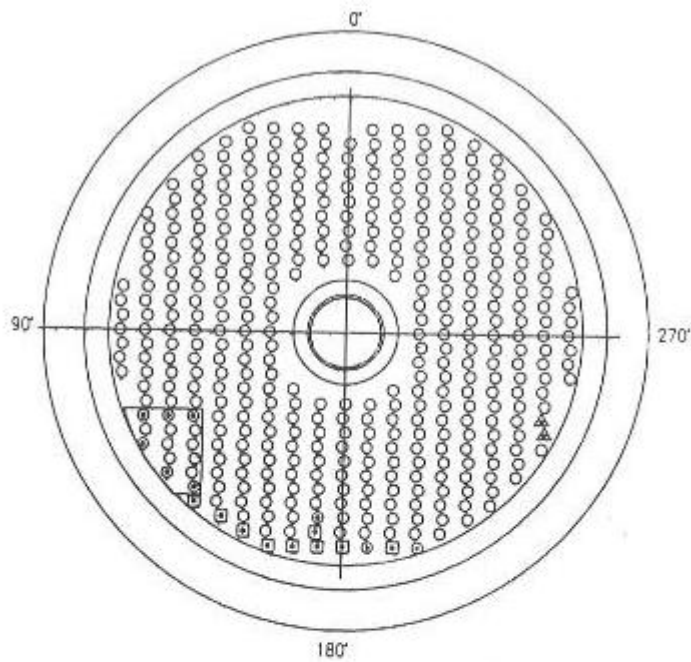
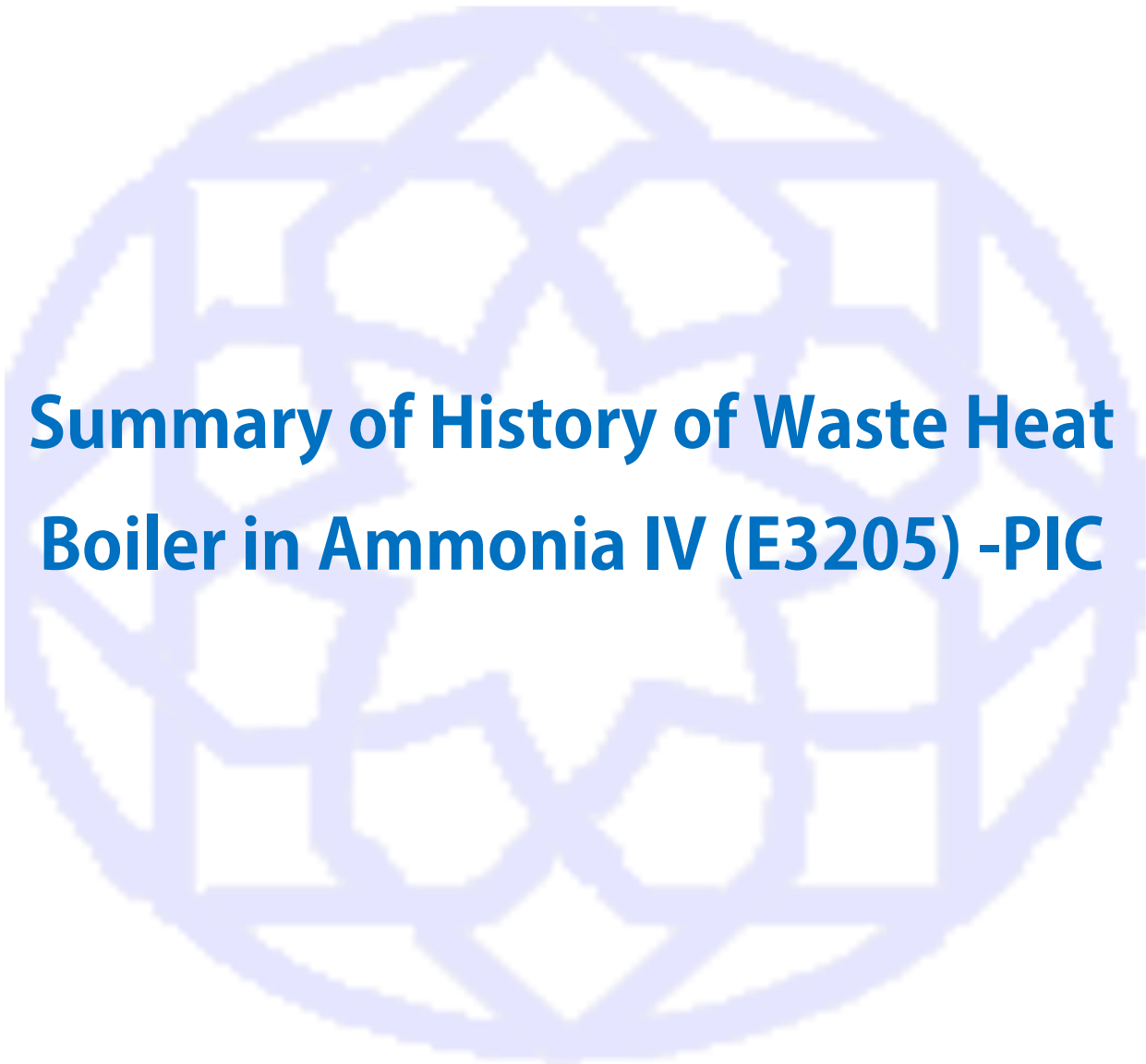


FIGURE-2: TUBE FAILURE LAYOUT



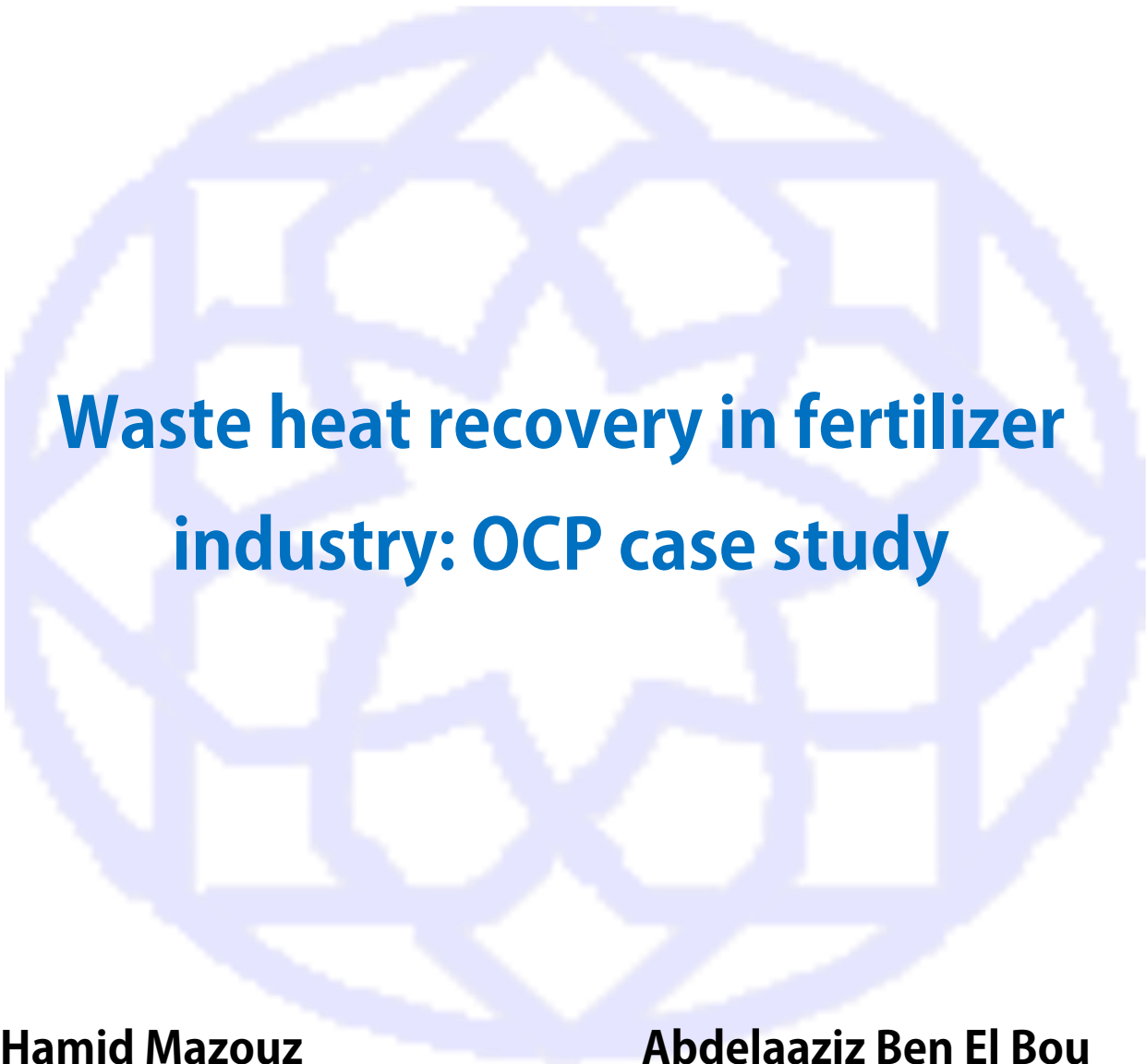
TOTAL TUBES (42.4odx4.5t): 420			
NO. OF COVERED/PLUGGED TUBES			
SHUT DOWN	NO. OF TUBES	DATE	SYMBOL
1ST	17	10-3-91	⊙ ⊙
2ND	2	25-8-91	△
3RD	9	10-10-91	■



Summary of History of Waste Heat Boiler in Ammonia IV (E3205) -PIC

Mohammed Folad
Plant Engineer
PIC
Kuwait

DAY 3: Wednesday December 03, 2014



Waste heat recovery in fertilizer industry: OCP case study

Hamid Mazouz
Researcher

Abdelaaziz Ben El Bou
Production Manager

OCP SA
Morocco

AFA Workshop on
Process Waste Heat Boilers Integrity and Reliability

**WASTE HEAT RECOVERY IN FERTILIZER
INDUSTRY: OCP CASE STUDY**

H.MAZOUZ & A.BEN EL BOU
OCP SA

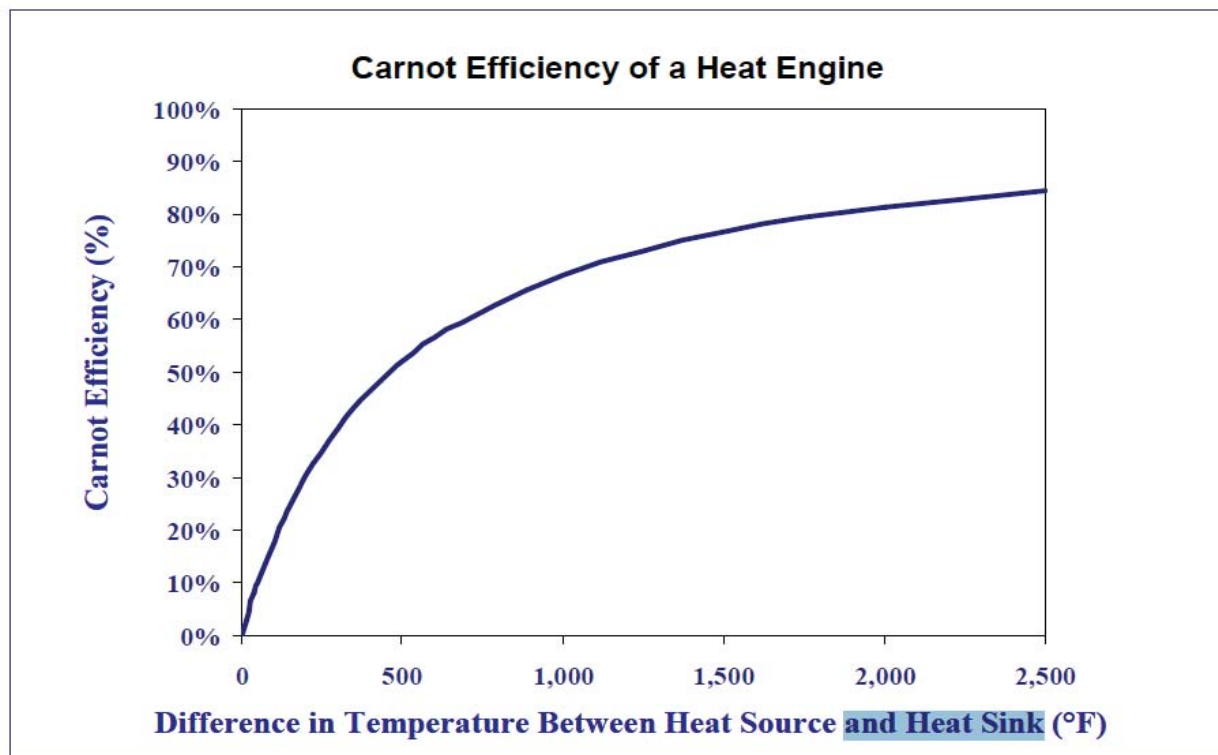
Qatar : 1-3/12/2014



THE FACT OF WASTE HEAT IN INDUSTRY

- ☐ Roughly one-third of the energy consumed by industry is discharged as thermal losses directly to the atmosphere or to cooling systems,
- ☐ These is the result of process inefficiencies,
- ☐ In USA it is estimated that between 20 to 50% of industrial energy input is lost as waste heat,
- ☐ Recovering waste heat losses provides an attractive opportunity for an emission free and lesscostly energy resource,
- ☐ Numerous technologies are commercially available for waste heat recovery, However, in many cases heat recovery is not economical or even possible,

WASTE HEAT RECOVERY (WHR) FEASIBILITY AND EFFICIENCY



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WASTE HEAT RECOVERY OPPORTUNITY

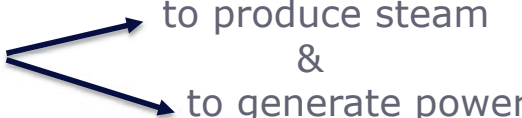
Temperature Classification of Waste Heat Sources and Related Recovery Opportunity

Temp Range	Example Sources	Temp (°F)	Temp (°C)	Advantages	Disadvantages/ Barriers	Typical Recovery Methods/ Technologies	
High >1,200°F [> 650°C]	Nickel refining furnace	2,500-3,000	1,370-1,650	High-quality energy, available for a diverse range of end-uses with varying temperature requirements	High temperature creates increased thermal stresses on heat exchange materials	Combustion air preheat	
	Steel electric arc furnace	2,500-3,000	1,370-1,650			Steam generation for process heating or for mechanical/ electrical work	
	Basic oxygen furnace	2,200	1,200				
	Aluminum reverberatory furnace	2,000-2,200	1,100-1,200	High efficiency power generation	Increased chemical activity/corrosion	Furnace load preheating	
	Copper refining furnace	1,400-1,500	760-820				
	Steel heating furnace	1,700-1,900	930-1,040				
	Copper reverberatory furnace	1,650-2,000	900-1,090			Transfer to med-low temperature processes	
	Hydrogen plants	1,200-1,800	650-980				
	Fume incinerators	1,200-2,600	650-1,430				
	Glass melting furnace	2,400-2,800	1,300-1,540				
Coke oven	1,200-1,800	650-1,000					
Iron cupola	1,500-1,800	820-980					
Medium 450-1,200°F [230-650°C]	Steam boiler exhaust	450-900	230-480	More compatible with heat exchanger materials		Combustion air preheat	
	Gas turbine exhaust	700-1,000	370-540			Steam/ power generation	
	Reciprocating engine exhaust	600-1,100	320-590	Practical for power generation		Organic Rankine cycle for power generation	
	Heat treating furnace	800-1,200	430-650			Furnace load preheating, feedwater preheating	
	Drying & baking ovens	450-1,100	230-590			Transfer to low-temperature processes	
	Cement kiln	840-1,150	450-620				
Low <450°F [<230°C]	Exhaust gases exiting recovery devices in gas-fired boilers, ethylene furnaces, etc.	150-450	70-230	Large quantities of low- temperature heat contained in numerous product streams.	Few end uses for low temperature heat	Space heating	
	Process steam condensate	130-190	50-90			Domestic water heating	
	Cooling water from:				Low-efficiency power generation	For combustion exhausts, low-temperature heat recovery is impractical due to acidic condensation and heat exchanger corrosion	Upgrading via a heat pump to increase temp for end use
	furnace doors	90-130	30-50				
	annealing furnaces	150-450	70-230				
	air compressors	80-120	30-50				
	internal combustion engines	150-250	70-120				
	air conditioning and refrigeration condensers	90-110	30-40				
	Drying, baking, and curing ovens	200-450	90-230				
	Hot processed liquids/solids	90-450	30-230				

Source: US department of energy

ENERGY PRODUCTION IN PHOSPHORIC ACID PLANT

- ❑ Phosphoric acid process uses phosphate and Sulfuric acid to produce phosphoric acid,
- ❑ Sulfuric acid processing is an exothermic process, the heat released is used for steam production and electrical power generation,

-70% recovered 

-28%  lost by acid cooling

- 2%  lost by radiation

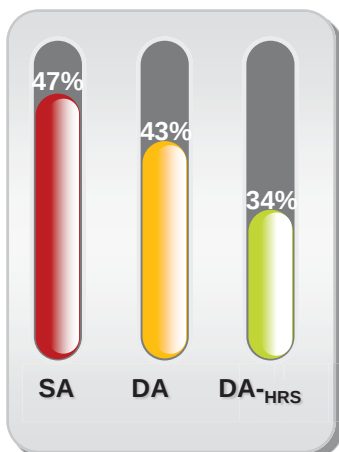


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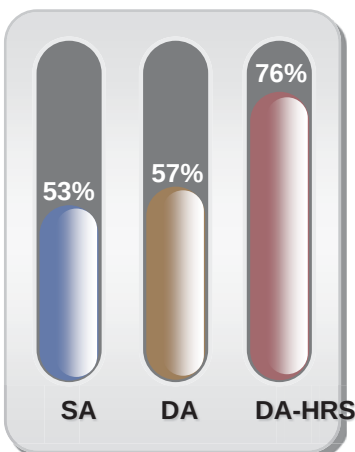
PROCESS WASTE HEAT BOILERS INTEGRITY AND RELIABILITY – 1-3 DECEMBER 2014

PROCESS CONTACT ENERGY EFFICIENCY

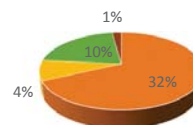
Energy waste



Energy recovery

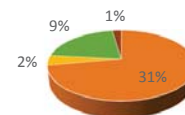


SA



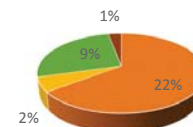
■ Cooling acid ■ Gaz release ■ Thermal losses ■ acid product

DA



■ Cooling acid ■ Gaz release

DA+HRS



■ Cooling acid ■ Gaz release ■ Thermal losses ■ acid product

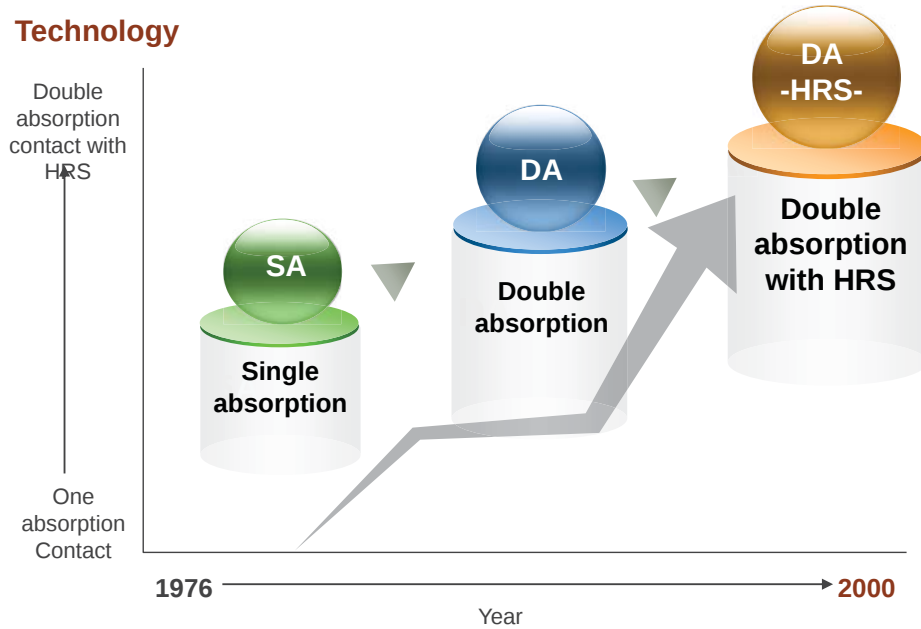


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PROCESS WASTE HEAT BOILERS INTEGRITY AND RELIABILITY – 1-3 DECEMBER 2014

EVOLUTION OF TECHNOLOGIES USED IN SULFURIC ACID PLANT FOR WASTE HEAT RECOVERY

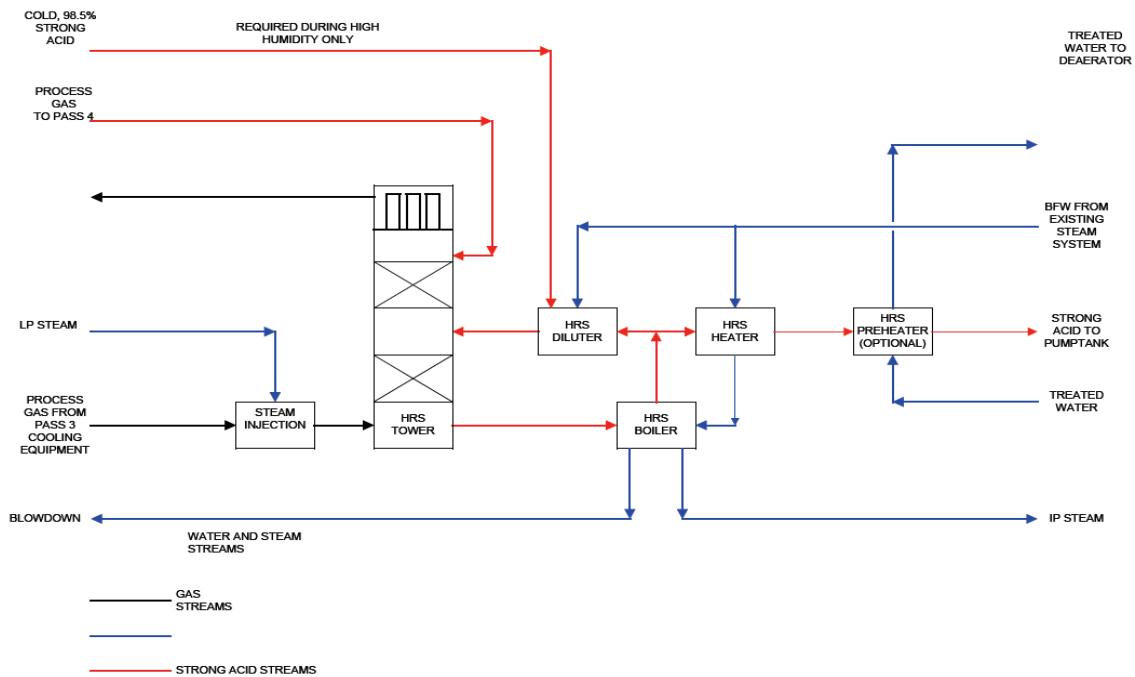
Technology



7 PROCESS WASTE HEAT BOILERS INTEGRITY AND RELIABILITY – 1-3 DECEMBER 2014



2 STAGE HRS FLOWSKETCH

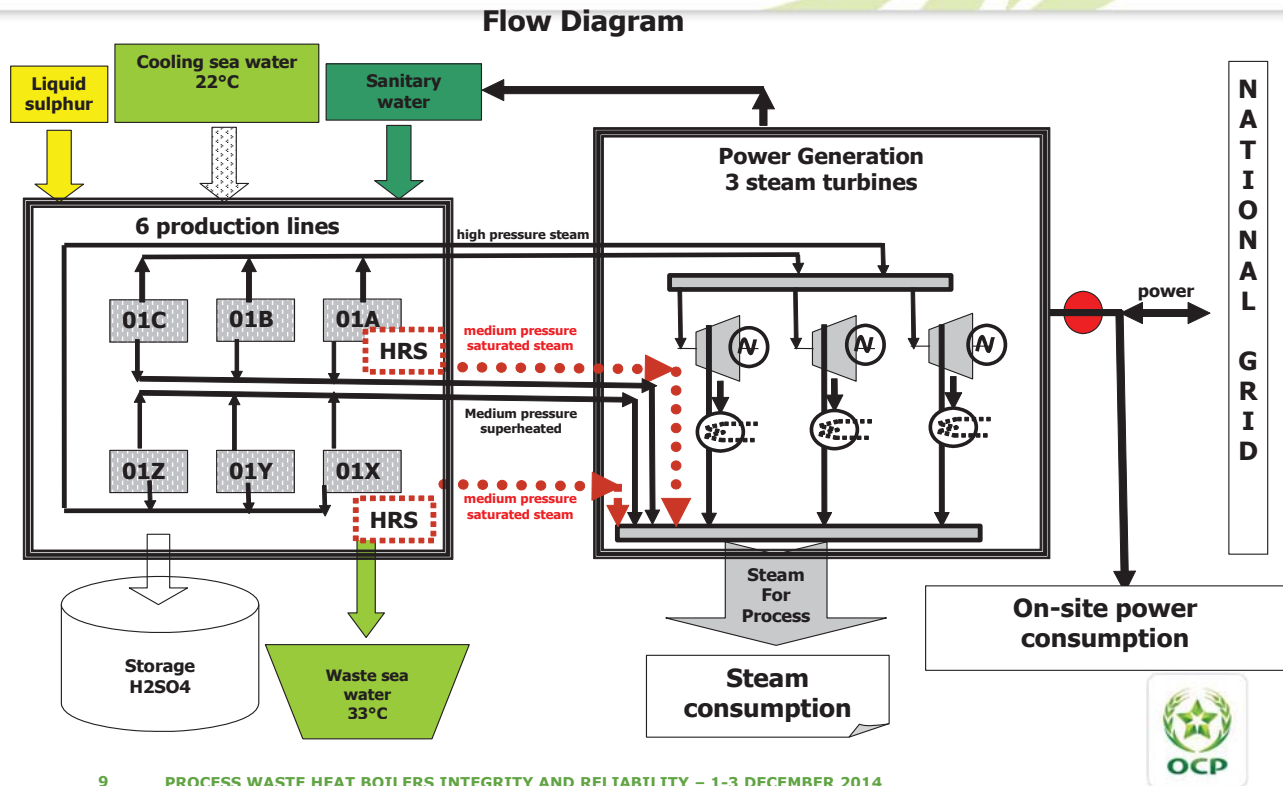


Source: sulfur and sulfuric acid conference 2009

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(HRS) IMPLEMENTATION IN OCP SULFURIC ACID PLANT

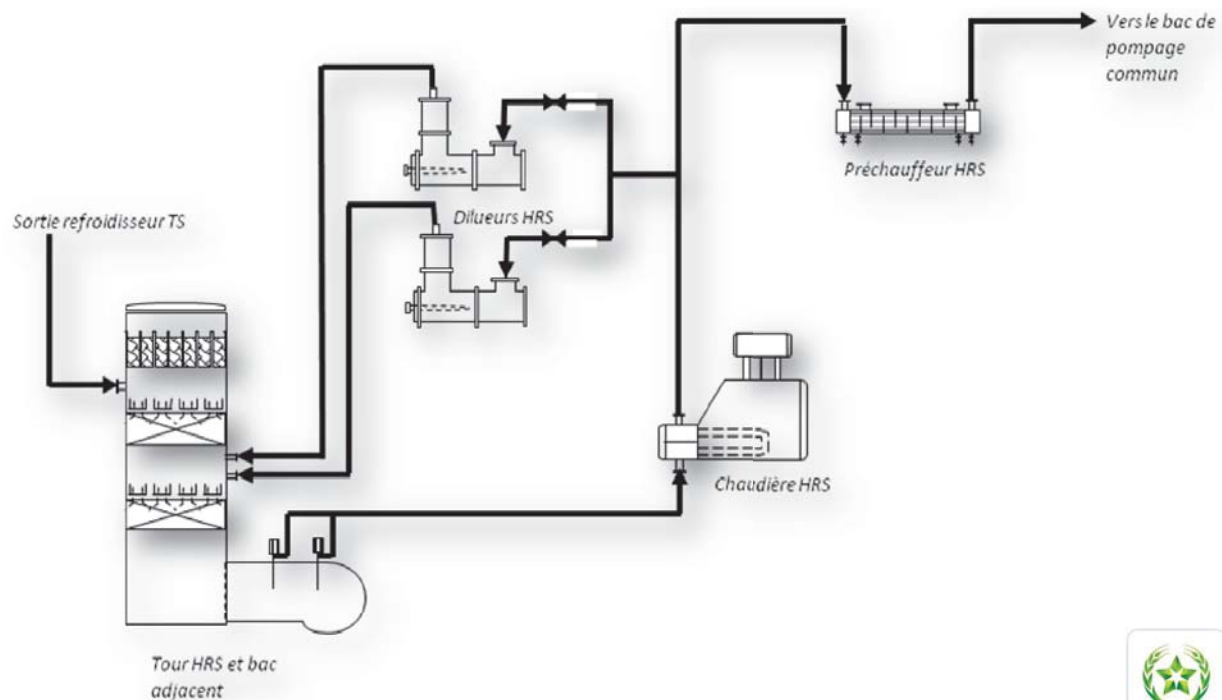


PRODUCTION EFFICIENCY INCREASED WITH HSR

Installation of two heat recovery systems (HRS) in sulfuric acid unit that led to:

- ❑ Additional production of sat. steam : 50 t/hr at 9,5 bars
- ❑ Additional power capacity : 16 MW
- ❑ Reduction of atmospheric pollutants SO₂, NO_x, CO

REPLACEMENT OF 2 UNIT (SA) BY 1 UNIT WITH HRS

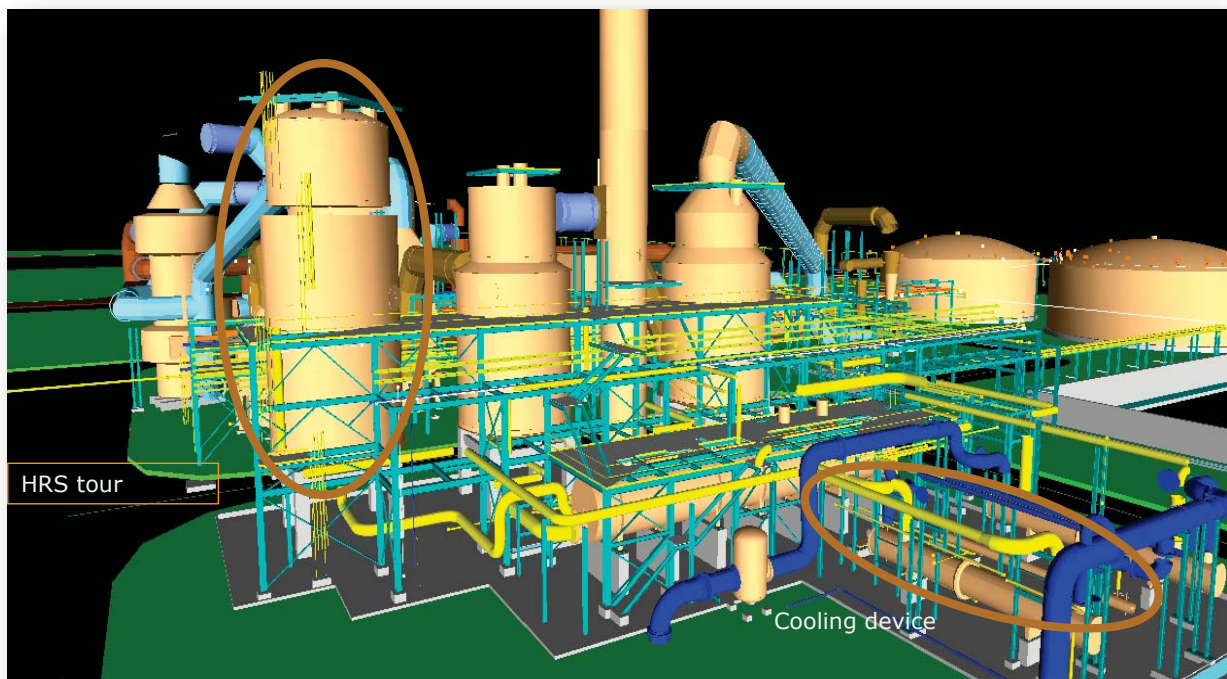


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PROCESS WASTE HEAT BOILERS INTEGRITY AND RELIABILITY – 1-3 DECEMBER 2014



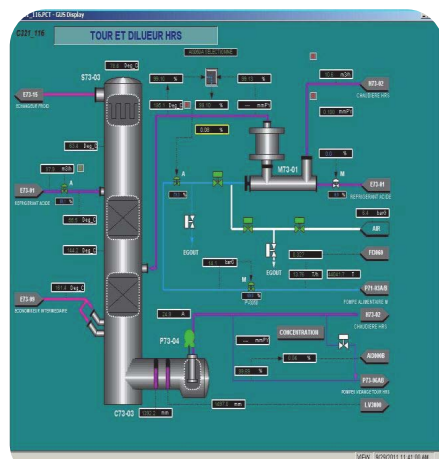
THE NEW SULFURIC ACID UNIT WITH HRS SYSTEM



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PROCESS WASTE HEAT BOILERS INTEGRITY AND RELIABILITY – 1-3 DECEMBER 2014

CONSTRUCTION OF THE NEW SULFURIC ACID UNIT



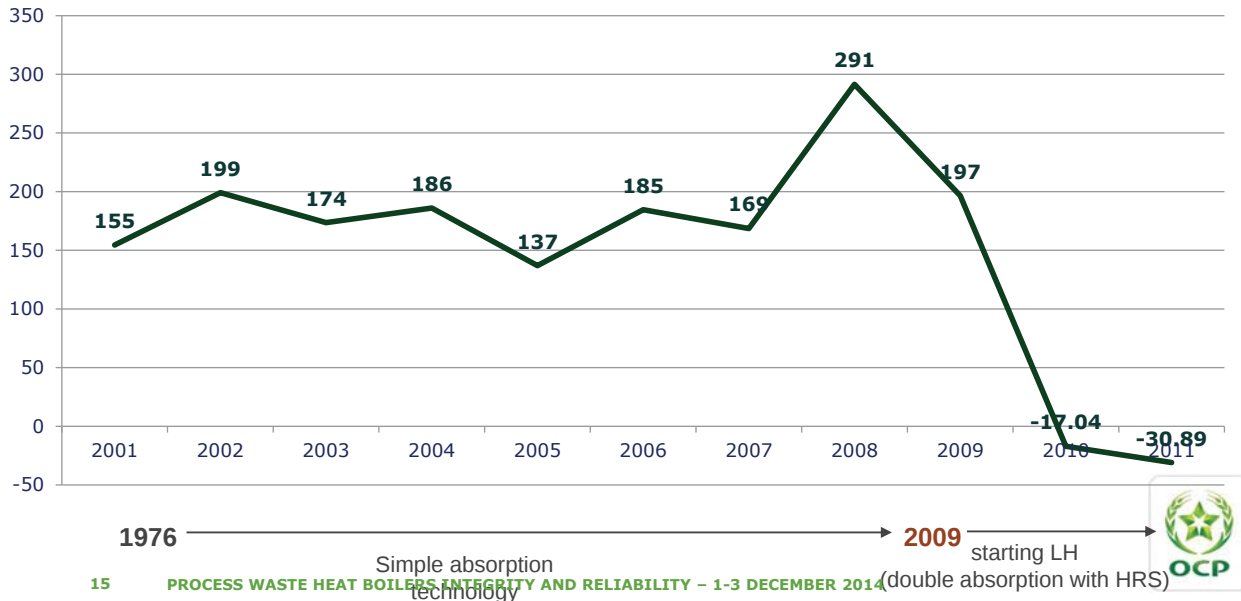
13 PROCESS WASTE HEAT BOILERS INTEGRITY AND RELIABILITY – 1-3 DECEMBER 2014

PERFORMANCE OF THE NEW SULFURIC ACID UNIT

	Ligne H	Ligne B & D
Technology	Double absorption avec HRS	Simple absorption
Starting date	2009	1976
Production capacity	3410 TMH/J	1500 TMH/J
Conversion yield	99,7	98
Specific production VHP	1,19	1,11
pecific production VBP	0,47	0
Emissions	≤417ppm	≤2000ppm

ENERGY COST REDUCTION WITH HRS SYSTEM

(DH/TP205)



CONCLUSION

- Recovering waste heat losses provides an attractive opportunity for an emission free and less costly energy resource.
- The main factors that affect the heat recovery are: heat quantity, heat quality and temperature,
- The implementation of HRS in OCP sulfuric acid unit led to:
 - Increase in steam production,
 - Increase in power generation,
 - Decrease in gas emission CO₂ and NO_x

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Replacing of Waste Heat Boiler in Sulphuric Acid Plant

Ibrahim Makhamreh
Plant Manager
JPMC
Jordan



Gas side corrosion of stack gas heat recovery economizer in oil-fired

Osama KHALIL
Chemical Supervisor
APC
Jordan

AFA Workshop on Process Waste Heat Boilers Integrity & Reliability Doha, 2014

CASE STUDY on

**Gas side corrosion of stack gas heat recovery economizer
in oil-fired high pressure steam boiler**

Arab Potash Company
Power & Water Dept.

Prepared by Eng. Osama Khalil/Power Plant Chemical Supervisor

Reviewed by Eng. Fuad Al-Zoubi, Power and Water Manager

INTRODUCTION

This is a case study carried out by APC to investigate a gas side corrosion problem that resulted in repetitive tube failures and a severe fouling occurring on economizer heating surfaces of boiler unit No.2 at its thermal power plant.

The study relied on physical examination of the economizer tube, field data, collected at various boiler loads, reviewing the performance data and the economizer and boiler design.

An evaluation has been done and solutions including immediate corrective actions and future more efficient alternatives are discussed and presented. The study presents description of the failure, possible causes and mechanisms followed by conclusions and recommendations.

The study concluded that the severe corrosion at the lower section of the economizer is due to sulfuric acid condensation and the heavy fouling on the economizer tubes is due to the present economizer configuration and arrangement that resulted in ineffective soot blowing

For immediate operation and in order to restore the boiler reliability in a short time, the corrosion was minimized by increasing the economizer feed water temperature from 138°C to about 170 °C with the consequence loss in the boiler efficiency

Future opportunities and alternatives to improve the boiler efficiency while controlling the fouling and corrosion problems were addressed and presented.

PROBLEM:

APC cogeneration thermal Power Plant consists of 2 steam boiler units and one auxiliary steam boiler unit with a back pressure steam turbine and the according auxiliary systems

Boiler unit No.2 (SG4-Boiler) has a design capacity of 110 t/h process steam at 64 bar, 478°C. The boiler with first commissioning at 1982 was completely replaced in 2004. The economizer which made of carbon steel is a separate unit with plane casing and external reinforcement and external insulation. One year after commissioning, the economizer started facing repetitive tubes and bends ruptures in its lower part.

In addition to the corrosion and tube failures there was severe fouling occurring on the economizer heating surfaces, preventing efficient heat transfer to the economizer tubes, which resulted in a high flue gas exit temperature and hence a reduction in boiler efficiency and increase in fuel consumption.

DATA GATHERING AND ANALYSIS

Heavy fuel oil is fired in the boiler. The oil contains about 4.0 % sulfur by weight and also vanadium and potassium in ash. Feed water was originally supplied at 126 °C increased later to 138 °C from a deaerator operating at 2.4 kg/cm²a and further heated by steam in a HP heater.

The study relied on physical examination of the economizer tube, field data collected at various boiler loads, reviewing the performance data and the economizer and boiler design. The influence of fouling on the behavior of some operational parameters such as the pressure in furnace and pressure drop in economizer and pipe metal temperature, among others, has been verified.

An evaluation has been done and the solutions including immediate actions and the future long-term solutions are discussed and presented in this study.

BOILER FEED WATER TEMPERATURE CONCERN

Combustion calculations and estimation of acid dew point was the starting point for the analysis of the problem.

The calculations and the analysis clearly indicated that the feed water temperature and hence the tube wall temperature in the inlet portions of the economizer were below the sulfuric acid dew point temperature, sulfuric acid was condensing on the economizer tubes. Hence the back

end of the finned tube economizer were facing severe acid corrosion (see figure 1) and tube failures were occurring within weeks of repair/replacement



Figure 1: severe acid corrosion of economizer tube

Combustion and Acid dew point Calculations

Combustion calculations and estimation of acid dew point is the starting point for the analysis of the problem. The following fuel data (table 1) was used as the basis:

Table 1: heavy fuel oil **HFO** analysis

Fuel Oil Analysis (% by weight)	
Carbon	84.19%
Hydrogen	11.21%
Sulphur	4.38%
Nitrogen	0.22%
	100.00%

Table 2 shows the flue gas analysis on wet and dry basis in % volume at various excess air levels at an ambient temperature of 35°C and 60 % relative humidity:

Table 2: flue gas analysis on wet/dry basis

composition of flue gases						
Component	mole %	mole %	mole %	mole %	mole %	mole %
	Wet	Dry	wet	Dry	Wet	Dry
% Excess Air	10%	10%	15%	15%	20%	20%
CO ₂	12.33%	14.2%	11.82%	13.6%	11.35%	13.0%
SO ₂	0.24%	0.28%	0.23%	0.26%	0.22%	0.25%
O ₂	1.75%	2.0%	2.52%	2.9%	3.22%	3.7%
N ₂	72.43%	83.5%	72.58%	83.3%	72.73%	83.1%
H ₂ O	13.25%	---	12.85%	---	12.48%	
Total	100%	100.0%	100%	100.0%	100%	100.0%

The next step is the computation of acid dew points. There are a few correlations for acid dew points and the following correlation is widely used:

Sulfuric acid dew point "Tdp" in °K is given by:

$$1000/T_{dp} = 2.276 - 0.0294 \cdot \ln p_{H_2O} - 0.0858 \cdot \ln p_{SO_3} + 0.0062 \cdot \ln p_{H_2O} \cdot \ln p_{SO_3}$$

PSO₂ vw (SO₂ volume percent in wet gas)

$$p_{SO_3} = (\text{partial pressure of } SO_3, \text{ mmHg}) = PSO_2vw/100 \cdot CF/100 \cdot \text{stack pressure}$$

$$PH_2O \text{ vw (volume percent in wet gas)} = (\text{partial pressure of } H_2O, \text{ mmHg}) = (PH_2O \text{ vw}/100) \cdot \text{stack pressure}$$

The major portion of sulfur in fuel is burned and appears as sulfur dioxide in the stack gas; a small portion (2 to 4 percent) is further oxidized to sulfur trioxide. These oxides combine with the moisture in the flue gas to form sulfurous and sulfuric acid vapors. When in contact with a surface below the acid dew point, condensation takes place. Table 3 shows the acid dew point calculations at different excess air levels:

Table 3: sulfuric acid dew point calculations

Composition of Wet Flue Gases (mole %)						
% Excess Air	10%	10%	15%	15%	20%	20%
Conversion factor, % of SO ₂ to SO ₃	2%	4%	2%	4%	2%	4%
CO ₂	12.33%	12.33%	11.82%	11.82%	11.35%	11.35%
SO ₂	0.24%	0.24%	0.23%	0.23%	0.22%	0.22%
O ₂	1.75%	1.75%	2.52%	2.52%	3.22%	3.22%
N ₂	72.43%	72.43%	72.58%	72.58%	72.73%	72.73%
H ₂ O	13.25%	13.25%	12.85%	12.85%	12.48%	12.48%
SO ₃ ppmv (volume/volume)	48	96.2	46.1	92.3	44.3	88.6
Sulfuric acid dew point (°C)	156.6	164.0	155.9	163.3	155.2	162.6

Hence the acid dew point varies from 155 to 163 C.

It should be noted that due to steam soot blowing, the moisture content will increase for brief periods locally when the dew point temperature can be slightly higher. Also, the ash particulates present in the flue gas deposit on the tubes lowering the tube wall temperatures further causing condensation. Considering these issues and some margin in the correlation, a safe value for acid dew point would be 170 C if no other measures were taken to help in lowering this value.

Solving the corrosion problem

Increasing the feed water temperature

As sulfuric acid dew point calculated above based on the field data ranges 155 °C to 163 °C, so for immediate operation, the feed water temperature was increased to 170 °C by using an auxiliary steam heat exchanger, which already installed between the deaerator and the economizer to prevent condensation of acid vapor on tubes and thus minimize acid dew point corrosion concerns. The exit gas temperature became higher in the range of 215 °C to 225 °C. This is much higher than the value shown by the boiler supplier for the original design (namely 157 °C) with about 3% consequence loss in the boiler efficiency.

Utilization of Fuel Additives:

The study considered a further method for reducing the sulfuric acid dew point by the use of fuel additives.

The plant already utilizes magnesium hydroxide slurry and organometallic additives for protection against low- and high-temperature corrosion and for avoiding and neutralizing high corrosive settlements on boiler tubes and economizers.

By applying these additives, reduction in the conversion of SO_2/SO_3 and thus decreasing the acid dew point could be achieved.

The study considered increasing the magnesium hydroxide slurry dosage rate and decreasing the feed water temperature in a controlled manner. This enabled us working safely below the sulfuric acid dew point calculated above, and reducing the loss in boiler efficiency by about 1%.

Gradually increasing the fuel additive dosage rate from 250 ppm to 400 ppm with consequent decreasing of the feed water temperature from 170°C to 155°C was successfully accomplished. A close monitoring of ash pH downstream the economizer and the behavior of some operational

parameters such as the pressure in furnace and pressure drop in the economizer while allowing sufficient trial time was necessary to guarantee success. Table 4 shows the results obtained:

Table 4: fuel additive dosage rate versus feed water temp and ash pH

Feed Water Temp. °C	Magnesium Hydroxide ppm	Trial Period, months	Ash PH, range
170	250	3-4	5.0 – 6.0
165	300	3-4	4.8 - 5.9
160	350	3-4	4.4 – 5.5
155	400	3-4	4.1- 4.9

The results indicate a successful reduction in the feed water temperature and hence reduction in boiler efficiency loss.

Replacement of the economizer's lower section

The study concluded that the heavy fouling on the economizer tubes is due to its current configuration and arrangement as it has been designed with staggered arrangement at close tube spacing. This will be discussed later.

Though the above conclusion and to restore the boiler reliability in a short time, the heavily corroded lower section was replaced with the same tube arrangement; due to difficulties of the inline arrangement as lower fin density needs extra spaces and modification on the existing flue gas duct arrangement.

ECONOMIZER ARRANGEMENT CONCERNS

There are some other concerns with the present design of the economizer

- The boiler economizer has been designed with staggered arrangement at close tube spacing. For a clean fuel such as natural gas, a staggered-tube arrangement may be used. For heavy oil fuel, an in-line arrangement is necessary to combat tubing deposit buildups and to avoid plugging. The presence of the layer of dust or particulates will in turn lower the tube wall temperatures further, thereby causing further condensation of acid vapor. Staggered arrangement is not recommended when flue gases contain ash or dust particulates, though small in quantity. Over a period of time, the accumulation can become large as can be seen from the failed tubes. Fig 1 shows Inline and staggered arrangement of tubes

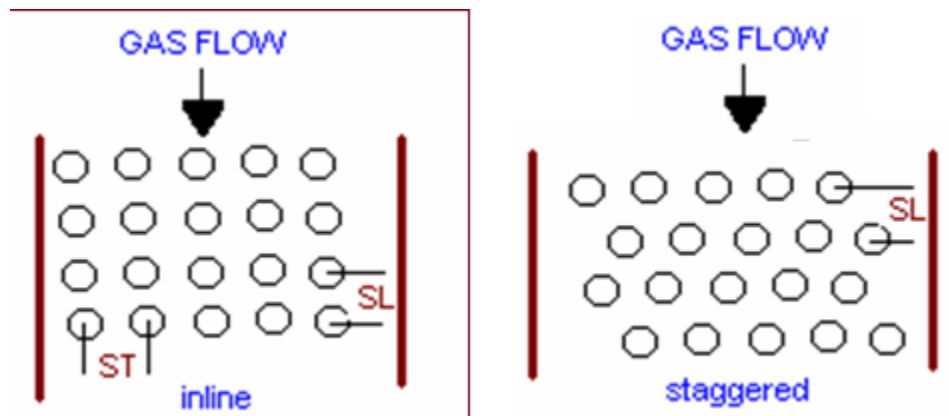


Fig 1: Inline and staggered arrangement of tubes. Staggered is difficult to clean with ash/dust laden gases

- The use of 3 fins/in for this situation is also not a good choice for the design of the economizer. As can be seen from the failed tubes, the ash and dust settles on the tubes and is difficult to clean. Frequent soot blowing also is a concern as it increases the moisture and makes the ash wet and sticky, besides increasing the acid dew point temperature. The acid then corrodes and eats away the tubes and fins. Hence a lower fin density is recommended for the tubes for better cleaning and lesser fouling.
- Field data were collected at 76 t/h and 107 t/h as shown below in table 5 and the boiler calculations were reconciled to provide predicted data close to the field data for both the cases. The fouling factor for the economizer had to be raised to a very high value, namely 0.006 to 0.01 m²hC/kcal to match the field data. This is a very high fouling factor. Normal fouling factor is in the range of 0.001 m²hC/kcal for heavy oil firing.

Table 5: data used for performance evaluation and predictions

Case	Field data	Predict	Field data	Predict	Heat balance	Predict
Steam flow, t/h	107	107	76	76	110	110
Pressure, kg/cm ² g	60	60	49	49	64	64
Steam temperature, C	488	488	476	476	487	487

Feed water temp,C	150	150	165	165	138	138
Water temp leaving eco,C	256	263	252	251	239	267
Steam temp before spray,C	380	430	370	414	409	434
Steam temp after spray,C	351	366	340	350	301	367
Spray water flow,kg/s	-	1.8	-	1.24	0.9	1.97
Gas temp to eco,C	>510	529	445	467	602	533
Gas temp leaving eco,C	>200	205	216	208	157	174
Oxygen % vol dry	2.5	2.5	3.2	3.2	2.4	2.4
Eco fouling,m2hc/kcal		0.0061		0.01	0.001	0.001

The study recommended replacing the economizer's bottom section which faced severe fouling with equivalent finned tubes in inline arrangement with 2 fins/in instead of the existing 3 fins/in staggered arrangement. This option needs some modifications on the flue gas duct and extra space. It is possible that with inline arrangement and lower fin density, soot blowing will be more effective and fouling will be less and hence exit gas temperature may not be that high, say 10 to 15 C lower.

BOILER ARRANGEMENT CONCERNS

The study shows some other concerns with the design of the boiler; it indicates that the boiler design was not optimized and could have been better. The evaporator size should have been larger with a lower gas temperature entering the economizer. This will help to have a higher economizer approach temperature and will also reduce the duty of the economizer. The surface area for the economizer also would have been reduced. This would permit operation without economizer steaming even if the superheater and evaporator surfaces got fouled up over a period of time.

Future opportunities and alternatives to improve the boiler efficiency

It's worth mentioning that reducing excess air will reduce the "cold-end" corrosion problem. Reducing the excess air decreases the quantity of sulfuric acid vapor within the stack gas. Research indicates a direct relationship between sulfur trioxide formation and excess oxygen (or

air) levels. With reduced excess air, stack gas volume is also reduced. Stack gas temperature is also reduced because gas velocities are reduced, allowing the gas to spend more time inside the boiler where the heat can be absorbed. The economics are attractive. As a rule of thumb, boiler efficiency can be increased one percent for each 1.8 reduction in excess oxygen or 20 C reduction of stack gas temperature

Future opportunities and alternatives to improve the boiler efficiency while controlling the fouling and corrosion problems:

1. The study recommended replacing the economizer's bottom section which faced severe fouling with equivalent finned tubes in inline arrangement. This option needs some modifications on the flue gas duct and extra space. It is possible that with inline arrangement and lower fin density, soot blowing will be more effective and fouling will be less and hence exit gas temperature may not be that high, say 10 to 15 C lower. The study concluded that due to the smaller evaporator surface, it will be difficult to add more surfaces to the economizer to improve the efficiency as steaming of economizer can occur, which is to be avoided.

The estimated cost of this option; equivalent carbon steel inline arrangement and lower fin density, is 200,000 USD; the improvement in the boiler efficiency will be about 0.5% equivalent to 175,000 USD annually.

2. Using Teflon coated tubes for the lower section or stainless steel finned tubes or duplex tubes and operate at better efficiency with a lower feed water temperature. This alternative prolongs the life of the economizer and allows operation even with some acid condensation and so the economizer exit gas temperature can be lower and boiler efficiency can be higher. These are however expensive materials and some modifications to the existing system will be required to implement this option as liquid sulfuric acid can be formed.

It is important that when implement this option, the stack gas exit temperature be maintained above the acid dew point to avoid corrosion downstream of the economizer.

By the implementation of this option the feed water temperature will be reduced to the minimum while keeping flue gas temperature leaving the economizer above 160 C to prevent stack corrosion. The estimated cost of this option using 2205 duplex tubes, inline and low fin density arrangement is 450,000 USD the improvement in the boiler efficiency will be about 2.0 % equivalent to USD 700,000 annually.

CONCLUSIONS

The study concluded the following immediate actions and future more efficient opportunities and alternatives

The following immediate actions have been taken to restore the boiler reliability in a short time:

1. The sulfuric acid dew point calculated based on the field data ranges 155 °C to 165 °C, so for immediate operation, the feed water temperature was increased to 170 °C with the consequence loss in boiler efficiency of about 3%.
2. To mitigate this high loss of efficiency, the magnesium hydroxide slurry fuel additive used to decrease the feed water temperature gradually from 170 °C to 155 °C. This reduced the efficiency loss by around 1%.
3. To restore the boiler reliability in a short time, the heavily corroded lower section was replaced with the same tube arrangement; due to difficulties of the inline arrangement as lower fin density needs extra spaces and modification on the existing flue gas duct arrangement.

Future opportunities and alternatives to improve the boiler efficiency while controlling the fouling and corrosion problems:

1. The study recommended replacing the economizer's bottom section which faced severe fouling with equivalent finned tubes in inline arrangement. It is possible that with inline arrangement and lower fin density, soot blowing will be more effective and fouling will be less and hence exit gas temperature may not be that high, say 10 to 15 C lower.
2. Using Teflon coated tubes for the lower section or stainless steel finned tubes or duplex tubes and operate at better efficiency with a lower feed water temperature.

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CASE STUDY ON

GAS SIDE CORROSION OF STACK GAS HEAT RECOVERY ECONOMIZER IN OIL-FIRED HIGH PRESSURE STEAM BOILER

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Power & Water Dept.

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Reviewed by Eng. Fuad Al-Zoubi, Power and Water Manager

INTRODUCTION

- *This is a case study carried out by APC to investigate a gas side corrosion problem that resulted in repetitive tube failures and a severe fouling occurring on economizer heating surfaces of boiler unit No.2 at its thermal power plant.*
- *The study relied on physical examination of the economizer tube, field data collected at various boiler loads, reviewing the performance data and the economizer and boiler design.*
- *An evaluation has been done and solutions including immediate actions and future more efficient alternatives are discussed and presented.*

PROBLEM

- Boiler unit No.2 (SG4-Boiler) has a design capacity of 110 t/h process steam at 64 bar, 478°C. The boiler with first commissioning at 1982 was completely replaced in 2004. The economizer which made of carbon steel, it started facing repetitive tubes and bends ruptures in its lower part one year after commissioning
- Severe fouling occurring on the economizer heating surfaces, preventing efficient heat transfer to the economizer tubes, which resulted in a high flue gas exit temperature and hence a reduction in boiler efficiency and increase in fuel consumption.

PROBLEM



DATA GATHERING AND ANALYSIS

BOILER FEED WATER TEMPERATURE CONCERN

- Heavy fuel oil is fired in the boiler. The oil contains about 4.0 % sulfur by weight and also vanadium in ash. Feed water was originally supplied at 126 °C increased later to 138 °C from a deaerator operating at 2.4 kg/cm²a and further heated by steam in a HP heater.
- Combustion calculations and estimation of acid dew point is the starting point for the analysis of the problem. The following fuel data was used as the basis:

DATA GATHERING AND ANALYSIS

BOILER FEED WATER TEMPERATURE CONCERN

Fuel Oil Analysis (% by weight)

Carbon	84.19%
Hydrogen	11.21%
Sulphur	4.38%
Nitrogen	0.22%

DATA GATHERING AND ANALYSIS

BOILER FEED WATER TEMPERATURE CONCERN

flue gas analysis on wet and dry basis in % volume at various excess air levels at ambient temperature of 35°C and 60 % relative humidity

Component	mole %	mole %	mole %	mole %	mole %	mole %
	Wet	Dry	wet	Dry	Wet	Dry
% Excess Air	10%	10%	15%	15%	20%	20%
CO ₂	12.33%	14.2%	11.82%	13.6%	11.35%	13.0%
SO ₂	0.24%	0.28%	0.23%	0.26%	0.22%	0.25%
O ₂	1.75%	2.0%	2.52%	2.9%	3.22%	3.7%
N ₂	72.43%	83.5%	72.58%	83.3%	72.73%	83.1%
H ₂ O	13.25%	---	12.85%	---	12.48%	----
Total	100%	100.0%	100%	100.0%	100%	100.0%

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BOILER FEED WATER TEMPERATURE CONCERN

Combustion and Acid dew point Calculations

- The next step is the computation of acid dew points. There are a few correlations for acid dew points and the following correlation is widely used:
- Sulfuric acid dew point "Tdp" in °K is given by:

$$1000/Tdp = 2.276 - 0.0294 * LNpH_2O - 0.0858 * LNpSO_3 + 0.0062 * LNpH_2O * LNpSO_3$$

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BOILER FEED WATER TEMPERATURE CONCERN

Combustion and Acid dew point Calculations

Composition of Wet Flue Gases (mole %)						
% Excess Air	10%	10%	15%	15%	20%	20%
Conversion factor,% of So ₂ to So ₃	2%	4%	2%	4%	2%	4%
CO ₂	12.33%	12.33%	11.82%	11.82%	11.35%	11.35%
SO ₂	0.24%	0.24%	0.23%	0.23%	0.22%	0.22%
O ₂	1.75%	1.75%	2.52%	2.52%	3.22%	3.22%
N ₂	72.43%	72.43%	72.58%	72.58%	72.73%	72.73%
H ₂ O	13.25%	13.25%	12.85%	12.85%	12.48%	12.48%
SO ₃ ppmv (volume/volume)	48	96.2	46.1	92.3	44.3	88.6
Sulfuric acid dew point(°C)	156.6	164.0	155.9	163.3	155.2	162.6

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BOILER FEED WATER TEMPERATURE CONCERN

Combustion and Acid dew point Calculations

It should be noted that the critical factors governing the sulfuric acid dew point corrosion include

- the presence of corrosive quantities of sulfur trioxide,
- the presence of moisture in the flue gas, and
- the presence of metals whose surface temperature is below the sulfuric acid dew point

The dew point increases as the quantity of sulfur trioxide in the flue gas and the moisture content of the flue gas increase

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BOILER FEED WATER TEMPERATURE CONCERN

Solving the corrosion problem

The following immediate actions have been taken to restore the boiler reliability in a short time

1. Increasing the feed water temperature

- As sulfuric acid dew point calculated above based on the field data ranges 155 °C to 163 °C, so for immediate operation, the feed water temperature was increased to 170 °C by using an auxiliary steam heat exchanger
- The exit gas temperature became higher in the range of 215 °C to 225 °C. This is much higher than the value shown by the boiler supplier for the original design (namely 157 °C) with about 3% consequence loss in the boiler efficiency

BOILER FEED WATER TEMPERATURE CONCERN

Solving the corrosion problem

2- Utilization of Fuel Additives:

- The study considered a further method for reducing the sulfuric acid dew point by the use of fuel additives.
- The plant already utilizes magnesium hydroxide slurry and organometallic additives for protection against low- and high-temperature corrosion and for avoiding and neutralizing high corrosive settlements on boiler tubes and economizers.
- By applying these additives, reduction in the conversion of SO₂/SO₃ and thus decreasing the acid dew point could be achieved.
- This enabled us working safely below the sulfuric acid dew point calculated above, and reducing the loss in boiler efficiency by about 1%.

BOILER FEED WATER TEMPERATURE CONCERN

Solving the corrosion problem

fuel additive dosage rate vs. feed water temp and ash pH

Feed Water Temp. °C	Magnesium Hydroxide ppm	Trial Period, months	Ash PH, range
170	250	3-4	5.0 – 6.0
165	300	3-4	4.8 - 5.9
160	350	3-4	4.4 – 5.5
155	400	3-4	4.1- 4.9

BOILER FEED WATER TEMPERATURE CONCERN

Solving the corrosion problem

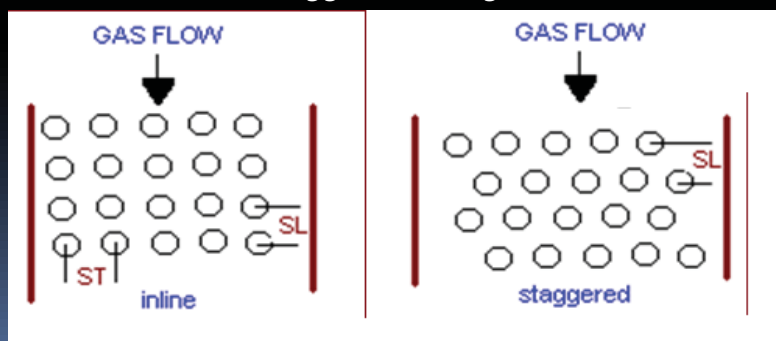
3- Replacement of the economizer's lower section

- The study concluded that the heavy fouling on the economizer tubes is due to its current configuration and arrangement as it has been designed with staggered arrangement at close tube spacing. This will be discussed later.
- Though the above conclusion and to restore the boiler reliability in a short time, the heavily corroded lower section was replaced with the same tube arrangement; due to difficulties of the inline arrangement as lower fin density needs extra spaces and modification on the existing flue gas duct arrangement.

ECONOMIZER ARRANGEMENT CONCERNS

- The boiler economizer has been designed with staggered arrangement at close tube spacing. For a clean fuel such as natural gas, a staggered-tube arrangement may be used. For heavy oil fuel, an in-line arrangement is necessary to combat tubing deposit buildups and to avoid plugging.

Inline and staggered arrangement of tubes



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ECONOMIZER ARRANGEMENT CONCERNS

- The use of 3 fins/in for this situation is also not a good choice for the design of the economizer. As can be seen from the failed tubes, the ash and dust settles on the tubes and is difficult to clean. Frequent soot blowing also is a concern as it increases the moisture and makes the ash wet and sticky, besides increasing the acid dew point temperature. The acid then corrodes and eats away the tubes and fins.
- Field data were collected at 76 t/h and 107 t/h as shown in the table below and the boiler calculations were reconciled to provide predicted data close to the field data for both the cases. The fouling factor for the economizer had to be raised to a very high value, namely 0.006 to 0.01 m²hC/kcal to match the field data. This is a very high fouling factor. Normal fouling factor is in the range of 0.001 m²hC/kcal for heavy oil firing

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ECONOMIZER ARRANGEMENT CONCERNS

Case	Field data	Predict	Field data	Predict	Heat balance	Predict
Steam flow, t/h	107	107	76	76	110	110
Pressure,kg/cm2g	60	60	49	49	64	64
Steam temperature,C	488	488	476	476	487	487
Feed water temp,C	150	150	165	165	138	138
Water temp leaving eco,C	256	263	252	251	239	267
Steam temp before spray,C	380	430	370	414	409	434
Steam temp after spray,C	351	366	340	350	301	367
Spray water flow,kg/s	-	1.8	-	1.24	0.9	1.97
Gas temp to eco,C	>510	529	445	467	602	533
Gas temp leaving eco,C	>200	205	216	208	157	174
Oxygen % vol dry	2.5	2.5	3.2	3.2	2.4	2.4
Eco fouling,m2hc/kcal		0.0061		0.01	0.001	0.001

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Future opportunities and alternatives to improve the boiler efficiency while controlling the fouling and corrosion problems:

1. Replacing the economizer's bottom section which faced severe fouling with equivalent carbon steel inline arrangement and lower fin density
 - in-line arrangement is necessary to combat tubing deposit buildups and to avoid plugging
 - a lower fin density is recommended for the tubes for better cleaning and lesser fouling.
 - The estimated cost of this option is 200,000 USD; the improvement in the boiler efficiency will be about 0.5% equivalent to 175,000 USD annually

Future opportunities and alternatives to improve the boiler efficiency while controlling the fouling and corrosion problems:

- 2- Using Teflon coated tubes for the lower section or stainless steel finned tubes or duplex tubes and operate at better efficiency with a lower feed water temperature. This alternative prolongs the life of the economizer and allows operation even with some acid condensation and so the economizer exit gas temperature can be lower and boiler efficiency can be higher.
 - These are however expensive materials and some modifications to the existing system will be required to implement this option as liquid sulfuric acid can be formed.

Future opportunities and alternatives to improve the boiler efficiency while controlling the fouling and corrosion problems:

- It is important that when implement this option, the stack gas exit temperature be maintained above the acid dew point to avoid corrosion downstream of the economizer.
- By the implementation of this option the feed water temperature will be reduced to the minimum while keeping flue gas temperature leaving the economizer above 160 C to prevent stack corrosion. The estimated cost of this option using 2205 duplex tubes, inline and low fin density arrangement is 450,000 USD the improvement in the boiler efficiency will be about 2.0 % equivalent to USD 700,000 annually.



Thank You



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