Heating Systems Study

Energy Best Practice Guide

KBR | ENERGY SOLUTIONS | CONSULTING

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Abbreviations

APH	Air Preheater
BFW	Boiler Feed Water
BPT	Backpressure Turbine
BTX	Benzene, Toluene, Xylene
CCR	Continuous Catalytic Reforming
CHP	Combined Heat and Power
CIP	Cleaning-in-Place
DCS	Distributed Control System
DT_{min}	Minimum Temperature Approach
EDB	Economic Development Board
EIV	Energy Influencing Variable
EOR	End-of-Run
EPA	Environmental Protection Agency
EPI	Energy Performance Indicator
GE	General Electric
GHG	Greenhouse Gas
GT	GT
HEPA	High Efficiency Particulate Air
HP	High Pressure
HRSG	Heat Recovery Steam Generator
KBR	Kellogg Brown & Root Asia Pacific Pte Ltd
LNG	Liquefied Natural Gas
LP	Low Pressure
LPG	Liquefied Petroleum Gas
LPS	Low Pressure Steam
MP	Medium Pressure
MPPS	Most Penetrating Particle Size
NEA	National Environment Agency
NG	Natural Gas
O&M	Operation and Maintenance
ORC	Organic Rankine Cycle
ORNL	Oak Ridge National Laboratory
PHE	Plate Heat Exchanger
PSV	Pressure Safety Valve

RO	Reverse Osmosis
S&T	Shell and Tube
SOR	Start-of-Run
STG	Steam Turbine Generator
UA	Overall heat transfer coefficient / Area
VSD	Variable Speed Drive
WHB	Waste Heat Boiler

PREFACE

Objectives of this Document

This Best Practice guide has been prepared as part of the National Environment Agency (NEA) heating study. This document provides best practice guidelines in relation to four major heating systems for oil refining, petrochemical and chemical plants, namely: 1) Furnace Systems; 2) Hot Oil Heater Systems; 3) Boiler Systems; 4) Cogeneration Systems.

The aim of this document is to provide guidance on best practices in relation to the design, operation and maintenance, as well as to illustrate the common opportunities that can be found in manufacturing plants for the systems mentioned above. Plants can then make use of this guide to identify energy efficiency opportunities on-site.

Information Sources

This document represents a summary of information collected from several sources which includes, KBR's best design practices as well as internationally recognised standards such as European Union and U.S. Department of Energy Best Available Techniques.

How to understand and use this Document

The information provided in this document is intended to be used as an input to the determination of best energy efficiency practices for oil refining, petrochemical and chemical plants in relation to furnaces, hot oil systems, boilers and cogeneration systems.

The information included provided guidelines and examples of energy efficiency opportunities captured during the assessment of industrial players in Singapore as well as world-wide.

Section 1 provides an introduction to energy usage in Singapore and the importance of implementing energy efficiency to achieve Greenhouse Gas (GHG) emission targets.

Section 2 to Section 5 presents the best practices in relation to the design and operation in relation to furnaces, hot oil systems, boilers and cogeneration systems. These sections are the core part of this document and should be used to determine potential energy improvement opportunities on the site relevant to the reader.

Section 6 covers the most common challenges in implementing energy efficiency opportunities and highlights ways to overcome them.

1 Introduction

According to the Department of Statistics Singapore, Singapore's industry (manufacturing) sector is an important contributor to economic growth and was responsible for 20.5%[1] of Singapore's gross domestic product in 2019. Major industries include refining, petrochemical, specialty chemicals, pharmaceuticals, and semiconductors. The Energy Market Authority has estimated that the industrial-related sector accounted for 89.2% (or 53 524 TJ) of total natural gas (NG) consumption and 41.5% (or 21.4 TWh) of all electricity in 2019[2].

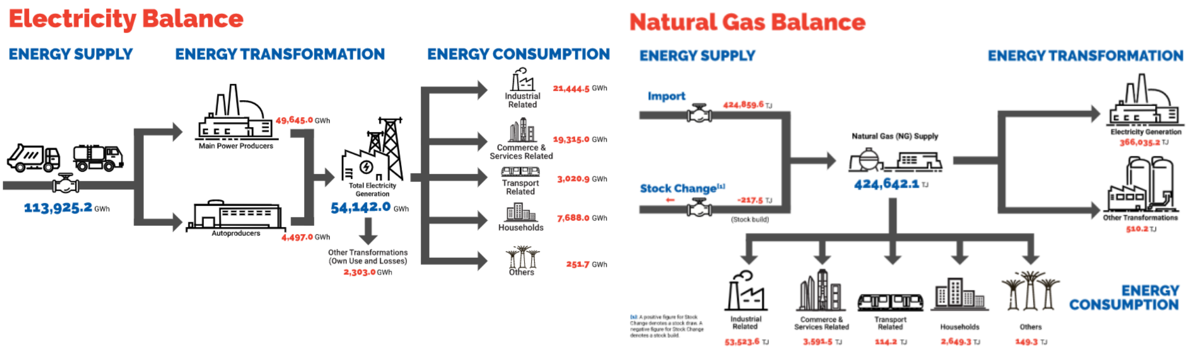


Figure 1.1 – 2019 Electricity and Natural Gas Usage in Singapore [2]

Today, energy efficiency is a focal point for governments and society. In addition to reducing operating cost and increasing margin for the industrial sector, energy efficiency improvement represents an important opportunity for Singapore to further reduce emissions and improving industrial competitiveness.

Oil refining, petrochemical and chemical plants account for bulk of energy use in the industrial sector in Singapore. According to the NEA, heating systems alone account for about 95.7%[3] of the energy consumption for these plants. The breakdown of energy consumption shows that greater emphasis should be placed on direct and indirect heating systems and cogeneration.

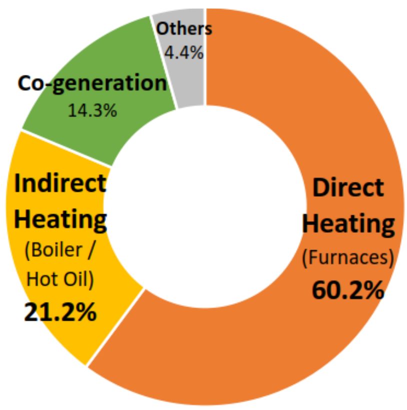


Figure 1.2 –Energy Use Distribution[3]

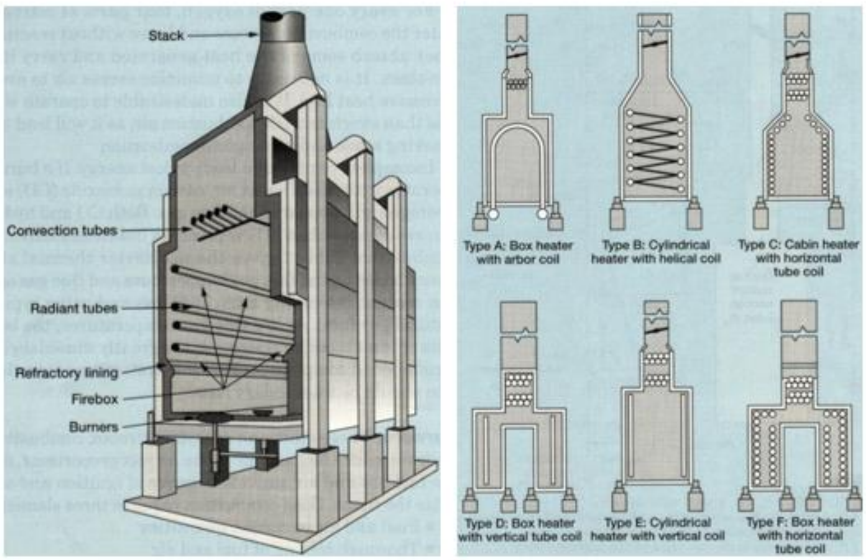
In 2019, the NEA set out to investigate potential emission reduction through the improvement of the energy efficiency of industrial sites. This project focused on oil refining, petrochemical and chemical plants that account for the bulk of energy use in the industrial sector in Singapore. Heating systems (defined as: furnaces, boilers, hot oil loop and cogeneration systems) are estimated to account for about 95.7%[3] of the energy consumption for these plants. Improving the energy performance of these heating systems could potentially lead to significant energy savings and abatement of GHG emissions for Singapore. The best practices identified during this study, along with those that KBR has seen in other plants (locally and internationally), are gathered in subsequent sections of this document.

2 Furnace Systems

2.1 Definition

In the process industry (oil refining, petrochemical, chemical), a furnace is a piece of equipment used to either increase the temperature of 1) a process stream to a target temperature (e.g. before sending it to a fractionator such as in the Atmospheric Crude Distillation or to provide the required reboiling duty as in the Benzene, Toluene, Xylene (BTX) unit), 2) a reaction system (e.g. Hydrotreating Process), or 3) provide enough heat for an endothermic reaction to take place (e.g. Ethane Cracker Unit).

A furnace or direct fired heater has four basic components namely: encasement box, burner, coil and a stack. There are different types of furnaces depending on the box type and coils as illustrated in Figure 2.1.



An inside view of a typical horizontal tube heater (reproduced from API-573, 1st edition)

The different types of fired heaters (reproduced from API 560, 2nd edition)

Figure 2.1 – Furnace Components and Type

On top of the above, an important factor to take into account, as it might somehow be limiting potential opportunities, is the type of draft. There are four types of design (Figure 2.2):

- Natural draft: a stack effect induces the combustion air and removes the flue gases;
- Forced-draft: combustion air is supplied by a fan or other mechanical device;
- Induced-draft: uses a fan to remove the flue gas and to maintain a negative pressure in the heater. This induces the combustion air without the need of a forced-draft fan; and
- Balanced draft: this approach uses forced-draft fans to supply the combustion air as well as induced draft fans to remove the flue gases.

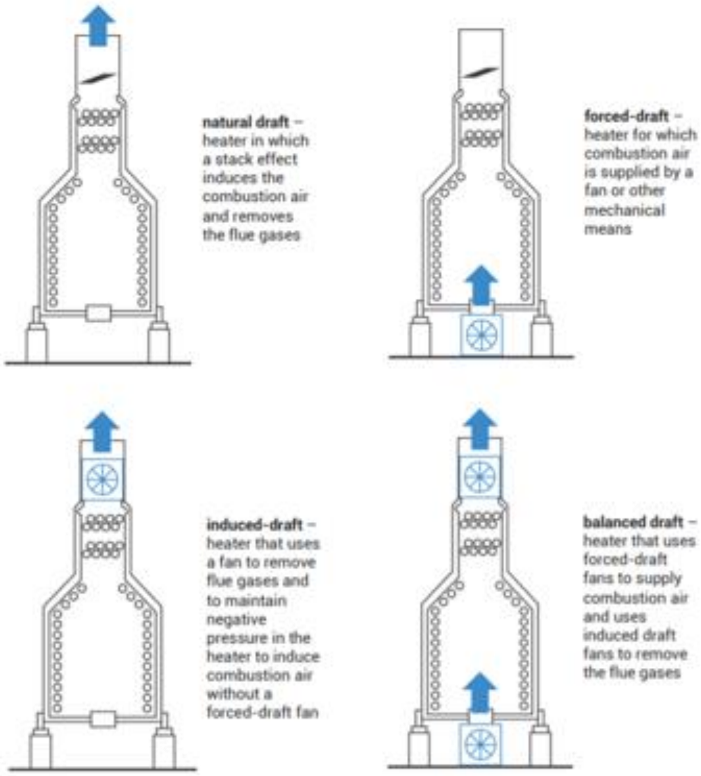


Figure 2.2 – Draft Type

2.1.1 Energy Requirements

The dominant energy input will typically be the combustion fuel (charge pump or compressor power / work required is usually negligible compared to fuel) which provides the heat duty required by the process, minus the inefficiencies associated with the furnace itself (i.e. excess air, radiation losses and heat losses through flue gas exit temperature).

On top of the furnace (equipment) performance, there are other factors associated with the system performance related to the process in which a furnace is employed. These include: 1) the pump or compressor (gas), which is used for the process stream to reach the desired pressure level; 2) the configuration of the preheat train used to raise the process fluid temperature before the process stream is sent to the furnace (this does not apply when furnaces are used as reboiler). A simple block flow diagram of a typical furnace flow is shown below in Figure 2.3.

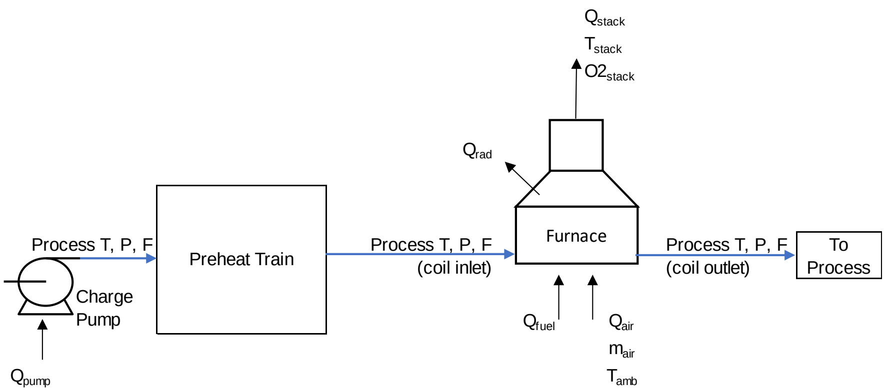


Figure 2.3 – Typical Elements of a Furnace System

The energy output in the system shown in Figure 2.3 consists of:

- Heat transferred to the process stream in the radiant / convection zone and other streams heated in the convection zone (e.g. Boiler Feed Water [BFW]).
- Furnace losses consisting of heat lost to the stack gases (these are a function of the stack gas temperature and excess oxygen) and radiation losses which are a function of the furnace design. Radiation losses are usually fixed and do not vary with the amount of fuel used by the furnace.
- Insulation losses which are a function of the pipe length, pipe diameter and insulation.

Features that need to be considered to improve the efficiency of this type of system are covered in Section 2.2.

There are other potential heat losses associated with furnaces:

- Moisture in fuel: fuel usually contains some moisture and some of the heat is used to evaporate the moisture inside the furnace.
- Hydrogen in fuel which results in the formation of water.
- Loss through openings in the furnace: radiation loss occurs when there are openings in the furnace enclosure and these losses can be significant, especially for furnaces operating at temperatures above 540°C. A second loss is through air infiltration because the draft of furnace stacks / chimneys causes a negative pressure inside the furnace, drawing in air through leaks or cracks or whenever the furnace doors are opened.
- Furnace skin / surface losses, also called wall losses: while temperatures inside the furnace are high, heat is conducted through the roof, floor and walls and emitted to the ambient air once it reaches the furnace skin or surface.
- Other losses: there are several other ways in which heat is lost from a furnace, although quantifying these is often difficult. Some of these include:
    - Stored heat losses: when the furnace is started, the furnace structure and insulation are also heated, and this heat only leaves the structure again when the furnace shuts down. Therefore, this type of heat loss increases with the number of times the furnace is turned on and off.

- Material handling losses: the equipment used to move the stock through the furnace, such as conveyor belts, walking beams, bogies etc, also absorbs heat. Every time equipment leaves the furnace it loses heat, therefore heat loss increases with the amount of equipment and the frequency by which it enters and leaves the furnace[5].

2.2 Best Practices & Design Considerations - Furnaces

There are two areas affecting the performance of a furnace system, namely, the furnace itself and the performance of the associated preheat train. This section covers the best practices in design, operation and maintenance as well as metrics and best available technologies for furnace equipment. Section 2.3 covers the parameters related to the best practices for preheat train design, operation and maintenance.

2.2.1 Best Practices in Design

The use of best practice furnace design is to enable a safe, efficient, and long working asset life at the minimum utility cost. Furnace selection and design depend on the type of service that the furnace is employed: all-liquid vaporising service or all-vapour service.

For all-liquid or vaporising services, strong consideration is given to the formation of coke within the process fluid tubing. Fired heaters should be designed to minimise coking inside the tube wall as this can interfere with the heat transfer process and reduce efficiency. Incipient coke can begin to form at bulk fluid temperatures of 315°C or film temperatures of 350°C. In services with inherent cracking, such as visbreaking or thermal cracking, coke formation can be managed with bulk fluid temperatures at or below 470°C or film temperatures around 490°C. Effective management of coking requires maintaining turbulent mass flow through the tubing, to maintain a high heat transfer coefficient at the wall of the tubing, thus minimising the temperature difference between the bulk fluid and the film / wall of the tubing.

For all-vapour service, little attention is required to coke formation as it is less severe compared to all-liquid or vaporising services.

Alongside the process fluid flow control design, the following design features for the furnace are considered:

1. Fired heaters shall be spaced and designed for uniform heat distribution.
2. Minimum number of single-circuit passes is desired. For multi-pass heaters, the tubing network should be hydraulically and thermally symmetrical across all passes.
3. Average heat flux density in the radiant section is normally based on a single row of tubes with two nominal tube diameters spacing.
4. The maximum allowable inside film temperature for any process service shall not be exceeded in the radiant, shield, or convection sections.
5. Provision for thermal expansion shall take into consideration all specified operating conditions, including short-term conditions such as steam-air decoking.
6. The convection section tube layout shall include space for future installation of soot blowers or steam lancing doors.
7. The convection section shall incorporate space for future addition of two rows of tubes.

8. When the heater is designed for fuel oil firing, soot-blowers shall be provided for convection section cleaning.
9. Vertical cylindrical heaters are typically designed with maximum height to diameter ratio of 2.75, where the height is the radiant section height and the tube circle diameter.
10. Shield sections shall have at least three rows of bare tubes.
11. Convection sections shall be designed to minimise flue gas bypass. Baffles may be employed.
12. An air preheater should be in place to maximise the heat recovery from the furnace's flue gases. Additionally, designers should consider including boiler feed water economiser, steam generation and steam superheating, depending on the process and site steam usage.
13. The minimum clearance from grade to burner plenum or register shall be 6 feet 6 inches (2.0 meters) for floor-fired heaters.
14. For vertical cylindrical heaters, the maximum radiant straight tube length shall be 60 feet (18.3 meters).
15. For horizontal heaters fired from both ends, the maximum radiation straight tube length shall be 40 feet (12.2 meters).
16. Radiant tubes shall be installed with minimum spacing from refractory or insulation to tube centerline of one and one half nominal tube diameters, with a clearance of not less than 4 inches (10 centimeters) from the refractory or insulation.
17. For horizontal radiant tubes, the minimum clearance from floor refractory to tube outside diameter shall be not less than 12 inches (30 centimeters).
18. The heater arrangement shall allow for replacement of individual tubes without disturbing adjacent tubes.
19. Target maximum radiation losses 2.5% of the total heat input.
20. Heaters shall be designed such that a negative pressure of at least 0.10 inches of water (0.025 kilopascals) is maintained in the radiant and convection sections at maximum heat release with design excess air.
21. The flame impingement and consequent tube failure that could result can be avoided by specifying a minimum safe distance between burners and tubes, based on experience.
22. Control system in place to operate the furnace at the optimum temperature (this will depend on the specific process). This is done to avoid human error. Operating at too high temperatures causes heat loss, excessive oxidation, de-carbonisation and stress on refractories.
23. Selection of the refractory will depend on: type of furnace, type of metal charge, presence of slag, area of application, working temperatures, extent of abrasion and impact, structural load of the furnace, stress due to temperature gradient in the structures and temperature fluctuations, chemical compatibility to the furnace environment and cost considerations.

2.2.2 Best Practices in Maintenance & Operations

The target efficiency for a Best Practice furnace is 92%, with the exception of ethane cracking furnaces that target a best practice of 94%. The difference is due to the tighter control of excess air and inherently more complex design of the convection section of the ethane cracking furnace. These values assume NG or clean fuel gas is burnt.

To achieve these high efficiency levels, the following practices are recommended:

Excess Air (Oxygen Content in Flue Gases)

Excess air is required to ensure complete combustion. For natural draft furnaces, the target for fuel gas firing is 10% excess combustion air and for fuel oil or mixed firing 15%. This means 1 to 3% stack oxygen. Best Practice stack oxygen content for process furnaces ranges between 2.0% to 3.0%. For ethylene furnaces, Best Practice stack oxygen content is 1.5% as these usually come with advanced control of furnace stack oxygen. It should be noted that too much air might be due air leakage or issues with the metering device.

Excess air is best monitored by flue gas analysers (portable analyser is an option – e.g. TESTO, Land Pyrometer, etc). This type of equipment typically monitors oxygen, CO and NO_x content. Optimisation of excess air should be straightforward on furnaces which fire at relatively constant duty. For furnaces which change heat load significantly, the operators will need to adjust the excess air with the firing duty.

Excess air might be difficult to control for furnaces operating close to their minimum fired duty. However, having excess air is necessary to prevent incomplete combustion, which would lead to the release of CO to the atmosphere.

It is recommended to set a multi-disciplinary task force team (from appropriate representatives from the site's Operations, Instrument, Maintenance and Technical departments) to effectively reduce, and maintain, furnace excess air levels. The team responsibility would be to:

- Define the base operating efficiency of each furnace;
- Establish realistic operating targets (based on historical or design values) for each furnace;
- Identify cost effective improvements and define new efficiency targets;
- Establish a program for routine monitoring of furnace efficiencies; and
- Establish effective monitoring and controls systems and procedures that prompt corrective action when operating parameters (i.e. stack oxygen) and / or efficiencies fall below target levels.

Optimisation of excess air is expected to be relatively simple on furnaces for which duty requirement is constant. However, for furnaces which significantly change duty requirement, the plant operators will need to make adjustments to match the firing duty requirements.

Openings

Heat can be lost by direct radiation through openings in the furnace, such as the peephole in the wall or ceiling. Heat is also lost due to pressure differences between the inside of the furnace and the ambient environment causing combustion gases to leak through the openings. But most heat is lost if outside air infiltrates into the furnace, because in addition to heat loss this also causes uneven temperatures inside the furnace and stock and can even lead to oxidisation of billets.

It is therefore important to keep the openings as small as possible and to seal them. Another effective way to reduce the heat loss through furnace openings is by opening the furnace doors less frequently and for the shortest time period as possible. This heat loss is about 1% of the total quantity of heat generated in the furnace, if furnace pressure is controlled properly[5].

Heat Recovery (Stack Temperature)

The stack temperature is the measured temperature of the flue gas that exits into the atmosphere. This temperature measurement should be taken after the economiser or any stack heat recovery exchanger to ensure that existing heat recovery measures have been accounted for.

Process furnaces designed following best practice will achieve a stack temperature of about 150°C assuming NG or clean fuel gas is burnt.

For ethylene furnaces, best practice stack temperature can be as low as 110°C with the use of clean fuels. For incinerators, the upper stack temperature should target around 200°C to avoid dew point.

Flue Gas Acid Dew Point

The flue gas acid dew point can be predicted, and the minimum tube-metal temperature should be kept high enough to prevent condensation (typically up to 20°C above dew point), if the fuel's sulphur content has been correctly stated (estimated flue gas dew points calculated with respect to sulphur content in fuel oil and gas).

Fire Side Cleaning and Maintenance

Particulates and residue will build up on the fire side of the furnace during normal operation, however excessive particulate build-up can be an indication of a failed internal component expelling unburned fuel into the combustion chamber, causing excess sooting. This can result in not only poor emissions from the furnace but also inadequate heat transfer into the furnace tubes. The fire side of the furnace should be cleaned once per year and may be mandated by the local emissions regulatory committee.

Heat Distribution

Where burners are used to fire the furnace, the following should be ensured for proper heat distribution:

- The flame should not touch or be obstructed by any solid object. Obstruction causes the fuel particles to de-atomise, which affects combustion and causes black smoke. If the flame impinges on the stock, scale losses will increase. If the flame impinges on refractories, products from incomplete combustion can settle and react with the refractory constituents at high temperatures.
- The flames of different burners should stay clear of each other, as intersecting flames cause incomplete combustion. It is also desirable to stagger burners on opposite sides.
- The burner flame has a tendency to travel freely in the combustion space just above the material. For this reason, the axis of the burner in small furnaces is never placed parallel to the hearth but always at an upward angle, but the flame should not hit the roof.
- Large burners produce longer flames, which may be difficult to contain within the furnace walls. More burners of less capacity ensure a better heat distribution inside the furnace and also increase the furnace life.
- In small furnaces that use furnace oil, a burner with a long flame with a golden yellow colour improves uniform heating. But the flame should not be too long, because heat is lost if the flame reaches the chimney or the furnace doors[5].

Loading

Optimal load

There is a particular load at which the furnace will operate at maximum thermal efficiency, i.e. where the amount of fuel per kg of material is lowest. This load is generally obtained by recording the weight of material of each charge, the time it takes to reach the right temperature, and the amount of fuel used. The furnace should be loaded to the optimum load at all times, although in practice this may not always be possible.

If the furnace is under-loaded, the proportion of total heat available that will be taken up by the load is smaller, resulting in a lower efficiency. Overloading can result in the process stream not being heated to the right temperature within a given period of time[5].

Downtime

Small furnaces might not operate continuously (operating periods alternate with the idle periods). When the furnaces are turned off, heat that was absorbed by the refractories during operation gradually dissipates through radiation and convection from the cold face and through air flowing through the furnace. When the furnace is turned on again, additional fuel is needed to heat up the refractories again. For instance, for a furnace with a firebrick wall of 350 mm thickness, it is estimated that during the 16 hours that the furnace is turned off, only 55% of the heat stored in the refractories is dissipated from the cold surface. Hence, if a furnace is operated continuously for once (24 hours continuous operation) in three days, practically all the heat stored in the refractories is lost; but if the furnace is operated 8 hours per day all the heat stored in the refractories is not dissipated[5].

Careful planning of the furnace operation schedule can therefore reduce heat loss and save fuel.

2.2.3 Best Available Technologies

There are two main aspects to consider regarding the energy performance of a furnace, namely: excess air (also addressed as stack oxygen) and heat recovery from the furnace flue gases (also addressed as stack temperature). This section covers the best technologies available in this area.

Excess Air – Stack Oxygen Control System

In terms of monitoring, the best practice is to monitor air composition using on-line analysers (e.g. Combustion One from Yokogawa, Quantitec, etc). In the absence of fixed analysers, it is recommended to use calibrated portable oxygen / CO analysers (e.g. Testo, Ametek-Land). Oxygen measurement itself is of limited value where tramp air leakage may be occurring into a furnace, which is common.

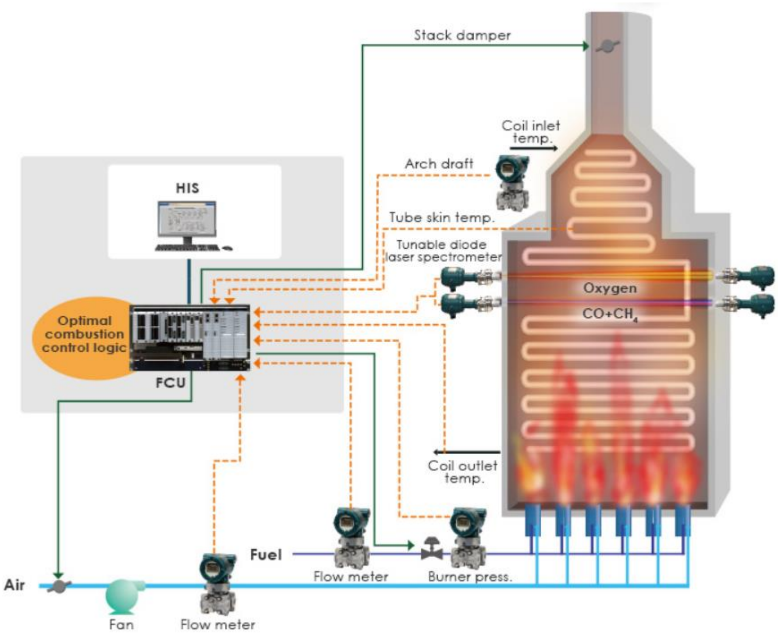


Figure 2.4 – Typical Arrangement for Online Oxygen Analysers

Generally, air should be reduced at the registers until significant CO is noted, or flame patterns become poor. Flames and registers should all be equal. For natural draft furnaces, a good target in fuel gas firing is 10% excess combustion air. These values should be achievable with well-maintained burners.

Additional Heat Recovery from Flue Gases – Reducing the Stack Temperatures

The main concern regarding heat recovery of flue gases is reaching the dew point which would lead to corrosion. HeatMatrix provides a solution to this dilemma by using an arrangement of polymer tubes in the Air Preheater (APH) section of the furnace. This could lead to energy savings of around 4% (based on observed values for this type of project across multiple industries).

Regarding the technology, users need to be aware of the upper temperature limit of the equipment, which is set at 200°C. Above this temperature there is the possibility of equipment failure as the tubes would likely melt.

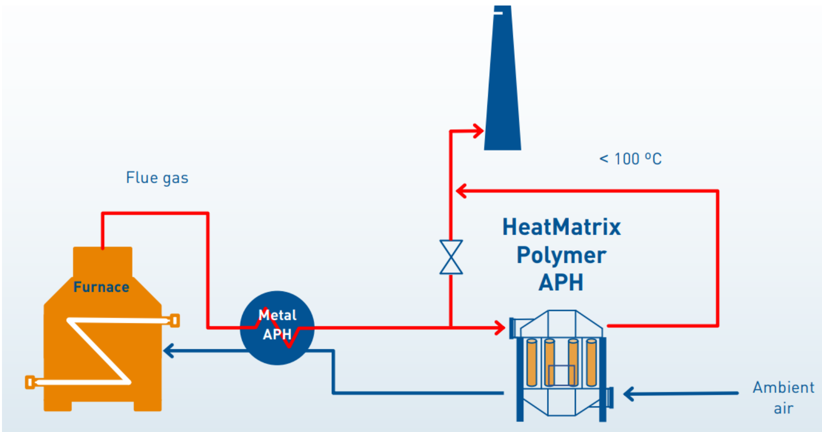


Figure 2.5 – Example of a HeatMatrix Arrangement

[courtesy of Heat Matrix Group]

2.3 Best Practices & Design Considerations – Preheat Trains

The performance of preheat trains indirectly affects the performance of the furnace system by reducing the furnace load. There are two main factors influencing the behaviour of a preheat train: 1) heat integration efficiency (given by its design), and 2) fouling and how to tackle it to restore (improve) the performance of the preheat train. This section covers these two areas.

2.3.1 Best Practices in Design

The best energy practice when designing a preheat train is to use pinch principles to achieve the minimum utility consumption within the system. Pinch Technology provides a systematic methodology for energy saving in processes and total sites. The methodology is based on thermodynamic principles. A Pinch Analysis starts with the heat and material balance for the process. Using Pinch Technology, it is possible to identify appropriate changes in the core process conditions that can have an impact on energy savings. After the heat and material balance is established, targets for energy saving can be set prior to the design of the heat exchanger network.

The Pinch Design Method ensures that these targets are achieved during the network design. Targets can also be set for the utility loads at various levels (e.g. steam and refrigeration levels). The utility levels supplied to the process may be a part of a centralised site-wide utility system (e.g. site steam system). Pinch Technology extends to the site level, wherein appropriate loads on the various steam mains can be identified to minimise the site-wide energy consumption. Pinch Technology, therefore, provides a consistent methodology for energy saving, from the basic heat and material balance to the total site utility system.

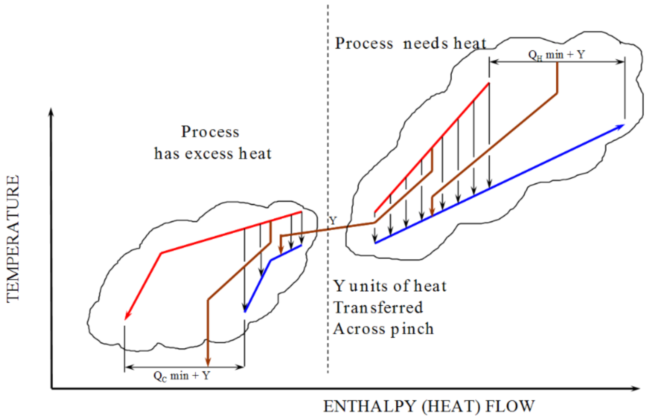


Figure 2.6 – Example of Composite Curves

In summary, Pinch is a technique that calculates best match use of sources and sinks to minimise the use of utilities external to the process. The technique helps users to understand heat recovery opportunities by establishing minimum utility targets (for a selected minimum temperature approach), locating inefficiencies in the network (by checking the existing layout against pinch principles) and developing viable energy saving projects.

Energy Targets

Pinch Analysis provides a target for the minimum energy consumption. The energy targets and location of the process pinch are obtained using a problem table method:

1. Divide the temperature range into intervals and shift the cold temperature scale.
2. Make a heat balance in each interval.
3. Cascade the heat surplus / deficit through the intervals.
4. Add heat so that no deficit is cascaded.

The data required to calculate the minimum energy consumption targets for a heat exchanger network, for each relevant process stream, include:

- Inlet temperature (temperature at which the stream is available before any cooling or heating takes place);
- Target temperature (also known as temperature out); and
- Duty, alternatively flow rate (typically mass basis) and heat capacity can be used.

Refer to PINCH ANALYSIS AND HEAT INTEGRATION (ou.edu) [6] for a detailed example on the application of the problem table method.

Alternatively, graphical methods using "Composite Curves" can be employed. Composite curves consist of temperature-enthalpy (T-H) profiles of heat availability in the process (the "hot composite curve") and heat demands in the process (the "cold composite curve") together in a graphical representation. The construction of the hot and cold composite curve simply involves the addition of the enthalpy changes of the streams in the respective temperature intervals.

The composite curves provide a counter-current picture of heat transfer and can be used to indicate the minimum energy target for the process. This is achieved by overlapping the hot and cold composite curves, separating them by the selected minimum temperature approach DT_{min} (e.g. 20°C). This overlap shows the maximum process heat recovery possible, indicating that the remaining heating and cooling needs are the minimum hot utility requirement and the minimum cold utility requirement of the process for the chosen DT_{min}.

Selection of Minimum Temperature Approach

Minimum Temperature Approach (DT_{min}) determines how close the hot and cold composite curve will be. The selection of the optimum DT_{min} is an economic factor. Its selection depends on the trade-off between capital investment and energy cost, as illustrated in Figure 2.7 – Energy vs Capital Trade-off. The more energy that is recovered within the system, the more area will be needed. Hence, the more capital investment is required.

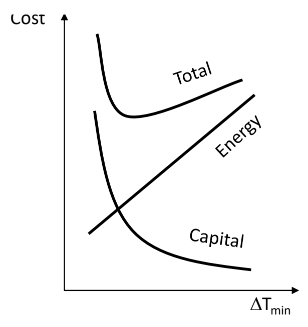


Figure 2.7 – Energy vs Capital Trade-off

Regarding typical recommended DT_{min} values, they vary depending on the type of industry and whether it is a green field or a revamp, as illustrated in Table 2.1.

Table 2.1: Recommended DT_{min} Approach

Industry	New Design	Revamp
Oil Refining	10°C	20°C – 30°C
Petrochemical / Chemical	10°C	10°C – 20°C
Refrigeration	3°C – 5°C	3°C – 5°C

Pinch Principles

There are three pinch principles that need to be followed on all designs and revamps.

1. **No Hot Utility Below the Pinch,** heat required by the cold streams should be provided by the hot streams;
2. **No Cold Utility Above the Pinch,** cooling required by the hot streams should be provided by the cold streams; and
3. **No Heat Flow Across the Pinch,** optimal distribution of heat transfer is achieved when "Hot streams above the pinch are matched with cold streams on this region and vice versa for the section below the pinch".

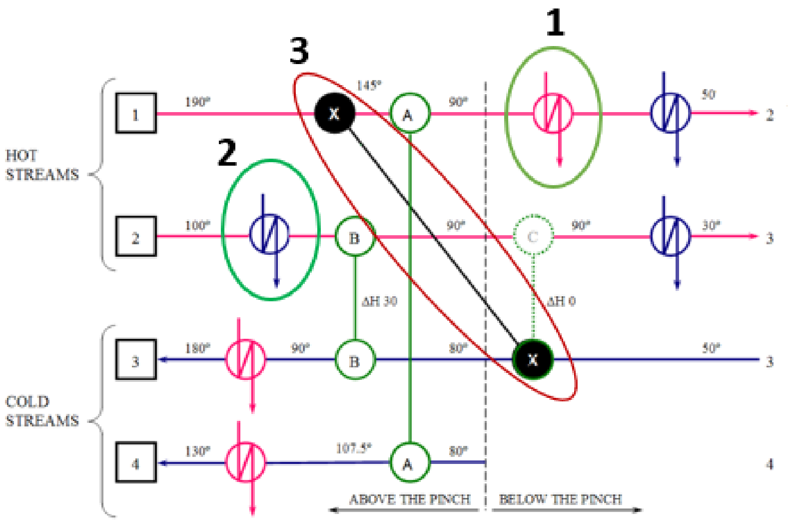


Figure 2.8 – Illustration of Pinch Principles

2.3.2 Best Practices in Maintenance & Operations

Fouling in heat exchanger preheat trains is a well-known problem, especially in the oil refining industry. Fouling will gradually reduce heat transfer coefficients and therefore heat recovery. This means that the furnace inlet temperature will drop over time, thus increasing the furnace duty and the operating cost. A further effect is that fouling deposits effectively reduce tube diameters leading to an increase in the pressure drop. All these issues will increase operating energy cost.

Fouling mitigation is therefore necessary to minimise these costs. It is typical that most refineries do some fouling mitigation, such as filtration, desalting, some cleaning outside of the main shutdowns and some monitoring. However, leading practices within the industry are moving towards a complete approach, firstly focused on prevention, followed by early diagnosis of fouling and then ensuring that cleaning is the most cost-effective it can be [7].

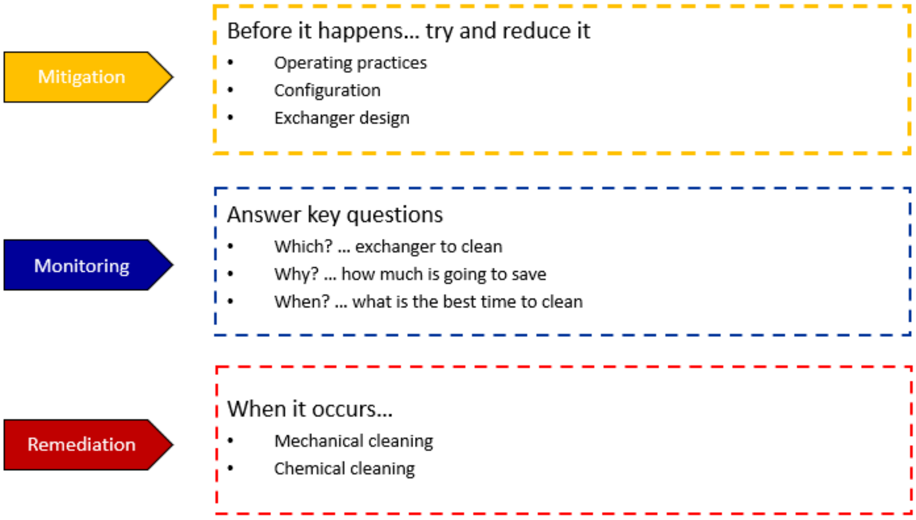


Figure 2.9 – Approach to Handling Fouling

Fouling Prevention

The types of fouling experienced in crude oil include:

1. Particulate fouling due to deposition of organic precursors (e.g. asphaltenes);
2. Corrosion fouling due to the presence of naphthenic acid, salts, sulphur and water; and
3. Chemical reaction fouling due to polymerisation of heavy hydrocarbons at high temperatures.

The fouling prevention mechanism would depend on the type of fouling. Some of the common techniques to prevent fouling are: filtration, desalting, fouling inhibition, crude compatibility and preheat revamp.

Regarding filtration, crude oil from the reservoir is generally contaminated with water, salt, wax, sand and mud, which contain ferric oxides and other particulates. These particulates deposit on the heat exchanger surfaces, promoting build-up of organic and inorganic fouling. It has been reported[8,9] that fouling at the cold end of the preheat train can be reduced by filtering the crude oil. After filtration, water and any residual salt can be removed through desalting. This will reduce corrosion fouling.

Fouling inhibition can be achieved by mixing hydrocarbons[10] and by anti-fouling chemicals. Leading refineries are now accompanying these with further fouling prevention, such as crude compatibility checks. In some cases, revamp of the preheat train is also considered in order to reduce fouling. This is done to: (a) switch fluids placement, (b) avoid vaporisation, (c) avoid corrosion, and (d) ensure optimum tube and shell velocities.

Fouling Monitoring

Irrespective of the fouling prevention methods, it is standard practice for refiners to clean all the exchangers in the preheat train during shutdown. The period between start-up and shutdown is termed the run length for the preheat train and this is normally between four and six years.

The preheat train run length may be set by a regulatory body or determined by the refinery managers based on economics. In the second case, the typical objective is to maximise the run length, and wherever possible extend it, as a shutdown on the refinery has a significant financial implication. This will usually necessitate cleaning of some exchangers during the run, to maintain the throughput and operating performance of the preheat train.

The key questions are then "Which exchangers to clean, why, and when?" To answer this, site personnel will typically use "experience", in-house monitoring tools or rigorous simulation software.

Experience-led cleaning can achieve savings, but such experience is hard to maintain and update with the latest plant conditions, so additional exchangers may be cleaned with little or no impact on the network performance. Also, experience is easily lost as people move on, and businesses cannot afford to have repeated cycles of trial and error learning.

The next step, an in-house monitoring tool, is typically a stand-alone spreadsheet model which simply calculates the “UA” (overall heat transfer coefficient / area) in the exchangers. It may, or may not, be linked to real plant data. These are typically created by the plant engineering experts and are difficult to update or maintain. They are usually limited to showing fouling trends, rather than simulating the benefit of cleaning. Also, they must make many simplifying assumptions about how to model exchangers and calculate fluid properties. One weakness of this is that they cannot distinguish between “UA” reductions caused by fouling and those caused by flow decreases. Consequently, the results can only be properly interpreted by expert users.

In-house models are labour intensive, due to the need for manual data reconciliation, crude property determination and the vital result analysis. The time taken for these tasks, as well as the potential loss of the expert resource or software changes, add further complications to creating an effective and streamlined business.

Leading Practice

Leading practice for fouling monitoring should be a system and a set of procedures that supports enhanced decision-making across many disciplines:

- Operations: it should be used to support operational activities and to display the impact of fouling and cleaning on furnaces and process conditions. The benefits of doing this include optimising the heat exchanger network, gaining operational insight, and troubleshooting.
- Maintenance: fouling monitoring information should be used for all cleaning decisions, to determine exchanger cleaning priority, assess the effectiveness of cleaning methods and cleaning work, and to investigate scenarios for cleaning timing (based on shutdowns, cost, availability of resources and constraints). The expected benefits are: focused cleaning tasks for most process benefit, optimisation of cleaning activities in limited shutdown windows (including unplanned shutdowns), and future cleaning methods, where it is necessary to determine the value of cleaning exchangers when only partially fouled versus delaying cleaning until later in the fouling cycle.

- Process: should use it to create realistic operating limits to trigger decision and workflow around maintenance, investigate fouling tendencies based on feedstock, product mix and operating conditions, and to investigate alternative heat integration options.
- Planning: heat exchanger cleaning and benefits should be integrated into planning and scheduling workflows and collaboration (include fouling cost into crude selection and planning, optimised exchanger cleaning decision-making during throughput downturn or operational constraint relief – when cleaning results in lower fuel usage or avoids costly normal process constraints). This will provide accurate information for future plans, the true cost of processing crudes and will maximise benefits of cleaning at opportune times.
- Modelling approach: this is done via a process simulator to be able to capture stream quality, heat exchanger geometry and automatically reconcile data and calculate fouling factors. The advantage of this method is that it allows the evaluation of the benefits that can be achieved by cleaning either one or a set of heat exchangers. Moreover, this approach can help define which heat exchangers can be cleaned during unexpected (short) stops of the plant and if considerations should be given to installing bypasses to allow on-line cleaning.

2.3.3 Best Available Technologies

Best technologies for preheat trains, or heat exchanger networks, apply to the type of exchanger used for different services. Traditionally shell and tube type would be used, but there are other heat exchanger types (and internals) that can provide advantages (less overall cost, fouling, etc) for certain applications. This section covers such equipment.

Plate Exchanger

The design of a Plate Heat Exchanger (PHE) comprises several heat transfer plates, held by a fixed plate and a loose pressure plate to form a complete unit. Each heat transfer plate has a gasket arrangement, providing two separate channel systems. The arrangement of the gaskets allows through-flow in single channels. This enables the primary and secondary media in a counter-current flow. The mediums are not mixed because of the gasket design. The corrugated plates create turbulence in the fluids as they flow through the unit. This turbulence gives an effective heat transfer coefficient[11].

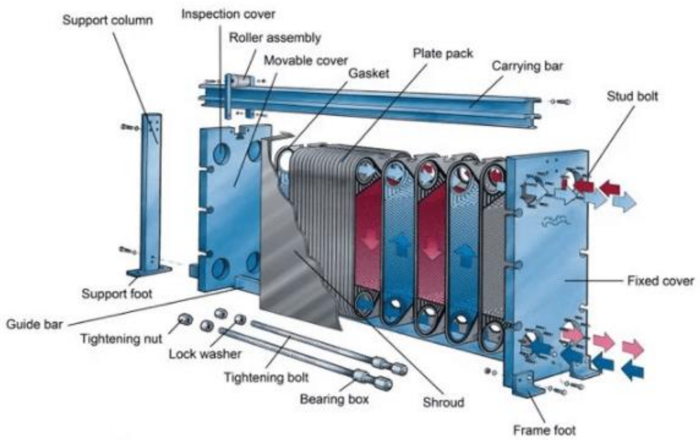


Figure 2.10 – Plate Heat Exchanger

[courtesy of AlfaLaval]

The advantages of plate exchangers include:

- Tighter temperature approaches can be achieved economically;
- True counter-current flow;
- 80-90% less hold-up volume;
- Lower cost for applications where more than one shell is required for a shell and tube exchanger;
- Less fouling (if operated within the design flows), stress, wear, and corrosion. which is likely to reduce cleaning requirements; and
- Easy to expand capacity due to adjustable plates on existing frames.

The disadvantages of plate exchangers include:

- Poor sealing would cause leakage occurrence;
- Limited pressure use, generally not more than 1.5 MPa (based on AlfaLaval designs);
- Limited operating temperature due to temperature resistance of the gasket material;
- Small flow path, and not suited for gas-to-gas heat exchange or steam condensation;
- High blockage occurrence especially with suspended solids in fluids; and
- The flow resistance is larger than the shell and tube.

There are two main vendors of plate exchangers, AlfaLaval and Kelvion.

AlfaLaval's plate exchanger offer includes compabloc, packinox and spiral exchangers (among others).

Compabloc considerations:

- Temperature around 350°C, pressure up to 42 bar;
- Typical locations: condensers, reboilers, product rundown; and
- Unless extremely viscous / dirty service, where Alfa Laval recommends Spiral.

Packinox considerations:

- Temperature up to 650°C;
- Pressure up to 120 bar; and
- Typical locations: hydrotreating, Continuous Catalytic Reforming (CCR), paraxylene and toluene production.

Kelvion offers multiple type of plate exchangers as illustrated in Table 2.2.

Table 2.2: Kelvion – Plate Heat Exchangers

	Liquid-liquid	High fouling	High viscous liquid	Particles or fibres	Gas-liquid	Gas-gas	Evap./ cond.	Multi-phase flow
Gasketed PHE	excellent	okay	less	less	less	less	good	good
GEABloc								
Chevron	excellent	okay	good	less	good	good	excellent	good
Dimple	excellent	good	excellent	good	good	good	excellent	excellent
GEAFlex	excellent	good	good	good	excellent	excellent	excellent	excellent
GEABox	excellent	excellent	excellent	excellent	okay	less	good	good
GEAShell	excellent	no	no	no	okay	less	excellent	good
REKULUVO/ REKUGAVO	no	no	no	okay	no	excellent	no	no

Twisted Tubes

Twisted tubes include bundle construction that increases heat transfer and reduces pressure drops (in the shell side) while increasing heat transfer surface area and eliminating damaging vibration. In terms of heat transfer coefficient, a UA increase between 30% to 40% is expected (50% due to an improved U value and 50% due to the replacement of a square pitch bundle with a triangular pitch bundle which allows more tubes), compared to traditional tubes arrangement.

There is expectation of lower installed cost for green fields, as heat exchangers with twisted tubes can achieve the required duty being smaller or with fewer shells than traditional shell and tubes arrangements.

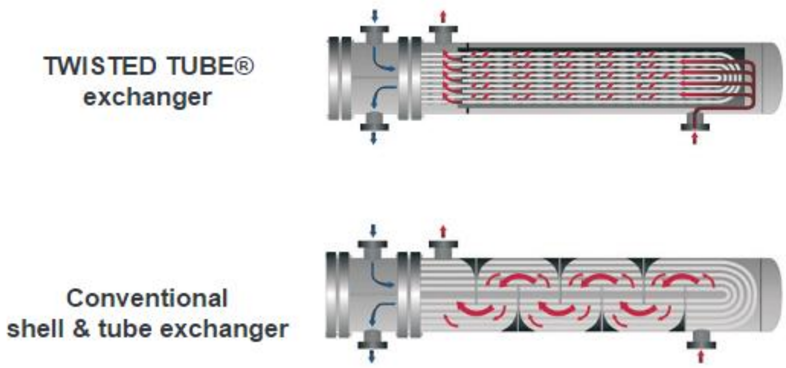


Figure 2.11 – Plate Heat Exchanger

[courtesy of Koch Heat Transfer]

There is also an additional potential benefit in terms of extended run time between cleanings, as the twisted tube arrangement tends to reduce fouling. There are sites that report issues when cleaning. Hence, it is recommended to get the manufacturers (Koch Heat Transfer) involved during the first cleaning of these exchangers. Considerations for each side are listed below.

- Shell side:

- Cleaning lanes allow complete mechanical cleaning by hydroblasting; and
- Chemical Cleaning-In-Place (CIP) is more common than conventional Shell and Tube (S&T) due to uniform flow distribution;

- Tube side:
  - Tube side effectively cleaned by hydroblasting;
  - CIP is more effective than conventional S&T due to swirl flow; and
  - No special tools required.

Applications of this technology include:

- Crude preheat;
- Feed / effluent for: Reformer (CCR and semi-regeneration), hydrotreater, hydrocracker;
- Alkylation;
- Overhead condensers;
- Reboilers (kettle and J-shell);
- Lean / rich amine; and
- Compressor interstage coolers.

Helical Baffles

Helical baffles improve the heat exchanger's shell side heat transfer coefficient and fouling by increasing the turbulence. This type of application shows lower vibration risk and decrease on the pressure drop of the shell side.

On top of this, helical baffles improve two-phase flow distribution and eliminate dead zones that exist in conventional segmental baffles (increased cross flow (B)-stream flow fraction at the expense of tube-to-baffle leakage stream (A) and baffle-to-shell leakage stream (E)- flow fractions).

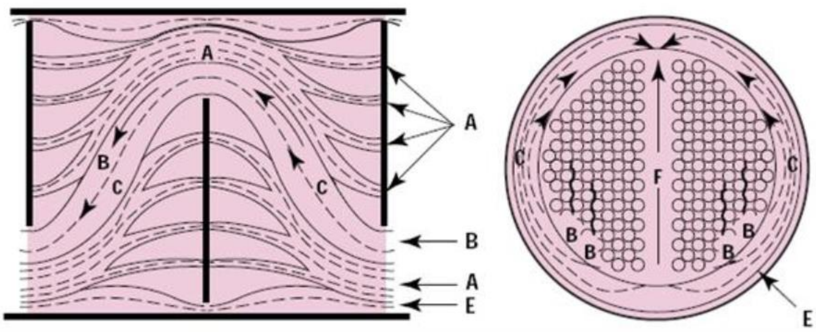


Figure 2.12 – Flow Fractions

Applications of this technology include:

- Solution for shell-side if heat exchanger exhibits:
  - Heavy fouling;
  - High pressure drop;

    - Vibration; and

- Shell-side media may range from hydrogen-rich gas to viscous fluid with high fouling tendencies.

Expanded Metal Baffles

This application allows reduction of fouling rates by eliminating stagnant or 'dead zones' found in traditional segmental baffle heat exchangers. On top of this, it eliminates damaging flow-induced tube vibration, because of the longitudinal flow on the shell side.

According to the manufactures, the open flow structure of the baffle allows the shell side fluid to flow along the tubes, but in the vicinity of the baffles the flow area is constricted, creating local turbulence and velocity increase in the flow while breaking up the boundary layer over the tubes. The grid shape induces a local cross flow component on top of the longitudinal bulk flow pattern which, together with the localised turbulent flow, improves the heat transfer characteristics at the surface of the tubes.

The break-up of the boundary layer occurs repeatedly at each expanded metal baffle along the length of the heat exchanger, resulting in lower hydraulic resistance while maintaining heat transfer. Pressure loss is effectively converted into improved heat transfer and, compared with the segmental baffle, heat transfer at the same fluid velocity is significantly higher.

(a) Expanded Metal Baffles (b) Flow Pattern in EMBaffle

Figure 2.12 – Example of Expanded Metal Baffles

Applications include:

- Feed / effluent exchangers;
- Crude preheat exchangers;
- Gas / gas exchangers;
- Solar power exchangers (heat transfer fluid / molten salt heat exchangers);
- Overhead condensers;
- Chilled water / seawater coolers; and
- Diluted bitumen.

High Flux Tubes

High flux tubes can lead to a boiling side heat transfer coefficient of 10-30 times that of bare tubes. This represents an overall heat transfer improvement of 2-4 times that of bare tubes. Hence, for new designs, the use of high flux tubes in reboiling applications leads to a reduction of the required surface area (cost). This technology is particularly attractive for grassroots designs of the following applications:

- Heavy aromatics separation;
- Natural gas de-ethanising;
- Heat-pumped propylene / isobutene fractionators; and
- Ammonia plant syngas chilling applications.

It should be mentioned that high flux tubes are not prone to fouling due to the extremely active boiling surface.

Low Finned Tubes

This application is specifically for cooling services and it is estimated to reduce up to 20% of the tube length due to greater heat transfer coefficients. This results in a reduction on the required capital investment.

2.4 Metrics

Monitoring for furnaces is done to determine, among other factors, thermal efficiency and fuel consumption (or gap to target). Table 2.3 shows a list of metrics for monitoring of a furnace system, noting whether the metric may be manipulated (influencing variable) or is a resultant metric (performance indicator).

Table 2.3: Recommended Energy Metrics for Furnaces

Energy System	Hierarchy	Metric	Method
Furnace equipment only	Energy performance indicator	Thermal efficiency (%)	Calculated
	Energy performance indicator	Energy performance gap (Gcal/h)	Calculated
	Energy influencing variable	Stack temperature (°C)	Measured
	Energy influencing variable	Stack oxygen (%)	Measured
Furnace preheat train	Energy performance indicator	Charge pump specific energy consumption (kW/unit throughput)	Calculated
	Energy influencing variable	Coil inlet temperature (°C)	Measured

Energy Performance Indicators (EPI): these are calculated values that allow the management and engineering team to track the overall performance of a piece of equipment, process or even the whole site.

Energy Influencing Variables (EIV): these items represent elements within the system that can be manipulated to improve the efficiency of the equipment or process.

Companies following best energy practices would set targets for draught and excess air and would display in real time furnace efficiency. On top of this, furnace efficiency would be reported to management monthly, including the reason for deviation from target and the equivalent monetary losses associated with any deviation.

Moreover, if the furnace is equipped with an air preheater, it is recommended to monitor the APH performance. To do this will require temperature indications immediately adjacent to the air preheater (both sides – inlet and outlet temperatures) and one in the combined stream after the junction with the air preheater bypass. If the furnace is close to its design limits, the measurement of the furnace limit should be recorded and trended. These could be done via items such as: 1. percent opening of pass control valves; 2. percent fuel control valve opening; 3. bridge-wall draught; and 4. tube metal temperatures.

Refer to the Assessment Framework [4] document for more details.

2.5 Identification of Energy Efficiency Opportunities

As mentioned at the start of Section 2.2, there are two factors affecting the performance of a furnace system, namely, the furnace itself and the performance of the associated preheat train. For the furnace itself, its thermal efficiency can be maximised by reducing heat losses to the atmosphere. Improvements to furnace efficiencies generally fall into 2 areas: 1) reducing excess air (typically non-investment opportunity), and 2) reducing stack temperatures (which requires capital investment). The major heat loss is through the stack flue gas stream. Parameters such as the stack excess oxygen content and stack temperature will heavily influence the amount of heat lost to the atmosphere.

The economics of investment to reduce stack temperatures is dependent on the economies of scale, the base efficiency of the furnace and the price of marginal fuel.

A second factor, which indirectly affects the performance of the furnace system by reducing the furnace load, is related to the performance of the preheat train associated with the furnace. In this case, an assessment of the preheat train is necessary. The recommended approach for this activity is to perform a Pinch analysis to identify the potential target as well as opportunities to maximise waste heat recovery within the system, which will lead to an increase on the process stream's inlet temperature to the furnace.

Minimising the furnace load may lead to lower thermal efficiency especially when the furnace is near minimum turndown operations. However, the overall energy performance of unit will improve if the furnace load reduction is achieved through improved heat integration.

2.6 Common Opportunities Observed in Plants

Opportunities for furnace systems are commonly identified in three main areas:

- Tuning excess air (reducing stack oxygen);
- Improving heat recovery from the furnace's flue gases (reducing stack temperature); and
- Reducing furnace load by improving heat recovery on the associated preheat train (pinch improvement).

This section covers case studies for each of these areas.

2.6.1 Case 1: Reducing Stack Temperature - Cleaning

Background

Energy improvement assessment performed for an aromatic complex in Southeast Asia.

Opportunity

The site's xylene furnace exhibited a high stack temperature (above 330°C) which lead to an overall low efficiency, at 84%. However, the furnace was designed with an air preheater and targeting a stack temperature of 195°C. The site confirmed that the convection section of this furnace (over 20 years in operation) had never being cleaned.

Results

By cleaning the convection section, the site managed to reduce this energy efficiency gap (improving the furnace efficiency to 91%). Fuel savings achieved were in the order of 5.8 Gcal/h (equivalent to USD 1.1 million per year).

The lesson learnt here is that savings can be achieved by cleaning the convection section of furnaces, especially if the equipment was used to fire fuel oil, or equivalent, in the past.

2.6.2 Case 2: Reducing Stack Oxygen

Background

Energy improvement assessment performed for a large refinery complex in Northeast Asia.

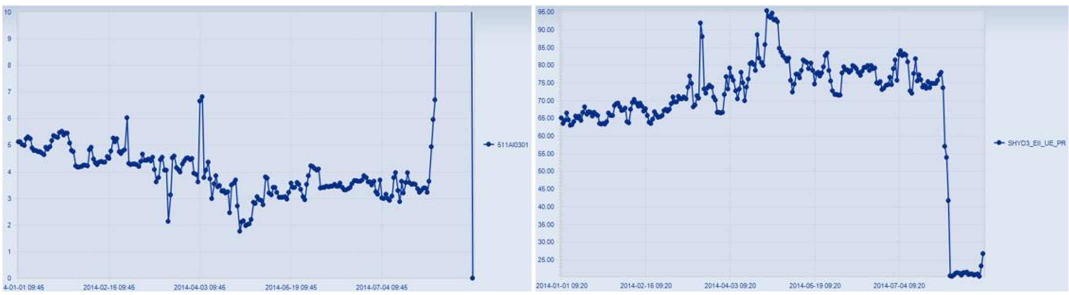
Opportunity

The site reformer furnace exhibited high levels of excess air. Distributed Control System (DCS) data showed an average above 5%. Following discussions with the site, tests were carried out (refer to Figure 2.13) to set realistic targets. The target was set to achieve 3% stack oxygen when the furnace utilisation level (duty) was above 75% of design.

Results

By implementing this measure, the site achieved fuel savings of 0.8 Gcal/h (equivalent to USD 500k per year).

The lesson learnt here is that reducing excess air might be easily achieved; however, historical data should be analysed to set correct and realistic targets (stack oxygen vs furnace utilisation).



(a) Stack O_2 (b) Utilization

Figure 2.13 – Stack Oxygen vs Furnace Utilisation

2.6.3 Case 3: Reducing Stack Temperature – Air Preheater

Background

This refinery located in Southeast Asia has a furnace with a stack temperature of just over 240°C. The combustion air is preheated using LP steam to a temperature of around 120°C.

Opportunity

There is an opportunity to preheat the combustion air by using heat from the furnace exhaust gases. This will save LP steam and ultimately NG (as the operation of the steam system is readjusted to avoid any steam venting). By using new technology, HeatMatrix polymer heat exchangers, the final stack temperature is reduced to around 100°C.

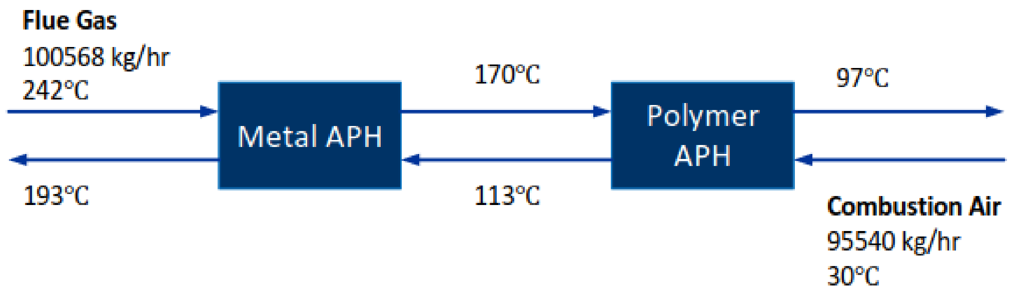


Figure 2.14 – Example of Reducing Furnace Stack Temperature by a New APH

Results

The estimated savings are around SGD 1.2 million per year. The project payback is estimated to be just over 6 years.

2.6.4 Case 4: Pinch Improvement – Example 1

Background

Energy improvement assessment performed for an oil refinery in Europe.

Opportunity

The pinch analysis showed the site's reactor effluent was sent to the air cooler around 130°C (reaching the cooler at 105°C after being mixed with wash water). However, this waste heat could be recovered against the feed. Increasing the effective heat transfer area of the feed / effluent heat exchanger would recover part of this waste heat, resulting in a reduction of the furnace duty.

Results

Twisted tubes were installed to achieve the savings. This was done to minimise disruption of the system in terms of increase of pressure drop, by adding an additional shell to the feed / effluent, as well as site issues regarding availability of space for a new shell.

The project was estimated to achieve an overall 0.4 Gcal/h of fuel savings, equivalent to USD 250k per year. The payback of the project was less than 3 years.

The figure below illustrates the project for the Start-Of-Run (SOR) and End-Of-Run (EOR) scenarios.

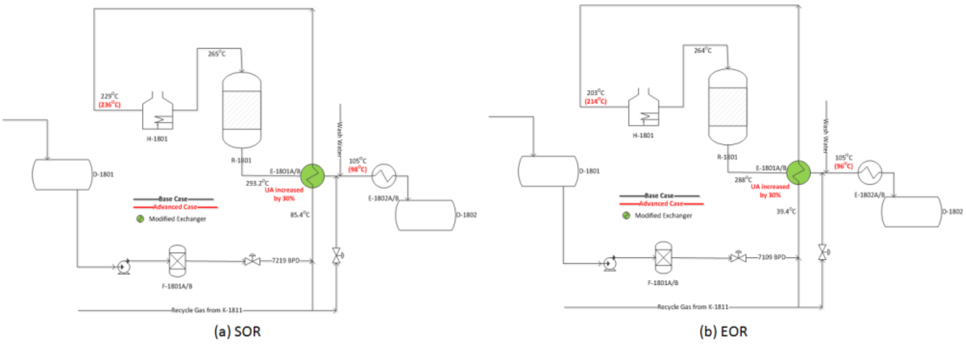


Figure 2.15 – Example of a Pinch Improvement Leading to Reduction of Furnace Duty

2.6.5 Case 5: Pinch Improvement – Example 2

Background

This refinery is located in Singapore with a complex preheat train to preheat a hydrocarbon stream before being sent to a furnace, where it reaches the required final temperature.

There are various product streams that are sent to coolers at temperatures above what it is considered best practice (100°C).

Opportunity

Using pinch techniques to modify the preheat train allowed the site to recover this waste heat with minimum modifications. In this case, twisted tubes on multiple heat exchangers as well as a new S&T exchanger were needed.

Results

The modifications are estimated to improve the coil inlet temperature by over 10°C. The estimated savings are around SGD 1.1 million per year. The project payback was estimated to be just below 5 years.

2.7 Summary

A furnace is a piece of equipment used to either increase the temperature of a process stream to a target temperature (e.g. before sending it to a fractionator such as in the Atmospheric Crude Distillation or to provide the required reboiling duty as in the BTX unit), a reaction system (e.g. Hydrotreating Process); or provide enough heat for an endothermic reaction to take place (e.g. Ethane Cracker Unit). Although the furnace can be operating on its own in applications such as a reboiler of a distillation column, a furnace system typically comprises the furnace itself plus its associated preheat train.

There are multiple elements to consider for the best energy practice design and operation; however, special attention must be paid to: 1. the heat recovery from the furnace exhaust gases (stack temperature); 2. the amount of excess air targeted (stack oxygen); and 3. using pinch principles to design and revamp the heat exchanger networks linked to the furnace, which is done to minimise the utility requirement of the system. These are also the key elements to review when looking at potential opportunities to improve the energy efficiency of furnace systems.

3 Hot Oil Heater Systems

3.1 Definition

A hot oil system usually comprises:

- Heater(s) to raise the temperature of the oil to the temperature required by the end users;
- Pump(s) to transfer the oil to the end users; and
- Heat exchangers to transfer the energy to the end users.

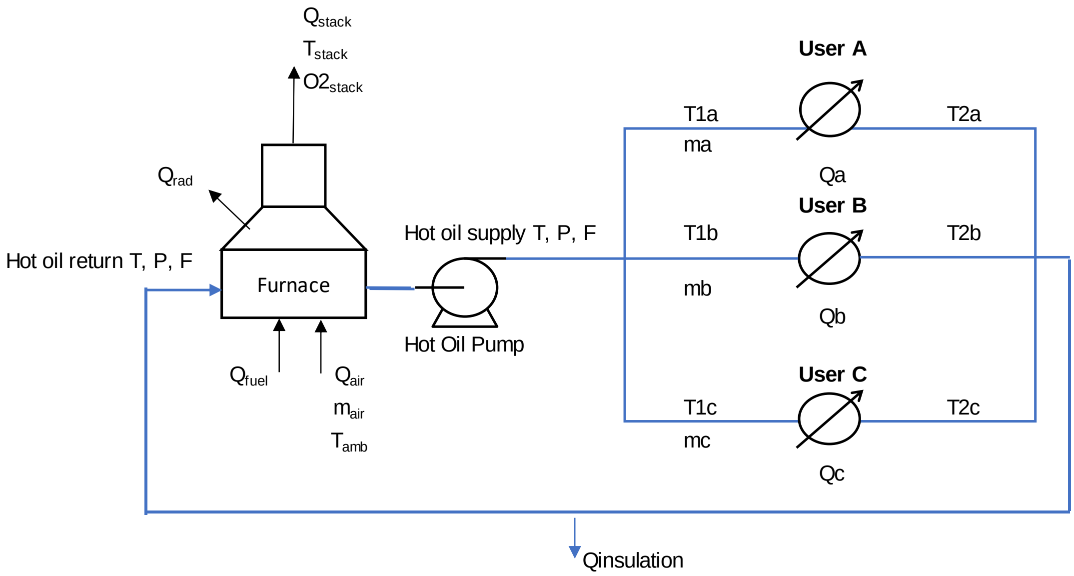


Figure 3.1 – Main Considerations for Assessing the Performance of Hot Oil Systems

Figure 3.1 shows a simple schematic of a typical hot oil system. In this example, the oil is heated to a target supply temperature in the heater before being pumped to three end users, and then returned to the heater at a return temperature.

The energy input to a hot oil system consists of:

- Fuel provided to the hot oil heater;
- Heat from the ambient (combustion) air, which is usually considered negligible and accounted for when calculating the stack losses; and
- Electrical energy used to drive the pump(s).

Of these, the fuel consumption is usually significantly higher than the energy used by the pumps. Thus, fuel consumption is the main parameter to track when looking at energy efficiency of a hot oil system.

The fuel consumption of the heater can be reduced by increasing the temperature of the combustion air, either by using the stack gases of the heater itself or by heating with an external heat source, for example steam or process waste heat. If the air is preheated using an external heat source, this should be considered as additional heat input to the heater.

The energy output in the system shown in Figure 3.1 consists of:

- Heat transferred to the end users. All this energy is considered to be usefully used by the end users.
- Heater losses consisting of heat lost to the stack gases (these are a function of the stack gas temperature and excess oxygen), conductive and radiation losses which are a function of the heater design. Radiation losses are usually fixed and do not vary with the amount of fuel used by the heater. On a well-maintained heater, losses by heat conduction through the refractory or ceramic fibre insulated walls are quite small.
- Insulation losses which are a function of the pipe length, pipe diameter and insulation.

Some potential advantages of hot oil systems, according to the U.S. National Board of Boiler and Pressure Vessel Inspectors, over steam include:

- No corrosion or freezing concerns;
- Simple circuit; no blow downs, steam traps, or condensate return systems;
- Minimal maintenance:
  - No hand-hole gasket replacement;
  - No re-tubing;
- No water treatment requirements;
- High operating temperatures obtained with minimal system pressures (system pressure drop only); and
- If a process requires heating and cooling, it may be done with a single fluid.

3.2 Best Practices & Design Considerations

As the fired heater of the hot oil heater system is typically a furnace, the design and operation considerations for hot oil heaters will not vary from what has been covered in the Furnace Systems section, which includes the associated preheat train best practices (refer to Section 2.2 and Section 2.3). On top of these considerations, other factors to consider include:

Selection of the Hot Oil Fluid

Factors to consider when selecting the thermal fluid include:

- Maximum recommended bulk temperature, the system operation should never exceed the maximum bulk temperature of the fluid;
- Minimum operating temperature;
- Minimum start-up temperature, which will be influenced by outdoor or indoor applications; and
- Vapour pressure and boiling point, as special construction requirements will be needed if the operating temperature exceeds the boiling point.

Some common thermal fluids include:

- Dow: Dowtherm A, G, RP;
- Monsanto: Therminol 55, 59, 66;

- Paratherm: NF, HE; and
- PetroCanada: Calfo AF, Purity FG.

Selection of the Hot Oil Circuit Heat Source

Most hot oil applications burn NG (or other type of fuels) to provide the heat and reach the temperature required by the system. However, for some facilities there is the opportunity to use heat from exhaust gases of other equipment, such as incinerators and Gas Turbines (GTs), to fulfil this duty. It is recommended for designers to consider heat sources available on site when designing hot oil systems.

Hot Oil Filters

Organic hot oil fluids degrade over time due to thermal cracking, oxidation and contamination. The by-products of degradation are sludge and coke. Contaminants can also include dirt, sand, dust, mill scale, and slag from piping that accumulate during down-time maintenance or from installation.

Installing a filter (at the pump suction) in the loop has the following benefits:

- Removal of particulates that can degrade the oil;
- Maintains viscosity of fluid longer by reducing sludge build-up;
- Maintains thermal efficiency of the system longer and reduces energy cost;
- Extends fluid life; and
- Reduced maintenance costs by protecting pumps and valves from contaminates.

Hot Oil Trim Cooler

Trim coolers (typically air coolers) are used to increase the flexibility of the hot oil system. These coolers are used to reject heat during heater start-up or when duty requirements decrease below the hot oil furnace minimum fired duty due to decrease in plant throughput or upsets in operation.

The cooler should be capable of rejecting the minimum heater duty at stable operation (heater turn-down is ~ 25%, usually specified by the manufacturer) or highest process consumer duty in the system, whichever is more.

Pumps

Hot oil circulating pumps are centrifugal pumps designed for use with the thermal fluid at temperature (note that standard hot water and boiler feed pumps are not appropriate). The typical arrangement is of '1 working + 1 stand-by'. Flow rate of the pump is designed based on heat duty of all the consumers plus a 10% flow margin. The pump capacity should be adjusted, if continuous filtration is applied via a bypass across the pump.

If significant flow fluctuation is expected, the best practice is to install a Variable Speed Drive (VSD) to save energy as the pump operation will adjust to the flow requirement.

3.3 Metrics

Table 3.1 shows a list of metrics for monitoring of a hot oil system.

Table 3.1 – Recommended Energy Metrics for Hot Oil Heaters

Energy System	Hierarchy	Metric	Method
Heater equipment only	Energy performance indicator	Thermal efficiency (%)	Calculated
	Energy performance indicator	Energy performance gap (Gcal/h)	Calculated
	Energy influencing variable	Stack temperature (°C)	Measured
	Energy influencing variable	Stack oxygen (%)	Measured
	Energy influencing variable	Hot oil supply temperature (°C)	Measured
	Energy influencing variable	Hot oil return temperature (°C)	Measured
Hot oil system	Energy performance indicator	Overall mass / energy balance of hot oil system	Calculated
	Energy performance indicator	Hot oil pump specific energy consumption (kW/unit throughput)	Calculated

Energy performance indicators: these are calculated values that allow the management and engineering team to track the overall performance of an equipment, process or even the whole site.

Energy influencing variables: these items represent elements within the system that can be manipulated to improve the efficiency of the equipment or process.

Refer to the Assessment Framework [4] document for more details.

3.4 Identification of Energy Efficiency Opportunities

Opportunities associated with fired heaters (furnace) and heat exchanger networks have been covered in a previous section (refer to Section 2.5). Other energy saving opportunities specific to hot oil loops include:

- Replacement of the hot oil heat source, this is for systems when NG or other type of fuel is used in the furnace and there is waste heat available at high temperature and required duty;
- Replacement of the hot oil system by lower temperature sources, this is typically the case in applications where low temperatures are required and waste heat (or excess steam) is available within the site; and
- VSD on hot oil pump, when the system is operating below design flow.

3.5 Common Opportunities Observed in Plants

Opportunities for hot oil systems lay in two main areas:

- Hot oil furnace performance:
  - Heat source, in case NG burnt in the hot oil furnace can be replaced by other heat sources;
  - Tuning excess air (reducing stack oxygen);
  - Improving heat recovery from the furnace's flue gases (reducing stack temperature); and
- Performance of the heat exchanger network associated to the hot oil system:
  - Reducing the hot oil system load by improving heat recovery on the associated preheat train (pinch improvement).

This section covers case studies for each of these areas.

3.5.1 Case 1: Replacing Hot Oil System Heat Source – Integration with GT Exhaust

Background

This gas processing site uses NG to provide the heat needed by the hot oil system. At the same time the site GT is operating as simple cycle without heat recovery from the GT's exhaust gases.

Opportunity

The opportunity was to recover the heat from the GT's exhaust gases against hot oil. This saved NG currently burnt in the hot oil furnace. The hot oil heat requirement was stipulated to be 5.5 MW – based on average data, which was equivalent to a fired duty of 6.1 MW (heater efficiency of 90.0%). A plate exchanger type was selected to replace the hot oil furnace, providing the interface between the exhaust gases and the hot oil fluid.

Results

The implementation of this project saved 6.1 MW of NG (equivalent to USD 1.1 million per year). The payback for this project was just over 5 years.

3.5.2 Case 2: Optimisation of Users to Decrease Hot Oil System Requirements

Background

The gas plant located in Asia uses a hot oil loop to provide heat to multiple distillation columns. In this case an Liquified Petroleum Gas (LPG) column designed and operated at 15.5 barg.

Opportunity

The column overhead drum temperature (70°C) and available cooling sources (air at 30°C) showed there was scope to reduce the column operating pressure. Hence, this reduces the reboiling requirement. A test-run showed that there was potential to reduce the operating pressure by 1.0 barg while maintaining all product specifications.

Results

The implementation of this operational project saved 2.4 MW of NG (equivalent to USD 500k per year) burnt in the hot oil furnace.

3.5.3 Case 3: Replacing Hot Oil System by a Lower Temperature Utility

Background

The gas processing plant in Southeast Asia provides heat to multiple users via a hot oil system. The hot oil is at over 200°C; however, the users require temperatures around 100°C. Although steam was not available at this site, there was an excess of LPS being vented from a neighbouring site (owned by the same company).

Opportunity

The opportunity was to import LPS to provide heat to the users, which would allow the site to shut down the hot oil loop.

Results

The implementation of this project saved 6.1 MW of NG (equivalent to USD 700k per year). The payback for this project was estimated at just below 5 years.

3.6 Summary

A hot oil system is no more than an arrangement where thermal oil is used as the working fluid to transfer heat from a heat source (typically a furnace) to multiple users across an industrial site.

There are multiple elements to consider for the best energy practice design and operation; however, as the typical elements of the system are the hot oil furnace and associated preheat train, special attention must be paid to: 1. the heat recovery from the furnace exhaust gases (stack temperature); 2. the amount of excess air targeted (stack oxygen); and 3. using pinch principles to design and revamp the heat exchanger networks linked to the furnace, which is done to minimise the utility requirement of the system.

On top of these key elements that should be analysed when evaluating the efficiency of hot oil systems, other opportunities exists, such as:

- Replacement of hot oil heat source, this is for systems when NG or other type of fuel is used in the furnace and there is waste heat available at high temperature and required duty;
- Replacement of the hot oil system by lower temperature sources, this is typically the case in applications where low temperatures are required and waste heat (or excess steam) is available within the site; and
- VSD on the hot oil pump, when the system is operating below design flow.

4 Boilers Systems

4.1 Definition

Boilers are utilised for steam generation for steam distribution systems for either heat, live / process steam or power generation. Steam is produced in the boiler system at the highest steam level within a site and let down either to the requirement pressure level (dependant on plant-specific steam header layout via letdown stations or via backpressure turbines (for power generation or turbine-driven equipment e.g. pump or compressor).

There are two basic types of boilers: fired tube and water tube. The fundamental difference between these boiler types is which side of the boiler tubes contains the combustion gases or the boiler water / steam.

Fired Tube Boilers

In fired tube boilers, the combustion gases pass inside boiler tubes, and heat is transferred to water between the tubes and the outer shell. An example of a firetube boiler is shown in the Figure 4.1.

Fired tube boilers are often characterised by their number of passes, referring to the number of times the combustion (or flue) gases flow the length of the pressure vessel as they transfer heat to the water. Each pass sends the flue gases through the tubes in the opposite direction. To make another pass, the gases turn 180 degrees and pass back through the shell. The turnaround zones can be either dryback or waterback. In dryback designs, the turnaround area is refractory-lined. In waterback designs, this turnaround zone is water-cooled, eliminating the need for the refractory lining[12].

Figure 4.1 – Firetube Boiler

[courtesy of AESYS Technologies]

Water Tube Boilers

In water tube boilers, boiler water passes through the tubes while the exhaust gases remain in the shell side, passing over the tube surfaces. Tubes can typically withstand higher internal pressure than the large chamber shell in a firetube; water tube boilers are used where high steam pressures (up to 200 bar) are required. Water tube boilers are also capable of high efficiencies and can generate saturated or superheated steam. The ability of water tube boilers to generate superheated steam makes these boilers particularly attractive in applications that require dry, high-pressure, high-energy steam, including steam turbine power generation.

The performance characteristics of water tube boilers make them highly favourable in process industries, including chemical manufacturing, pulp and paper manufacturing, and refining[11].

Table 4.1 shows a comparison of the main parameters between fired tube and water tube boilers.

Table 4.1 – Comparison of fired tube and water tube boiler [13]

Parameter	Fired Tube	Water Tube
Rate of steam generation	Less rapid	More rapid
Pressure	< 25 kg/cm^2	> 125 kg/cm^2
Risk of explosion	Less	More
Floor space	More	Less
Cost	Higher	Less
Operating skill	Less	Higher
Water treatment	Low	Higher

Waste Heat Boiler (WHB)

WHB may be either fired tube or water tube design and use heat that would otherwise be discarded to generate steam.

Typical sources of heat for WHBs include exhaust gases or high-temperature products as well as combustion of a waste fuel in the boiler furnace.

Heat Recovery Steam Generators

Heat Recovery Steam Generators (HRSGs) transfer energy from the exhaust of a GT to an unfired or supplementary fired heat-recovery steam generator to produce steam. Exhaust gases leave the GT at temperatures of 540°C or higher and can represent more than 75% of the total fuel energy input. This energy can be recovered by passing the gases through a heat exchanger (steam generator) to produce hot water or steam for process needs. If the amount of steam needed by the process exceeds the amount produced by simple heat recovery, then supplementary fuel can be burned in an inline duct burner between the GT and the HRSG.

4.1.1 Energy Requirements

Boilers are typically major energy consuming systems in an industrial site. The main components of the system include the following and are shown in Figure 4.2 below:

- Boilers, used to fulfil the steam balance;
- Pump(s) to transfer the BFW from the deaerator to the steam generators; and
- Deaerator(s) use heat, typically in the form of LPS, to decrease oxygen content in the BFW.

The combustion fuel is the dominant energy input in a boiler system (energy required by the BFW pump is usually negligible compared to fuel demand). Fuel provides the heat duty required by the boiler to meet the steam demand, plus the inefficiencies associated with the boiler design and / or operation (i.e. excess air, radiation losses and heat losses through flue gas exit temperature).

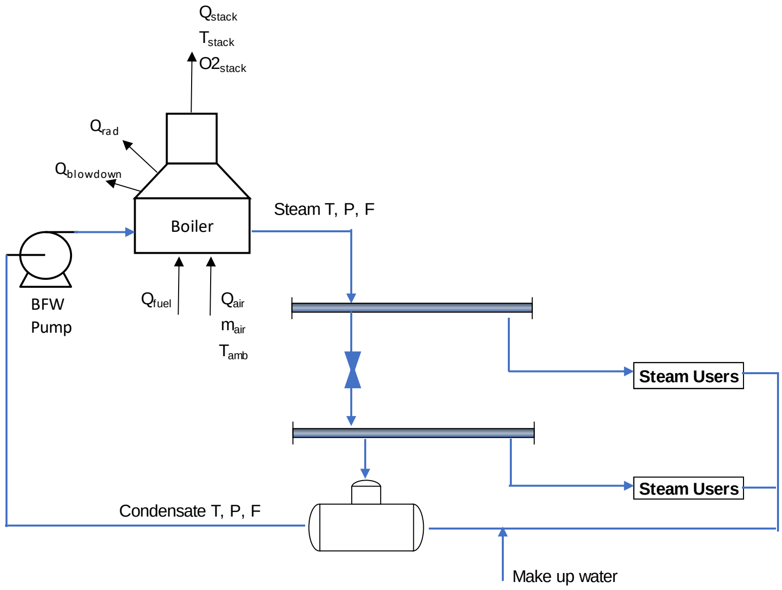


Figure 4.2 – Simple Process Flow Diagram of a Boiler System

The energy output in the system shown in the figure above consists of:

- Boiler losses consisting of heat lost to the stack gases (these are a function of the stack gas temperature and excess oxygen) and radiation losses which are a function of the boiler design. Radiation losses are usually fixed and do not vary with the amount of fuel used by the boiler.
- Steam demand, which depends on the utility system and process requirements, as well as deaerator operation.
- Steam header and piping losses which are a function of the pipe length, pipe diameter and insulation.

Features that need to be considered to improve the efficiency of this type of system are covered in the following section.

4.2 Best Practices & Design Considerations

4.2.1 Best Practices in Design

The following design considerations for boilers are considered:

1. Boiler design should include an economiser. This provides an effective method of increasing boiler efficiency by transferring the heat of the flue gases to incoming feedwater.
    a. Tubes should be of extended surface type on a NG fired boiler and may use up to 9 fins/in and for heavy oil fired 2 fins/in.
    b. It is recommended to be equipped with three valve bypasses on the water side to allow bypassing water at low boiler loads and minimise economiser corrosion.
    c. Noncondensing economisers must be operated at temperatures that are reasonably above the dew points of the flue gas components. Condensing economisers are designed to allow condensation of the exhaust gas components.

2. Combustion air preheaters are recommended to be in place. In these devices, the energy is transferred to the incoming combustion air. The efficiency benefit is roughly 1% for every 40°C increase in the combustion air temperature[14].

3. The walls and combustion regions should be lined with insulating materials to reduce energy loss and to prevent leakage. Insulating lining is exposed to high temperatures and is subject to degradation. It should be periodically inspected and repaired when necessary.

4. Pre-treatment equipment should be considered as it improves the quality of the incoming water. This will help to reduce excessive scaling or foaming, which can reduce boiler efficiency and cause tube failure. Pre-treatment equipment includes, but is not limited to, clarifiers, filters, softeners, dealkalisers, decarbonators, Reverse Osmosis (RO) units, and demineralisers.

5. Deaerators and deaerating heaters use heat, typically steam, to reduce the oxygen content in water. In applications that require lower oxygen levels than achievable with a deaerator, deaerating heater, or open feedwater heater, a chemical agent, known as an oxygen scavenger, can be used to remove more oxygen. In most systems, an oxygen scavenger is part of the system's water treatment programme[11].

6. BFW pumps transfer water from the deaerator to the boiler. These pumps are driven by electric motors or by steam turbines. In a modulating feedwater system, the feedwater pumps run constantly as opposed to an on/off operation in relatively small boilers. Smaller systems should consider installation of VSDs to improve the energy efficiency of the system.

7. VSDs should be considered for boilers controlling the air to the combustion system via forced draft or induce draft fans.

8. The heat from the boiler continuous blowdown water should be recovered, either directly through the installation of a heat exchanger (typically used to heat BFW) or indirectly by flashing it. The most advanced systems would use a combination of the mentioned approaches, by firstly flashing the blowdown and using the heat from the condensate to heat make-up water before being discharged to the sewer.

9. The system should be properly insulated to reduce heat loss to ambient. Some common insulating materials used in steam systems include calcium silicate, mineral fibre, fibreglass, perlite, and cellular glass.

10. Steam condensate should be recovered and returned to the generation system (typically sent back to the deaerator). For high pressure levels, this steam condensate should be flashed and recovered as LPS (medium pressure steam [MPS] or LPS depending on the condensate pressure).

11. Appropriate insulation should be in place for steam pipes and condensate return pipes. Pipes without insulation are a constant source of energy loss. Insulation can reduce energy losses by 90%[12]. The North American Insulation Manufacturers Association has developed a software package, 3E Plus, that determines the optimum thickness for a wide variety of insulating materials. Outputs include the simple payback period, surface heat loss, and surface temperature for each specified insulation thickness.

4.2.2 Best Practices in Maintenance and Operations

Combustion Efficiency

To improve boiler combustion efficiency and minimise heat lost to through stack gases adequate flue gas temperature and excess oxygen (air) should be maintained. It is important to periodically monitor flue gas composition and tune the air flow to the combustion chamber to maintain optimum excess air levels.

Online flue gas analysers may be considered to routinely identify energy loss trends for boiler systems. Similarly, a feedback control lock controlling the excess air or "oxygen trim" control to optimise the air-to-fuel ratio is recommended for boiler systems with variable fuel gas composition or where steam production is highly variable.

Alongside air-to-fuel ratio, the following adjustments may be considered to maintain or improve combustion efficiency of a boiler:

- Burner position;
- Fuel pressure;
- New tips / orifices;
- Boiler pressure;
- Damper, control or refractory repair;
- Swirl at burner inlet;
- Atomizing pressure;
- Bed thickness; and
- Undergrate air distribution.

Thermal Efficiency

Best practice boiler thermal efficiency is 92%. This assumes NG or clean fuel gas is burnt.

Stack Temperature

The stack temperature is the measured temperature of the flue gas that exits into the atmosphere. This temperature measurement should be taken after the economiser or any stack heat recovery exchanger to ensure that existing heat recovery measures have been accounted.

Boilers designed following best practice will achieve a stack temperature of about 150°C assuming NG or clean fuel gas is burnt.

Oxygen Content in Flue Gases

Best practice stack oxygen content for process boilers ranges between 2.0 to 3.0%.

Deaerator Operation

The deaerator and associated systems (e.g. make-up water heat exchangers) should be operated in such a way that there is a minimum of 20°C between the deaerator operating temperature and the temperature of the water (make-up / condensate returned) entering the equipment. This allows for effective removal of oxygen.

Once this requirement is met, the operating pressure of the deaerator is set depending on the overall performance of the system. If there is no steam venting, the target operating pressure for the deaerator is as low as possible, typical lowest value observed in industry is 0.2 barg. For systems where steam venting is taking place, the deaerator's operating pressure is increased (which translates on an increase on the deaeration steam requirement) to try and eliminate the vent. The highest operating pressure is constrained by the pressure level of the deaerating steam (typically low pressure steam is used for this service) as well as deaerator design parameters.

Deaerator Vent Rate

Steam provided to the deaerator provides a physical stripping action and heats the mixture of returned condensate and BFW make-up to saturation temperature. Most of the steam will condense, but a small fraction (usually 5 to 14%) must be vented to accommodate the stripping requirements[15]. Most advanced designs would recover heat from the deaerator vent, typically against make-up water.

Blowdown rate

The quantity of boiler blowdown is adjusted until the amount of impurities removed from the boiler equals the amount entering with the BFW. Factors that are taken into consideration are the amounts of:

- Sludge, which can cause both deposits and carryover;
- Total dissolved solids, which do not cause deposits but, in excessive amounts, can cause foaming and carryover;
- Silica, which is important if the feed water has been pre-softened, and if the boiler produces high pressure steam, can cause carryover and under some conditions, deposits; and
- Iron, which can cause deposits in some High Pressure (HP) boilers.

The optimum blowdown rate is determined by various factors including the boiler type, operating pressure, water treatment, and quality of makeup water. Preferably, blowdown is controlled as ratio / flow control against steam production. Most sites take a sample (of conductivity) once per shift and make an adjustment of the continuous blowdown based on that. Online conductivity analysers are the recommended best practice.

Recommended quality levels of the above factors for BFW are listed in Table 4.2 below. Table 4.2 covers a variety of sources to cover more aspects of water quality.

Table 4.2 – Recommended Boiler Feed Water Quality

	Boiler Water									Feed Water	
Boiler Pressure	Total Solids	Suspended Solids	Alkalinity (as $CaCO_3$)	SiO_2	Specific Conductivity	Total Hardness (as $CaCO_3$)	Turbidity	Oil	Phosphate Residual	Iron	Copper
psig	ppm	ppm	ppm	ppm	µmho/cc	ppm	ppm	ppm	ppm	ppm	ppm
0-300	3500	300	700	150	7000	0.300	175	7	140	0.100	0.050
301-450	3000	250	600	90	6000	0.300	150	7	120	0.050	0.025
451-600	2500	150	500	40	5000	0.200	125	7	100	0.030	0.020
601-750	2000	100	400	30	4000	0.200	100	7	80	0.025	0.020
751-900	1500	60	300	20	3000	0.100	75	7	60	0.020	0.015
901-1000	1250	40	200	8	2000	0.050	63	7	50	0.020	0.015
1001-1500	1000	20	0	2	150	0.000	50	7	40	0.010	0.010
1501-2000	750	10	0	1	100	0.000				0.010	0.010
>2000	500	5									
Data Source	1	1	2	2	2	2	3	3	3	2	2

1 Chemical Engineering, August 28, 1978; *Raw Water Treatment in the CPI*; by A. Krisher; page 82
2 GPSA *Engineering Data Book*; page 11-4; 1974
3 Perry's *Chemical Engineers' Handbook*, 4th Edition; page 9-51; 1963

If the blowdown rate cannot be reduced due to water quality issues, then heat recovery from this stream (if not flashed) should be considered. Any boiler with continuous blowdown exceeding 4% of the steam rate is a good candidate for the introduction of blowdown waste heat recovery[15]. This can be done by either installing a heat exchanger to recover the blowdown heat for instance against BFW or flashing the condensate to lower pressure.

Water Side Operation and Maintenance

For steam boilers with water softening via chemical dosing and further deaeration equipment, daily logs should be kept monitoring the continuous operation. The water-chemistry records should be benchmarked to determine the necessary treatment, which will be defined by local water treatment companies unique to the water quality of the region.

Similarly, the oxygen content of the BFW should be regularly monitored to observe trends and operate the deaeration process accordingly to prevent excess oxygen in the BFW as this can lead to oxygen pitting and corrosion in the water pipework.

Insulation

Steam pipes and condensate return pipes must be insulated and localised damage to insulation must be repaired. Steam and condensate return pipes might lack insulation as it might have been removed or not replaced during operation maintenance (or repairs). This includes removable insulation covers for valves or other installations which may be absent.

On top of this, wet or hardened insulation needs to be replaced. The cause of wet insulation can often be found in leaking pipes or tubes. The leaks should be repaired before the insulation is replaced.

4.2.3 Best Technologies

Best technologies to control excess air and reduce stack temperature in Section 2.2.3 also apply to Boilers.

Steam Trap Monitoring and Maintenance

Site steam systems usually have hundreds if not thousands of steam traps distributed across the site. There is a high likelihood of a significant number of steam traps failing each year. This leads to steam and condensate losses which ultimately, unless fixed or replaced, result in an increase in the boiler fuel and water cost.

The best performance sites have in place a steam trap monitoring and maintenance programme with surveys carried out every 6 months. The programme can be carried out by a steam trap vendor or by the site's own maintenance department after suitable training. The most advanced approach is to have real-time monitoring systems that detects and pin-point traps that are failing (e.g. Bitherm SmartWatchWeb™, SteamIQ, Everactive).

Steam System Modelling

Best practice for sites with utility systems is to have at least an off-line static model of the system. This tool can provide an experienced team with the additional insights that they need to identify the main drivers and the means of maximising value from a reasonably complex system. Moreover, the model can be used to calculate the steam header balance and identify unaccounted steam. Most advanced sites allow a maximum deviation (unaccounted steam) of 3% of the total steam generated by the site.

Experience has shown that up to 80% of the potential benefits can be captured by an experienced operations / engineering team working with an offline model. At the simplest level, the model is a means of developing heat and mass balances of the utility system. More powerfully, it allows engineers to identify the main levers to make a step change in operational performance. Evidence indicates that this can reduce operating costs by 2-4%. Further still, it can be a tool for evaluating case studies in support of operational planning, or new capital investments, in which case, potential savings can rise to 10% or higher.

Although such significant value can be achieved with a relatively simple model, a strong business case is required for additional model functionality. In general, installing a model online and using it for performance monitoring can lead to an additional 1-3% reduction in costs. This is mainly achieved in terms of sustaining savings realised with quick-wins, due to a more pro-active approach from site personnel[16].

4.2.4 Metrics

Table 4.3 shows a list of metrics for monitoring of a boiler system and the method for calculating the metric.

Table 4.3 – Recommended Energy Metrics for Boiler Systems

Energy System	Hierarchy	Metric	Method
Boiler equipment only	Energy performance indicator	Thermal efficiency (%)	Calculated
	Energy performance indicator	Energy performance gap (Gcal/h)	Calculated
	Energy influencing variable	Stack temperature (°C)	Measured
	Energy influencing variable	Stack oxygen (%)	Measured
	Energy influencing variable	Steam flow (t/h)	Measured
General steam and condensate system	Energy performance indicator	Overall mass / energy balance of steam system	Calculated
	Energy performance indicator	BFW pump specific energy consumption (kW/unit throughput)	Calculated
	Energy influencing indicator	Condensate recovery (%)	Calculated
	Energy influencing variable	Deaerator pressure	Measured

Energy performance indicators: these are calculated values that allow the management and engineering team to track the overall performance of an equipment, process or even the whole site.

Energy influencing variables: these items represent elements within the system that can be manipulated to improve the efficiency of the equipment or process

Refer to the Assessment Framework [4].

4.3 Identification of Energy Efficiency Opportunities

Operation and maintenance best practices should be maintained to ensure reliable and efficient operations. In addition, there are typical energy efficiency opportunities for boiler systems outlined below.

Reduction of Excess Air

As per furnaces, stack oxygen for boilers should target 2% to 3%.

Waste Heat Recovery

A standard form of heat recovery is an economiser for air or BFW preheating. The limiting constraint for determining whether an economiser to recover the stack gas waste heat would be economic is the approach temperature between the stack / flue gas and the acid dew temperature of the flue gas. It is necessary to maintain the flue gas temperature at least 10°C above the acid dew point of the flue gas to prevent condensation and ultimately corrosion. Non-conventional heat recovery may be considered (low grade heat recovery) for recovering flue gas heat below the acid dew point temperature, however this would need to be assessed for economics on a case by case basis.

APH

The air ducts of a boiler can be arranged to draw hot air from the top of the boiler house, where typically the dissipate radiant heat from the boiler and stack is captured in the surrounding air. This can marginally reduce the heating requirement for combustion air. Similarly, the blowdown or other process recovered process heat could be utilised to preheat the boiler combustion air.

Blowdown Reduction

Continuous and intermittent blowdown are utilised to remove any sludge or dissolved solids built up within the boiler system, however it results in the heat energy being lost to the sewer without recovery. Regular review of the continuous blowdown programme and frequency of the intermittent blowdown should be performed to observe the closeness of the water quality parameters to the tolerances provided by the boiler manufacturer. Avoiding unnecessary blowdown will result in reduced energy lost to sewer. Typically, best energy performance sites target a 1% blowdown rate.

Blowdown Waste Heat Recovery

As well as appropriate frequency of intermittent blowdowns, if the continuous blowdown is significant (e.g. >5% boiler capacity), then waste heat recovery heat exchangers for the blowdown may be economic. Examples of uses of the blowdown heat include:

- Combustion air pre-heat;
- Make-up water heating;
- Boiler feedwater heating;
- Process water heating; and
- Domestic water heating.

Steam Header Pressure

It may be the case that since inception, the design steam header pressure levels may be operating at above the necessary pressure, subject to process heating requirements.

A review of the process heating requirements should be performed after any major process design changes that effect the heating demand to consider reducing steam pressure headers to an appropriate level.

Deaerator Operating Pressure

This will depend on the overall steam balance; if there is steam venting, the site should try and increase the deaerator pressure to stop venting.

On the other hand, if there is no venting, the site could try and reduce the deaerator operating pressure. Best practice value for this scenario is 0.2 barg. On top of reduction of deaeration steam consumption, fuel savings might come because of additional heat recovery from the boiler's economiser (if in place).

4.4 Common Opportunities Observed in Plants

There are multiple areas of opportunities for boiler systems (utility systems), including:

- Reduction of boiler continuous blowdown;
- Flash and heat recovery from boiler continuous blowdown;
- Reduce boiler excess air;
- Improve heat recovery from boilers' convection section (e.g. APH, economiser);
- Review system's operating philosophy (e.g. N, N+1, N+2, etc);
- Review deaerator operating pressure;
- Heat recovery from deaerator vent;
- Recover waster heat against make-up water;
- Recover waster heat against BFW;
- Header pressure optimisation; and
- Improve steam trap maintenance programme.

This section covers case studies for some of the points above.

4.4.1 Case 1: Adjusting Deaerator Operating Pressure

Background

Energy improvement assessment performed for a petrochemical site in Asia.

Opportunity

Analysed data showed an average of 20 t/h of steam being vented from the site. This was confirmed by the site personnel. The system did not have Backpressure Turbine (BPT) / motor that could be adjusted to reduce the vent.

The deaerators were operating at 0.3 barg, while their design was for up to 1.4 barg. There was an opportunity to partly recover this vent by increasing the deaerator operating pressure.

Results

By increasing the deaerator pressure to near its design limit, the vent was reduced by 3 t/h. This resulted in water savings of USD 50k per year.

The lesson learnt here is if there is steam venting, this can be reduced if the deaerator operating can be increased.

4.4.2 Case 2: Switching Turbine to Motor to Eliminate Steam Vent

Background

Energy improvement assessment performed for a large chemical complex in Europe.

Opportunity

The site was venting around 7 t/h of LPS. Although power import price was high, there was spare capacity on the exiting cogeneration facility to generate cheaper power. There was an opportunity to stop the vent by switching a BPT to motor and fulfil that power by increasing the GT load.

Results

The implementation of this project had an overall fuel saving of over 3 Gcal/h (equivalent to USD 500k per year). The payback for this project was just below 2 years.

The lesson learnt is that there might be opportunities for reducing the vent and optimising the system by adjusting the BPT / motor operation especially if cheap power can be generated within the existing facility.

4.4.3 Case 3: Increase High Pressure Steam Header Operating Pressure

Background

Energy improvement assessment performed for a fertiliser plant in South East Asia.

Opportunity

An HP steam header was operated at 111 barg. However, this steam (and header) could be generated at higher pressure (115 barg) while being within the agreed system limits. This change would allow a reduction on the steam requirement by HP turbines driving site's compressors and pumps.

Results

The implementation of this project decreased the HP steam requirements by 2 t/h. In monetary terms, this was equivalent to USD 250k per year.

The lesson learnt is that sites should assess the benefits of increasing the pressure of the HP steam level, if the opportunity exists within the operating limits.

4.4.4 Case 4: Steam Trap Maintenance Programme

Background

Energy improvement assessment performed for an oil refinery in Europe.

Opportunity

The site has over 4000 steam traps. During the survey, executed in conjunction with a steam trap vendor, 314 traps were found to have failed open.

Results

The implementation of this project decreased fuel consumption by about 2 Gcal/h. This was equivalent to USD 100k per year. Payback time was under 10 months.

4.4.5 Case 5: Insulation of Steam Line[12]

Background

An oil refinery, located in North America, conducted a survey of the steam distribution and condensate return piping including insulation.

Opportunity

In a plant where the fuel cost is USD 8.00 per million Btu (USD 8.00/MMBtu), a survey of the steam system identified 1,120 feet of bare 1-inch-diameter steam line, and 175 feet of bare 2-inch line, both operating at 150 pounds per square inch gauge (psig). An additional 250 feet of bare 4-inch-diameter line operating at 15 psig was found.

Results

The implementation of this project was estimated to save USD 45k per year.

4.5 Summary

Boilers are utilised for steam generation for steam distribution systems for either heat, live / process steam or power generation. Steam is produced in the boiler system at the highest steam level within a site and let down either to the requirement pressure level (dependant on plant specific steam header layout via letdown stations or via backpressure turbines (for power generation or turbine driven equipment e.g. pump or compressor).

There are multiple elements to consider for the best energy practice design and operation; however, special attention must be paid to:

- Operating philosophy (required spare capacity);
- Heat recovery from exhaust gases and excess air target;
- Blowdown target and heat recovery configuration;
- Dearator operation (pressure, vent rate, target make-up water temperature); and
- Condensate recovery.

The elements mentioned above cover the typical areas that can be improved to make the system more efficient, specifically:

- Reduction of boiler continuous blowdown;
- Flash and heat recovery from boiler continuous blowdown;
- Reduce boiler excess air;
- Improve heat recovery from boilers' convection section (e.g. APH, economiser);
- Review system's operating philosophy (e.g. N, N+1, N+2, etc);
- Review deaerator operating pressure;
- Heat recovery from deaerator vent;
- Recover waste heat against make-up water;
- Recover waste heat against BFW;
- Header pressure optimisation; and
- Improve steam trap maintenance programme.

5 Cogeneration Systems

5.1 Definition

Cogeneration is defined as *the simultaneous generation in one process of thermal energy and electrical and / or mechanical energy*[15]. Cogeneration is also known as Combined Heat and Power (CHP) systems, which in simple terms are plants that produce combined heat and power (e.g. combined cycle GTs – GT with waste heat recovery steam generator).

Combined Cycle Steam / Power Plant

The main components of this type of cogeneration system include:

- A GT to generate shaft work, which is used to generate electrical power.
- An HRSG to recover energy from the hot GT exhaust gas. The HRSG is usually used to generate steam (in some instances at multiple pressure levels) and can have burners to fire additional fuel to increase steam production and increase steam temperature.
- Boiler(s) to provide steam to supplement steam production from the HRSG.
- Steam import from third party suppliers to supplement steam production from the HRSG / boiler.
- Steam Turbine Generator(s) (STG) to generate additional shaft work and power. The STG can be used to provide steam to end users via extraction to a lower pressure and to increase power production by condensing the exhaust steam under vacuum conditions.
- Pump(s) to transfer the BFW from the deaerator to the steam generators.
- Deaerator(s) use heat, typically in the form of LPS, to decrease oxygen content in the BFW.

Figure 5.1 below shows a simplified sketch of an example cogeneration system.

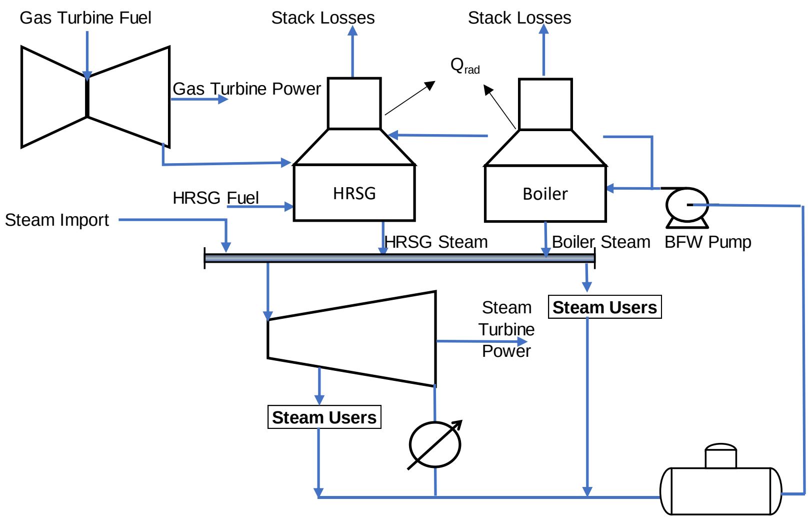


Figure 5.1 – Simplified Sketch of a Cogeneration System

- Steam users are divided in three categories:
  - Live steam users, where the steam or condensate is not returned, but joins the process stream (e.g. stripping steam);
  - Heating steam users, where the condensate can be returned (e.g. steam sent to distillation column reboiler); and
  - Steam turbines, where energy from steam is extracted as shaft work.

Figure 5.1 above shows a simple schematic of a cogeneration system. In this example, steam from the HRSG is sent to a two-stage STG with extraction and condensing to provide steam to end users and power. In this case, the HRSG steam is sufficient to provide enough steam for the end users and for the power production from the STG. In situations where the HRSG steam is insufficient, additional steam demand may be fulfilled by boilers (see Assessment Framework [4]).

Some GTs have water / steam injection to reduce NOx emissions. This practice also increases power output. However, the economics of producing additional power in this way will depend on the steam (or fuel depending on the marginal mechanism of steam pricing) and power prices. Where this is the case, the additional heat input from the water / steam must be considered, as additional GT fuel.

The energy input into a cogeneration system consists of:

- Fuel provided to the GT;
- Heat content of any water / steam injection into the GT;
- Fuel provided to the HRSG (for supplementary burners, if applicable); and
- Fuel to boilers.

The energy output in the system shown in the Figure 5.1 above consists of:

- Power output from the GT;
- Power output from the STG;
- Heat (typically in the form of steam) transferred to the end users; and
- Heat losses consisting of:
  - Heat lost to the stack gases from the HRSG and boilers;
  - Radiant losses from the HRSG and boilers;
  - Losses from the vacuum condenser (if applicable) on the exhaust of the STG; and
  - Steam losses across the system due to pipework insulation and condensate losses.

The most significant losses are usually through the stack gas, vacuum condensers (for systems with condensing turbines) and condensate losses.

Other Cogeneration Systems (Internal Combustion Engines)

Although the combined cycle steam / power plant, including a GT and HRSG, covered above is the focus of this section, other cogeneration systems such as the traditional industry steam and power system using boilers (without GT / HRSG arrangement) has been covered in Section 4 (Boiler Systems). Other cogeneration systems such as internal combustion engines are briefly covered in this section. However, such systems are seldom found in the refining, petrochemical and chemical industry.

In an internal combustion, fuel is converted to thermal energy by combustion. On one hand, electricity is generated via the thermal expansion of the flue gas that takes place in the cylinder. This moves the piston, generating mechanical energy that is transferred to the flywheel by the crankshaft and transformed to electricity by an alternator connected to the flywheel. On the other hand, heat can be recovered from lubrication oil, engine cooling water and from exhaust gases to generate steam, hot water or hot oil as well as using it directly against process streams (via heat exchangers).

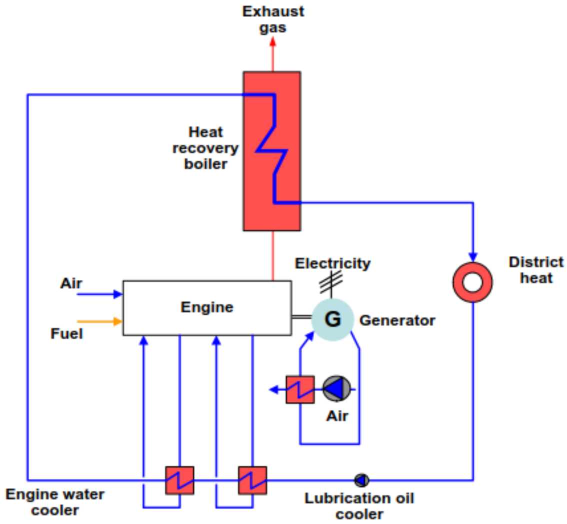


Figure 5.2 – Internal Combustion Engine[17]

Internal combustion or reciprocating engines typically have fuel efficiencies in the range of 40% to 48% when producing electricity. Fuel efficiencies may come up to 85% to 90% in CHP cycles, when the heat can be effectively used. Flexibility in trigeneration can be improved by using hot water and chilled water storage, and by using the topping-up control capacity offered by compressor chillers or direct-fired auxiliary boilers[15].

Internal combustion engines may be suitable for sites where:

- Power or processes are cyclical or not continuous;
- LPS or medium or low temperature hot water is required;
- There is a high power to heat demand ratio;
- NG is available – gas powered internal combustion engines are preferred;
- NG is not available – fuel oil or LPG powered diesel engines may be suitable;
- The electrical load is less than 1 MWe – spark ignition (units available from 0.003 to 10 MWe); and
- The electrical load is greater than 1 MWe – compression ignition (units from 3 to 20 MWe)[15].

Refer to United States Environmental Protection Agency (EPA) Catalog of CHP technologies[18] and Oak Ridge National Laboratory (ORNL) 'Guide to Combined Heat and Power Systems'[19] for additional information on GTs , internal combustion engines and other type of cogeneration configurations.

5.2 Best Practices & Design Considerations

5.2.1 Best Practices in Design

This section addresses GT / HRSG configuration including steam turbines. Steam boilers have been considered in Section 4.2.1.

The best configuration of a steam and power system will depend on the power to steam requirements. The R-curve is the best available tool to decide guide designers on what type of configuration (steam boilers versus GT with HRSG) is optimum for a certain power to steam demand.

The R-curve

The R-curve is used to benchmark the site's steam system and can be used to evaluate the effectiveness of the design of a cogeneration system. The R-curve plots cycle efficiency against Power / Steam Energy ratio and allows the calculation of indicatives efficiency target for the system as it accounts for the optimal arrangement of boilers, GT & HRSGs and steam turbines.

For a steam system, the power to heat ratio (R) determines the maximum cogeneration efficiency that can be achieved.

- If R is less than 0.1 (exact number dependent on steam header pressures and steam demand at each header, typically range 0.05 to 0.25), then power for the site can be supplied by backpressure turbines which generate the required power, with steam to the turbines provided by boilers. A backpressure turbine generates power at the efficiency of the boilers, as all the steam from the exhaust of the turbine is used for heating purposes. For a best practice system, the boiler efficiency is 92%.
- For higher site power demands (typically R > 0.25), it is not possible to use backpressure turbines to generate power as the steam demand is not high enough. In this situation, the site can either import power or can generate power with condensing turbines or with GTs, provided the heat from the GT is recovered in a HRSG. The more efficient option is to use a GT & HRSG.

The figure below shows how the power to heat ratio (R) affects the cogeneration efficiency for different power generating cycles.

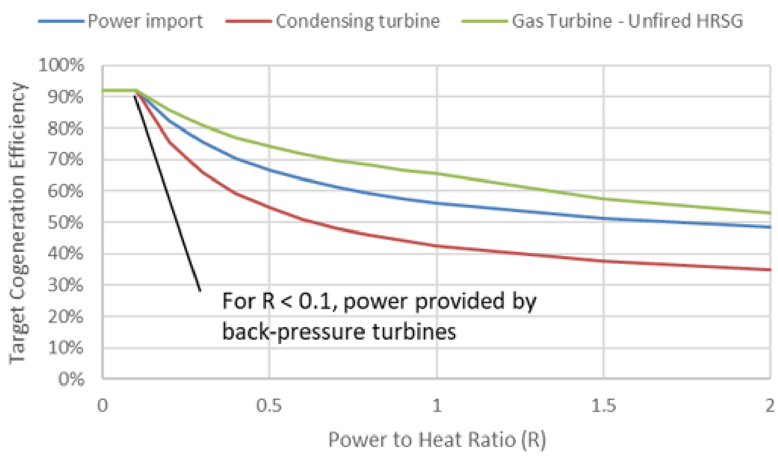


Figure 5.3 – Example of R-curves for Different Configurations

Best Design Elements of Steam and Power Systems

The best design elements of steam and power systems are:

- The size of the GT (the base electric load) is to be selected to meet the power demand of the site, taking into consideration the steam balance configuration (e.g. backpressure turbine, turbogenerators). In some cases, depending on the economics, the size of a GT is adjusted to exceed the site power demand to export the surplus electricity. In terms of efficiency, values above 30% (latest model can achieve up to 40% - e.g. efficiency of GE LM6000 model ranges between 39.1 to 41.4%, depending on the new power output) should be targeted.
- According to General Electric (GE), approximately 20% of the inlet air to the axial flow compressor gets lost to the thermal cycle. Such losses are mainly associated with the cooling hot gas path and large clearances. To avoid losses related to air leakage, designers should consider:
  - High pressure packing brush seals (closer clearance – for forward and aft outer bearing casing seals - more durable than labyrinth seals);
  - First stage shroud cloth seals instead of the traditional 'pumpkin-tooth' design (this feature restricts the higher pressure, compressor discharge air from leaking into the hot gas path);
  - No. 2 bearing brush seals;
  - No. 2 and No. 3 bucket / shroud honey-comb seals; and
  - Abraidable coating for stage 1 shroud blocks.

  These elements are considered not only for new designs but also are intended to reduce performance degradation between major overhauls.
- High Efficiency Particulate Air filters (HEPA), defined as filters with an efficiency greater than 85% for particles greater than or equal to a filter's Most Penetrating Particle Size (MPPS - between 0.07 and 0.2 microns for filters used in GT inlet applications). This system results in cleaner compressors, longer cycles between water washing, and subsequently higher compressor efficiency and equipment availability.

- The approach to steam generation from the GT exhaust will depend on the site steam balance. For sites with low power to heat ratios, a fully fired configuration can be selected. On one hand, it meets the site power demand, and on the other hand, firing can be adjusted to meet the steam requirements. For sites with high power to heat ratios, unfired configuration would be more appropriate.
    - Unfired HRSG, generates steam by using the heat in the GT exhaust gas. Typically, the steam conditions range from 10 barg to 100 barg and temperatures can go up just over 500°C. The performance of an unfired HRSG unit is driven by the GT operation. Steam flow control is limited in this mode of operation.
    - Supplementary fired HRSG has the firing capability that allows the control of the steam generation within the equipment. GT exhaust gas is at a high temperature and has a relatively high content of unused oxygen (15% or more[20]). Supplementary fired HRSGs are equipped with duct burners to use this hot oxygen to burn additional fuel. This increases the gas temperature (to about 900°C) and increases steam generation. The advantage of burning fuel in a HRSG, as opposed to a conventional boiler, is that its thermal efficiency can be considered as 100%.
    - A fully fired boiler is essentially a utility boiler which uses GT exhaust as its combustion air. It burns additional fuel to use all oxygen available in the flue gas to generate steam. The application will be appropriate for sites with low power to heat ratios.

  Depending on GT operating parameters, installing a recuperator can increase efficiency from 30% to 40%[19].

- Typically, for effective heat transfer, the temperature of the exhaust gases exiting the HRSG is designed to target 40°C to 50°C delta between the temperature exhaust and that of the fluid being heated[21]. However, best practice designs would target for 15°C.
- To ensure proper flow of exhaust gases under all weather conditions, the temperature of the HRSG's exhaust gas stream must remain sufficiently high (typically above 150°C) to allow the gases to rise from the point of discharge into the surrounding atmosphere.
- Steam generation from boilers and HRSG should ideally target 110 barg to 120 barg. This will allow the site to generate power in backpressure turbines (e.g. driving a power generator or a large compressor) while producing the high-pressure steam levels (i.e. around 40barg) traditionally found in industry through let-down.
- Steam pressure levels should be optimised to suit the specific process configuration and allow optimum heat integration between processes through the steam system (i.e. inter-unit integration via steam generation / usage). This is done using the total site approach, which comprises pinch targeting of the site's heat sinks and sources.
- Efficiency of backpressure (including multi-stage turbines) turbines equipment should be targeted at 75% or better. The selected design should match CHP pressure and temperature to maximise the electrical efficiency while providing the required thermal output (extracted steam).
- Vacuum quality on the condensing turbine should be ideally designed at 10 kPa. However, this value might change depending on the temperature of the available cooling medium.

- For driver selection, the recommendation is to have most pumps and compressors driven by electric motors and to have large, efficient backpressure turbogenerators (with an isentropic efficiency of 75% or better) to maximise on-site power generation. This is done to minimise the number of small turbines with low efficiencies (typically less than 50%). Depending on the site's operating philosophy, critical drivers such as cooling water and BFW pumps, boiler fans, instrument air, fire water pumps and relief / blowdown systems might be steam turbine-driven.

5.2.2 Best Practices in Maintenance and Operations

Aside from the factors explained in Section 4.2.2 on the boiler systems, there are additional elements on cogeneration (steam and power) system related to the best practices of steam and power systems. These elements are outlined below.

Steam Turbines

For **condensing turbines,** achieving optimum vacuum quality is key. Best practice vacuum quality is in the order of 10 kPA. However, achieving this value will depend on the temperature of the cooling medium. The condenser vacuum might be underperforming the design expectations due to:

- The cooling water inlet temperature is different from the design value. This is the most common reason for variations in the condenser vacuum because the temperature of the cooling water is significantly influenced by weather conditions such as temperature and humidity. Hot, humid weather could result in the cooling water temperature increasing, the condenser vacuum quality degrading and the turbine output reducing (with a consequential reduction in thermal efficiency). On the other hand, cool, dry weather conditions could have the reverse effects.
- The cooling water flow rate is not optimum.
- The condenser tubes are fouled or partially blocked.
- Air leaks into the condenser[5].
- If the steam ejector system is not operating well, then inert gas can blanket some of the condenser tubes. The best way to identify this is to see if the condensate temperature from the condenser is below the turbine exhaust temperature. Inert gas blanketing the lower tubes means that condensate from the upper tubes is sub-cooled. A difference of 3°C or 4°C implies problems. In this situation, condenser vacuum quality is not as good as it could be and leads to increased steam consumption.
- One of the most common causes of inert gas leaking into condensers is air leaking in through the Pressure Safety Valve (PSV). These valves rely on a water seal and the normal design relies on a visible over-flow from the water seal. It is recommended to check that the overflow is visible and overflowing.
- A common point for air entry into the vacuum end of the turbine is the lack of sealing steam to the labyrinth seal at the exhaust end of the turbine. There should be a "whiff / slight trace" of steam from the labyrinth vent.
- Isolation valves on the cooling water supply and return lines are not fully open.

Other elements to account for air cooled condensing turbines:

- Check the fan motors and make sure that the motors are loaded to 85% of name plate amps;
- Check for leakage of cold air between the fan and the tube bank;

- Check for debris against the tubes on the upstream air side;
- Inspect the fins on the cooling tubes - make sure the tubes are clean on the outside;
- Make sure there are no short circuit air flows around the tubes (not contributing to cooling);
- Look at the tip clearance of the blades from the shroud;
- Make sure there is a centre cover between the blades to prevent spill back;
- Make sure there is maximum free air flow; and
- If hogging ejectors are used to increase the vacuum, then there is likely an air leak.

For **backpressure turbines**, small turbines will have low isentropic efficiency, typically less than 40%. In such cases, and depending on the overall steam balance as well as trade-off between fuel versus power price, sites should consider replacing these drivers with more efficient electrical motors.

Slow rolling of turbines should be avoided. Slow-rolling turbines can use up to 10% of their nominal steam load, without generating power or shaft work. Most new turbines are designed to start direct from cold, without risking disks coming loose or excessive vibration.

GT

Considerations for the GT are as follow:

- Gas temperature and pressure: If the gas temperature and pressure conditions at the inlet to the GT vary from the design optimum conditions, the turbine may not be able to operate at maximum efficiency. Variations in gas conditions can be due to errors in plant design (including sizing) or non-optimal plant operation.
- Part load operation, starting and stopping: peak GT efficiency occurs at 100% of the full rated load[19]. However, site decisions to operate the generating unit at certain loads for certain periods will have a major influence on its average thermal efficiency. Similarly, site decisions on when the plant is to come on and off-line also have a bearing on average thermal efficiency because of energy losses while starting or stopping the system.
- Increased temperature of the hot gas leaving the combustors generally results in increased power output.
- Reduced temperature of exhaust gas generally results in increased power output.
- In general, higher mass flow through the GT results in higher power output.
- A decrease in pressure loss across the exhaust gas silencers, ducts and stack increases power output.
- An increase in pressure of the air entering or leaving the compressor increases power output[5].
- To minimize damage, most GTs are designed to burn clean fuel such as NG that is free from potentially harmful impurities. Although firing of fuels other than NG is feasible, it is usually not practical unless the combustion system includes auxiliary fuel cleaning equipment[21].

Air Purity

Proper air filtration is critical to GT performance. Deposits on turbine blades can significantly reduce efficiency.

Heat Recovery Steam Generator

GT exhaust systems may include a diverter valve and a dump stack to provide operating flexibility. The diverter valve is used to modulate the exhaust gas flow into the heat-recovery equipment or to divert the entire exhaust gas stream to the dump stack when heat recovery is not required.

CHP Performance Monitoring Programme

Installing Energy Performance Monitoring of the CHP system allows operators / engineers to track and calculate energy metrics as well as to compare the current equipment performance against clean conditions using in-built live simulation. This enables plants to assess the gap in performance (i.e. deterioration) and take actions aligned with the maintenance programme whenever possible.

CHP Maintenance Programme

CHP projects are often expected to last up to 25 years[22]. However, during their lifetime, CHP systems can show degradation in availability (which affects capacity factor), electrical, or thermal performance from first-year operations unless a maintenance program is in place. Maintenance activities often include routine inspections, on-line and preventive maintenance, and scheduled overhauls at 12 000 to 50 000 operating-hour intervals. Routine inspections may involve visual examinations of filters and general site conditions, vibration measurements to detect worn bearings, rotors, and damaged blade tips, and other types of internal examinations of critical items such as fuel nozzles and hot gas components[19].

Steam turbines, especially smaller units, may leak steam around blade rows and out of the end seals. When the turbine operates or exhausts are at a low pressure, as is the case with condensing steam turbines, air can also leak into the system. The leakages cause less power to be produced than expected, and the make-up water must be treated to avoid boiler and turbine material problems. Air that has leaked needs to be removed, which is usually done by a steam air ejector or a fan removing non-condensable gases from the condenser[18].

Operating Philosophy

Some facilities prefer to run their boilers or GTs on N+1 or even higher (e.g. N+2) modes due to reliability concerns. However, this will affect the overall efficiency of the system as the equipment load will be lower, leading to poorer efficiencies.

5.2.3 Metrics

The following table shows a list of metrics for monitoring of a cogeneration system.

Table 5.1 – Recommended Energy Metrics for Cogeneration Systems

Energy System	Hierarchy	Metric	Method
Entire cogeneration system	Energy performance indicator	Thermal efficiency (%)	Calculated
	Energy performance indicator	Energy performance gap (%)	Calculated
GT only	Energy performance indicator	Thermal efficiency (%)	Calculated
HRSG only	Energy performance indicator	Thermal efficiency (%)	Calculated
	Energy influencing variable	HRSG stack temperature (°C)	Measured
Steam turbine only	Energy performance indicator	Thermal efficiency (%)	Calculated
General steam and condensate system	Energy performance indicator	Overall mass / energy balance of steam system	Calculated
	Energy performance indicator	Condensate recovery (%)	Calculated
	Energy performance indicator	BFW pump specific energy consumption (kW/unit throughput)	Calculated
	Energy influencing variable	Deaerator pressure	Measured

Energy performance indicators: these are calculated values that allow the management and engineering team to track the overall performance of an equipment, process or even the whole site.

Energy influencing variables: these items represent elements within the system that can be manipulated to improve the efficiency of the equipment or process.

Refer to the Assessment Framework [4] for more details.

5.3 Identification of Energy Efficiency Opportunities

There are some opportunities for cogeneration (steam and power) systems in addition to the factors explained on the Boiler system section (Section 0). These factors are outlined below.

GT and HRSG

There are systems that, for economic reasons (e.g. availability of cheap power import), have been designed to fulfil the site's steam demand via boilers and power demand mainly met through power import. If economics changes (i.e. cheap fuel and expensive power), there is an opportunity to replace the import power by installing a GT. Whether the GT arrangement is simple or combined cycle will depend on the efficiency of existing boilers.

Assessing the feasibility of new GT and HRSG is also applicable when analysing potential site expansion, which will lead to additional steam and power demand.

For systems with GTs, the efficiency of the equipment will depend on load as well as type and technology of the GT. In most cases, it does not pay back to replace with 'new' GTs to gain a few efficiency points. However, in the case of old GTs, replacing them for new technologies could bring up to 10% improvement on the GT single cycle efficiency. In this scenario, payback will depend on the fuel cost.

Waste Heat Recovery from Single Cycle GT

In cases where the heat from the exhaust of the GT in the utility systems is not recovered, there is a clear opportunity to do so. To monetise this heat, the approach can follow the traditional steam generation through an HRSG or, depending on the system and fuel / power prices, other options, such as power generation via an Organic Rankine Cycle (ORC) can be considered. The ORC is a system based on a closed-loop thermodynamic cycle for the generation of electric and thermal power where the motive fluid is an organic stream instead of steam as is the case for the well-known Rankine Cycle.

For systems with GTs, the efficiency of the equipment will depend on load as well as type and technology of the GT. In most cases, it does not pay back to replace 'new' GTs to gain a few efficiency points. However, in the case of old GTs, replacing them for new technologies could bring up to 10% improvement on GT single cycle efficiency. In this scenario, payback will depend on the fuel cost.

Trigeneration

Trigeneration is generally understood to mean the simultaneous conversion of a fuel into three useful energy outputs: electricity, hot water or steam and chilled water. A trigeneration system is a cogeneration system with an absorption chiller that uses some of the heat to produce chilled water[15].

This type of application can be used on sites with steam, power and chilling requirement such as the petrochemical industry.

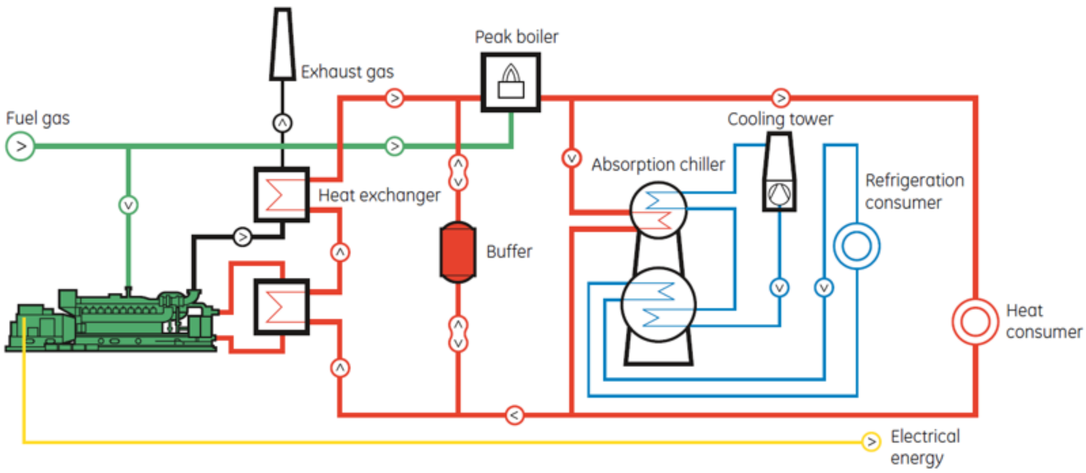


Figure 5.4 – Trigeneration Scheme

[Courtesy of Clarke-energy®]

Quadgeneration

Quadgeneration is taking Trigeneration one step further and utilise the CO_2 (recovered and scrubbed) within the GT exhaust gases. This CO_2 can be sent to greenhouses to be used by plants for photosynthesis. The CO_2, once scrubbed and cleaned, can also be used as carbonation gas in the drinks and food manufacturing or other industrial processes.

Decrease Temperature of GT Inlet Air

The GT air compressor performance is affected by the temperature of the combustion air. The lower the temperature, the more efficient the GT. As the air temperature decreases, the air density increases, resulting in increased mass flow and thus higher efficiency[21]. This variable is highly dependent on the ambient conditions. Various techniques can be deployed to reduce the temperature of the combustion air.

- Evaporative cooling is used where air humidity is low, with added advantage of cleaner air and lower NO_x. It has a modest air-cooling effect as the air temperature will be cooled to its wet bulb temperature only.
- Fogging involves the over-spraying of additional water into the inlet for compressor inter-cooling. Fine droplets can be carried into the compressor to be evaporated.
- External refrigeration uses chilled water to cool the inlet air. The chilled water can be produced by absorption chillers or mechanical chillers. Air temperatures as low as 8 – 10°C can be achieved. This approach is particularly interesting when there is excess steam or waste heat to power absorption chillers.

5.4 Common Opportunities Observed in Plants

Some of the opportunities for boiler systems that are relevant in cogeneration systems have been presented in Section 4.4. Additional examples as well as cases related to GT applications are shown below.

5.4.1 Case 1: Heat Recovery from GTs – Steam Generation through Installation of HRSGs

Background

Most GTs (in the range of 25 MW capacities) on this gas processing site located in Southeast Asia operate in open cycle configuration with efficiencies ranging between 23% to 29%. However, having a CHP operation — GT with a heat recovery exchanger, which recovers heat from turbine exhaust to produce steam is much more efficient.

Opportunity

If a HRSG is added to the configuration, the exhaust heat can produce steam or hot water to reach overall system efficiencies (electricity and useful thermal energy) of 70% –80%.

Results

The total potential steam generation that could be achieved is over 360 t/h (at 60 barg and 480°C). This was sufficient to shut down one of the existing steam boilers, which was operating at an efficiency of 83%. The payback of this project was below 4 years.

The lesson learnt here is that utilisation of the exhaust heat from GTs can lead to significant fuel savings.

Rate (MW)	Steam gen. potential (t/h)
20.4	39.0
20.4	41.5
21.7	41.5
21.7	41.5
22.9	43.8
22.9	43.8
22.9	43.8
22.9	43.8
22.9	43.8

Table 5.2 – Steam Generation Potential for the Site GTs

5.4.2 Case 2: Heat Recovery from GTs – Power Generation through Installation of an ORC

Background

Heat from the GTs (in the range of 10 MW capacities) at this gas fractionation site in Asia is not recovered. This useful high-grade heat, at 527°C, is lost to the atmosphere. There is no steam demand within the site. Hence, using this heat for steam generation is not an option.

Opportunity

Power was expected to be generated by recovering heat from GT exhaust gas via an ORC. This was selected as the best solution to recover heat as there was no steam demand on site and it allows for a reduction of 'expensive' power import.

Results

The implementation of this project generated 1.5 MW of power, equivalent to USD 600k per year. The payback for this project was just below 6 years.

5.4.3 Case 3: Change N+2 Operating Philosophy to N+1

Background

A Liquefied Natural Gas (LNG) liquefaction site in Southeast Asia operated with a N+2 philosophy (i.e. tripping of 2 equipment will still enable the remaining equipment to pick up the loads) with regards to their GT operations. This meant that the GTs (in the range of 25 MW capacities) were less efficient, operating between 23% to 29% of their rated capacities.

Opportunity

By reviewing the site load shedding strategy, the site was able to agree on a philosophy change from N+2 to N+1. This meant an increase on the GTs load, which lead to an improvement on their efficiency up to 32%.

Results

The implementation of this operational improvement project generated NG savings equivalent to USD 50 million per year.

5.4.4 Case 4: Optimisation of Steam Header Pressure – Intermediate Pressure Level

Background

An oil refinery in Europe operated the Medium Pressure (MP) steam header at 40 barg. This steam header has been maintained at 45 barg in the past and was designed for even higher pressures.

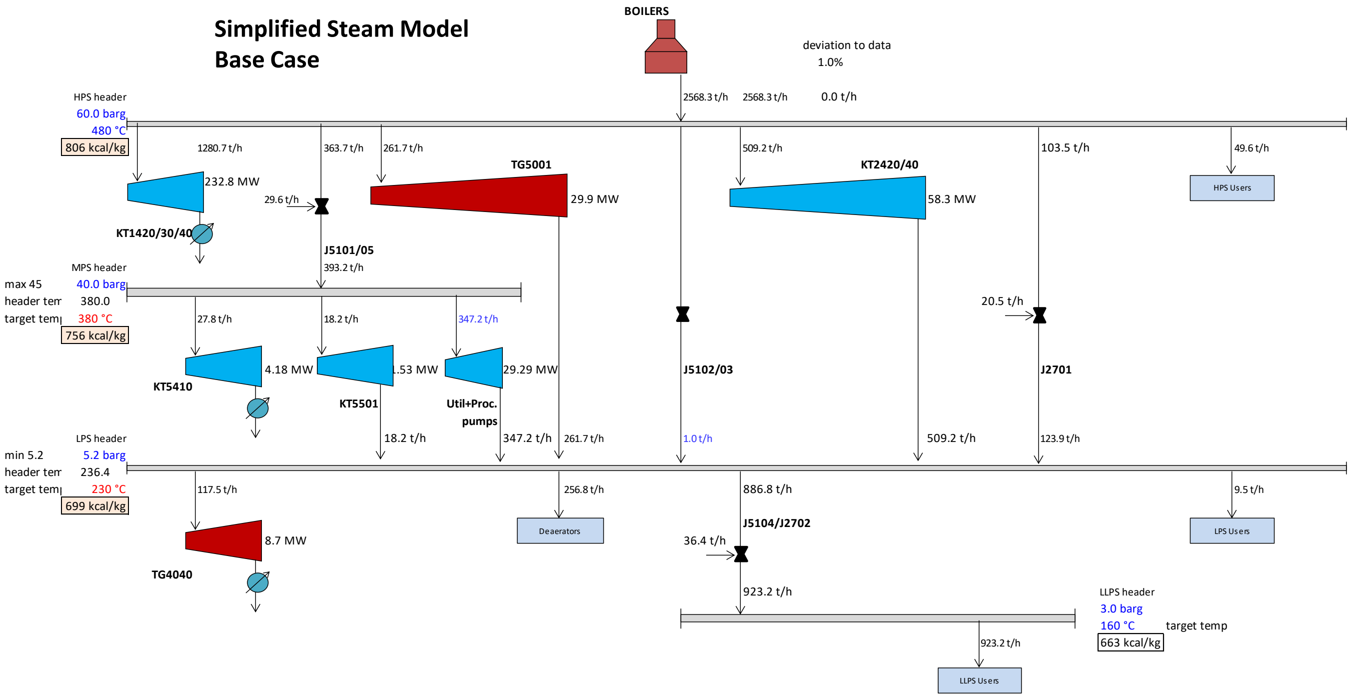


Figure 5.5 – Optimisation of Steam Header Pressure – Base Case

Opportunity

Increasing its operating pressure reduced the amount of steam required by KT-5501 and other rotating equipment driven by MP / Low Pressure (LP) turbines. The power losses from TG-4040 were compensated by increasing the steam through TG5001, as the site was letting down HP steam to LP level through a letdown valve.

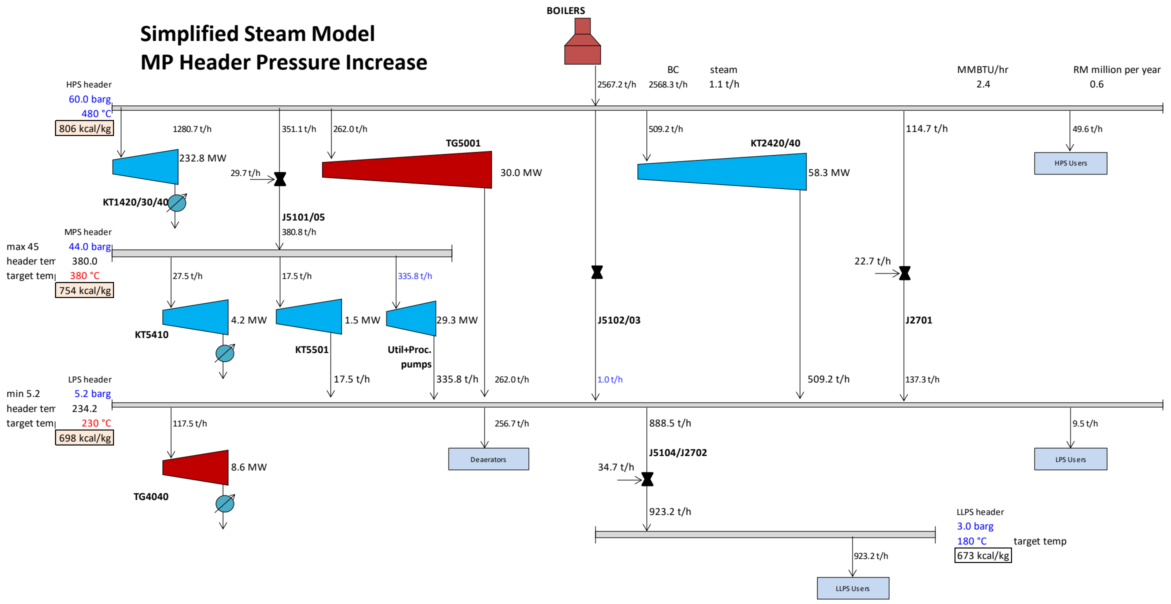


Figure 5.6 – Optimisation of Steam Header Pressure – Intermediate Pressure Level – Optimised System

Results

The implementation of this operational improvement project generated NG savings of 2.4MMBTU/hr, equivalent to USD 200k per year.

The lesson learnt here is that steam modelling allows us to visualise the system and to test the benefits of optimising the steam header pressure.

5.4.5 Case 5: Optimisation of Steam Header Pressure – LP Level

Background

An oil refinery in Europe operated the LP steam header at its minimum of 5.2 barg. LP steam was used to provide heat to various users as well as to produce electricity via condensing turbine TG-4040. The base case is shown in Figure 5.7.

Opportunity

Fuel savings can be achieved by increasing the operating pressure of the LP steam header, in this case to an optimum of 6.0 barg. To achieve benefits, the site implemented the following logic:

1) Adjust steam to MP / LP turbines to meet base case power requirement;

2) LP steam flow to TG-4040 was reduced until generated power matched base case value; and

3) HP steam flow through TG-5001 was increased until generated power matched base case value.

This project made economic sense as the HP / LP letdown valve is open. An increase on the LP pressure helps to re-adjust the balance to decrease the HP / LP letdown. This makes the system more efficient.

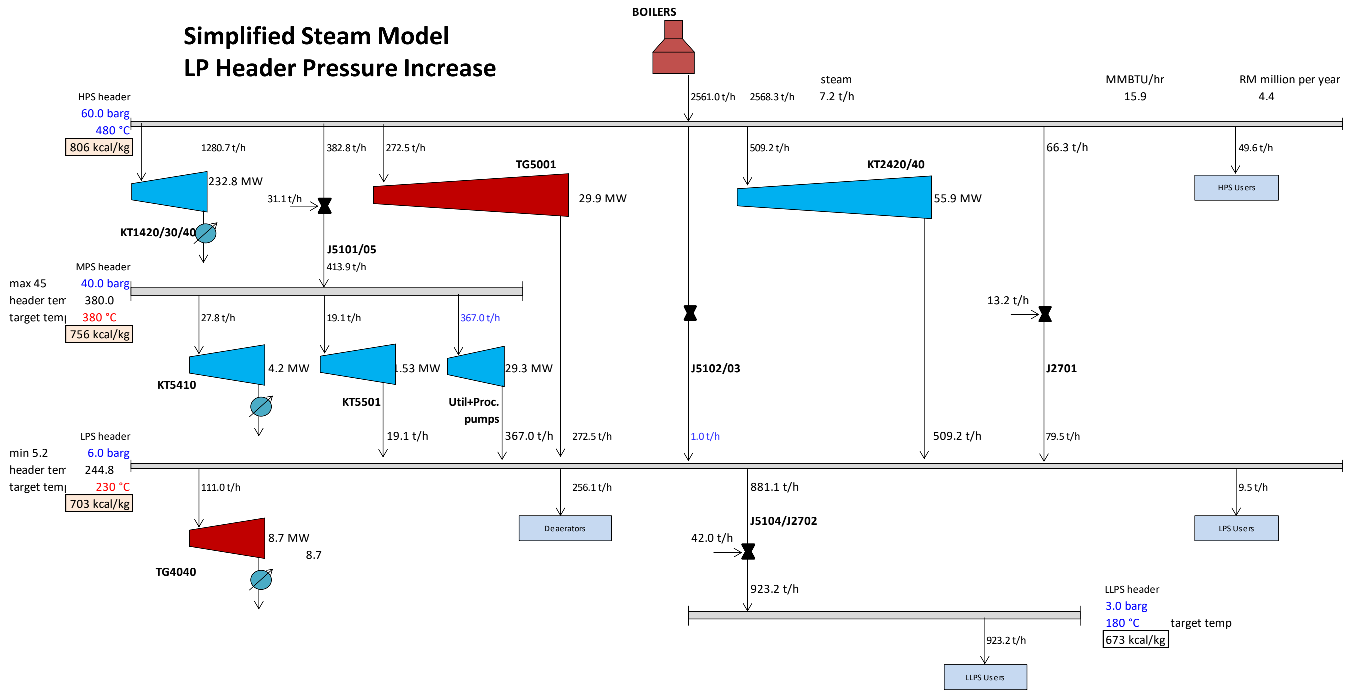


Figure 5.7 – Optimisation of Steam Header Pressure – Low Pressure Level – Optimised System

Results

The implementation of this operational improvement project generated NG savings of 15.9 MMBTU/hr, equivalent to USD 1.1 million per year.

The lesson learnt here is that the steam model allows us to visualise the system and to test the benefits of optimising the steam header pressure.

5.4.6 Case 6: Taking Advantage of Steam Let-downs for Power Generation

Background

An LNG liquefaction site located in Southeast Asia was letting down a significant amount of steam (around 350 t/h), through let-down valves between the 100 barg and the 40 barg steam header. This represented a significant inefficiency of the system considering the site also generated power through condensing (which is inefficient – estimated cycle efficiency for condensing power at this site was 28%).

Opportunity

This project looked at installing a new turbogenerator between the 100 barg and the 40 barg header to take advantage of the existing letdown. This extra power would then be used to stop power generation via the existing condensing turbine.

Results

Although the required capital investment was significant, at around USD 12 million, the fuel (NG) savings achieved (28.4 MMBTU/hr) by stopping the condensing turbines made this project pay back within one year.

The lesson learnt here is that power generation through condensing is extremely inefficient and alternatives such as using a BPT (if the steam balance allows) to replace condensing power typically show good returns on investment.

5.4.7 Case 7: Utilisation of Steam Venting

Background

A power and steam generation site located in Southeast Asia is equipped with multiple GTs and associated HRSGs. The steam and power generated here is exported to nearby facilities. Due to the system configuration, there is a vent of 20 barg steam. The site has already increased deaerator operating pressure to reduce the vent. However, the vent steam remained high at 15 t/h.

Opportunity

The site GTs were commissioned with a $DeNO_x$ steam flow of 0.3 t/MWh per GT, which means that the 20 barg steam could be injected to the GTs, opening the possibility of using the GTs as a new sink for steam. Injecting $DeNO_x$ steam to GTs allows sites to either generate more power or reduce fuel by rebalancing the GTs. In this case, the site did not need additional power. Hence, rebalancing the system would generate the same amount of power but with reduced fuel consumption as the 20 barg steam would now be sent to the GT.

Results

In this case, utilising the steam vented resulted in USD 300k per year of fuel savings. However, some considerations were needed before the implementation of this project:

1) Piping had not been in operation and no record of preservation was cited. The lines were checked prior to implementation and proper commissioning was conducted to avoid introducing contaminants into the GT.

2) The effect over equipment maintenance was reviewed with the licensor. Maintenance frequency was expected to increase due to the steam injection.

5.4.8 Case 8: Utility Swap – Fuel from Furnace to Steam from HRSG

Background

This site is in Singapore with a complex utility system that involves GTs with HRSGs. The column reboiler heats the stream from 226°C to 234°C. This is done via a furnace which operates with an efficiency of 87%, consuming around 8 Gcal/hr of NG.

As the temperature profile of this furnace is below the saturation temperature of HP steam, there is potential for energy saving by replacing the furnace with an HP steam heater. This is because energy for heating the process stream can be more efficiently fulfilled by HP steam generated via cogeneration supplementary firing.

Opportunity

This project proposes to replace the existing furnace with an HP steam heater. HP steam consumption is expected to be about 14.1 t/h. The overall energy performance improvement is expected to be about 1 Gcal/h.

Results

This opportunity would generate savings of SGD 400k per year. This project is estimated to payback within 3 years.

5.4.9 Case 9: Replacing a Condensing Turbine with an Electric Motor

Background

A chemical plant located in Europe ran a compressor using a condensing turbine. Although this is a common practice, it is not efficient as the cycle efficiency of a condensing turbine is only typically around 30%.

Opportunity

This project evaluated the possibility of replacing this condensing turbine to drive the compressor using an electric motor.

Results

This project generated savings of around USD 1.0 million per year, with payback within a year.

The lesson learnt here is that power generation through condensing is extremely inefficient and alternatives such as motor might show good returns on investment. However, this will be dependent on the power and fuel prices.

5.5 Summary

Cogeneration systems, also known as CHP systems, are simply systems that produce combined heat and power (e.g. combined cycle GTs – GT with waste heat recovery steam generator). The main components of this type of cogeneration systems include:

- A GT to generate shaft work, which is used to generate electrical power.
- An HRSG to recover energy from the hot GT exhaust. The HRSG is usually used to generate steam (in some instances at multiple pressure levels) and can have burners to fire additional fuel to increase steam production and increase steam temperature.
- Boiler(s) to provide steam to supplement steam production from the HRSG.
- Steam import from third party suppliers, again to supplement steam production from the HRSG / boiler.
- STGs to generate additional shaft work, and power. The STG can be used to provide steam to end users, by extraction to a lower pressure and to increase power production by condensing the exhaust steam under vacuum conditions.
- Pump(s) to transfer BFW from the deaerator to the steam generators.
- Deaerator(s) use heat, typically in the form of LPS, to decrease oxygen content in the BFW.

The best configuration of a steam and power system will depend on the steam to power requirements. The R-curve is the best available tool to guide designers on what type of configuration (steam boilers versus GT with HRSG) will be considered optimum for a certain power to steam demand.

Opportunities to improve the energy efficiency of this type of system includes:

- Installation of a GT and associated HRSG, for systems with high power to steam ratio and that currently only use steam boilers and backpressure turbines;
- Waste heat recovery from GT exhaust gases, when operating on single cycle;
- Operation philosophy in relation to spare capacity;
- Review deaerator operating pressure;
- Heat recovery from deaerator vent;
- Recover waster heat against make-up water;
- Recover waster heat against BFW;
- Header pressure optimisation;
- Replace small inefficient turbines with motors; and
- Improve steam trap maintenance programme.

As well as elements related to boiler operation, such as:

- Reduction of boiler continuous blowdown;
- Flash and heat recovery from boiler continuous blowdown;
- Reduce boiler excess air; and
- Improve heat recovery from boilers’ convection section (e.g. APH, economiser).

6 Typical Challenges in Implementing Energy Efficiency Opportunities

Technical Challenges

KBR has observed very keen interest from the plants in pursuing energy efficiency opportunities. Plant energy managers are found to have considered a diverse range of technologies and practices including advanced electric motors and drives, high efficiency boilers, waste heat recovery, modernisation / replacement of process equipment, improved process performance etc. However, plants may be faced with the following technical challenges when implementing energy efficiency opportunities.

- Space constraints – In the context of land scarce Singapore, plant equipment tend to be laid out in close proximity to one another by design. Retrofits to replace or install new equipment may lead to plot space problems. While it may be possible to overcome space problems through engineering solutions, it usually leads to increased capital requirements.
- Lack of simulation tools – It was observed that some process engineers do not have access to simulation files of their own process. Some plants may not have procured the necessary software. Others may have left the task of simulation analysis to the corporate headquarters, in which some of them sit outside of Singapore. Due to confidentiality reasons, some of the process simulations are kept by the corporate headquarters and not shared with the plant team in Singapore.
- Metering and energy consumption data - The lack of energy consumption data, such as process unit and equipment-level energy consumption data, and tools to evaluate such data, can prevent identification and evaluation of opportunities as the baseline cannot be quantified. This typically applies to smaller plants, where energy systems tend to be smaller in scale and comes with minimal instruments.
- Long implementation cycles - Unless energy performance improvements can be achieved via operational improvements, projects must follow the site turn-around cycles, which in some cases could take up to 6 years. This means that project economics would have to be re-assessed closer to the time of implementation, as economics and / or operating conditions would have changed.
- Deployment of new innovative technologies – Site personnel might not be aware of technology advances that could bring energy improvement. Together with the conservative approach of the industry where no site wants to be the first to implement, adoption of new technologies can be difficult. Plants need to commit additional resources to perform due diligence, evaluation of competing technologies and detailed feasibility studies to ensure a successful implementation of new technologies.

Financial Challenges

The main financial challenge has to do with internal competition for capital as sites often have limited budgets for projects. Typically, there is no split on the budget pool between energy efficiency and production-related projects, with the selection criteria being return on investment. Moreover, sites often require very short payback periods (one to three years) to justify capital investments.

On top of competition for capital, other financial-related challenges include:

- Potential low energy / carbon prices – volatile energy prices create uncertainty in project payback periods. Low energy prices reduce the incentives to pursue energy efficiency projects. Also, with today's low carbon price, it does not help to justify investment projects to a significant extent. In a few climate-focused corporations, a long term view of the future of carbon price has been adopted. The real social cost of carbon, significantly higher than today's carbon price, is used in internal project evaluations.
- Split incentives – sites may split costs and benefits for energy efficiency projects between business units, which complicates decision-making[23].
- Financial risk – finding low-cost financing might be challenging. Failure to do so will result in higher capital expenditure and lower internal rate of return.
- Sales of excess utilities (steam, fuel and power) – particularly in highly regulated environments where utilities cannot be sold "across the fence". Moreover, it might be difficult to achieve reasonable sale agreements for excess utilities.

6.1 Overcoming Challenges

There are multiple elements that need to be covered to tackle the barriers for implementation of energy improvement projects in the industrial sector. The list below illustrates some of the practices used by energy-focused corporations:

- Public commitment and engagement from top management to improve the energy efficiency of the site.
- Allocating budget to energy efficiency projects, separated from the budget for production / yield improvement projects.
- Accepting rate of return for energy efficiency projects ranging from 5 to 8 years.
- Clear inclusion of GHG cost benefit - in countries where there is no cost (or very low cost) associated with GHG emissions, companies set their own emission price based on international standards and their own emission reduction strategy.
- Clear knowledge development and training plan for energy-related activities across the different levels of the organisation. This should include marketing campaigns to make all personnel aware of the real cost of energy and management should be open to energy-saving ideas from the plant personnel.
- Space constraints are difficult to overcome but assessing 'new' technologies might provide the solution. For instance, using plate heat exchangers rather than shell and tube.
- Appropriate metering and tracking of energy consumption. This can be achieved through the implementation of standardised M&V approach to new designs and retrofits of heating systems. Details on standardised M&V approaches for heating systems can be found in the Assessment Framework [4].
- Make use of available energy efficiency financial incentives to justify projects and minimise risks. Refer to Section 6.1.1 below for information.

6.1.1 Available Financial Incentives in Singapore

The NEA, Economic Development Board (EDB) and Energy Market Authority provide funding support for Singapore companies to become more energy efficient and improve competitiveness. To learn more about the available funding support, please visit the following websites:

Energy Efficiency Fund:

https://www.nea.gov.sg/programmes-grants/grants-and-awards/energy-efficiency-fund

Resource Efficiency Grant for Energy:

https://www.edb.gov.sg/en/how-we-help/incentives-and-schemes.html

Genco Energy Efficiency Grant Call:

https://www.ema.gov.sg/Energy_Efficiency%20for%20Power%20Generation.aspx

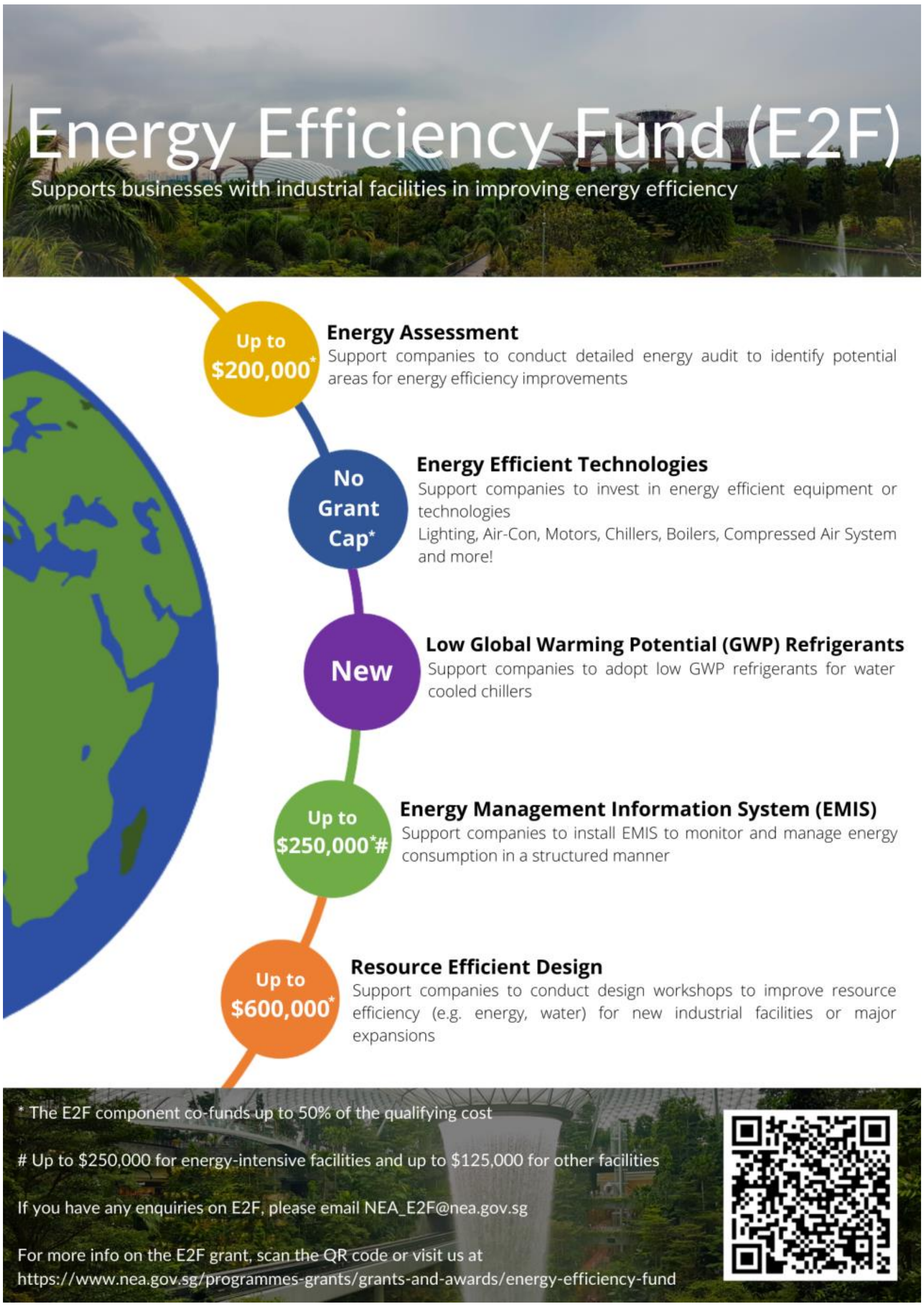


Figure 6.1 Energy Efficiency Fund in Singapore

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