STEAM SYSTEM OPTIMIZATION

ASSESSMENT REPORT

PREPARED FOR

Myanma Petrochemical Enterprise's

No. 5 Fertilizer Plant

Kangyidaunt – Ayerawaddy Region

UNIDO and GEF sponsored
Steam System Assessment Report

General Assessment Information

Company:	Myanma Petrochemical Enterprise	Assessment Type:	Steam
Plant:	No. 5 Fertilizer Plant	Assessment Dates:	07/02/2019 - 08/02/2019
Location:	Kangyidaunt, Ayerwaddy Region		

Plant Information

Principal Products: Ammonia & Urea

Address: Kangyidaunt, Hmawbi Township, Ayerwaddy Region, Myanmar

Participant Contact Information

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Mr. Zaw Naing - Plant Engineer

Preface

The work described in this report was performed by Messrs. Veerasamy Venkatesan, International Steam Systems Expert, under contract with United Nations Industrial Development Organization(UNIDO) within the scope of the its System Optimization program activities in Republic of Myanmar (hereinafter simply referred as Myanmar).

The objective of the UNIDO's Global Energy System Optimization program is to assist industrial enterprises in identifying and evaluating industrial energy efficiency improvement projects while upgrading enterprises' engineers and energy efficiency consultants' knowledge and competencies in the identification and development of energy system performance improvement measures.

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I. Executive Summary

During 07/02/2019 to 08/02/2019, Messrs. Venkatesan & a team of Myanmar Engineers, visited the No. 5 Fertilizer Factory to perform a Steam System Energy Assessment as a part of the steam system optimization Expert Training to Myanmar Engineers. This Steam System Optimization assessment was carried out as a part of the UNIDO-GEF project *"Catalyzing market transformation for industrial energy efficiency and accelerate investments in best available practices and technologies in Myanmar"*

This energy assessment identified 7 energy savings opportunities (ESOs) with a total potential savings of 678.9 million MMK/Yr at the No. 5 Fertilizer Factory at Kangyidaunt – Ayerwaddy Region (Table 1).

Table 1 – Identified Energy Saving Opportunities (ESOs) at No 5 Fertilizer plant

Assessment Opportunities		**Estimated Annual Savings**			***ESO Type**	**** Simple Payback (years)**
ESO #	**Recommended Opportunities**	**Cost Savings (million MMK)**	**Resource Savings in GJ[1] / m[3#]**	**CO_2 (m.tonnes)**		
1	Reduce Excess air at Boiler, B-4001 by adjusting the FD Fan damper, from Stack O_2 4.5% to 3.0%)	**20.3**	**10,898 GJ**	**544**	**N**	**< 0.5**
2	Fix all the leaking Valves in the 5.0MPa steam header	**92.2**	**39,529 GJ & 10,699 m³**	1975	**N**	**< 1.0**
3	Upgrade the Controls of B-4001, install Local DCS & arrange round the clock Operator attention	461.1	**197,652 GJ & 53,498 m³**	9873	N	**< 1.0**
4	Insulate the MP>LP PRV & Desuperhetaer	1.4	**597 GJ & 184 m³**	30	**N**	**< 1.0**
5	Recover flash steam from the blowdown water	**7.7**	**3,182 GJ & 998 m³**	318	N - M	1.0 – 1.5
6	Install an RO Filter upstream to the DeMin plant and closely monitor and maintain 30ppb Silica in BF Water	18.4	**5,741 GJ & 4,434 m³**	287	M	4.0 – 5.0
7	Add additional coils to the existing Economizer	**77.7**	**41,796 GJ**	2088	M	3.0 – 4.0
TOTAL		**678.9**	**299,395 GJ & 69,814 m³**	**15114**		

[1]*Natural Gas Fuel Savings & [#] Treated DeMin water savings*

*****N: Near Term Cost improvements, like Operation & Maintenance changes requiring *No significant investment*,

M: Medium Term Cost improvements, i.e. changes requiring *Significant Investment*,

******The indicated Simple Payback periods are based on extensive project experience in the United States, where the Simple Payback is equal to Total Investment/ Cost savings per annum.

The total potential savings includes savings from the reduced usage of natural gas, and treated Boiler Feed water (DeMineralized water). Natural gas used at this plant as a feed-stock also along with using as fuel. The average cost of Natural gas is about 74.7 MMK/NM^3. Implementation of these opportunities would also decrease total CO_2 emissions by 15,114 metric tons per year. The savings estimations were carried out using the Steam System Assessment Tool (SSAT) for all the 7 ESOs, based on the data provided by the plant and actual measurements made at the Boilers during the assessment period. While savings estimations are based on the provided & measured data and the standard engineering calculations, they can be treated as reliable. However, the plant engineers are requested to verify the source data and reconfirm the savings calculations.

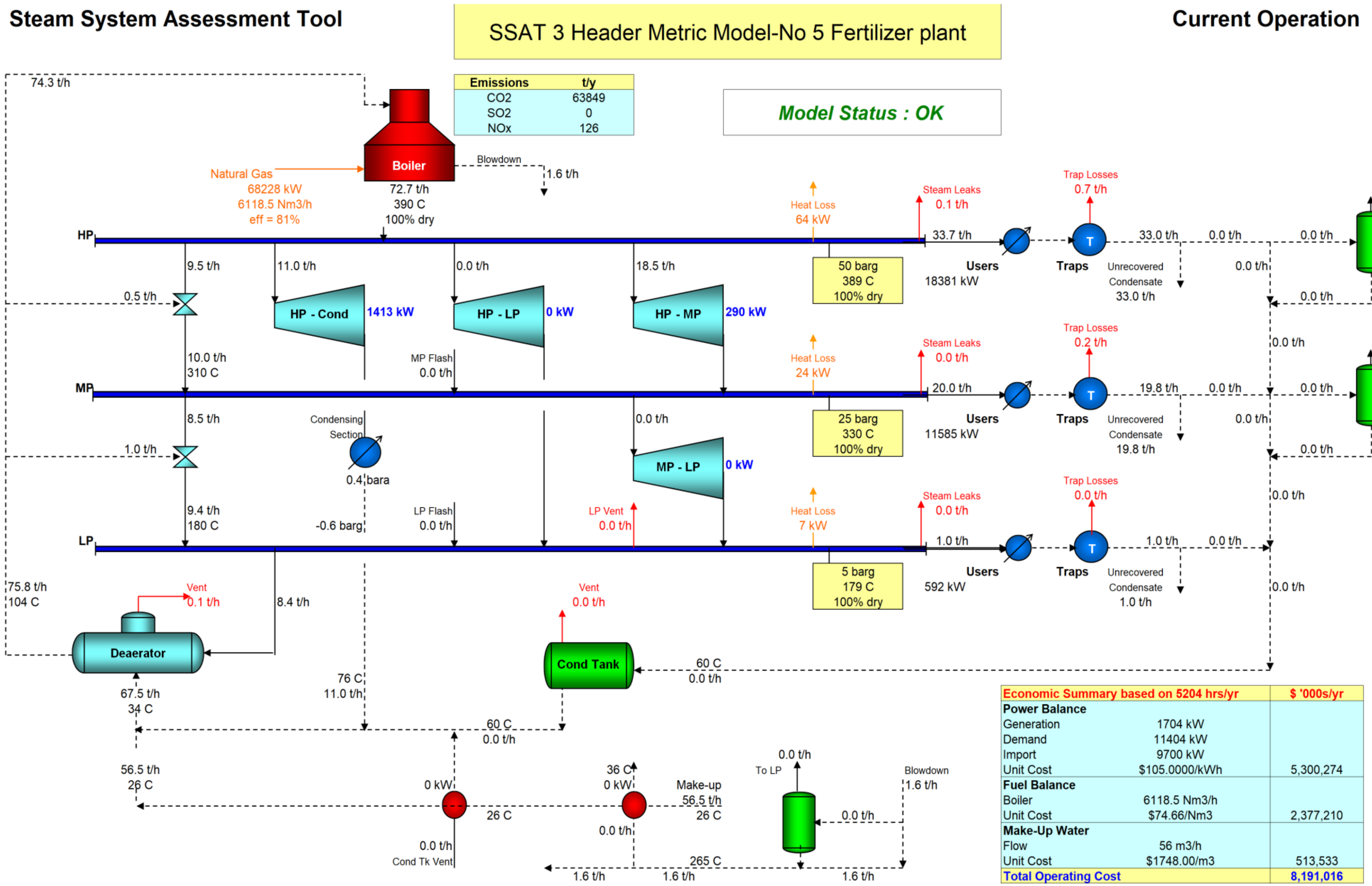
Estimating the projects' costs is beyond the scope of this initial Energy Savings Assessment, as it requires more details specific to each location where the savings assessment is done. Also, it is necessary for the plant management to review the concepts of the suggested recommendations, and then to proceed with the detailed engineering to develop them into formal improvement projects.

The annual savings for each ESO reported in Table 1 have been evaluated individually, i.e. in isolation from other ESOs, by comparing performance after each ESO with the same steam system operations baseline, i.e. the current operating conditions in No 5 Fertilizer plant. However, it is to mention that in "*real life*" depending on the implementation timing/sequence of the various ESOs, the actual savings for the above ESOs when implemented could be different, due to varying energy & utility costs at the time of implementing the specific ESOs.

The Steam System Model developed for the plant is shown in Figure 1. The monetary amounts indicated in the SSAT model are in Myanmar Kyats (MMK). Since the ($) sign in the SSAT model cannot be changed, the $ sign shall be considered as MMK for this report.

The Summary results of Steam System Scoping Tool (SSST) for No. 5 Fertilizer Factory that gives a benchmark score compared to Best-in Class steam systems is shown in Table 2.

Figure 1: Steam System Model for MPE's No. 5 Fertilizer Factory developed by the SSAT



<u>NOTE: Special note for No 5 Fertilizer plant at Myanmar on initial cost-benefit analysis</u>

Estimating the costs of each ESO is beyond the scope of this initial Energy Savings Assessment, as it requires more details specific to each location where the savings assessment is done, and opportunities are to be implemented. As a consequence, the simple payback period ranges indicated in Table 1 and in this report are not Myanmar specific, but are based on extensive steam system project implementation experience in the United States.

Payback period depends on the project costs and the annual savings. The project costs mainly depend on the material and labor costs, while the annual savings depend mainly on the fuel cost. The natural gas cost in USA varies between 3.0 and 5.0 USD/GJ, while MPE's reported a natural gas cost of ~ 1.5 USD/GJ (2000 MMK/1000ft^3) is lower compared to NG cost in USA. the Labor cost at Myanmar is expected to be much lower than the labor cost in USA.

However typical labor costs in USA for steam system optimization projects range from 50 US$/hour to 125 US$/hour, depending on the level of expertise and experience of the technician or of the engineer/specialist. The labor costs applicable to the Myanmar industries could be significantly lower than US labor costs.

Considering the relatively lower cost of energy and significantly lower cost of labor in Myanmar compared to the USA, it is legitimate to expect actual payback period may be different than those indicated in this report.

Based on the findings and information provided in the present Steam System Assessment report, the MPE's No. 5 Fertilizer factory management is expected and recommended to take the following next steps;

1. Review the recommended Energy Savings Opportunities,
2. Reconfirm its technical feasibility,
3. Collect the required site specific details like material cost, labor cost, investment criteria of the plant management & other items like compliance standards and evaluate the financial feasibility.

II. Assessment Observations and Findings

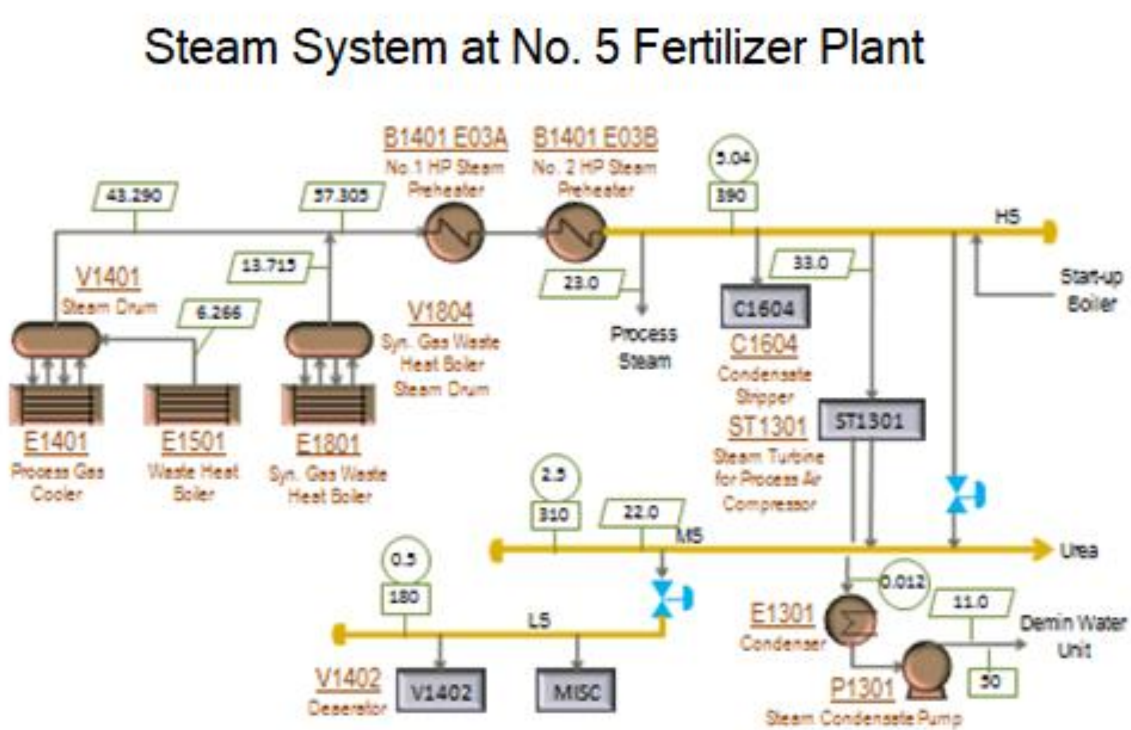
Brief Highlights about the Steam System at No. 5 Fertilizer Factory

The No. 5 Fertilizer Factory at Kangyidaunt, has a capacity to produce 500 tpd Ammonia & 600 tpd Urea. This plant designed by Chinese, has a steam generation capacity of 53 T/hr from its Process Waste heat Boilers and 40 T/hr from its fuel-fired Auxiliary Boiler B-4001. However, the current production rates at the plant is about 75 to 80% of its design capacity. There are 3 process waste heat boilers, namely Process Gas Coolers E-1401 & E1501 and the SynGas cooler E1804. High pressure (HP) Superheated steam is generated at 5.04MPa pressure and 390^{o}C temperature from these Boilers. About 23 T/hr of HP steam is used at the steam reforming process and about

35 T/hr steam is used by the Turbine drive of the Process Air Compressor (PAC). Balance HP steam is supplied to the Condensate Stripper (C-1604). The PAC turbine is an Extraction-cum-condensing type turbine. The turbine's extraction outlet, supply to the medium pressure(MP) steam header, maintained at 2.5MPa steam. The MP steam header supply steam to the Urea plant, Deaerator (V-1402) and other minor steam users. The turbine condenser pressure is maintained at 0.04MPa, and about 11 – 12 T/h condensate at 50°C is pumped back to the Deaerator. Make-up water to the Boilers are supplied from a Demineralizer unit.

Since the plant currently operates at 75% of its designed capacity, the waste heat steam generation is lower and to meet the total plant's steam demand, the Auxiliary boiler, that is supposed to operate only during start-up is on continuous steam generation mode. The common Deaerator V-1402 supplies feed water to both the process waste heat boilers and the fuel-fired Auxiliary boiler. The brief schematic diagram of the Steam & Condensate system at the No.5 Fertilizer plant is shown in Figure 2

Figure 2: Schematic diagram of the Steam & Condensate system at No. 5 Fertilizer plant



General Observations from the Assessment

Restricted Feedstock (Natural gas availability) and leak-free maintenance in handing pungent Ammonia gas are the major challenges in operating this No. 5 Fertilizer plant. The plant Engineers & Managers are handling these challenges well and try to maintain production targets.

The steam system scoping tool (SSST) was used to evaluate the No.5 Fertilizer plant's current status compared to the Best Practice steam systems in USA. The summary results of SSST are shown in Table 2 below:

Table 2: Summary results of Steam System Scoping Tool for No 5 Fertilizer Plant

SUMMARY OF STEAM SCOPING TOOL RESULTS		
	POSSIBLE SCORE	YOUR SCORE
STEAM SYSTEM PROFILING	90	76
STEAM SYSTEM OPERATING PRACTICES	140	74
BOILER PLANT OPERATING PRACTICES	80	50
DISTRIBUTION, END USE, RECOVERY OP. PRACTICES	30	16
TOTAL SCOPING TOOL QUESTIONAIRE SCORE	340	216
TOTAL SCOPING TOOL QUESTIONAIRE SCORE (%)		63.5%
Date That You Completed This Questionaire		7/11/2017

Typical average score of a Steam System in USA 65%.

Observed Best Practices

1: Open mindedness and enthusiasm to implement improvement actions.
The knowledge level of operating personnel is very good. The plant managers and engineers wer very enthusiastic in listening to improvement opportunities and taken steps towards implementatio within their means, when applicable. This is one of the very few Host plants, where improvement & savings reported even before the completion of the Host plant Energy Assessment.

2: The DCS control system for the process plant
Compared to most Myanmar industries, the No 5 Fertilizer plant has implemented its DCS contro system, which is a very useful process monitoring & control capability. Though some Flow Meters are not in good working order (due to the requirement of imported spare parts), overall plar information system is well maintained.

Energy Saving Opportunities

The following subsection of this report briefly discusses the projects recommended for implementation. The opportunities were identified during the site assessment. The projects presented here have an economically attractive implementation potential.

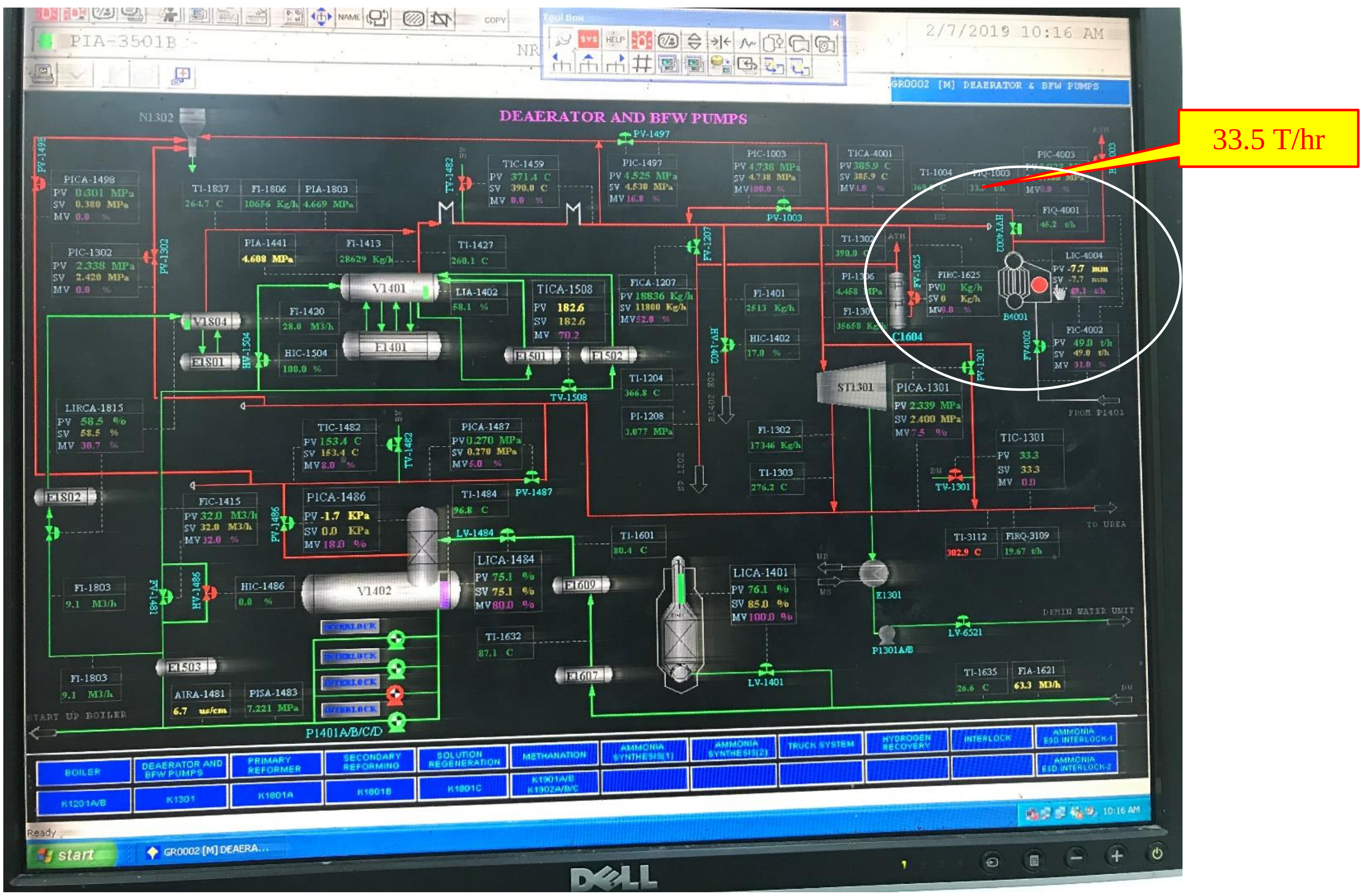
ESO # 1: Reduce Excess air at B-4001 by optimizing the Excess air level (Stack O2 from 4.5% to 3.0%)

	Estimated Annual Savings			ESO type	Simple Payback (years)
	million MMK	CO_2 Reduction (metric ton)	Resource	N / M / L	
Natural Gas	20.3	544	10,898 GJ	N	0 - 0.5
Total	**20.3**	**544**	**10,898**	**N**	**0 - 0.5**

Background

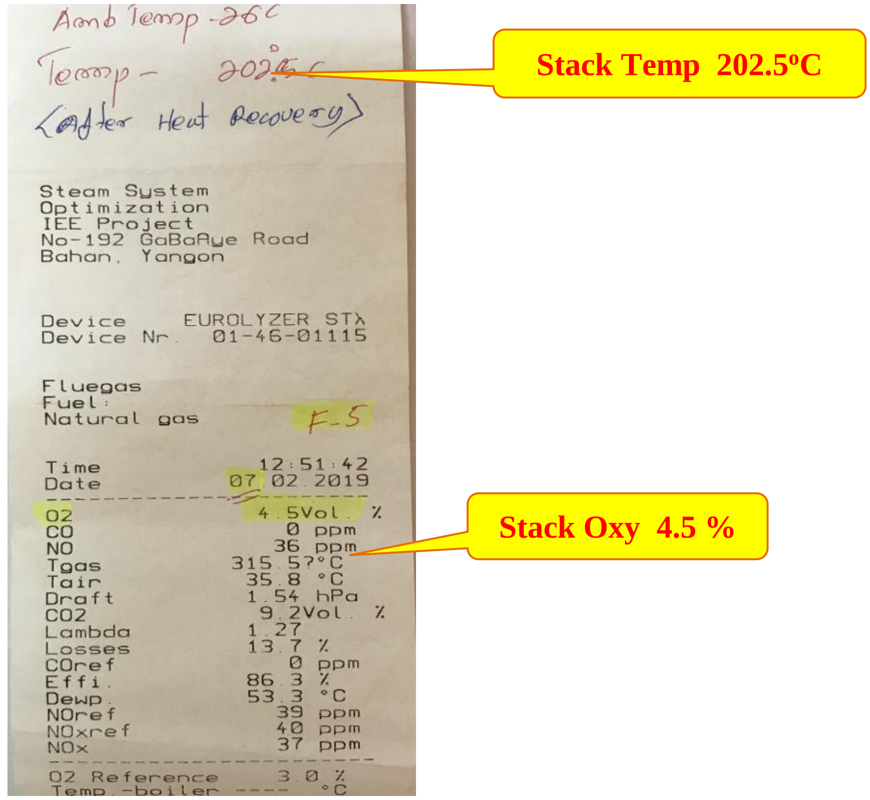
The fuel-fired Start-up Boiler, B-4001 that is currently operated near its full capacity generating about 33- 35 T/hr of steam. Figure 3 below taken at the Plant's control room indicates the 5.0MPa steam generation from Start-Up Boiler (B-4001) along with the 5.0MPa steam generation from the Reformer waste heat steam generators also.

Figure 3: Steam Generation from Start-up Boiler, B-4001



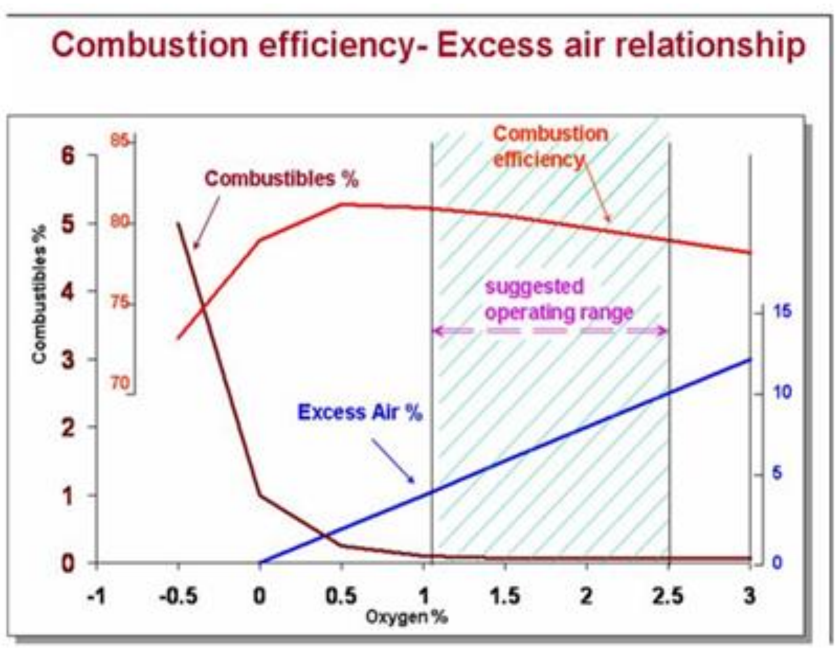
This Natural gas fired Boiler's stack on-line Oxygen indicator is not working for some time and could not be fixed for unavailability of spare parts. The Boiler's automatic load controller is also not working and hence the Boiler is operated at a fixed load all the time. The Boiler is provided with an Economizer, but the stack temperature after the Economizer is still measured at 205°C. The fluegas analysis print out taken at B-4001 is shown in Figure 4 below:

Figure 4: Flue gas Analysis result at the Fuel-Fired Boiler, B-4001



The suggested levels of flue gas O2 readings for Natural gas burners are shown in figure 5 below:

Figure 5: Suggested levels of O2 for Natural gas fired Burners



Recommendation

It is recommended to reduce the Excess air levels further to about 2.0 – 3.0% O_2 in the flue gas.. This would optimize the excess air level close to the Best Practice plants. By fixing the on-line analyzer that is already installed at the Boiler, sustaining the optimum excess air level at this furnace is achievable by the Operators, without any significant investment. Periodic nomination of Plant Operators to Fuel Efficiency courses would motivate them to sustain the efficiency levels.

Estimated Savings

When the stack gas Oxygen level is reduced from 4.5% to 3.0%, the stack losses at the Furnace is estimated to reduce from 17.9% to 17.2% and the Boiler efficiency improves by 0.7%, resulting in lesser natural gas consumption. The resultant energy cost reduction is estimated at 20.3 million MMK annually at No.5 Fertilizer factory. Due to less fuel usage, the CO_2 emission reduction at the site is estimated at 544 metric Tonnes / year.

The savings calculation as per the SSAT model is shown in Table 3 below:

Table 3: Savings due to Excess air Optimization at fuel-fired Boiler, B-4001

Reduce Excess Air from 4.5% to 3.0% Oxy				
Cost Summary ($ '000s/yr)	**Current Operation**	**After Projects**	**Reduction**	
Power Cost	5,300,274	5,300,274	0	0.0%
Fuel Cost	2,377,210	2,356,941	20,269	0.9%
Make-Up Water Cost	513,533	513,533	0	0.0%
Total Cost (in $ '000s/yr)	**8,191,016**	**8,170,748**	**20,269**	**0.2%**

Implementation Cost and Next Actions Towards Implementation

Reducing the Excess air level at Burners is only a process adjustment action and could be achieved with the existing control features at the Reformer furnace and without any significant investment.

ESO # 2: Fix the Leaking Relief Valves at B-4001 and the failed Steam Traps at the 5.0MPa steam header

	Estimated Annual Savings			ESO type	Simple Payback (years)
	million MMK	**CO_2 Reduction (metric ton)**	**Resource**	**N / M / L**	
Natural Gas	73.5	1975	39,529 GJ	N	< 1.0 year
Treated BFW	18.7	-	10,700 m^3		
Total	**92.2**	**1975**	**39,529**	**N**	**< 1.0 year**

Background

The Relief Valve at the B-4001 and several other pipe fittings, sample valves at the 5.0 MPa steam header were leaking. Some pictures taken at the significantly leaking Relief Valves, Pipe Fittings & Steam Traps with their Thermal Images during the field assessment are shown in Figure 6:

Figure 6: Leaking Relief Valves at B-4001, Flange & Steam Trap at the 5.0 MPa header

All the above leaks are due to lack of spare parts or enough maintenance funds to procure in a timely manner. Since natural gas is purchased at a highly subsidized price, the losses in monetary terms may not be significant, but that shouldn't be considered as an excuse to live with inefficiency.

Recommendation

It is recommended to form a Task Force, with the single specific task of fixing all the leaks in the 5.0 MPa system, procure the necessary spares and materials and fix all the 5.0 MPa steam leaks immediately on a war-footing basis.

Estimated Savings

Fixing the leaks would help manage the 5.0-MPa steam system mostly from the generated waste heat steam, without any steam generation from the fuel-fired Start-up boiler, B-4001. The Start up boiler B-4001, is not supposed to operate during normal Reformer operation. The net cost savings by fixing all the leaks in the 5.0 MPa system would save MMK 92.2 million annually.

To evaluate the savings, the SSAT model (summer) was used and the savings calculations are reported in Table 4 below:

Table 4: Estimated Savings by fixing the leaking RV, Fittings & Steam Traps in 5 MPa system

Fix all the leaking Valves in the 5.0MPa steam header				
Cost Summary ($ '000s/yr)	**Current Operation**	**After Projects**	**Reduction**	
Power Cost	5,300,274	5,300,274	0	0.0%
Fuel Cost	2,377,210	2,303,693	73,517	3.1%
Make-Up Water Cost	513,533	494,831	18,701	3.6%
Total Cost (in $ '000s/yr)	**8,191,016**	**8,098,798**	**92,218**	**1.1%**

Implementation Cost and Simple Payback

Periodic Steam Leak survey and fixing the leaking components of the Steam System is a routine maintenance activity and this shouldn’t be deferred at any plant operation. There is no technical expertise required to fix the steam leaks. Because the monetary losses due to steam leaks accumulates silently and exceeds the multifold over the deferred maintenance costs within an year. Some leaks may payback the repair cost just in a single day.

Next Actions Towards Implementation

It is recommended No 5 Fertilizer factory management to review & justify the Steam Leak management policy and implement this recommendation.

ESO # 3: Upgrade the Controls of B-4001, install Local DCS & round the clock Operator attention

	Estimated Annual Savings			ESO type	Simple Payback (years)
	million MMK	CO_2 Reduction (metric ton)	Resource	N / M / L	
Natural Gas	367.6	9873	197,652 GJ	N	< 1.0 year
Treated BFW	93.5		53,500 m^3		
Total	**461.1**	**9873**		**N**	**< 1.0 year**

Background

At present the Start-Up Boiler B-4001 is continuously operated, generating steam @ 5.04 MPa pressure ranging between 35 to 36 T/hr. The steam flow at B-4001 couldn't be reduced below 35 T/hr, due to problem in its Load Controller, which couldn't be fixed due to non-availability of spare parts. The Load Controller of B-4001 is supposed to adjust the Boiler load, by increasing or decreasing its firing rate, depending upon the plant's steam demand at the 5.04MPa steam header. The pictures of the Boiler's Load Controller is shown in Figure 7.

Figure 7: The Load Controller of Fuel-fired Boiler, B-4001

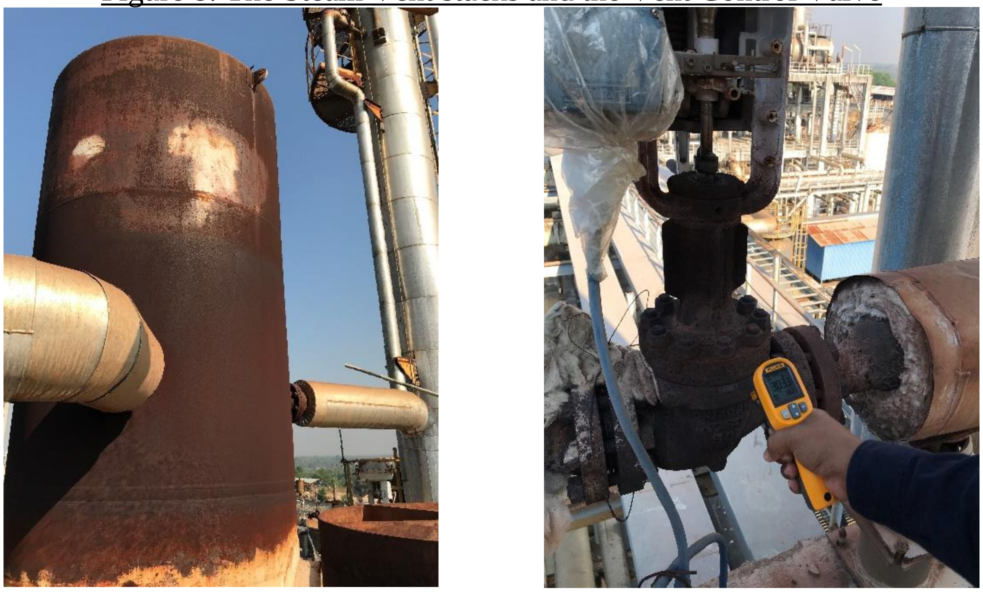
Discussion

Steam is required for the in this Ammonia production plant at 5.04 MPa pressure (HP steam), at the 3 main users, namely for injecting into the Reforming Process, for running the Process Air Compressor Turbine drive, ST-1301 and to supply medium pressure steam (MP steam) to the Urea plant. at 2.5 MPa. The Waste Heat Boilers at the Reformer Furnace, E-1401 & E-1801 generate about 50 – 55 HP steam, depending upon the processing condition of the Reformer, that is mostly maintained at a steady rate. Depending upon the plants total demand in the 5.04 MPa steam header, in excess to the Waste heat Boiler generation, the fuel-fired boiler B-4001 should be operated to meet the 5.04 MPa steam header pressure.

However, currently due to unreliable Load Controller at B-4001, the fuel-fired Boiler is operated at a steady load of about 36 T/hr, even when the actual steam demand, in excess to the generation from WHBs E-1401 & E-1801, is much lower. Hence to maintain the 5 MPa steam header pressure, the vent valves at the top of the structure between Reformer &

Compressor building is kept open partially all the time. The Steam Vent stack and the vent valve position are shown in Figure 8 below:

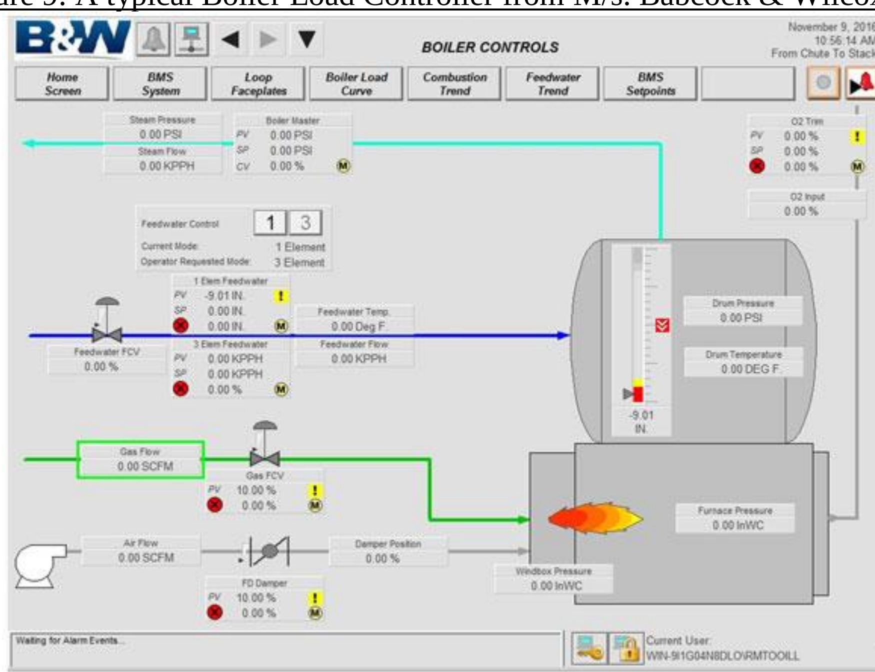
Figure 8: The Steam Vent stacks and the Vent Control Valve



Recommendation

It is proposed to set up a Task Force to procure a new Micro-Processer based Automatic Boiler Controller, servo motor operated Natural gas Control Valve, Reliable Feed water Control Valve, a Variable Speed Controller to the Boiler's FD fan and install them to operate the Boiler on Automatic Load Control mode all the time. There are several Boiler Load Controllers from Reputed manufacturers are available in the market. One such Boiler Load Controller is shown in Figure 9 below:

Figure 9: A typical Boiler Load Controller from M/s. Babcock & Wilcox Inc



Estimated Savings

By automatically adjusting the steam generation from B-4001, in conjunction with the steam generation from the process waste heat boilers, No 5 Fertilizer plant is expected to eliminate all its steam venting and save MMK 461 million annually.

Savings as evaluated by the SSAT model, when the waste heat steam generation is at 36 T/h is shown in Table 5 below:

Table 5: Savings due to flash steam recovery from the Blowdown water of WH boilers

Upgrade the Controls of B-4001, install Local DCS & round the clock Operator attention & reduce 53 T/hr to 25 T/hr				
Cost Summary ($ '000s/yr)	**Current Operation**	**After Projects**	**Reduction**	
Power Cost	5,300,274	5,300,274	0	0.0%
Fuel Cost	2,377,210	2,009,615	367,594	15.5%
Make-Up Water Cost	513,533	420,018	93,515	18.2%
Total Cost (in $ '000s/yr)	**8,191,016**	**7,729,907**	**461,109**	**5.6%**

Implementation Cost and Next Actions Towards Implementation

A new Micro-Processer based Boiler Controller, new Servo Motor operated Control Valves to Natural gas, Variable Speed Drive for the existing FD fan are required. An experienced Vendor can choose the above components suitable to existing B-4001 and integrate these components installing together during the next shutdown opportunity. Investment for such Boiler Control upgrading projects usually will have simple payback periods ranging between 0.5 – 1.5 years. In No 5 Fertilizer plant, the payback period is guesstimated conservatively below 1 year.

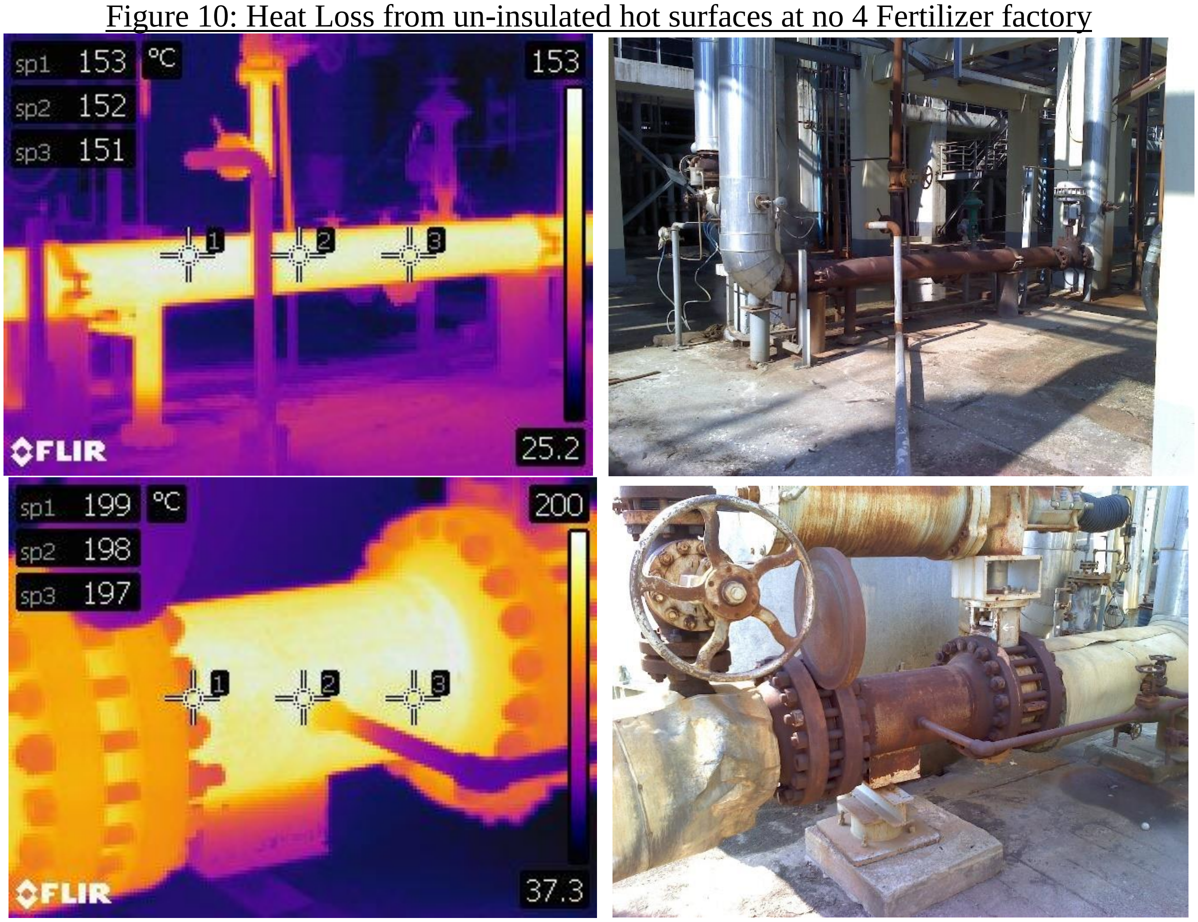
ESO # 4: Insulate the 2 Desuperheater body after the MP>LP (0.5MPa) PRV

	Estimated Annual Savings			ESO type	Simple Payback (years)
	million MMK	**CO_2 Reduction (metric ton)**	**Resource (GJ)**	**N / M / L**	
Natural Gas	1.43	30.0	597	N - M	< 1.0 year
Total	**1.43**	**30.0**	**597**	**N - M**	**< 1.0 year**

Background

The insulation of steam pipelines, heat exchangers and heated vessels at no 5 Fertilizer plant is found at acceptable levels. However, several Valves, Flanges, Heat exchanger ends were found un-insulated. One such noticeable hot surface is the Desuperheater of the 0.5MPa header immediately after the 2.5 MPa to 0.5 MPa Pressure Reducing Valve (PRV). Some of the thermal images and pictures taken during the field visits are shown in Figure 10 below:

Figure 10: Heat Loss from un-insulated hot surfaces at no 4 Fertilizer factory



To evaluate the heat losses from un-insulated surfaces, proper insulation survey need to be conducted. However, this UNIDO assessment's objective is to train the Expert candidates, only few hot surface losses were identified and evaluated.

Recommendation

It is recommended to conduct an Insulation survey with the help of a Thermal Imager, at No 5 Fertilizer plant, with the following activities listed below:

- Identify all the hot surfaces that cause significant heat loss,
- Evaluate the heat loss quantity,
- List them in descending order starting from the largest heat loss, and
- Start fixing them from the top of the list.

The insulation survey & repair actions should be taken up annually.

Estimated Savings

Only sample survey and energy loss evaluation was conducted during this UNIDO Host assessment as a part of the Expert Training programme. The savings potential from the sample loss evaluation is shown in Table 6.

Table 6: Savings estimate for reducing hot surface loss & steam leak losses

Heat Loss at the MP>LP PRV Desuperheater			
The PRV is not Insulated	6" Valve	eqvt length	8 dia of pipe le
The Desuperheater line is not insulated	10" line	12' long	(4 m)
Bare pipe heat loss *(from 3E-Plus)*	4016	W/m	
Heat loss with 40mm Insulation *(from 3E-Plus)*	305.7	W/m	
Heat Savings by insulating the Desuperheater	278040977	kJ/yr	
Enthalpy of 5-barg, 179^{o}C, steam	2804	kJ/kg	
Enthalpy of 5-barg saturated condensate	671	kJ/kg	
Steam loss by unnecessary condensation	130352	kg/yr	
	25.05	kg/hr	
PRV			
Bare pipe heat loss	4885	W/m	
Heat loss with 40mm Insulation	376.6	W/m	
Heat Savings by insulating the Desuperheater	101354603	kJ/yr	
Enthalpy of 5-barg, 179oC, steam	2804	kJ/kg	
Enthalpy of 5-barg saturated condensate	671	kJ/kg	
Steam loss by unnecessary condensation	47517	kg/yr	
	9.13	kg/hr	
Total Heat Loss at the MP>LP PRV & Desuperheater	34.18	kg/hr	

Insulate the MP>LP PRV & Desuperhetaer				
Cost Summary ($ '000s/yr)	**Current Operation**	**After Projects**	**Reduction**	
Power Cost	5,300,274	5,300,274	0	0.0%
Fuel Cost	2,377,210	2,376,100	1,109	0.0%
Make-Up Water Cost	513,533	513,211	322	0.1%
Total Cost (in $ '000s/yr)	**8,191,016**	**8,189,585**	**1,431**	**0.0%**

However, the actual savings potential at No 5 Fertilizer plant is expected to be higher than the above, if proper Insulation survey is completed.

Implementation Cost and Next Actions Towards Implementation

The initiation of Best Practice Steam Trap Management program, Insulation improvement and leak arresting would reduce the unaccounted steam losses at no 5 Fertilizer plant and improve the overall house-keeping of the plant. Typically, these projects have very attractive simple payback periods ranging between 1 month and 2 years.

The No 5 Fertilizer plant management is requested to initiate the Insulation survey first with the above recommended actions in this project.

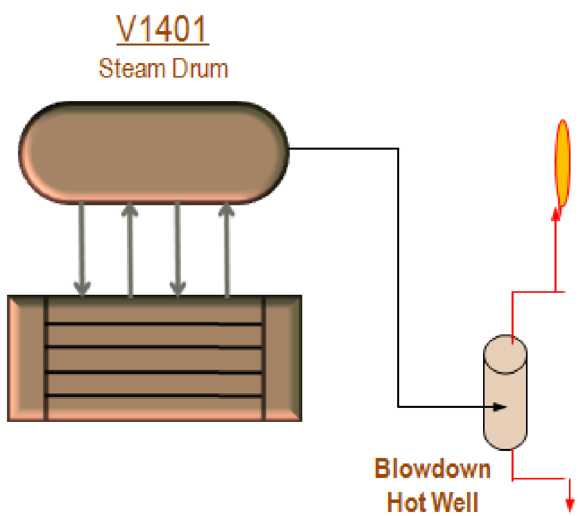
ESO # 5: Recover flash steam from the blowdown water *(only 50% until B-4001 is also connected)*

	Estimated Annual Savings			ESO type	Simple Payback (years)
	million MMK	CO_2 Reduction (metric ton)	Resource	N / M / L	
Natural Gas	5.9	318	3182 GJ	N	< 1.0 year
Treated BFW	1.8		998 m^3		
Total	**7.7**	**318**		**N**	**< 1.0 year**

Background

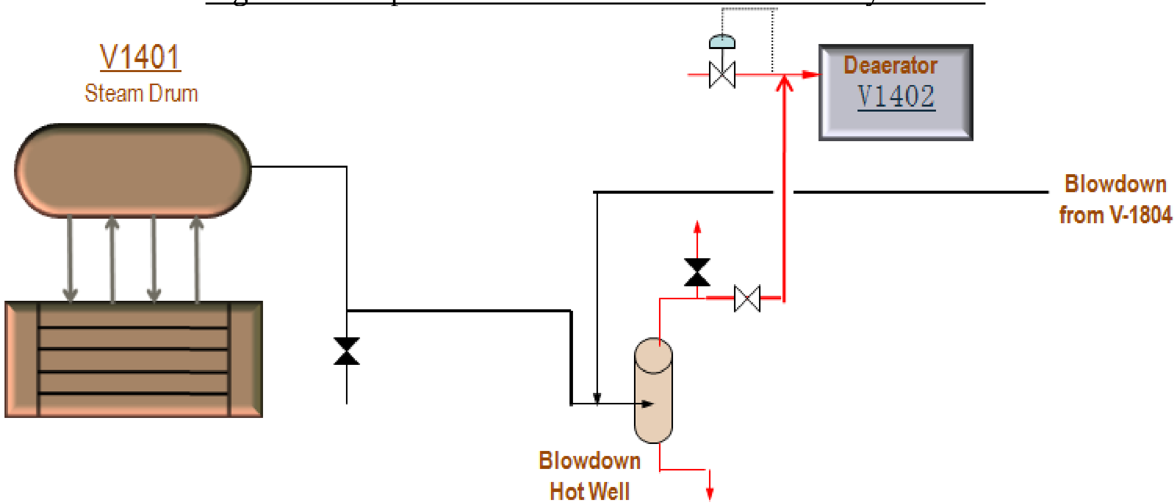
The continuous blowdown (B/D) water from the waste heat boiler drums V-1401 & V-1804 are currently routed to a hot-well located near E-1501 at ground level and flash steam from it is vented to atmosphere. The pictures shown in Figure 11 indicate the B/D hot-well and its venting.

Figure 11: The B/D hot-well and flash steam venting from blowdown water



Recommendation
It is proposed to relocate the blowdown hot-well below the Deaerator V-1402 and route the blowdown water from V-1401 to it. The blowdown water from V-1801 also should be routed to the relocated hot-well. The flash steam from the hot-well should be routed to the steam supply line to the Deaeartor V-1402, after the existing pressure regulator. The suggested schematic arrangement for blowdown water flash steam recovery is shown in Figure 12:

Figure 12: Proposed blowdown flash steam recovery scheme



Estimated Savings
By recovering the flash steam from the blowdown water of process waste heat boilers, No 5 Fertilizer plant is expected to save MMK 7.7 million annually. Savings as evaluated by the SSAT model, when the waste heat steam generation is at 35 T/h is shown in Table 7 below:

Table 7: Savings due to flash steam recovery from the Blowdown water of WH boilers

Recover flash steam from the blowdown water (after excluding Blowdown flash from B-4001)				
Cost Summary ($ '000s/yr)	**Current Operation**	**After Projects**	**Reduction**	
Power Cost	5,300,274	5,300,274	0	0.0%
Fuel Cost	2,377,210	2,365,373	5,918	0.5%
Make-Up Water Cost	513,533	510,043	1,745	0.7%
Total Cost (in $ '000s/yr)	**8,191,016**	**8,175,690**	**7,663**	**0.2%**

Implementation Cost and Next Actions Towards Implementation
Flash steam recovery from blowdown water requires one small tank relocation and routing of pipelines. Typical investment for flash steam recovery projects usually will have simple payback periods ranging between 1 - 2 years. In No 5 Fertilizer plant, the payback period is guesstimated conservatively be between 2.5 to 3.0 years.

It is suggested to No 5 Fertilizer plant management to initiate the Detailed Engineering for this project.

ESO # 6: Install an RO Filter upstream to the DeMin plant and closely monitor and maintain 1.5 ppm Silica in DeMin water

	Estimated Annual Savings			ESO type	Simple Payback (years)
	million MMK	CO_2 Reduction (metric ton)	Resource	N / M / L	
Natural Gas	10.7	287	5,740 GJ	L	4.0 – 5.0
Treated BFW	7.7		4,430 m^3		
Total	**18.4**			**L**	**4.0 - 5.0**

Background

The current blowdown rate at No. 5 Fertilizer plant is 2%. Typically, Boilers using De Min water as make-up, should maintain feed water cycles above 100 and their blowdown rate should be below 1%. The observed Reading from the Log Sheet of water analysis is shown in Table 8 below:

Table 8: Silica Content in BFW, Drum Water and the Blowdown rates

Log Sheet Entry → Dates ↓	Feed Water Silica (*in ppb*)	Drum Water Silica (in ppm)	Feed Water Cycles	Blow Down rate (%)
30-Jan-19	40	2.9	72.5	1.38%
31-Jan-19	41	1.8	43.9	2.28%
1-Feb-19	41	1.8	43.9	2.28%
2-Feb-19	28	2.8	100.0	1.00%
3-Feb-19	26	0.7	26.9	3.71%
4-Feb-19	26	0.7	26.9	3.71%
5-Feb-19	23	1.5	65.2	1.53%
6-Feb-19	23	1.5	65.2	1.53%
7-Feb-19	69	1.2	17.4	5.75%
Average	35.2	1.7	47.0	2.13%

Discussion

During the Site Assessment, it was suggested that No 5 Fertilizer plant's average blowdown rate is more than twice the blowdown rates maintained at plants following the Best Practices with make-up DeMin water. The plant engineers responded that their current pre-filtering system cannot maintain the Silica in Feed Water below 30 ppb all the time. Hence, they are trying to adjust the Boiler blowdown manually to maintain around 1.5 ppb Silica in the Boiler Drum Water. Better Boiler Blowdown management require better water treatment system. Since the current pre-treatment of water is unable to control the Silica levels entering the DeMin plant, the DeMin plant is unable to maintain the Silica levels below 30 ppb as desired at the Feed water. Adding few modules of Reverse Osmosis (RO) downstream to the existing pre-treatment system, before it enters the DeMin plant would improve the DeMin plants performance and would also extend the life of the Resins life, between each regenerations.

Recommended Action for reducing the blowdown losses

It is recommended to install a set of RO modules upstream to the existing DeMin plant to control the Silica levels in the water entering the DeMin plant. This would enable the existing DeMin plant to supply BF water with less than 30 ppb Silica all the time. The required size of the RO modules could be discussed and decided with the RO plant vendors, by providing the water analysis readings, specifically with Silica content before it enters the DeMin plant.

Estimated potential savings:

The estimated energy cost savings by reducing the blowdown rate with sustained lower levels of Silica content in the Boiler feed water would be MMK 18.4 million annually. This would also save 4400 m3 of boiler feed water annually. The savings estimated by the US DoE's SSAT model is shown in Table 9 below:

Table 9: Estimated Energy & Water cost Savings due to lowering the Blowdown rates

Install an RO Filter upstream to the DeMin plant and closely monitor and maintain 1.5 ppm Silica in DeMin water				
Cost Summary ($ '000s/yr)	**Current Operation**	**After Projects**	**Reduction**	
Power Cost	5,300,274	5,300,274	0	0.0%
Fuel Cost	2,377,210	2,366,533	10,677	0.4%
Make-Up Water Cost	513,533	505,781	7,751	1.5%
Total Cost (in $ '000s/yr)	**8,191,016**	**8,172,588**	**18,428**	**0.2%**

Next Actions Towards Implementation

This project opportunity needs to be carefully reviewed by the Engineers & Managers of the No 5 Fertilizer plant.

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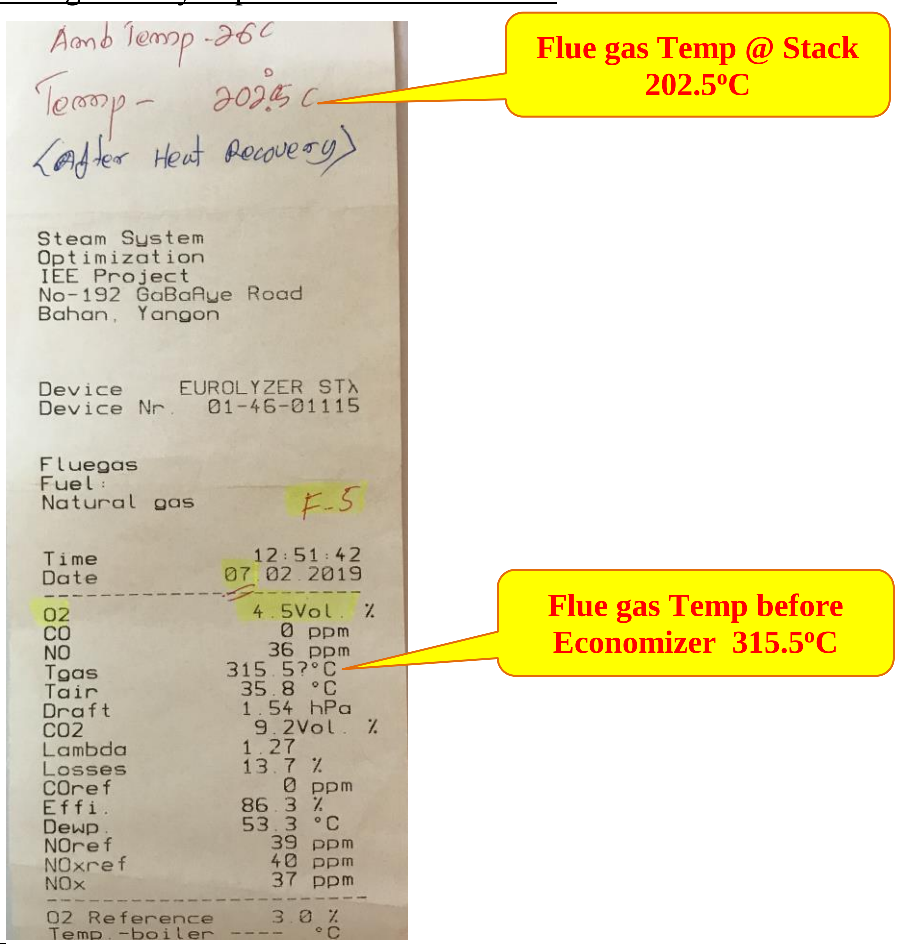
ESO # 7: Increase the Economizer size at the fuel-fired Boiler, B-4001

	Estimated Annual Savings			ESO type	Simple Payback (years)
	million MMK	CO_2 Reduction (metric ton)	Resource	N / M / L	
Natural Gas	77.73	2088	41,796 GJ	L	3.0 – 4.0
Total	**77.7**	**2,088**	**41,800 GJ**	**L**	**3.0 - 4.0**

Background

The stack temperature after the existing Economizer of the fuel-fired Boiler, B-4001 at No. 5 Fertilizer plant is over 200°C. The measured Stack gas (Flue gas) analysis print-out is shown in Figure 13 below: *(This same Figure is also included as Figure 3 at page of this report)*

Figure 13: Flue gas Analysis print out taken at B-4001



Discussion

Typically, Boilers using Natural gas as fuel could be fitted with enough heat recovery surfaces to bring down the stack gases below 120°C. Any stack temperature in excess of 120°C, is a waste of fuel and necessary actions to be taken to bring down the excess losses and fuel firing. Our physical inspection at the site confirms that the duct length after the existing Economizer and the Stack inlet is over 8m in length and the duct length where the current Economizer is installed is about 5m long. Hence, there is enough space available in the existing duct to accommodate additional Economizer tubes in B-4001.

Recommended Action for reducing the blowdown losses

It is recommended to install additional Economizer tubes of matching dimensions with the existing Economizer at B-4001, to bring down the stack temperature from 202.5^{o}C to about 130^{o}C. Since the Boiler is of FD (Forced Draft) design, with excess capacity indicated by the current partial damper opening, the increase in pressure drop due to the additional Economizer tubes should not cause any problem. Since Natural gas is the fuel, the stack temperature would never go below the Sulphur dew point.

Estimated potential savings:

The estimated energy cost savings by recovering more heat at the boiler, B-4001 by reducing the stack temperature to 130^{o}C, would be MMK 77.7 million annually. The savings estimated by the US DoE's SSAT model is shown in Table 14 below:

Table 10: Estimated Energy & Water cost Savings due to lowering the Blowdown rates

Economizer addition with Excess Air reduction				
Cost Summary ($ '000s/yr)	**Current Operation**	**After Projects**	**Reduction**	
Power Cost	5,300,274	5,300,274	0	0.0%
Fuel Cost	2,356,941	2,279,209	77,732	3.3%
Make-Up Water Cost	513,533	513,533	0	0.0%
Total Cost (in $ '000s/yr)	**8,170,748**	**8,093,016**	**77,732**	**1.0%**

Next Actions Towards Implementation

This project opportunity needs to be carefully reviewed by the Engineers & Managers of the No 5 Fertilizer plant.

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Qualitative Recommendations (QRs)

Qualitative recommendations (QRs) are energy saving opportunities that were identified during the assessment that should be considered for further investigation and implementation; however, due to lack of measurements, information, and/or lack of resources during the assessment, specific energy savings were not quantified. QRs may also include potential industry best practices to be incorporated into the plant. The following recommendations should be considered for further investigation and implementation.

1. **Conduct a Steam Trap & Steam Leak survey and fix the defective steam traps and the steam leaks**

2. **Install Automatic Blowdown Control with on-line conductivity analyzer**

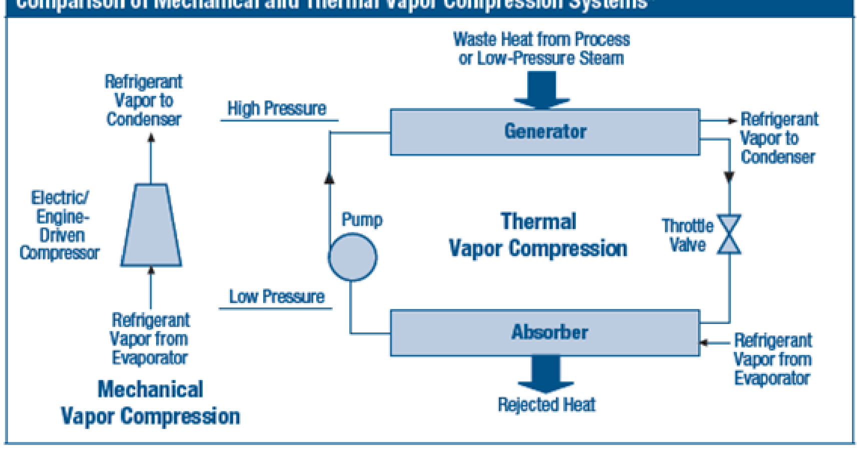
3. **Explore the benefits of installing an Absorption Chiller* utilizing the vented steam at the Urea plant**

The above listed opportunities were identified during the February 2019 plant visit. The plant engineers can review these opportunities and evaluate their applicability to the plant and their cost benefit characteristics.

**Absorption Chiller using vented LP steam*

Absorption Chillers use heat, instead of mechanical energy, to provide cooling. The mechanical vapour compressor is replaced by a thermal compressor (see figure) that consists of an absorber, a generator, a pump and a throttling device. The refrigerant vapour from the Evaporator is absorbed by a solution mixture in the absorber. This solution is pumped to the Generator, where it is heated to re-vaporize the refrigerant using a waste heat source. The refrigerant depleted solution is then returned to the absorber via a throttling device. Two most common refrigerants used in Absorption Chillers are Ammonia & Water. When Ammonia is the refrigerant water is its absorbent. When water is the refrigerant, Lithium Bromide is its absorbent.

Comparison of Mechanical and Thermal Vapor Compression Systems*



* The evaporator and the condenser, required for both systems, are not shown in the figure.