Training Manual

2- Day User Industrial Steam System Optimization (SSO) Training

October 2011

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ABSTRACT

The 2-Day User Industrial SSO Training Manual is developed as an additional reference and resource to the actual classroom training offered by the UNIDO IEE industrial Steam System Optimization Project. It DOES NOT replace the classroom instructor-led 2-Day User training. Nevertheless, it is used to teach end-users, operators and maintenance staff of enterprises, energy managers, supervisors, facility and consulting engineers, on how to assess and optimize steam systems. Its sole purpose is to identify, quantify and achieve energy and cost savings through proper operation and controls, system maintenance, appropriate process uses of steam and application of state-of-the-art technologies in an industrial steam system.

This Training Manual covers the operation of typical industrial steam systems that include steam generation; steam distribution; steam end-uses; condensate recovery and combined heat and power (CHP). The Training Manual then describes each of the areas in detail and identifies critical and important parameters, measurements, etc. that are required to be done to undertake a "Systems Approach" based steam system energy assessment at a plant. The Training Manual identifies performance improvement opportunities in each of the above-mentioned areas that lead to the optimization of the overall steam system.

All steam system level analysis should obey the fundamental laws of physics and thermodynamics (heat and mass balance). Sometimes it is not easy to conduct this analysis manually and the user needs to model these applications in commercially available software tools. The use of software tools is becoming very prevalent with industry having "real-time" Data Acquisition Systems and dash boards in their control rooms for steam system models and analysis. Any methodology used for steam system analysis should realize the "Systems Approach" and be based on sound engineering principles. The US Department of Energy's Steam system BestPractices software tools suite can also be used for modeling industrial steam systems. They quantify energy and cost savings from projects and provide an excellent platform for the steam system user. The Training Manual introduces these software tools and provides information on where to get them online.

Overall, this Training Manual provides an easy to understand methodology to systematically take a "Systems Approach" to optimize industrial steam systems and provides the user with simple examples and sample problems to test their knowledge as they progress through the different sections in an industrial steam system.

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Nomenclature

$A_{orifice}$ – area of orifice
C_p – specific heat
$d_{orifice}$ – diameter of orifice
$h_{blowdown}$ – enthalpy of blowdown stream
$h_{condensate}$ – enthalpy of condensate returned
h_{exit} – enthalpy at turbine exit
$h_{feedwater}$ – enthalpy of feedwater
HHV_{fuel} – Higher Heating Value of fuel
h_{inlet} – enthalpy at turbine inlet
h_{makeup} – enthalpy of make up water
h_{PRV} – enthalpy at PRV exit
h_{steam} – enthalpy of steam
h_{water_in} – enthalpy of water into a vessel
h_{water_out} – enthalpy of water out of a vessel
$K_{bd\_savings}$ – blowdown reduction fuel energy cost savings
K_{bd_system} – fuel cost energy related to system blowdown loss
K_{boiler} – boiler fuel operating cost
$k_{electric}$ – cost of electrical energy
k_{fuel} – unit cost of fuel
k_{fuel_1} – cost of fuel 1
k_{fuel_2} – cost of fuel 2
K_{shell} – fuel cost energy related to shell loss
k_{steam} – unit cost of steam or steam cost indicator
kW – electric power generated by the steam turbine
$m_{blowdown}$ – mass flow rate of blowdown from the boiler
$m_{blowdown\_current}$ – current mass flow rate of blowdown from the boiler
$m_{blowdown\_new}$ – new mass flow rate of blowdown from the boiler
$m_{condensate}$ – mass flow rate of condensate returned
m_{fuel} – fuel flow rate
m_{PRV} – mass flow rate of steam through PRV
m_{steam} – mass flow rate of steam from the boiler
m_{steam_saved} – mass flow rate of steam saved
$m_{turbine}$ – mass flow rate of steam through turbine
m_{water_in} – mass flow of water into a vessel
m_{water_out} – mass flow of water out of a vessel
P_{steam} – steam pressure
Q_{air_1} – heat transferred to the air in current operation
Q_{air_2} – heat transferred to the air in the new operation
Q_{bd_boiler} – blowdown thermal energy content loss for the boiler
$Q_{bd\_savings}$ – blowdown reduction thermal energy savings
Q_{bd_system} – system blowdown thermal energy content loss
$Q_{condensate}$ – amount of thermal energy in condensate compared to makeup water
Q_{enduse} – heat transferred to the endues
$Q_{saved\_insulation}$ - energy savings associated with insulating surfaces

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Q_{steam} – heat transferred by steam
Q_{water} – heat transferred to water in a heat exchanger
T – operating hours
T_{in} – inlet temperature
T_{out} – outlet temperature
V_{air} – volume flow rate of air
$V_{condensate}$ – volume flow rate of condensate returned
W_{actual} – shaft work done by the actual turbine
W_{ideal} – shaft work done by the ideal (or perfect) turbine

Greek Symbols

β – boiler blowdown ratio as a percent of feedwater
η_{boiler} – boiler efficiency
η_{boiler_1} – boiler efficiency with fuel 1
η_{boiler_2} – boiler efficiency with fuel 2
$\eta_{current}$ – current boiler efficiency
η_{new} – new boiler efficiency
$\eta_{turbine}$ – turbine isentropic efficiency
λ_{bd_system} – system blowdown loss
$\lambda_{blowdown}$ – boiler blowdown loss
$\lambda_{miscellaneous}$ – boiler miscellaneous losses
λ_{shell} – boiler shell loss
λ_{stack} – boiler stack loss
ρ_{air} – density of air
$\rho_{condensate}$ – density of condensate
σ – fuel cost savings
σ_{CHP} – net economic benefit associated with running a steam turbine
$\sigma_{condensate}$– fuel cost savings associated with returning condensate
$\sigma_{electric}$ – electrical energy cost savings associated with running a steam turbine
$\sigma_{ExcessAir}$ – fuel cost savings associated with implementing excess air control
σ_{fuel} – fuel energy cost increase associated with running a steam turbine
$\sigma_{FuelSwitch\_savings}$ – fuel cost savings associated with implementing excess air control
$\sigma_{insulation}$– fuel cost savings associated with insulating surfaces
σ_{steam}– fuel cost savings associated with saving steam
$\sigma_{steamleak}$– fuel cost savings associated with eliminating a steam leak

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1. INTRODUCTION

This 2-Day User Training Manual for Steam System Optimization (SSO) is intended for steam system operators and maintenance staff, energy managers, facility and consulting engineers. This manual will discuss methods of system efficiency improvements, methodologies for quantifying energy and cost savings from these improvements, aspects of implementation and continuous improvement programs. The 2-Day User Training has the following objectives:

- Understand the need and importance of using a Systems Approach to accurately evaluate steam systems and optimization opportunities
- Train end-users and consulting engineers in doing steam system assessments and optimization
- Help industry assess steam systems and achieve energy and cost savings in steam system operation and controls; system maintenance; appropriate process uses of steam; Combined Heat and Power / Cogeneration; and application of the state-of-the-art technologies
- Conduct field assessments and identify, quantify and implement projects for energy and cost savings thereby optimizing the overall industrial steam system
- Identify a good set of tools and resources, including software, standards and guidance, that can help identifying steam system performance improvement opportunities

1.1 Industrial Steam Users

Steam usage is very widespread in the industry. Data from industry shows that average steam energy usage in industry could be as much as 35-40% of the onsite energy usage. Hence, it is very important to optimize these systems and minimize their operating costs. Nevertheless, no two systems or processes are alike and it is very difficult to generalize between steam systems. Industrial steam systems can be classified into three categories based on their pressure levels, amount of steam usage and a multitude of processes that use steam as a heating, stripping, drying and power generating source:

- **Heavy Steam Users**
    - Petrochemicals
    - Refining
    - Forest Products
    - Food & Beverage
    - Plastics
    - Rubber
    - Textiles
    - Pharmaceuticals
    - Manufacturing Assembly

- **Medium Steam Users**
    - Large commercial heating
    - Breweries
    - Laundries
    - Bakeries

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- Metal Fabrication
- Large chiller plants

- **Small Steam Users**
  - Electronics
  - Paint booths
  - Humidification systems

1.2 Advantages of Using Steam

Steam is an extremely efficient heating source which maintains a constant temperature and has high heat transfer coefficients. Steam has the highest amount of transferrable energy (in the form of latent heat) per unit mass and hence, becomes an extremely cost-effective medium of heat transfer. Steam flows through the system unaided by external energy sources such as pumps and can be controlled very accurately. When saturated steam is used, temperature and pressure of steam are correlated by thermodynamics and hence, system temperature can be controlled very accurately by controlling the steam pressure to the end-use. Steam, by nature, is a very flexible energy transfer medium that can be used for process heating as well as power generation.

1.3 The Systems Approach

For understanding and evaluating any industrial utility system, the key to cost-effectiveness is to take a “Systems Approach”. For a Systems Approach, the user needs to consider the whole steam system rather than investigate just a single component. The general approach for a steam system optimization starts with the establishment of current system conditions and operating parameters followed by an understanding of both the supply and demand sides of the system. The potential areas (projects) for steam system optimization are then identified, analyzed and implemented to meet both the plant operational and financial constraints. As a final step, the overall system performance is continuously monitored and trended to ensure that as process needs change the system does remain in its optimal configuration.

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2. FUNDAMENTALS OF STEAM SYSTEMS

2.1 Generic Steam System and Components

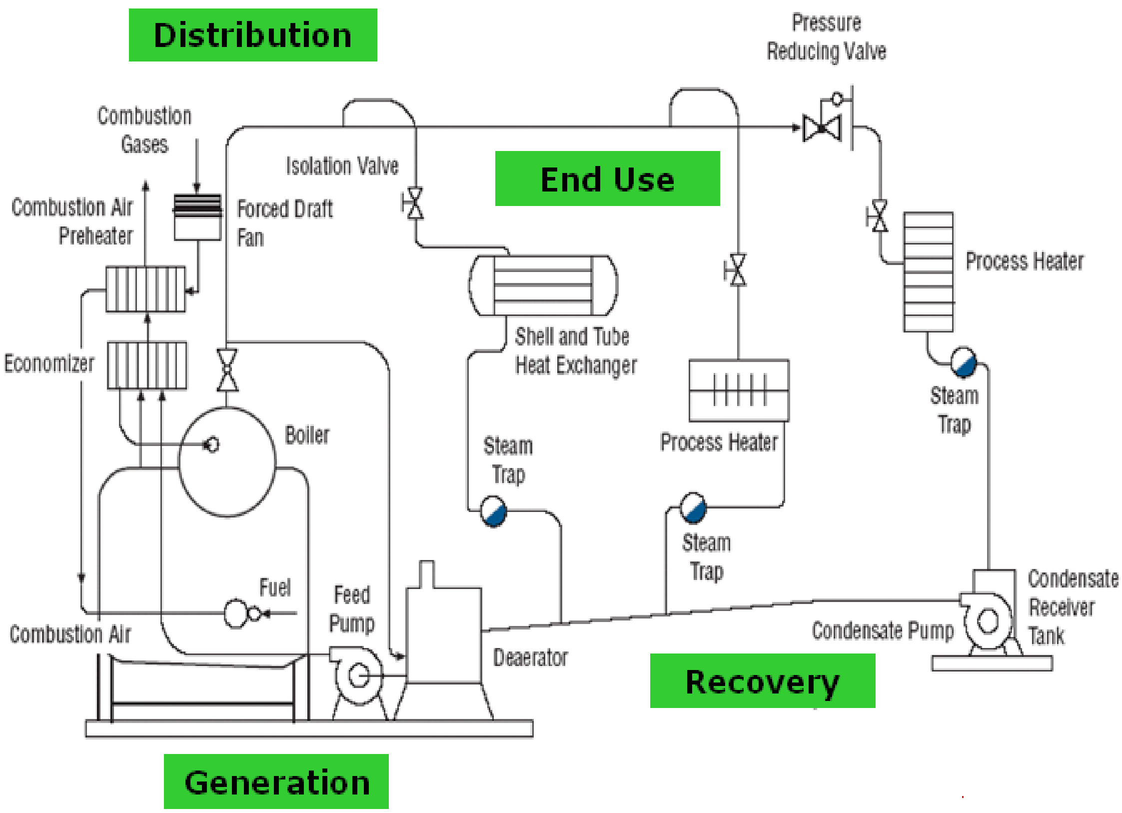

Figure 1: Generic Steam System
(Courtesy: US DOE Steam BestPractices Program – Steam System Sourcebook)

Any generic steam system (industrial, commercial, institutional) will have four major areas:

- Generation
- Distribution
- End-Use and/or Cogeneration
- Condensate Recovery

Upon detailed investigation, it maybe found that industrial steam systems will most surely have all the above four areas distinctly separated but smaller systems and institutional plants may or may not have a large distribution system. Combined Heat and Power (CHP) or also termed as Cogeneration is frequently found in industrial systems which are large steam users. It may or may not exist in medium or small steam users. Additionally, each of these four areas have several components. There maybe multiple components performing the same function in an area or there maybe certain components that may not exist in a specific system. Nevertheless, it is

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very important to construct a simple line diagram of the overall system identifying the major steam system equipment that exists and will need to be investigated using a Systems Approach when evaluating and optimizing industrial steam systems.

The major components of an industrial steam system (broken down by area) are:

- **Generation**
  - Boilers
  - Boiler Auxiliaries (Force-Draft, Induced-Draft fans, controls, etc.)
  - Economizers
  - Air Preheaters
  - Water Treatment equipment
  - Deaerator
  - Feedwater Pumps
  - Fuel Storage and Handling equipment

- **Distribution**
  - Steam Piping
  - Pressure Reducing Stations (Valves)
  - Drip legs
  - Steam Accumulators
  - Desuperheaters

- **End-Use and/or Cogeneration**
  - Heat Exchangers
  - Stripping columns
  - Evaporators
  - Cookers
  - Dryers
  - Live Steam Injection Process Heating equipment
  - Steam Turbines

- **Condensate Recovery**
  - Steam Traps
  - Condensate Collection Tanks
  - Condensate Pumps
  - Condensate Piping

As mentioned earlier, it should be noted that a steam system may or may not have all the above mentioned components (equipment) or may have multiples of these components. This is NOT an exhaustive list but it provides information about the components found in the most generic steam systems. For a proper steam system optimization analysis, an engineer will need to understand the functions and operations of each of the components in the steam system. Additionally, it is very important to understand how each of these components interact with the whole steam system and their impact on the operations and reliability of the steam system.

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2.2 Steam System Line Diagrams

A Steam System Line Diagram is a very simple tool that puts down on a single sheet of paper the overall steam system. The main purpose of the line diagram is to understand at a very high level the steam system operations at a plant (or facility) without getting into technical details and specific operating conditions. This line diagram should list all the major components as well as those that will possibly become impact components. Figures 2a, 2b, 2c and 2d represent examples of basic steam system line diagrams with an increasing order of complexity.

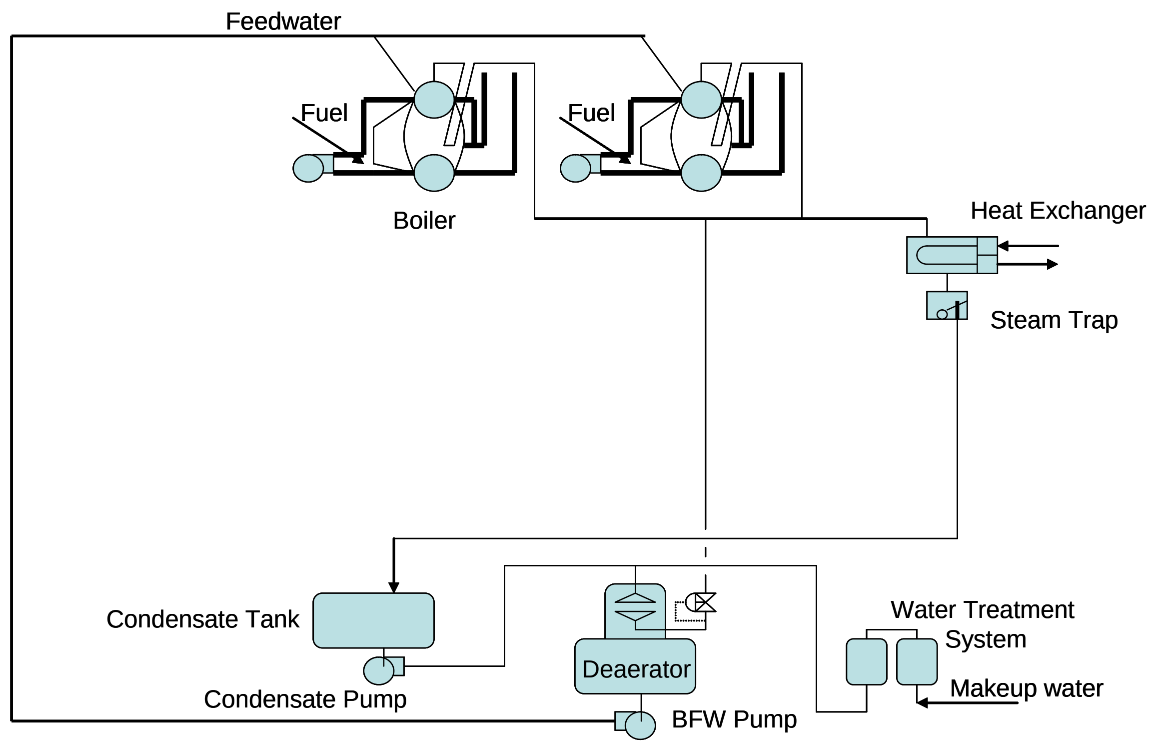

Figure 2a: A 1-Pressure Header Steam System Line Diagram
(Courtesy: US DOE Steam BestPractices End User Training Program)

It has to be noted that even in a the simplest of steam systems (as shown in Figure 2a), a line diagram provides all the necessary high level information that one would need to have for doing a detailed steam system optimization. All the components are marked here and though these specific component symbols do not follow any international standards, their main purpose is to identify and schematically show their location in the overall steam system and depict their operations. The subsequent figures 2b, 2c and 2d will use these same symbols for the components but will not call them out individually unless a “new” component is introduced in the figure. Users of this Training Manual are once again reminded that each steam system in industry is unique but the general components and their operations are very similar. Hence, a user will have to develop a line diagram for each and every steam system that needs a steam system optimization assessment.

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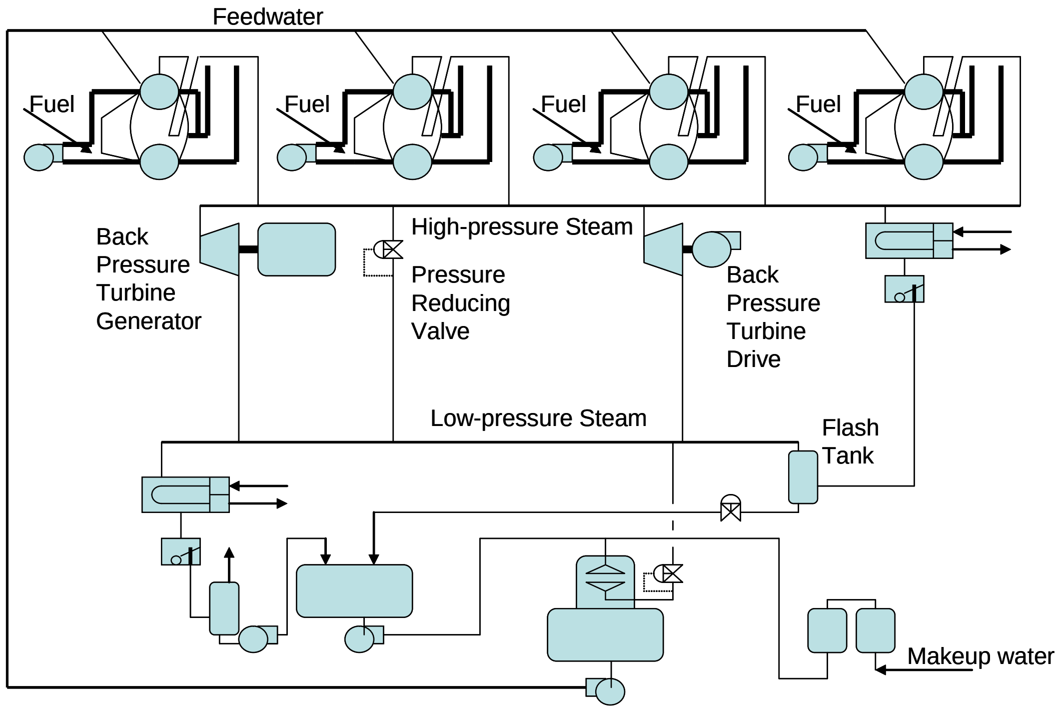

Figure 2b: A 2-Pressure Header Steam System Line Diagram
(Courtesy: US DOE Steam BestPractices End User Training Program)

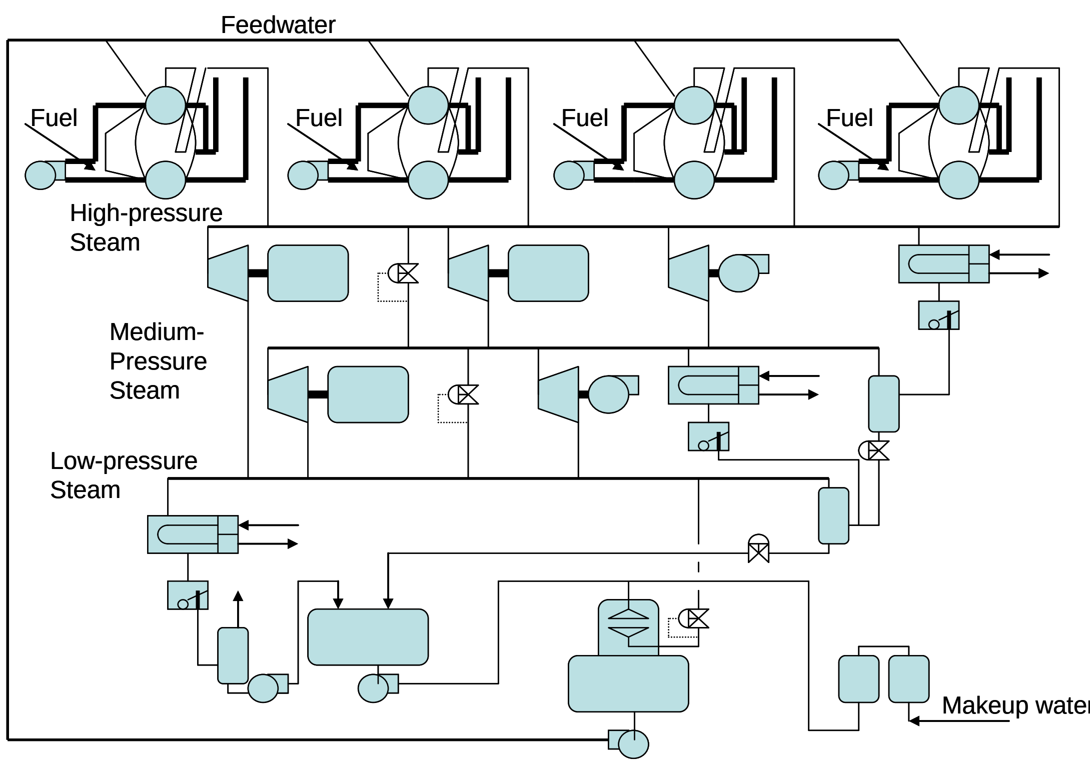

Figure 2c: A 3-Pressure Header Steam System Line Diagram
(Courtesy: US DOE Steam BestPractices End User Training Program)

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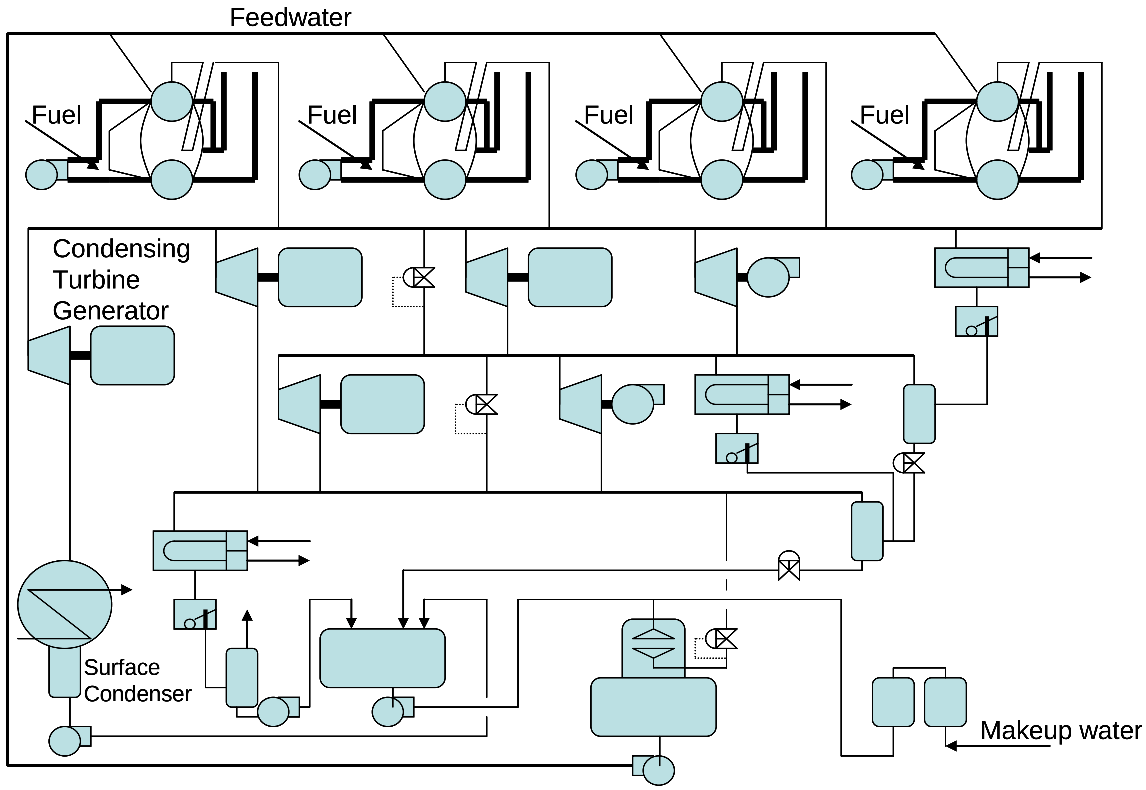

Figure 2d: A 3-Pressure Header w/Condensing Turbine Steam System Line Diagram
(Courtesy: US DOE Steam BestPractices End User Training Program)

2.3 Steam Thermodynamics

The three basic thermodynamic states of water (in an industrial steam system) are subcooled, saturated, and superheated. Each is defined as follows:

Subcooled: Water is in the form of liquid and its temperature is lower than the saturation temperature (at the existing pressure). The energy content of subcooled water is directly proportional to its temperature.

Saturated: As sub-cooled water is heated it reaches its saturation temperature. This state is called saturated liquid (water). Adding more heat leads to a change in its state from liquid to vapor without a change in temperature. This change of phase continues till it all becomes vapor. This state is now called saturated vapor (steam). The energy content of the saturated state is a function of temperature (or pressure) and quality (amount of vapor in the 2-phase mixture).

Superheated: A further increase in heat input to the saturated vapor state leads to an increase in the steam temperature beyond the saturation point. This is the superheated state of steam. The energy content of the superheated steam is proportional to both temperature and pressure.

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Based on the state of steam dictated by the pressure and temperature, thermodynamic properties such as the following can be obtained from Steam Tables.

- Pressure (bars, atmospheres, kPa, MPa)
- Temperature (°C)
  - Absolute Temperature (K)
- Quality
- Density (kg/m3)
- Volume (m3/kg)
- Enthalpy (kJ, kcal)
  - Specific Enthalpy – (kJ/kg, kcal/kg)
- Entropy (kJ/K, kcal/K)
  - Specific Entropy (kJ/kg-K, kcal/kg-K)

Steam Tables are available in several different forms including Mollier Diagram, P-h diagram, tabulated data in handbooks and standards, Equation-of-State, etc. Appendix A provides an easy to reference Steam Tables from the REFPROP software developed by the National Institute of Standards & Testing (NIST), USA. It is very important to note that Steam Tables from different sources may vary for enthalpy and entropy values because their reference point (Enthalpy = 0) may not be the same. Hence, it is very critical that all throughout the steam system analysis the <u>SAME</u> source of steam tables be used.

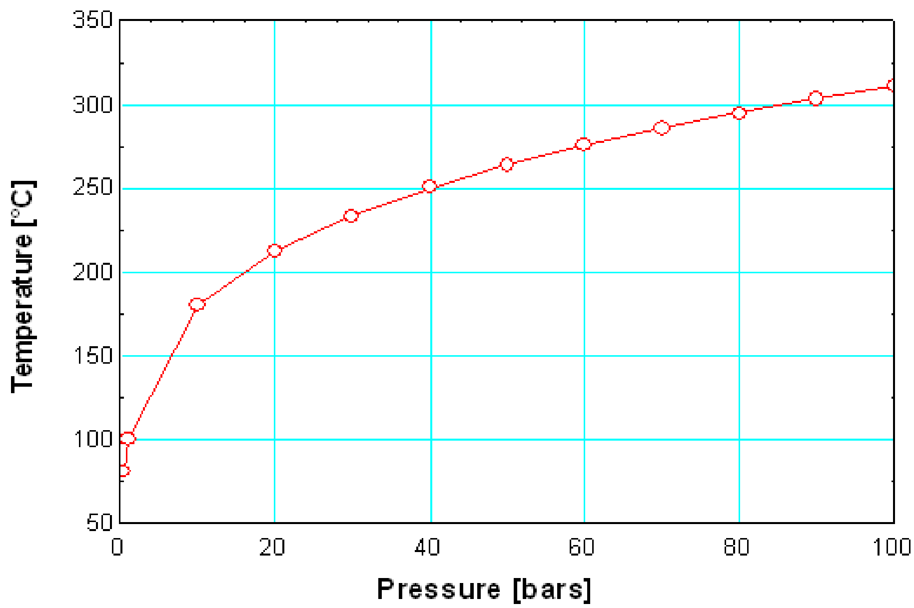

Figure 3: Saturation Temperature – Pressure Relationship for Steam

Figure 3 presents the saturation temperature - pressure relationship for steam. As can be observed, saturation temperature and pressure exhibit a non-linear relationship. Figure 4 provides the steam properties in a graphical manner, commonly known as the Mollier Diagram. It provides a relationship between pressure, temperature, enthalpy, entropy, quality and specific volume. The bold "red" line represents the saturation curve of steam. To the left of the saturation curve is the "subcooled liquid (water)" region and on the right side of the graph above the

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saturation curve is the “superheated vapor (steam)” region. Within the saturation curve, the lines indicate quality of the two-phase and there lies the “saturated” region.

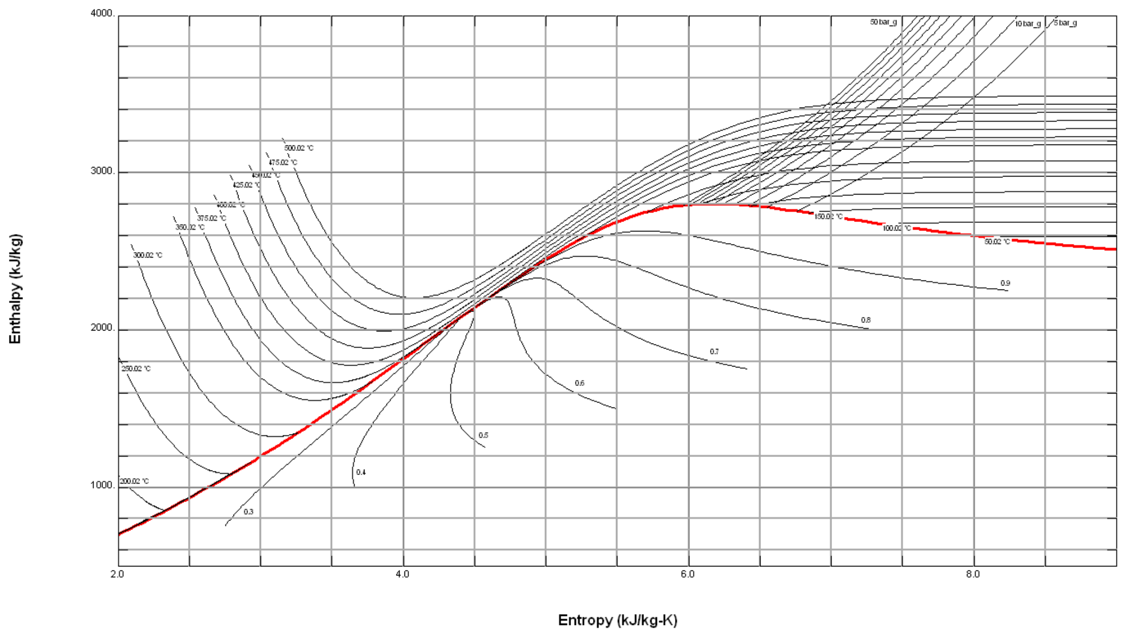

Figure 4: Mollier Diagram (Steam)

2.4 Fundamental Laws & Principles

<u>Conservation of Mass</u>
The conservation of mass states that *Mass can neither be created nor destroyed in a control volume*. *It can only change its state.*

<u>Conservation of Energy (1st Law of Thermodynamics)</u>
The conservation of energy states that *Energy can neither be created nor destroyed in a control volume. It can only be changed from one form to another*.

<u>Principle of Steady State Steady Flow (SSSF)</u>
SSSF means that the rate of change of mass and energy in a control volume are each equal to zero. This implies that there is no storage of mass or energy in the control volume that is being analyzed. Additionally, steady state implies that the individual operating parameters (temperature, pressure, flows) DO NOT vary over the time period for which the analysis is being conducted.

The Conservation of Mass and Energy laws and the SSSF principle are the cornerstone of any industrial steam system optimization efforts. Dynamic analysis, start-up, shut-down and upset conditions are typically neglected while doing steam system optimization. Energy experts and end-users will need to have a very good understanding of the steam system dynamics to appropriately justify whether the system does conform to SSSF conditions.

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3. SCOPING THE INDUSTRIAL STEAM SYSTEM

Understanding the current operations and management of the industrial steam system to be optimized is the first step in beginning the process of Steam System Optimization (SSO). Secondly, realizing the final objective(s) of the SSO and identifying the goals and targets are key in the implementation of SSO at a plant. Most of the time the objectives of SSO are:

- Minimize steam use
- Reduce system-wide energy losses
- Reduce GHG emissions
- **Reduce steam system operating costs**

Before beginning any detailed analysis, there is a strong need to be able to understand the steam system in a systematic manner. The next step would be to identify potential areas that need to be investigated and further due-diligence done on those areas to quantify the system level energy and economic impacts.

This activity can be done in several different forms:

- Face-to-Face Q&A session
- Phone interviews
- Questionnaire – filled up and returned by plant personnel, etc.

One such tool that can be used to scope a system is the US Department of Energy's Steam System Scoping Tool (SSST).

3.1 US DOE's Steam System Scoping Tool (SSST)

The SSST is a software-based (MS-Excel) based questionnaire that is designed to enhance the awareness of the areas of steam system management. It is divided into typical steam system focus areas and it provides the user with a score that is indicative of management intensity. The SSST is used to identify potential improvement opportunity areas in an industrial steam system. It does this by comparing the steam system being investigated to a state-of-the-art BestPractices industrial steam system. Opportunity gaps are identified and these become prime targets of investigation in optimizing the steam system. It has to be noted that the intention of the SSST is NOT to quantify the energy savings opportunities but be a beacon to identify them.

SSST can be used by plant managers, utility engineers and managers, plant process engineers and energy experts who are working on optimization of steam system operations. There are a total of 26 qualitative questions. These questions are divided into the following sections:

- System profiling
- Overall system operating practices
- Boiler plant operating practices
- Distribution, end-use and recovery operating practices

After completing the questionnaire in SSST, the "Results" page provides the user a score that is indicative of management intensity and serves as a guide to identify potential steam system

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optimization opportunities. Table 1 provides the SSST summary of results for an average industrial steam system.

Table 1: SSST "Summary of Results" for an Average Industrial Steam System

SUMMARY OF RESULTS SCOPING TOOL AREAS	POSSIBLE SCORE	TYPICAL SCORE
STEAM SYSTEM PROFILING	90	63%
STEAM SYSTEM OPERATING PRACTICES	140	69%
BOILER PLANT OPERATING PRACTICES	80	63%
DISTRIBUTION, END USE, RECOVERY OP. PRACTICES	30	58%
TOTAL SCOPING TOOL QUESTIONAIRE SCORE	340	222.0
TOTAL SCOPING TOOL QUESTIONAIRE SCORE	100%	65%

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4. MODELING THE INDUSTRIAL STEAM SYSTEM

After having a good understanding of the potential improvement opportunities from the Scoping section, the next step in the overall steam system optimization is to develop a "Steam System Model" that accurately reflects the overall steam system balance, models all the impact components and can realistically model the true energy and economic benefits of steam system optimization projects.

There are several high-fidelity commercially available software tools that can develop a very accurate and robust industrial steam system model for the plant. These models can be customized and can provide extremely detailed performance and operating information as maybe required for a high level of due-diligence. But these may also be very expensive and will surely need training to build steam system models that reflect the industrial plant's steam system. Additionally, there may be several proprietary software, applets, engines available from the internet (free and at a cost) that can be used for modeling steam systems.

The intent of this section is NOT to emphasize a particular steam system modeling tool or software but to make the users aware of all the characteristics and requirements that would be needed for undertaking a steam system optimization activity. The main goal of modeling the steam system is to provide the user an ability to understand the energy and economic impacts of steam system optimization projects. It is of paramount importance that any modeling or software tools be based on:

- Fundamental laws of conservation of mass and energy
- Economics balance
- Preserving steam balance on headers
- Impact cost and component (equipment) modeling analysis
- Using a Systems Approach

One such industrial steam system modeling software is the US DOE's Steam System Assessment Tool (SSAT). It is MS-Excel based and has the ability to model common steam system optimization projects and do a "what-if" analysis.

4.1 US DOE's Steam System Assessment Tool (SSAT)

The SSAT is set-up with 3 pre-defined steam system templates: 1-header, 2-header and 3-header. Figures 5a, 5b and 5c show the different header configurations and represent the pre-built system templates. Each SSAT template has the following worksheets:

- Input – to provide system level information
- Model – Line diagram of the system showing headers, steam balance, heat duties, etc.
- Projects Input – To turn "ON" projects and modify system operations
- Projects Model – Line diagram of the system with the Projects
- Results – Tabulated information of the energy and economic impacts
- Stack Loss Chart – Determines stack loss for certain fuels
- User Calculations – for doing any data analysis and calculations outside the model

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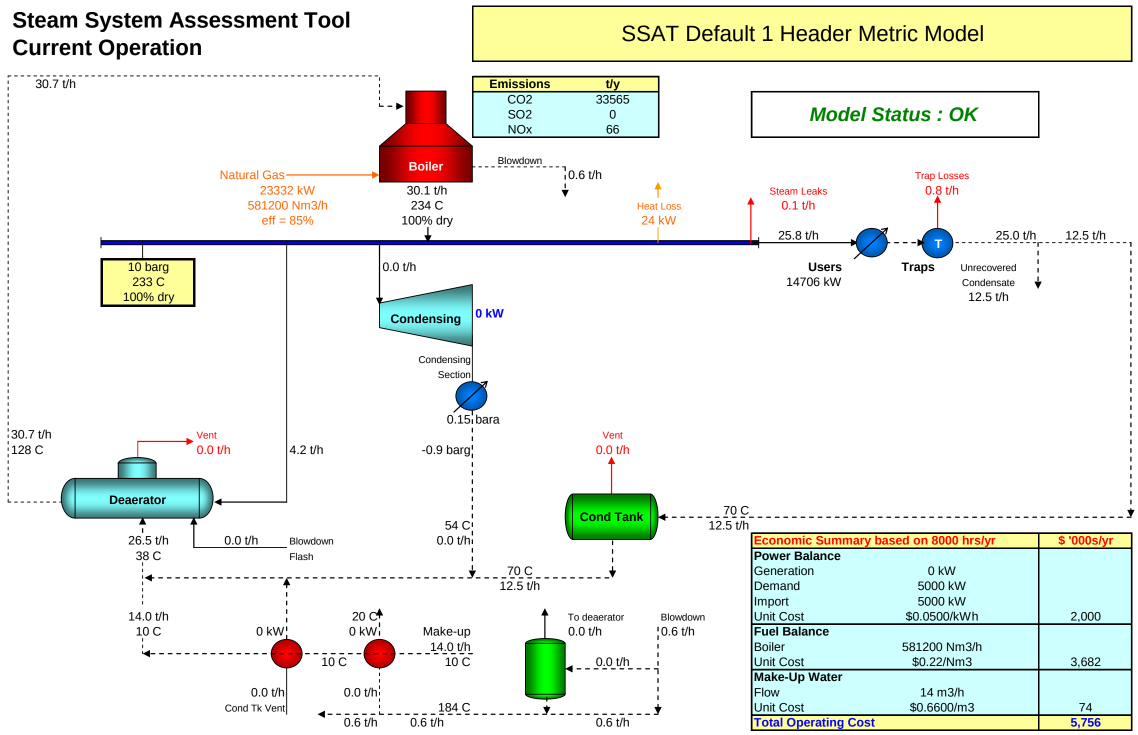

Figure 5a: SSAT "1-Header" Steam System Model

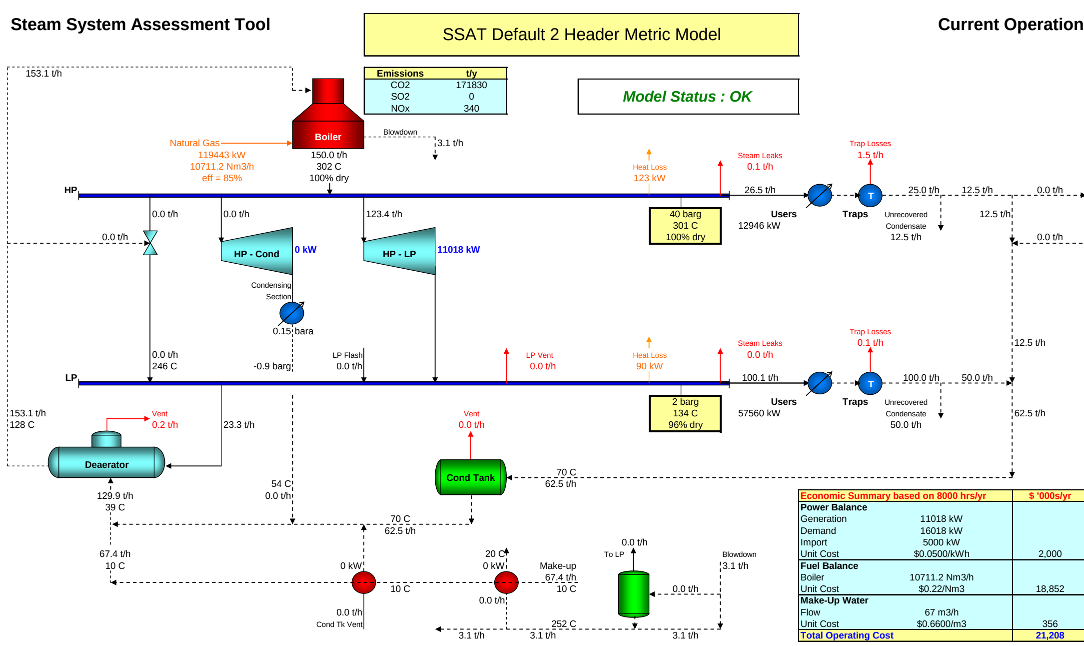

Figure 5b: SSAT "2-Header" Steam System Model

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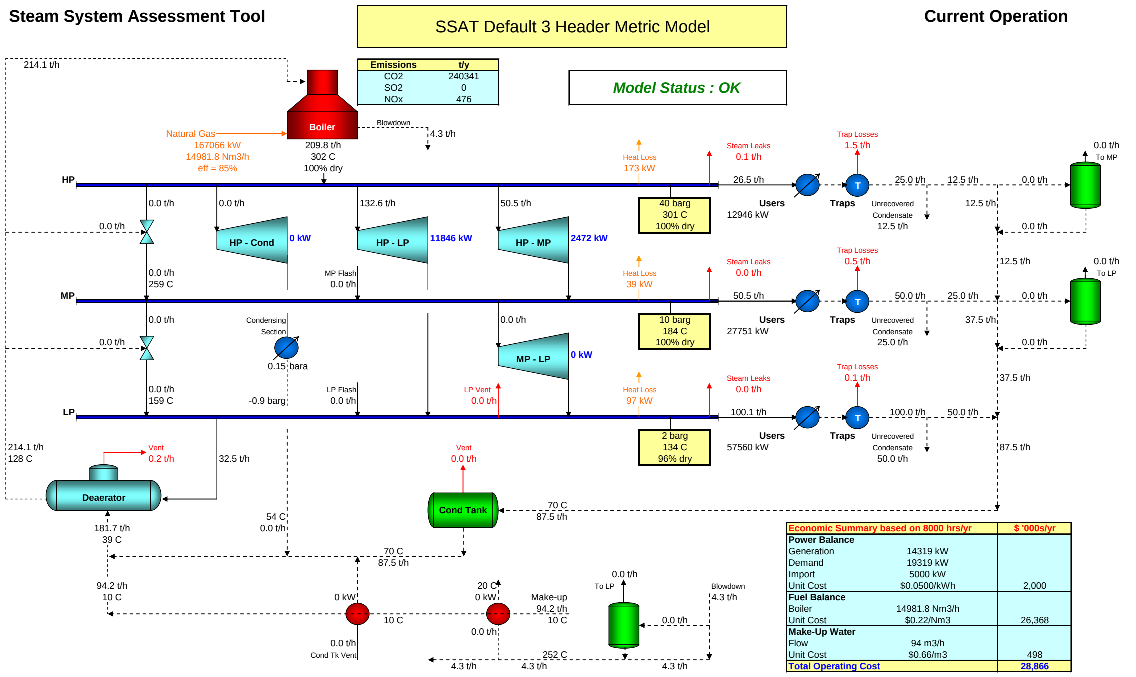

Figure 5c: SSAT "3-Header" Steam System Model

4.2 Steam System Optimization Projects in SSAT

The 3-header SSAT steam system model is the superset of the 1-header and 2-header models and is the most comprehensive steam system model available in SSAT. The "Input" page will require significant site detail information to accurately model the system being evaluated. All the input information required is always pre-populated with defaults and hence, the user can run the steam system model right away. Then as more site information becomes available, it can be added to the "Input" page to make the steam system model as representative of the actual steam system.

There are 18 steam system optimization projects built into the "Projects Input" page that can be turned ON to modify the existing steam system. This allows the user to do a "what-if" analysis on the steam system being optimized. Additionally, SSAT provides a cumulative analysis of multiple projects that are can be done for optimizing the steam system. The SSAT model takes a true "Systems Approach" and has the following 18 steam system optimization projects that can be evaluated for any steam system:

- Steam Demand Savings
- Use an alternative fuel (fuel switching)
- Change boiler efficiency
- Change boiler blowdown rate
- Implement blowdown flash tank to generate low pressure steam
- Change steam generation conditions
- Install and/or modify high pressure to low pressure backpressure steam turbine
- Install and/or modify high pressure to medium pressure backpressure steam turbine
- Install and/or modify medium pressure to low pressure backpressure steam turbine

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- Install and/or modify condensing steam turbine
- Install make-up water heat recovery exchanger on condensate tank vent
- Install make-up water heat recovery exchanger on boiler blowdown
- Improve condensate recovery
- Flash high pressure condensate to medium pressure steam
- Flash medium pressure condensate to create low pressure steam
- Implement a steam trap management program
- Implement a steam leaks management program
- Improve insulation on steam and condensate lines and equipment

Figure 6 shows a snapshot of the "Results" page which provides tabulated information on the energy and economic impacts of steam system optimization.

Steam System Assessment Tool

3 Header Model

Results Summary

SSAT Default 3 Header Model

Model Status : OK

Cost Summary ($ '000s/yr)	Current Operation	After Projects	Reduction	
Power Cost	2,000	2,000	0	0.0%
Fuel Cost	24,178	24,178	0	0.0%
Make-Up Water Cost	453	453	0	0.0%
Total Cost (in $ '000s/yr)	**26,631**	**26,631**	**0**	**0.0%**

On-Site Emissions	Current Operation	After Projects	Reduction	
CO2 Emissions	486135 klb/yr	486135 klb/yr	0 klb/yr	0.0%
SOx Emissions	0 klb/yr	0 klb/yr	0 klb/yr	N/A
NOx Emissions	962 klb/yr	962 klb/yr	0 klb/yr	0.0%

Power Station Emissions	Reduction After Projects	Total Reduction	
CO2 Emissions	0 klb/yr	0 klb/yr	-
SOx Emissions	0 klb/yr	0 klb/yr	-
NOx Emissions	0 klb/yr	0 klb/yr	-

Note - Calculates the impact of the change in site power import on emissions from an external power station. Total reduction values are for site + power station

Utility Balance	Current Operation	After Projects	Reduction	
Power Generation	13883 kW	13883 kW	-	-
Power Import	5000 kW	5000 kW	0 kW	0.0%
Total Site Electrical Demand	18883 kW	18883 kW	-	-
Boiler Duty	523.0 MMBtu/h	523.0 MMBtu/h	0.0 MMBtu/h	0.0%
Fuel Type	Natural Gas	Natural Gas	-	-
Fuel Consumption	522874.9 s cu.ft/h	522874.9 s cu.ft/h	0 s cu.ft/h	0.0%
Boiler Steam Flow	416.5 klb/h	416.5 klb/h	0.0 klb/h	0.0%
Fuel Cost (in $/MMBtu)	5.78	5.78	-	-
Power Cost (as $/MMBtu)	14.65	14.65	-	-
Make-Up Water Flow	22660 gal/h	22660 gal/h	0 gal/h	0.0%

Turbine Performance	Current Operation	After Projects	Marginal Steam Costs	
			(based on current operation)	
HP to LP steam rate	44 kWh/klb	44 kWh/klb	HP ($/klb)	8.28
HP to MP steam rate	23 kWh/klb	23 kWh/klb	MP ($/klb)	7.16
MP to LP steam rate	Not in use	Not in use	LP ($/klb)	6.06
HP to Condensing steam rate	Not in use	Not in use		

Figure 6: SSAT "3-Header" Steam System Model "Results" Page

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5. STEAM GENERATION OPTIMIZATION OPPORTUNITIES

The steam generation area is the focus of attention in any steam system optimization study. This is justified because the generation area is where fuel energy is supplied to produce steam. Fuel is typically purchased at a cost and releases a certain amount of energy in the combustion process that is then captured by the boiler to produce steam.

5.1 Fuel Properties

There are several different kinds of fuels used to produce steam in industrial plants. Some of the common fuels include:

- Solid – Coal, Wood, Biomass, Tire-Derived Fuel, etc.
- Liquid – Heavy fuel oil, Light fuel oil, Paraffin, Waste liquids for incineration, etc.
- Gas – Natural gas, Methane gas, Refinery off gas, etc.

Individual boiler design is based on the fuel used. In the industry, there are several situations where dual-fuel fired boilers are in operation which allow for fuel flexibility and enhance reliability of steam generation in the event of any fuel supply disruptions.

Every fuel has a "Heating Value" which is defined as the energy content of the fuel given either on a mass or volume basis. Most solid and liquid fuels have heating values defined on a mass basis (GJ/ton, KJ/kg or Kcal/kg). Most gaseous fuels have their heating values defined on a volume basis (KJ/m^3 or Kcal/m^3). Conversion between mass-based and volume-based heating values can be done if the fuel density is known.

<u>Higher Heating Value (HHV)</u>
This is also known as the Gross Heating Value. It is the total energy provided by the fuel that is obtained after water vapor in the flue gas stream is condensed back to its natural state (liquid water). Hence, it contains the latent heat of water which is recovered when the water vapor condenses back to liquid water.

<u>Lower Heating Value (LHV)</u>
This is also known as the Net Heating Value. It is the total energy provided by the fuel that is obtained without the condensation of the water vapor in the flue gas stream.

Heating values can be obtained from several different sources including: fuel supplier, Chemical and Mechanical Engineering handbooks, laboratory analysis of fuel samples, etc. All throughout this Training Manual, the fuel's HHV will be used in all the calculations. Using HHV in steam system optimization analysis is a more accurate methodology and results in a complete energy balance of the system. Nevertheless, LHV can also be used to do the same analysis and arrive at identical results. It is very important that the user be CONSISTENT while doing the steam system optimization analysis and ensures that project analyses are completed with either HHV or LHV. Switching between the two will lead to very erroneous results. Table 2 provides the HHV for some of the commonly used boiler fuels.

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Table 2: Higher Heating Values of Common Fuels

Fuel	Sales Unit	Typical Cost [$/sales unit]	HHV [kJ/kg]	Unit Price [$/GJ]
Natural Gas	Nm³	1.00	54,220	26.35
Number 2 Fuel Oil	tonne	1,500	45,125	33.24
Number 6 Oil (LS)	tonne	785	43,595	18.01
Number 6 Oil (HS)	tonne	797	43,764	18.21
Bituminous Coal	tonne	171	31,890	5.36
SubBituminous Coal	tonne	129	23,465	5.50
Green Wood	tonne	22	12,215	1.80

5.2 Steam Generation Cost

Along with the HHV, Table 2 also presents typical cost of the fuel in two configurations – cost per sales unit and cost per unit of energy (GJ). The fuel cost is the most important parameter for calculating the steam generation cost and the steam cost indicator.

$$K_{boiler} = m_{fuel} \times k_{fuel}$$

where K_{boiler} is the total fuel operating cost of boiler and m_{fuel} and k_{fuel} are fuel flow rate and fuel cost, respectively.

$$k_{steam} = \frac{m_{fuel} \times k_{fuel}}{m_{steam}}$$

where k_{steam} is the steam cost indicator (or unit cost of steam production) from the boiler and m_{steam} is the steam flow rate.

<u>Example</u>

Calculate the hourly natural gas boiler fuel cost that generates steam at 20 Tph (steady – all year). The measured natural gas flow rate is 1,693 m³/hr (28 m³/min) and the cost of natural gas is ($1.0/m³).

$$K_{boiler} = 1{,}693 \times 1.0 = \$1{,}693 / hr$$

$$K_{boiler} = 1{,}693 \times 1.0 \times 8{,}760 = \$14{,}830{,}680 / yr$$

$$k_{steam} = \frac{1{,}693}{20} = \$84.60 / tonne$$

The hourly cost for generating 20 Tph steam from this natural gas boiler is $1,693 and the marginal fuel-related steam cost (Steam Cost Indicator) is $84.60 per tonne of steam generated.

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5.3 Boiler Efficiency Calculation (Direct Method)

Boiler efficiency (or steam generation efficiency) is defined as the ratio of the heat absorbed by feedwater to generate steam and the fuel input energy.

$$\eta_{boiler} = \frac{m_{steam}\left(h_{steam} - h_{feedwater}\right)}{m_{fuel} \times HHV_{fuel}} \times 100$$

where h_{steam} and $h_{feedwater}$ are the enthalpies of steam and feedwater, respectively.

This equation can be applied to a specific boiler or a complete boiler plant. It can be applied for an instantaneous snapshot or any defined time-period (daily, month, annual, etc.). This is known as the “Direct Method” for calculating boiler efficiency. Boiler efficiency varies significantly based on the fuel used, installed equipment and controls, boiler design, operating load, etc. Typically, boiler efficiency is expected to be ~70-75% (for wood); 80-85% (for natural gas); and 85-90% (for oil and coal). Figure 7 presents a typical boiler efficiency curve based on actual data collected from a natural gas boiler.

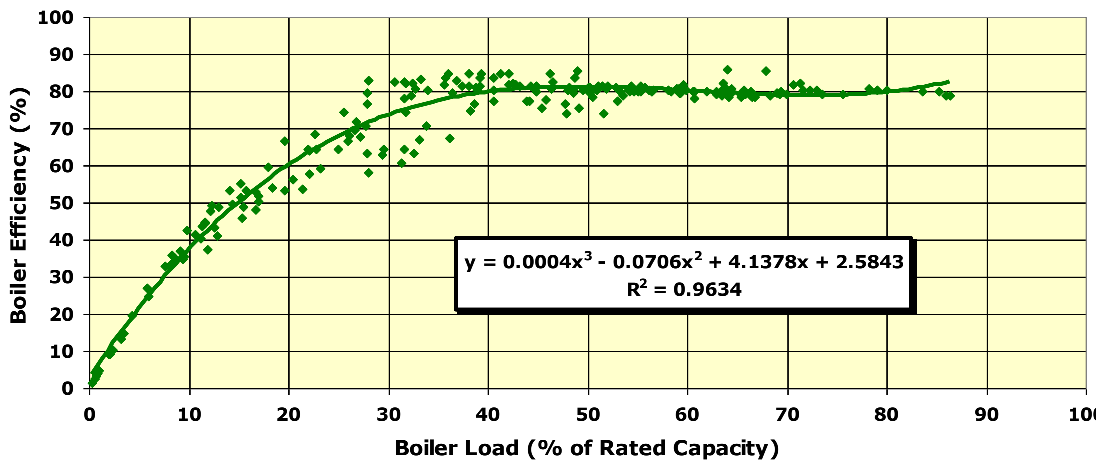

Figure 7: Typical Natural Gas Fired Boiler Efficiency Curve

<u>Example</u>

Calculate the natural gas boiler efficiency that generates steam at 20 Tph (steady – all year). The measured natural gas flow rate is 1,693 m^3/hr (28 m^3/min) and the cost of natural gas is (\$1.0/m^3). The HHV of the natural gas is 54,220 kJ/kg (40,144 kJ/m^3). Superheated steam is generated at 25 bars, 375°C and boiler feedwater from the deaerator is at 30 bars, 110°C.

From the information provided,

m_{steam} = 20,000 kg/hr

h_{steam} = 3,181 kJ/kg (from Steam Tables based on 25 bars, 375°C)

$h_{feedwater}$ = 463.5 kJ/kg (from Steam Tables based on 30 bars, 110°C)

m_{fuel} = 1,693 m^3/hr

HHV_{fuel} = 40,144 kJ/m^3

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Boiler efficiency can be calculated as follows:

$$\eta_{boiler} = \frac{m_{steam}\left(h_{steam} - h_{feedwater}\right)}{m_{fuel} \times HHV_{fuel}} \times 100$$

$$\eta_{boiler} = \frac{20{,}000\,(3{,}181 - 463.5)}{1{,}693 \times 40{,}144} \times 100$$

$$\eta_{boiler} = 80.0\,\%$$

5.4 Boiler Efficiency Calculation (Indirect Method)

Boiler efficiency can also be determined in an indirect manner by determining the magnitude of the individual energy losses. Figure 8 schematically provides information about the major energy losses that occur in an operating boiler.

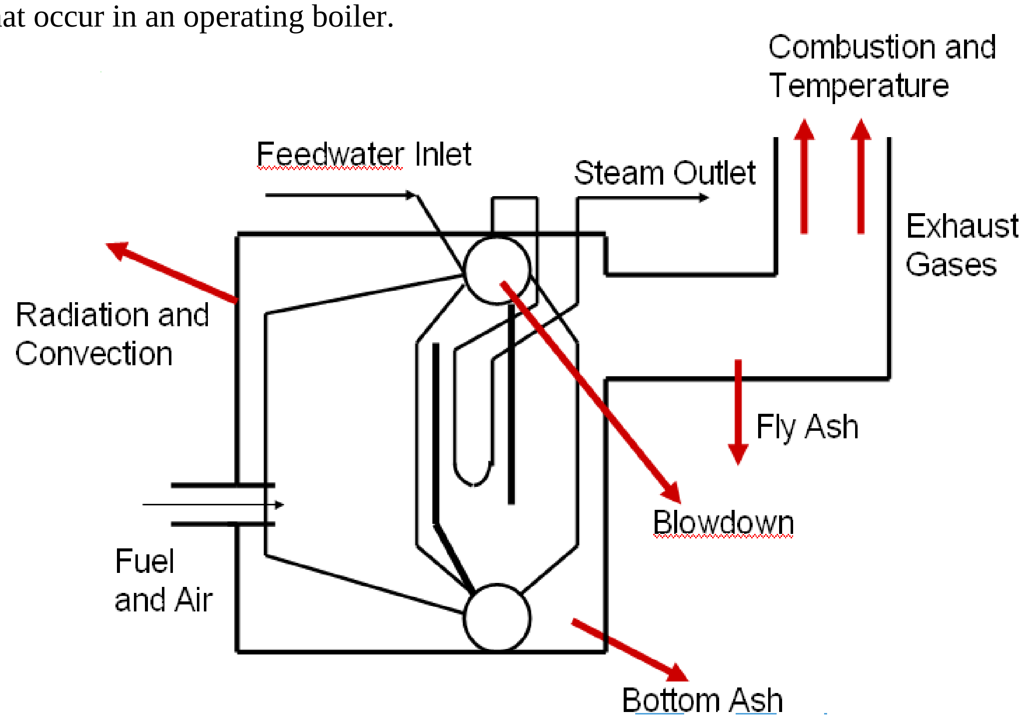

Figure 8: Operating Boiler Losses
(Courtesy: US DOE Steam BestPractices End User Training Program)

There are different kinds of losses in an operating boiler such as Shell loss, Blowdown loss, Stack (Combustion and Temperature) loss, Fly and Bottom ash loss, Loss on Ignition (LOI), etc. Using an energy balance on the boiler, the boiler efficiency can be calculated as:

$$\eta_{boiler} = 100 - \lambda_{shell} - \lambda_{blowdown} - \lambda_{stack} - \lambda_{miscellaneous}$$

where λ_{shell} represents the Shell loss (%); $\lambda_{blowdown}$ represents the Blowdown loss (%); λ_{stack} represents the Stack loss (%); and $\lambda_{miscellaneous}$ represents the other losses (%).

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This is known as the "Indirect Method" of calculating boiler efficiency. It will need significantly more information from the operating boiler compared to the "Direct Method" of boiler efficiency calculation and will also be more time consuming than the "Direct Method". Nevertheless, the "Indirect Method" has got significant advantages over the "Direct Method" including:

- Lesser uncertainty (higher accuracy)
- Ability to pinpoint and quantify the areas of energy losses

From a steam system optimization analysis, both methods should be used independently to calculate boiler efficiency. The calculated values can then be compared which helps to build confidence levels in the plant instrumentation and data gathering devices.

5.2.1 Shell Loss

Shell loss is the amount of fuel energy that leaves the boiler from its outer surface. The surface of the boiler is above ambient temperature and hence, there is always a certain amount of heat lost to the ambient. This heat loss occurs due to radiation and convection from the boiler surfaces. It is difficult to accurately measure the shell loss from a boiler. It is generally estimated from some limited field measurements. The American Society of Mechanical Engineers Performance Test Code 4 (ASME-PTC-4) provides a detailed methodology for calculating this loss from the boiler surfaces.

A first order of magnitude shell loss is provided in Table 3 below as a guide. The shell loss estimation methodology utilizes the characteristic temperature of a boiler surface, surface area and an estimated ambient surface airflow velocity. These estimates are used to complete a heat transfer analysis for all of the surfaces of the boiler yielding an estimate for the overall boiler shell loss. This technique is simple; however, the results must be considered a general estimate.

Table 3: First Order Shell Loss Guide

Shell Loss Gross Estimate Field Evaluations				
Boiler Type	**Steam Production Rating**		**Boiler Full-Load Shell Loss Estimate**	
	Minimum [Tph]	**Maximum [Tph]**	**Maximum [%]**	**Minimum [%]**
Water-tube	5	50	2.0	0.3
Water-tube	50	500	0.6	0.1
Water-tube	500	5,000	0.2	0.1
Fire-tube	0.5	20	1.0	0.1

It has to be noted that the boiler shell loss magnitude is constant and is independent of the boiler load. Shell loss is expressed as a percent of fuel input energy. Hence, shell loss (%) increases as the boiler load reduces. For most well-maintained boilers, the full load shell loss is expected to be ~0.1% to 2% of total fuel input energy.

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Example

An *ASME type* investigation of the shell loss for the 20 Tph natural gas boiler indicates that the shell loss is ~0.5%. The measured natural gas flow rate is 1,693 m³/hr (28 m³/min) and the cost of natural gas is ($1.0/m³). Estimate the fuel input energy cost associated with the shell loss.

From the information provided,
m_{fuel} = 1,693 m³/hr
k_{fuel} = 1.0 $/m³
λ_{shell} = 0.5%

$$K_{shell} = m_{fuel} \times k_{fuel} \times \lambda_{shell}$$
$$K_{shell} = 1{,}693 \times 1.0 \times 0.005 = \$8.47 / hr$$
$$K_{shell} = 8.47 \times 8{,}760 \approx \$74{,}200 / yr$$

5.2.2 Blowdown Loss

Boiler feedwater is treated make-up water and condensate. However, there are still dissolved chemicals in boiler feedwater which do not exit the boiler with steam because they are not soluble in steam. As a result, the concentration of these chemicals increases in the boiler. Elevated concentration of chemicals in boilers can result in serious operational problems and boiler integrity can be damaged. These problems could including, but not limited to: foaming resulting in liquid carryover, scaling on the water-side of the tubes resulting in tube leaks and failures, loose sludge in the boiler water, etc.

Blowdown is the primary mechanism that controls the water chemistry of the boiler water. Blowdown controls the concentration of dissolved and precipitated chemicals in the boiler and ensures that the boiler functions reliably and doesn't have an unplanned shutdown or failure.

Generally, blowdown is controlled based on boiler water conductivity. Conductivity is a direct measurement that can continuously provide an indication of boiler water quality. However, conductivity must be correlated to individual chemical contaminants through periodic water analysis. Conductivity and the results of specific boiler water testing aid in adjusting the blowdown rate.

It has to be noted that blowdown is saturated liquid at boiler pressure. Hence, there is a significant amount of thermal energy associated with blowdown. As blowdown is discharged from the boiler, this thermal energy (which was provided by the fuel) is lost. The ratio of this energy lost to the total fuel input energy is the blowdown loss - $\lambda_{blowdown}$.

Utilizing conventional flow meters for measuring blowdown flow is difficult because blowdown is saturated water which will flash at the slightest pressure drop. Most flow meter devices will impose a sufficient pressure drop that results in two-phase flow which is impossible to measure. Hence, in order to measure blowdown, a certain chemical composition in the feedwater and in the boiler water is measured. The chemical component measured in the analysis must be of sufficient concentration to allow an accurate measurement. The ratio of that chemical's concentration in the feedwater to it's concentration in the boiler water is used to establish the blowdown rate. Blowdown flow (β) as a percent of feedwater flow and is as follows:

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$$\beta = \frac{Blowdown\ Flow}{Feedwater\ \ Flow} \approx \frac{Feedwater\ Conductivity}{Blowdown\ Conductivity}$$

$$m_{blowdown} = \left(\frac{\beta}{1-\beta}\right) m_{steam}$$

where $m_{blowdown}$ is the blowdown flow rate.

Boiler blowdown thermal energy content loss (Q_{bd_boiler}) and blowdown loss ($\lambda_{blowdown}$) are calculated as follows:

$$Q_{bd\_boiler} = m_{blowdown}\left(h_{blowdown} - h_{feedwater}\right)$$

$$\lambda_{blowdown} = \left(\frac{Q_{bd\_boiler}}{m_{fuel} \times HHV_{fuel}}\right) \times 100$$

where $h_{blowdown}$ and $h_{feedwater}$ are the enthalpies of the blowdown and feedwater streams, respectively.

<u>Example</u>

Calculate the amount of blowdown and blowdown loss for the 20 Tph natural gas fired boiler operating at 25 bars. Boiler feedwater is supplied at 30 bars, 110°C. Additional information about the fuel flow rate and water chemistry is provided below.
HHV of natural gas = 54,220 kJ/kg (40,144 kJ/m^3)
Fuel supply = 1,693 m^3/hr (28 m^3/min)
Fuel cost = $1.0/m^3
Conductivity for blowdown = 2,000 μmhos/cm
Conductivity for feedwater = 100 μmhos/cm
Makeup water temperature: 20°C

Blowdown mass flow rate is calculated from the information provided as follows:

$$\beta \approx \frac{Feedwater\ Conductivity}{Blowdown\ Conductivity} = \frac{100}{2{,}000} = 0.05$$

$$m_{blowdown} = \left(\frac{0.05}{1-0.05}\right) 20{,}000 = 1{,}052\,\frac{\text{kg}}{\text{hr}} = 0.29\,\frac{\text{kg}}{\text{s}}$$

Boiler blowdown thermal energy content and blowdown loss are calculated as follows:

$$Q_{bd\_boiler} = m_{blowdown}\left(h_{blowdown} - h_{feedwater}\right) = 0.29 \times (971.8 - 463.5) = 148\ \text{kW}$$

$$\lambda_{blowdown} = \left(\frac{Q_{bd\_boiler}}{m_{fuel} \times HHV_{fuel}}\right) \times 100 = \left(\frac{148}{\frac{1{,}693}{3{,}600} \times 40{,}144}\right) \times 100 = 0.79\,\%$$

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It has to be noted that the control volume for the boiler blowdown loss calculation was just the boiler. Nevertheless, in an actual industrial steam system, feedwater is first heated in a deaerator or feedwater heater and then sent to the boiler. Hence, from a system perspective, blowdown is actually replaced by make-up water which is at ambient conditions (and not at feedwater conditions). The total system loss for blowdown is calculated as follows:

$$Q_{bd\_system} = m_{blowdown}\left(h_{blowdown} - h_{makeup}\right)$$

$$\lambda_{bd\_system} = \left(\frac{Q_{bd\_system}}{m_{fuel} \times HHV_{fuel}}\right) \times 100$$

<u>Example</u>

For the previous boiler blowdown system analysis, calculate the overall system based blowdown energy loss and the equivalent fuel energy cost associated with boiler blowdown. Assume that makeup water to the steam system is at 20°C.

System based boiler blowdown thermal energy content and blowdown loss are calculated as follows:

$$Q_{bd\_system} = m_{blowdown}\left(h_{blowdown} - h_{makeup}\right) = 0.29 \times (971.8 - 83.9) = 259\,kW$$

$$\lambda_{bd\_system} = \left(\frac{Q_{bd\_system}}{m_{fuel} \times HHV_{fuel}}\right) \times 100 = \left(\frac{259}{\frac{1{,}693}{3{,}600} \times 40{,}144}\right) \times 100 = 1.37\,\%$$

This equivalent fuel energy cost for the system impact for blowdown can be calculated as follows:

$$K_{bd\_system} = m_{fuel} \times k_{fuel} \times \lambda_{bd\_system}$$

$$K_{bd\_system} = 1{,}693 \times 1.0 \times 0.0137 = \$23.2/hr$$

$$K_{bd\_system} = 23.2 \times 8{,}760 \approx \$203{,}180/yr$$

Figure 9 presents a graphical chart that provides quantitative information on the boiler blowdown thermal energy content for boilers operating at different pressures and different blowdown rates. A generic steam production rate of 100 Tph is used in this graph. The user can use Figure 9 for a quick estimation of the boiler blowdown energy content or can revert to more detailed calculations as shown above.

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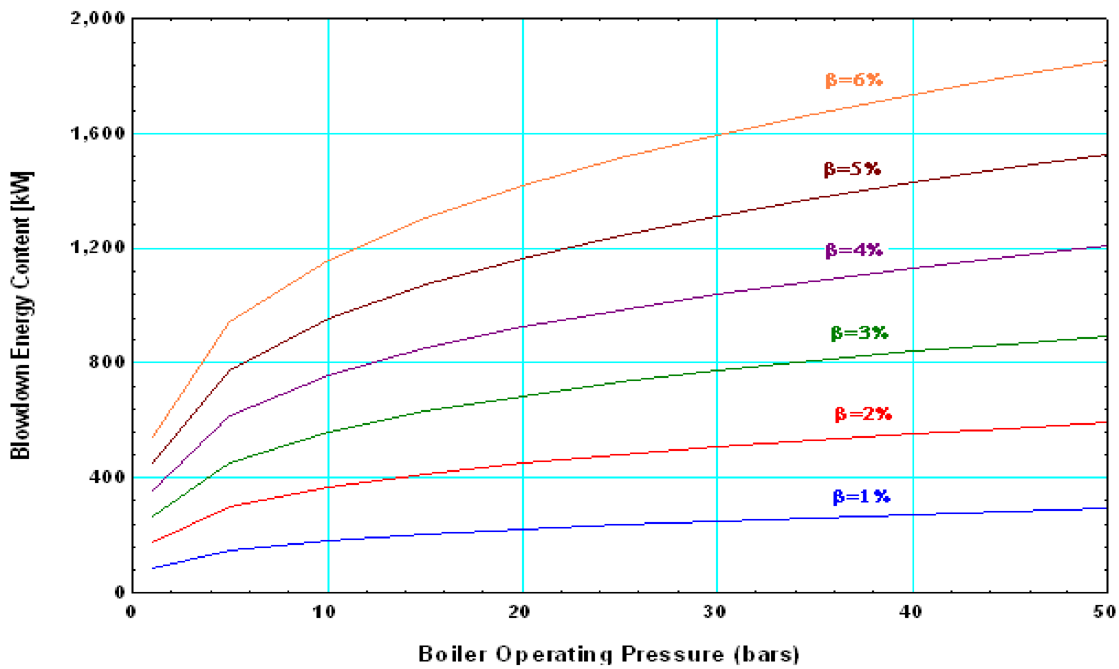

Figure 9: Boiler Blowdown Thermal Energy Content (100 Tph steam generation and feedwater at 20°C)

5.2.3 Stack Loss

While blowdown and shell losses are relatively small, stack loss is almost always the largest component of boiler efficiency loss. Stack loss has two components — temperature and combustion (or excess air). Managing the stack loss is a critical factor in optimizing boiler operations and increasing boiler efficiency. Both components of stack loss are discussed in detail below.

5.2.3.1 Flue Gas Temperature Component

A significant amount of fuel energy resides in the boiler flue gases. The temperature of the exhausting flue gas represents the amount of energy in the stack gas. The difference between the flue gas temperature and the combustion chamber inlet temperature (typically, ambient air temperature) is known as "Net Stack Temperature" and represents the amount of fuel energy that is lost in the stack. Assuming that the inlet air temperature is constant for a boiler, a higher flue gas temperature implies a higher stack loss. This leads to a lower boiler efficiency. Hence, boiler flue gas temperature is a critical parameter and should be carefully monitored and trended. There are several factors which affect the flue gas exhaust temperature and include:

- Boiler design
- Heat recovery equipment
- Boiler load
- Fire side fouling
- Water side fouling

It is important to take these factors into account while evaluating optimizing boiler operations.

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5.2.3.2 Combustion Component

The combustion component of the stack loss depends on the unburned components of the fuel and amount of excess air (or flue gas oxygen).

The first principle of combustion management is to ensure that there is enough oxygen in the combustion process to ensure that all the fuel is combusted and there are no (minimal) combustibles in the stack.

The second principle of combustion management aims to restrain the amount of oxygen (air) in the combustion process. All the combustion air is heated up by fuel. The extra air (oxygen) added to the combustion zone enters the boiler at ambient temperature and exits the boiler at flue gas temperature. Ambient air contains ~4 parts nitrogen for every 1 part of oxygen. As a result, a large amount of nitrogen enters the combustion zone with excess air (oxygen) and a significant amount of fuel energy is spent on heating this excess air.

There are different methodologies available to calculate stack losses but every method is based on some form of the combustion model. For example, the ASME Power Test Code 4 clearly defines all the parameters, equations, measurements and instruments required to accurately calculate stack loss. That methodology is very detailed and instead of users having to use a detailed combustion model, this training manual provides two sources of calculating stack losses based on a combustion model developed by Dr. Greg Harrell for the US Department of Energy. They include:

- ○ Stack loss tables (Table 4)
- ○ Stack Loss calculator in the US DOE SSAT software (Figure 10)

The stack loss model assumes minimal (or no) combustibles in the stack and no condensate. The data required is: fuel, flue gas temperature, flue gas oxygen content and inlet air temperature.

Table 4: Stack Loss Table for Natural Gas

Stack Loss Table for			Typical Natural Gas											
Flue Gas Oxygen Content Wet Basis [%]	Flue Gas Oxygen Content Dry Basis [%]	Comb Conc [ppm]	Stack Loss [% of fuel Higher Heating Value input] Net Stack Temperature [Δ°C] {Difference between flue gas exhaust temperature and ambient temperature}											
			100	128	156	183	211	239	267	294	322	350	378	406
1.0	1.2	0	13.6	14.7	15.8	16.9	18.0	19.1	20.2	21.3	22.4	23.6	24.7	25.9
2.0	2.4	0	13.8	14.9	16.1	17.2	18.4	19.5	20.7	21.9	23.1	24.2	25.4	26.6
3.0	3.6	0	14.0	15.2	16.4	17.6	18.8	20.0	21.3	22.5	23.7	25.0	26.3	27.5
4.0	4.7	0	14.2	15.5	16.7	18.0	19.3	20.6	21.9	23.2	24.5	25.8	27.2	28.5
5.0	5.8	0	14.5	15.8	17.2	18.5	19.9	21.2	22.6	24.0	25.4	26.8	28.2	29.6
6.0	6.9	0	14.8	16.2	17.6	19.1	20.5	22.0	23.4	24.9	26.4	27.8	29.3	30.8
7.0	8.0	0	15.1	16.6	18.1	19.7	21.2	22.8	24.3	25.9	27.5	29.1	30.7	32.3
8.0	9.1	0	15.5	17.1	18.8	20.4	22.1	23.7	25.4	27.1	28.8	30.5	32.2	33.9
9.0	10.1	0	16.0	17.7	19.5	21.2	23.0	24.8	26.6	28.5	30.3	32.1	34.0	35.8
10.0	11.1	0	16.5	18.4	20.3	22.2	24.2	26.1	28.1	30.1	32.1	34.1	36.1	38.1
Actual Exhaust T [°C]			**121**	**149**	**177**	**204**	**232**	**260**	**288**	**316**	**343**	**371**	**399**	**427**
Ambient T [°C]			**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**

Reference: Combustion model developed by Greg Harrell, Ph.D., P.E.

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Steam System Assessment Tool

Stack Loss Calculator

Based on user inputs of Stack Temperature, Ambient Temperature and Stack Oxygen Content, an estimate will be provided of the heat loss from the boiler stack. Losses are expressed as a percentage of the heat fired.

Stack losses are related to SSAT Boiler Efficiency as follows:

SSAT Boiler Efficiency = 100% - Stack Loss (%) - Shell Loss (%)

Shell Loss refers to the radiant heat loss from the boiler. Typically <1% at full load, 1-2% at reduced load.

Input Data

Stack Gas Temperature (°F)	200 °C	Stack Temperature - Ambient Temperature = 180°C
Ambient Temperature (°F)	20 °C	

Stack Gas Oxygen Content (%)	5 %	

Note: Stack gas oxygen content is expressed on a molar or volumetric basis

Results

Estimated Stack Losses for each of the default fuels are as follows:

Natural Gas	18.3 %
Number 2 Fuel Oil	14.0 %
Number 6 Fuel Oil (Low Sulfur)	13.5 %
Number 6 Fuel Oil (High Sulfur)	13.7 %
Typical Eastern Coal (Bituminous)	12.0 %
Typical Western Coal (Subbituminous)	13.6 %
Typical Green Wood	24.7 %

Figure 10: Stack Loss Calculator in US DOE SSAT Software

(Reference: Combustion model developed by Greg Harrell, Ph.D., P.E.)

<u>Example</u>

Estimate the stack loss on the 20 Tph operating boiler having the following conditions:
HHV of natural gas = 54,220 kJ/kg (40,144 kJ/m³)
Fuel supply = 1,693 m³/hr (28 m³/min)
Fuel cost = $1.0/m^3
Stack temperature: 200°C
Flue gas oxygen: 5%
Negligible combustibles were found in stack gas analysis
Ambient air temperature: 20°C

Input Data

Stack Gas Temperature (°F)	200 °C	Stack Temperature - Ambient Temperature = 180°C
Ambient Temperature (°F)	20 °C	

Stack Gas Oxygen Content (%)	5 %	

Note: Stack gas oxygen content is expressed on a molar or volumetric basis

Results

Estimated Stack Losses for each of the default fuels are as follows:

Natural Gas	**18.3 %**
Number 2 Fuel Oil	**14.0 %**
Number 6 Fuel Oil (Low Sulfur)	**13.5 %**
Number 6 Fuel Oil (High Sulfur)	**13.7 %**
Typical Eastern Coal (Bituminous)	**12.0 %**
Typical Western Coal (Subbituminous)	**13.6 %**
Typical Green Wood	**24.7 %**

λ_{stack}

Figure 11: Example Boiler – Stack Loss

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Example

Estimate the boiler efficiency (Indirect Efficiency Calculation) based on the different losses calculated in the previous sections on the 20 Tph natural gas operating boiler.

$$\eta_{boiler} = 100 - \lambda_{shell} - \lambda_{blowdown} - \lambda_{stack} - \lambda_{miscellaneous}$$

$$\eta_{boiler} = 100 - 0.50 - 0.79 - 18.3 - 0.0$$

$$\eta_{boiler} = 80.4\,\%$$

Note that the results from the indirect method of calculating boiler efficiency (80.4%) compares very well with the direct method of calculating efficiency (80%). These values are within the uncertainty limits given the accuracy levels of the measurements.

5.5 Steam Generation Optimization Opportunities & BestPractices

There are several optimization opportunities in the steam generation area including:
- Minimize excess air
- Install heat recovery equipment
- Clean boiler heat transfer surfaces
- Improve water treatment
- Install an automatic boiler blowdown controller
- Recover energy from boiler blowdown
- Add/restore boiler refractory
- Minimize the number of operating boilers
- Investigate fuel switching
- Optimize deaerator operations

5.3.1 Minimize Excess Air

Proper combustion management requires adding enough oxygen to the combustion zone to burn all of the fuel but not adding too much air to ensure that the thermal energy loss is minimized. Combustion management evaluates the controlling methodology of the combustion process and begins with measurements.

Typically in boilers, fuel flow is controlled by steam header pressure. If steam pressure decreases the fuel flow controller will increase fuel flow for the boiler to generate more steam — restoring the steam pressure to the set point. Conversely, if steam pressure increases, fuel flow will be decreased to reduce steam production.

As the fuel flow into the boiler changes combustion, air flow must correspondingly change to maintain proper combustion. There are two primary forms of combustion control:
- Positioning control
- Automatic oxygen trim control

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5.3.1.1 Positioning Control

Combustion air flow control is accomplished by mechanically linking the air-flow control device (damper) to the fuel-flow control device. This is commonly called *positioning control* because the air-flow control device will have a position that is based solely on the position of the fuel-flow control device. Figure 12 provides a schematic of the *positioning control* mechanism. It should be noted that this control does not incorporate any active oxygen or combustibles measurements. Oxygen and combustibles measurements are only taken periodically to establish the position relationship between the fuel controller and the air controller.

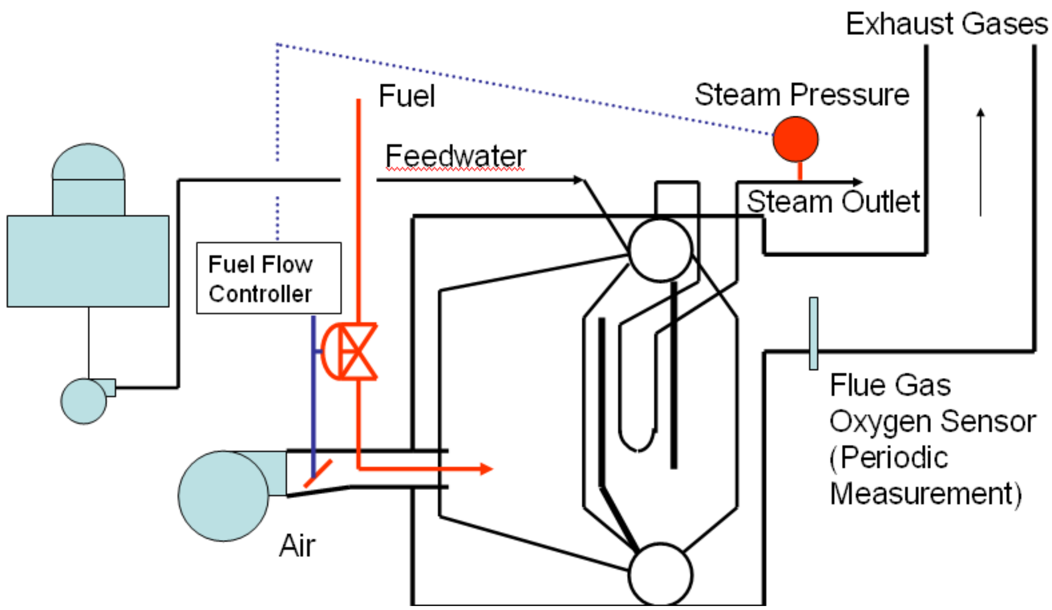

Figure 2: Positioning Control System

(Courtesy: US DOE Steam BestPractices End User Training Program)

"Tuning the boiler" is a BestPractice which should be done on a periodic basis to reestablish the positional relationship between the air and fuel. This will ensure that combustion air will be minimized within the limits of *positioning control*.

5.3.1.2 Automatic Oxygen Trim Control

With an *automatic oxygen trim control* methodology, combustion airflow is controlled by a combination of the fuel flow control valve and the flue gas oxygen monitor in the stack. Based on a burner manufacturers' combustion curve, a main air-flow control device (damper) is provided a signal based on the fuel-flow control valve as is the case with the *positioning control* methodology. But in addition, the flue gas oxygen is measured continuously and a much tighter relationship can be established to minimize the amount of excess air. This additional control trims the amount of combustion air and thereby minimizes the amount of excess air. This *automatic oxygen trim control* is much more effective and efficient compared to the *positioning control*. Figure 13 provides a schematic of the *automatic oxygen trim control* mechanism. In several installations, an *automatic oxygen trim control* is coupled with a variable speed driven (VSD) forced combustion fan which leads to additional electrical energy savings compared to a damper control as the case is in *positioning control*.

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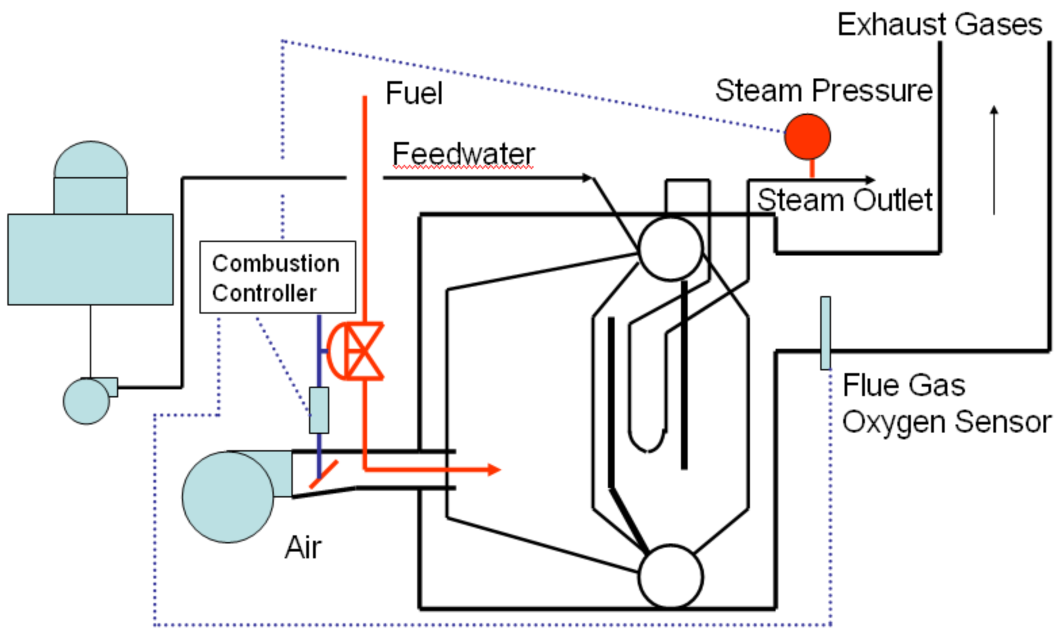

Figure 3: Automatic Oxygen Trim Control System
(Courtesy: US DOE Steam BestPractices End User Training Program)

Based on commercially best available control technology, Table 5 provides flue gas oxygen (and excess air) operating levels for boilers operating with different fuels for the two types of control methodologies. Generally, higher flue gas oxygen content values correspond with low burner loads and low flue gas oxygen contents correspond with high burner loads. Excess air is noted in the table for reference purposes. Flue gas oxygen content is the measured value. Excess air is calculated from the fuel composition and the measured oxygen value.

Table 5: Flue Gas Control Parameters
(Courtesy: US DOE ITP Steam BestPractices End User Training Program)

Typical Flue Gas Oxygen Content Control Parameters								
Fuel	Automatic Control Flue Gas O_2 Content		Positioning Control Flue Gas O_2 Content		Automatic Control Excess Air		Positioning Control Excess Air	
	Min. [%]	Max. [%]	Min. [%]	Max. [%]	Min. [%]	Max. [%]	Min. [%]	Max. [%]
Natural Gas	1.5	3.0	3.0	7.0	9	18	18	55
Numb. 2 Fuel Oil	2.0	3.0	3.0	7.0	11	18	18	55
Numb. 6 Fuel Oil	2.5	3.5	3.5	8.0	14	21	21	65
Pulverized Coal	2.5	4.0	4.0	7.0	14	25	25	50
Stoker Coal	3.5	5.0	5.0	8.0	20	32	32	65

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In order to estimate the potential benefit of minimizing excess air it will be necessary to evaluate the total boiler operating costs and the current and new operating boiler efficiencies. The equation below provides the ability to calculate the cost savings for the energy savings opportunity.

$$\sigma = K_{boiler}\left(1 - \frac{\eta_{current}}{\eta_{new}}\right)$$

where σ is the fuel cost savings, K_{boiler} is the current operating cost of the boiler, $\eta_{current}$ and η_{new} are the current and new boiler operating efficiencies, respectively.

Example

The 20 Tph natural gas-fired operating boiler has a positional controller that is periodically re-tuned. Estimate the annual energy cost savings opportunity for implementing an automatic oxygen trim controller for managing the excess air on the boiler. Neglect the shell and blowdown losses for the boiler efficiency calculations.
HHV of natural gas = 54,220 kJ/kg (40,144 kJ/m^3)
Fuel supply = 1,693 m^3/hr (28 m^3/min)
Fuel cost = $1.0/m^3
Stack temperature: 200°C
Flue gas oxygen: 5%
Negligible combustibles were found in stack gas analysis
Ambient air temperature: 20°C

The boiler operating cost was calculated in the earlier section as follows:

$$K_{boiler} = 1{,}693 \times 1.0 = \$1{,}693/hr$$
$$K_{boiler} = 1{,}693 \times 1.0 \times 8{,}760 = \$14{,}830{,}680/yr$$

Current stack loss was calculated from the US DOE SSAT Stack Loss calculator and is 18.3% for 5% flue gas oxygen, 200°C stack temperature and 20°C ambient temperature. Hence, the current boiler efficiency, $\eta_{current}$ is 81.7%.

From Table 5, it can be observed that commercially available automatic oxygen trim controllers can control the flue gas oxygen within 3%. Assuming that the stack temperature does not change, the new stack loss is calculated to be 17.4%. Hence, the new boiler efficiency, η_{new} is 82.6%.

The energy cost savings for minimizing the excess air by implementing an automatic oxygen trim controller are calculated as follows:

$$\sigma_{ExcessAir} = K_{boiler}\left(1 - \frac{\eta_{current}}{\eta_{new}}\right)$$
$$\sigma_{ExcessAir} = 14{,}830{,}680 \times \left(1 - \frac{81.7}{82.6}\right)$$
$$\sigma_{ExcessAir} = \$161{,}593/yr$$

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5.3.2 Install Flue Gas Heat Recovery Equipment

There are three main kinds of flue gas heat recovery equipment that are found in industrial boilers. They are:

- Feedwater economizers
- Air preheaters
- Condensing economizers

The type of heat recovery equipment found in industrial boilers will depend very heavily on the fuel being used and the corresponding boiler design. Almost all industrial boilers will (or should) have feedwater economizers. Most solid fuel boilers and fuels with significant moisture content will have air preheaters. A significant number of industrial boilers and power plant boilers will have both feedwater economizers and air preheaters. Boilers burning clean burning fuels (natural gas, methane, diesel, etc.) can benefit from condensing economizers depending on the overall system heat requirements.

5.3.2.1 Feedwater Economizer

A feedwater economizer is a heat exchanger installed to transfer thermal energy from the flue gas into the boiler feedwater. This is the most common energy recovery component installed on boilers. Even if the boiler design does not have a feedwater economizer configured, it maybe very feasible to install a modular feedwater economizer in the stack of an existing boiler. State-of-the-art heat exchanger design and material technologies allow for minimal flue gas side pressure drop and very good temperature approaches to maximize the heat recovery with minimal heat transfer area. Additionally, feedwater economizers are compact and typically do not present any major “real-estate” or size constraints.

5.3.2.2 Air Preheater

A combustion air preheater heats the combustion air by transferring energy from the flue gas in the stack. The heat exchange is identical to the feedwater economizer except that instead of the feedwater it is the combustion air being heated. The net result is a reduction in fuel usage and hence, an increase in the boiler efficiency.

Due to the nature of heat transfer – air-to-air, air preheaters are large and typically will have a much larger pressure drop associated with them. Most industrial boilers with an air preheater will almost always have an induced draft fan also to overcome this pressure drop and avoid significant back-pressure on the combustion chamber.

Additional care must also be taken to avoid reaching an exhaust flue gas temperature below the acid dew point. This minimum temperature limit depends on the sulfur content in the fuel. Condensation in the stack (or flue gas) would form sulfuric acid which is very corrosive and would lead to metal deterioration and lower operational reliability of the boiler. In addition to sulfuric acid, further reduction in the stack gas temperature would lead to the formation of carbonic acid. This is not a major concern for short durations since carbonic acid is a weak acid but over time it will surely become an operational issue if the metallurgy is not properly configured for condensation in the stack gas.

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5.3.2.3 Condensing Economizer

With water vapor being a product of combustion it typically, stays in the gaseous state and exits the stack. Nevertheless, this water vapor contains a significant amount of energy which can be recovered if this water vapor is allowed to condense. There is commercially available heat recovery equipment which has been specifically designed for clean burning fuels (natural gas, methane gas, propane, #2 fuel oil, etc.) to recover this latent heat of water vapor from the flue gas. These units are typically referred to as condensing economizers.

Depending on the fuel, condensing economizers can improve boiler efficiency by more than 10%. To achieve condensation in the flue gas stream, flue gas temperatures should get below the dew point. This is typically 60°C for natural gas combustion and as the flue gas temperature drops more and more water vapor condenses allowing for higher heat recovery.

It has to be noted that since the dew point controls the condensation process in the flue gas, there should be a need for low temperature heat in the plant. Condensing economizers can recover a large amount of heat but it is very low grade. Applications in industry which require a lot of low-grade heating such as food processing plants, steam plants with 100% make-up water, textiles, plant or district heating etc. are often good targets for condensing economizers.

Evaluation of condensing economizers will typically require a partial pressure-based combustion model and is not within the scope of this training manual. Nevertheless, condensing economizer manufacturers and text books can provide charts of heat recovery that have been developed for specific clean burning fuels.

<u>Example</u>

The 20 Tph natural gas-fired operating boiler used to have a feedwater economizer but it was removed for maintenance and removal of scale build-up. It has been a few years and the currently the boiler operates without the feedwater economizer. Estimate the annual energy cost savings opportunity for re-installing a feedwater economizer on the boiler. Neglect the shell and blowdown losses for the boiler efficiency calculations.

HHV of natural gas = 54,220 kJ/kg (40,144 kJ/m^3)

Fuel supply = 1,693 m^3/hr (28 m^3/min)

Fuel cost = \$1.0/m^3

Stack temperature: 200°C

Flue gas oxygen: 5%

Negligible combustibles were found in stack gas analysis

Ambient air temperature: 20°C

The boiler operating cost was calculated in the earlier section as follows:

$$K_{boiler} = 1{,}693 \times 1.0 = \$1{,}693 / hr$$
$$K_{boiler} = 1{,}693 \times 1.0 \times 8{,}760 = \$14{,}830{,}680 / yr$$

Current stack loss was calculated from the US DOE SSAT Stack Loss calculator and is 18.3% for 5% flue gas oxygen, 200°C stack temperature and 20°C ambient temperature. Hence, the current boiler efficiency, $\eta_{current}$ is 81.7%.

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Based on previous operating (design) conditions, it is known that with the feedwater economizer in place, stack temperature is ~160°C. Using the Stack Loss Calculator, as shown in Figure 14, the new stack loss is calculated to be 16.3%. Hence, the new boiler efficiency, η_{new} is 83.7%.

Input Data

Stack Gas Temperature (°F)	160 °C	Stack Temperature - Ambient Temperature = 140°C
Ambient Temperature (°F)	20 °C	
Stack Gas Oxygen Content (%)	5 %	

Note: Stack gas oxygen content is expressed on a molar or volumetric basis

Results

Estimated Stack Losses for each of the default fuels are as follows:

Natural Gas	**16.3 %**

Figure 44: Example Boiler – Stack Loss Calculation with Feedwater Economizer

The fuel energy cost savings after installing a feedwater economizer are calculated as follows:

$$\sigma_{ExcessAir} = K_{boiler}\left(1 - \frac{\eta_{current}}{\eta_{new}}\right)$$

$$\sigma_{ExcessAir} = 14{,}830{,}680 \times \left(1 - \frac{81.7}{83.7}\right)$$

$$\sigma_{ExcessAir} \approx \$354{,}375 / yr$$

5.3.3 Clean Boiler Heat Transfer Surfaces

Heat transfer surfaces get fouled over time. Fouling on the heat transfer surfaces leads to additional heat transfer resistance which leads to higher stack exhaust temperatures. As observed in the earlier sections, this leads to lower boiler efficiency because a significant amount of energy is left in the flue gases exiting the stack. Hence, there needs to be a predictive and preventative maintenance procedure that is aimed at periodically cleaning the heat transfer surfaces in the boiler.

Fireside heat transfer fouling is fuel dependent and for most gaseous and clean-burning fuels, it maybe negligible or non-existent. When heavier liquids and solid fuels (coal, wood, black liquor, etc.) are used in the boiler, there is significant ash and carbon soot build up on the tubes of the boiler. This needs to be removed with an efficient soot-blowing system. Soot-blowers are lances with nozzles that use high pressure steam or compressed air to break the soot forming on the tubes. Industrial boilers with soot-blowers will have a timing-based periodic setup for soot-blowing in different sections (zones) of the boiler tubes. It is very important to ensure that this system is working correctly. A direct indicator of fireside fouling will be an increase in the stack gas exhaust temperature and trending it will provide valuable information on the effective performance of the soot-blowing system.

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Waterside heat transfer fouling is controlled by boiler water chemistry and is a direct function of boiler pressure, feedwater quality and blowdown rate. Waterside fouling is “scale” on the tube surfaces that results in an increased heat transfer resistance. Scale has to be chemically or mechanically removed when the boiler is shutdown. Scale leads to increased tube wall temperatures and eventually a breakdown of the boiler tubes. Hence, waterside fouling has a direct impact on the reliability of boiler operations as well as the overall boiler efficiency. It is very important to perform inspections of boiler tubes for scale during the annual shutdown and undertake de-scaling of boiler tubes periodically.

Energy savings calculations using the stack loss calculator can be performed for justifying cleaning of boiler heat transfer surfaces.

5.3.4 Improve Water Treatment

Generally, feedwater quality is impacted most by the makeup water. Condensate is commonly the cleanest water in the steam system. Makeup water must be conditioned before it is added to the system. The makeup water treatment system can be improved resulting in improved makeup water quality.

Boiler make-up water has to be treated appropriately based on the water chemistry requirements for reliable boiler operations. Blowdown management depends on two factors: boiler operating pressure and water treatment. Ensuring the highest quality of make-up water available will reduce the amount of blowdown required. Reduction in the amount of blowdown leads to a proportional reduction in the thermal energy lost in the blowdown stream. Nevertheless, there could be a significant cost to improve water treatment if it requires additional infrastructure and implementation of capital assets such as a demineralization system or a reverse osmosis system. In most industrial boiler systems, there will be a water chemist (or a contractor) who will be responsible for maintaining boiler water chemistry. It is best to work with them to ensure what is the optimum quality of water treatment necessary for the site. Common improvements to water treatment quality include changing from sodium-cycle softening to demineralization or to reverse osmosis conditioning.

5.3.5 Install an Automatic Boiler Blowdown Controller

There are two types of blowdown that are done on industrial boiler systems: Surface blowdown and Bottom (Mud Drum) blowdown. Surface blowdown can be intermittent or continuous. Bottom blowdown is always intermittent and done once a shift to remove heavier settled impurities. This optimization opportunity applies only to surface blowdown and most specifically, to blowdown that is manually controlled. Boiler loads vary with time and ideally, blowdown flow rate should change accordingly to maintain proper boiler water chemistry. Most times the control range (typically conductivity or TDS) for boiler water will be set by the water chemist and boiler operators will sample the water periodically to ensure that the boiler water control parameters are within the set range.

In most circumstances, manual blowdown control leads to excessive blowdown and this is a large energy penalty. But sometimes manual blowdown can also be not enough and that can

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result in very poor boiler water chemistry control leading to issues with reliable boiler operations. Installing an automatic boiler blowdown controller allows for the minimum and exact amount of blowdown that is required for reliable boiler operations thereby, reducing unnecessary energy losses. An automatic boiler blowdown controller monitors boiler water conductivity continuously, in real-time, and controls a modulating or an ON/OFF valve to maintain the required blowdown. This is shown in Figure 15 below.

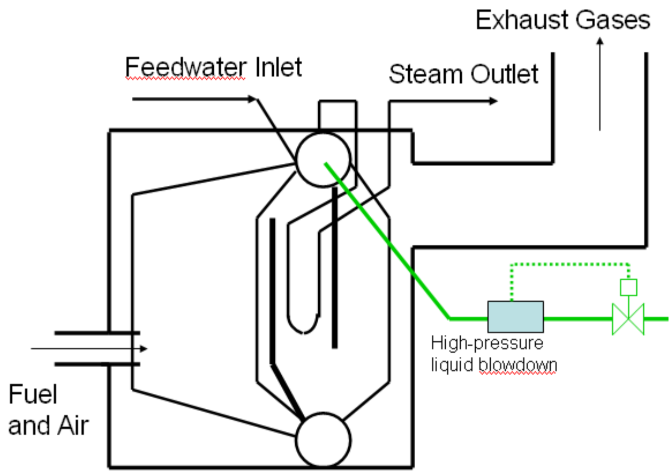

Figure 55: Automatic Boiler Blowdown Controller
(Courtesy: US DOE ITP Steam BestPractices End User Training Program)

Preliminary energy and cost savings from the installation of an automatic boiler blowdown controller (and/or improving water treatment) can be calculated as follows:

$$Q_{bd\_savings} = \left(m_{blowdown\_current} - m_{blowdown\_new}\right) \times \left(h_{blowdown} - h_{makeup}\right)$$

$$K_{bd\_savings} = \left(\frac{Q_{bd\_savings}}{\eta_{boiler} \times HHV_{fuel}}\right) \times k_{fuel} \times T$$

where $m_{blowdown\_current}$ and $m_{blowdown\_new}$ are calculated from the steam flow rates and blowdown percentage. T is the operating hours for calculating the savings over the period, For a more detailed analysis, a US DOE SSAT system type model will be required.

5.3.6 Recover Energy from Boiler Blowdown

Blowdown thermal energy recovery takes two forms and virtually all the energy lost in the boiler blowdown can be recovered using a combination of these two methodologies:

- Flash steam recovery
- Make-up water preheating

The high-pressure blowdown stream is first flashed into a pressure vessel (flash tank) operating at low-pressure (typically slightly above deaerator pressure). Part of the blowdown liquid flashes to steam at the lower pressure. This flash-steam is clean and can feed the low-pressure steam header or supply steam to the deaerator or feedwater heating system. The liquid that remains in

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the flash-vessel is at the saturation temperature (> 100°C) and can still be used to preheat make-up water in the make-up heat exchanger. The blowdown water is eventually discharged from the system at a temperature very close to the make-up water (or ambient) temperature. The blowdown loss can be virtually eliminated with very simple, robust equipment. Figure 16 provides a schematic of the blowdown energy recovery system.

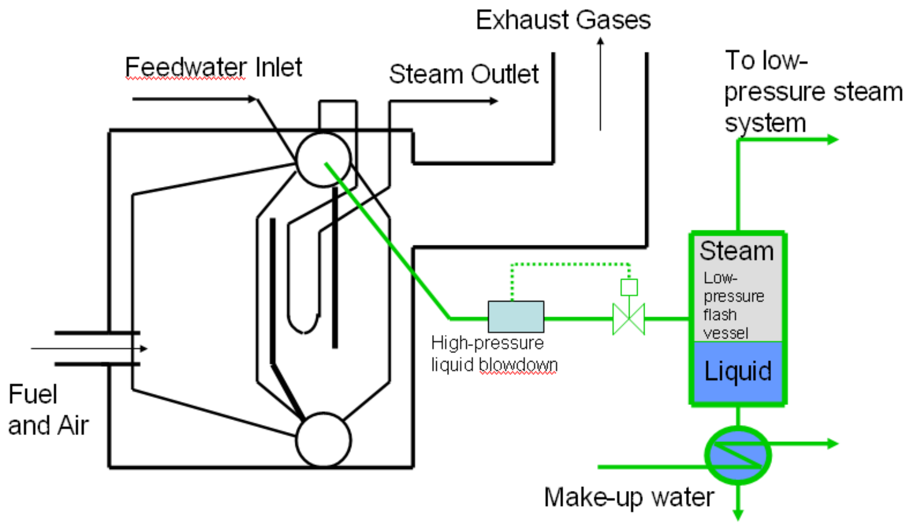

Figure 16: Bowdown Energy Recovery
(Courtesy: US DOE ITP Steam BestPractices End User Training Program)

The energy and cost savings possible with flash steam recovery and make-up water pre-heating was calculated as overall system impact in the "Blowdown Loss" section previously. Although manual hand calculations were presented in that section, a detailed steam system model, such as the US DOE SSAT, is typically required to accurately predict the energy savings.

From an equipment perspective, the flash tank is a very simple unit and can be procured very cheap. Nevertheless, the heat exchanger has to be selected carefully. The heat exchanger applied in this service must be capable of being cleaned because the blowdown stream can foul the heat exchange surface. Two types of heat exchangers perform well in this application:

- Shell-and-tube straight-tube heat exchanger with blowdown on the tube-side
- Plate-and-frame heat exchanger

5.3.7 Add/Restore Boiler Refractory

Boiler insulation and refractory aim to keep plant personnel safe and also reduce shell losses via radiation and convection. External surfaces due to ambient conditions or damage during operations may need repair periodically. Additionally, during annual inspections refractory should be inspected for any failures or cracks and breaks. There could be thermal cycling or direct impingement of hot material that may have led to a breakdown in the refractory. This opportunity falls under predictive and preventative maintenance BestPractices for reliable steam system operations. Plant personnel should use an infra-red thermal camera and search for hot spots (temperatures >70°C) and compare these images over time to see if any repair is necessary.

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5.3.8 Minimize the Number of Operating Boilers

Shell losses are typically small (in magnitude) when compared to other industrial boiler losses. But they can add up to significant numbers when there are multiple boilers operating. These losses can also become excessive if some boiler(s) are just on "hot standby". Typically, most industrial plants will operate with at least an "n+1" redundancy implying that there is available at least one extra boiler producing steam (or on hot standby) than what is needed to supply the total plant steam demand. This is mainly done to increase reliability of operations and to ensure that production doesn't get impacted due to any boiler trips or upset conditions.

Typically, steam system savings opportunities and optimization in the plant may not lead to shutting down an operating boiler but this opportunity has to be investigated every time there is a change in the steam demand. There maybe opportunities based on production cycles, seasonality, weekend/weekday and holiday operations, day/night operations that may all impact number of boilers operating in an industrial plant. Most often this opportunity is neglected due to the added complexity of turning ON and OFF a boiler and the amount of start-up time required. This can be an issue for large solid fuel-fired boilers but smaller boilers, especially operating with natural gas, methane gas, etc., should be much more amenable to a quick start-up.

When analyzing this as a potential optimization strategy, a thorough risk analysis should be done to identify any major issues that may result on the production end with a certain drop in steam production for a finite period of time. This risk analysis should also outlay the potential monetary damage to product and possible mitigation strategies. Additionally, the cost of additional controls or tell-tale instrumentation (alarms, temperature signals, pressure signals) should be taken into consideration when implementing this optimization strategy.

5.3.9 Investigate Fuel Switching

Fuel selection can provide significant reductions in operating costs due to differences in energy costs and boiler efficiencies. The fuel efficiency will generally be an influencing factor when changing fuel. Sometimes energy costs and maintenance expenditures maybe offsetting but this will not be evident unless additional due diligence is done on the optimizing opportunity. Additionally, environmental issues can become a significant concern associated with fuel selection. Each application will require an independent evaluation. Fuel switching doesn't necessarily imply to switching fuels "completely". Industrial steam generation plants may have multiple boilers operating and fuel switching could also imply:

- Shutting down a boiler operating with a certain fuel
- Reducing steam output of Boiler A working with Fuel 1 and correspondingly increasing output of Boiler B working with Fuel 2
- Dual or multi-fuel firing of any boiler and changing the ratios of the fuels firing the boiler

The cost savings from fuel switching can be calculated as follows:

$$\sigma_{FuelSwitch\_savings} = Current\ Operating\ Cost - New\ Operating\ Cost$$

$$\sigma_{FuelSwitch\_savings} = m_{steam}\left(h_{steam} - h_{feedwater}\right)\left(\frac{k_{fuel\_1}}{\eta_{boiler\_1}} - \frac{k_{fuel\_2}}{\eta_{boiler\_2}}\right)\times T$$

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where k_{fuel_1} and η_{boiler_1} are the current fuel cost and boiler efficiency, respectively while k_{fuel_2} and η_{boiler_2} are the new fuel cost and boiler efficiency, respectively. The mass flow of steam switched is given by m_{steam} and T represents the time period being evaluated for the fuel switch.

Example

Estimate the fuel switching opportunity annual energy cost savings for switching 1 Tph of steam from the natural gas fired boiler (k_{fuel_1} = \$25 per GJ; η_{boiler_1} = 80%) to Heavy Fuel Oil fired boiler (k_{fuel_2} = \$18 per GJ; η_{boiler_2} = 84%). The steam and feedwater enthalpies were obtained before and are as follows:
h_{steam} = 3,181 kJ/kg
$h_{feedwater}$ = 463.5 kJ/kg

The cost savings from fuel switching can be calculated as follows:

$$\sigma_{FuelSwitch\_savings} = m_{steam}\left(h_{steam} - h_{feedwater}\right)\left(\frac{k_{fuel\_1}}{\eta_{boiler\_1}} - \frac{k_{fuel\_2}}{\eta_{boiler\_2}}\right)\times T$$

$$\sigma_{FuelSwitch\_savings} = 1{,}000 \times \left(3{,}181 - 463.5\right)\left(\frac{25}{0.80} - \frac{18}{0.84}\right)\times \frac{1}{10^6}\times 8{,}760$$

$$\sigma_{FuelSwitch\_savings} \approx \$\,234{,}000\ /\ \mathrm{yr}$$

5.3.10 Optimize Deaerator Operations

The deaerator performs several functions in an industrial steam system. They include:
- Deaerating or removing dissolved oxygen from the feedwater (most important function)
- Preheating the make-up water
- May serve as a tank for mixing the returned condensate with make-up water
- Serving as a storage tank for feedwater and supplies the boiler feedwater pump

The deaerator operates at a fixed pressure. This pressure is dictated by the deaerator design. The main function of the deaerator – removal of dissolved oxygen from water – requires a stripping action. The stripping action is provided by the steam. Additionally, the steam preheats the make-up water which reduces the solubility of oxygen in the dissolved water further enhancing the stripping process. The deaerator requires a direct injection of live steam. The amount of steam used depends on:
- Deaerator pressure
- Amount of condensate returned and make-up water
- Temperature of condensate returned
- Temperature of make-up water
- Deaerator vent rate

As deaerator pressure is increased, more steam is needed and the amount of steam vented (from the vents) also increases. Nevertheless, if higher temperature condensate is being returned or if there is a waste heat recovery application that preheats the make-up water, then it maybe beneficial to operate the deaerator at a higher pressure. Higher pressure operation will also

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require a smaller size deaerator for the same steam load. There have been several instances where processes change over time or are modified in industrial plants. This in turn may change the amount of condensate returned, temperature of condensate and make-up water preheating. Hence, it is very important to evaluate deaerator operations and ensure that it is operating at the lowest possible pressure and deaerating with the highest efficiency possible.

Additionally, reducing deaerator pressure will reduce the feedwater inlet temperature to a feedwater economizer and this may help to reduce stack temperature which may lead to higher boiler efficiency. Care must be taken to ensure that lowering feedwater temperature doesn't reduce the stack temperature below its acid dew point.

Calculating energy and cost savings for this opportunity will require a detailed system model such as the US DOE SSAT.

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6. STEAM DISTRIBUTION OPTIMIZATION OPPORTUNITIES

This section focuses on the steam distribution area and the optimization opportunities and BestPractices in an industrial steam system.

6.1 Overview

The steam distribution area is very important because it serves as the conduit for moving the steam from the generation area to the end-use area. Some industrial steam systems are very small and a steam distribution network may not exist in those plants. But in most industrial plants, steam is distributed over a wide network of headers. Steam is generated at a high pressure and then maybe pressure reduced to supply different pressure headers. Alternatively, in some cases, there maybe only a single pressure header and steam is pressure reduced at each point of use. It has to be noted that steam does not require any mechanical device (compressor, pump, etc.) to distribute it to the headers. The steam pressure serves as the driving force to distribute steam as and where it is required.

The main components of a steam distribution system include:
○ Steam piping & fittings
○ Pressure reducing stations
○ Valves
○ Insulation
○ Safety relief valves
○ Condensate traps
○ Instrumentation (Pressure, Temperature, Flow)

From a process perspective, it is extremely important to ensure that the process not only receives the correct amount of steam that is required but it also receives it at the temperature and pressure specifications as required by the process. It has to be noted that process requirements and end-uses can change over time but the distribution system may not. Hence, it is important to focus, evaluate and optimize the distribution system on a continuous basis. This is key to reliable system operations. Although the generation area maybe optimized and maybe producing steam that is required by the process, due to issues in the distribution system there could be several problems for the process areas such as:
○ Lack of steam pressure on the header near end-user
○ Insufficient amount of steam available on the header for the end-user
○ Steam quality issues (wet steam entering process)
○ Water hammer in the headers

The intent of evaluating the steam distribution system on a continuous basis is always to look for optimizing the system for reliable operations (at the end-use) and to identify energy savings opportunities to optimize the overall steam system.

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6.2 Steam Distribution Optimization Opportunities & BestPractices

Optimizing steam distribution system in an industrial plant can focus on many different areas. These areas are fundamental in the field of energy management and generally result in attractive economics when savings opportunities are identified. These areas are also essential to the continued efficient and reliable operation of any steam system.

There are several optimization opportunities in the steam distribution area including:
- Repair steam leaks
- Minimize vented steam
- Ensure that steam system piping, valves, fittings and vessels are well insulated
- Isolate steam from unused lines
- Minimize flows through pressure reducing stations
- Reduce pressure drop in headers
- Drain condensate from steam headers

6.2.1 Repair Steam Leaks

Steam is an expensive utility for which significant economic losses can result when steam is lost from the system through leaks. Steam leaks occur everywhere but most common places such as:
- Flanges and gasketed joints
- Pipe fittings
- Valves, stem and packings
- Steam traps
- Relief valves
- Pipe failures

Steam leaks from pipe failures can be a major source of steam loss in an industrial plant. However, these typically present a “safety issue”, especially if they are in close proximity to plant personnel frequented areas. But those steam leaks that are in remote locations such as pipe racks do not get noticed and remain there forever.

Steam trap failures also account for a large portion of the leaks within an industrial plant and they will be handled in the chapter on “Condensate Recovery” later in this manual. Generally, steam trap failures are more difficult to observe than pipe failures, especially in closed condensate systems.

A continuous maintenance program based on finding and eliminating steam leaks is essential to the efficient operation of a steam system. Most times, such maintenance programs are questioned in the industrial plant as regards their cost-effectiveness and overall impact to operations. But it has been observed in all instances that having a steam leaks management program can be very beneficial both economically as well as from a reliable operations perspective for an industrial plant.

Typically, the steam loss magnitude through a leak is difficult to determine unless a proper procedure is followed. Nevertheless, an order of magnitude of the steam leak is all that is

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necessary to plan the repair strategy. Several theoretical and empirical methods have been developed to provide a gross estimate of the steam loss including, but not limited to:

- US DOE SSAT model
- Plume height measurement
- Napier's choked flow equation
- Pitot tube measurement in the field
- Ultrasonic techniques with manufacturers' protocols
- Thermodynamic mass and energy balance methodologies

Figure 17 shows the approximate leakage flow of saturated steam through sharp-edged orifice for a given operating pressure and the orifice size.

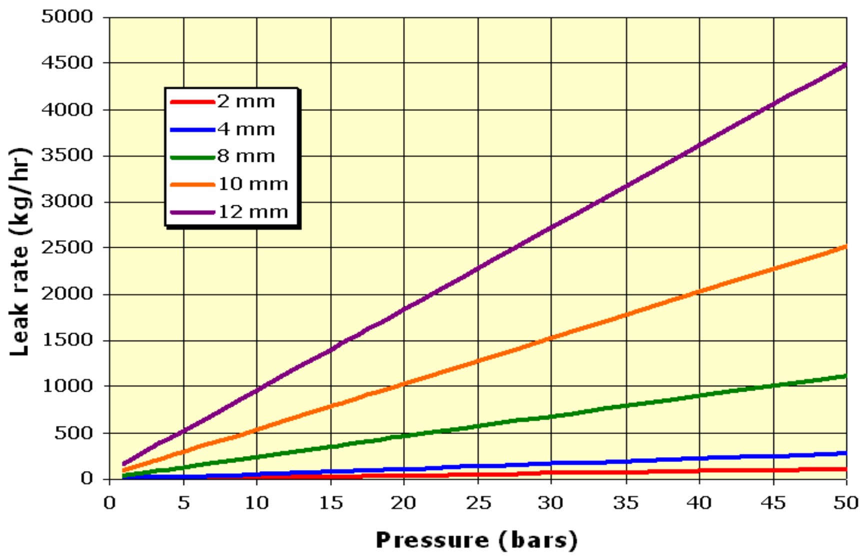

Figure 17: Steam Leakage Rate Through an Orifice

Figure 17 was developed from Napier's choked flow equation. This equation is as follows:

$$m_{steam} = 0.695 \times A_{orifice} \times P_{steam}$$

where, the m_{steam} is steam leakage flow rate (in kg/hr), $A_{orifice}$ is the area of the orifice through which the steam is leaking (in mm^2) and P_{steam} is the header pressure (in bars absolute). It has to be noted that this relationship is only valid for choked flow conditions which is when the exit pressure is less than 0.51 times the header pressure.

<u>Example</u>

A steam leak of ~4 mm diameter orifice was found on the 2 bar header. Estimate the steam leakage flow rate and the annual energy cost savings associated with repairing this steam leak. The steam cost calculated in the "Generation" area was $91.67 per tonne of steam. Assume that this steam leak exists on the steam header that is operating all year round (8,760 hours).

From the information given,

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$$A_{orifice} = \frac{\pi}{4} d_{orifice}^2 = \frac{\pi}{4} \times (4.0)^2 = 12.56\, mm^2$$
$$P_{steam} = 2 + 1.013 = 3.013\, bar\ (absolute)$$

Then using Napier's choked flow equation

$$m_{steam} = 0.695 \times A_{orifice} \times P_{steam}$$
$$m_{steam} = 0.695 \times 12.56 \times 3.013$$
$$m_{steam} \approx 26.2\, kg/hr$$

The steam leakage flow rate estimated is 26.2 kg/hr and the annual energy cost savings associated with repairing this steam leak is as follows:

$$\sigma_{steamleak} = m_{steam} \times k_{steam} \times T$$
$$\sigma_{steamleak} = 26.2 \times \frac{91.67}{1{,}000} \times 8{,}760$$
$$\sigma_{steamleak} \approx \$21{,}000 / yr$$

Steam leaks occur over time and it is important to realize that repairing steam leaks once and forgetting about them is not the solution to optimizing a distribution system. It is anticipated that a continuous steam leaks management program is put in place that can continuously monitor and repair steam leaks periodically.

6.2.2 Minimize Vented Steam

Steam venting should not be confused with steam leaks. Steam venting happens when safety relief valves or other pressure controlling devices vent steam to the ambient from the steam header. This typically happens due to steam unbalance on the headers when more steam is being generated than needed by the end-use processes. The energy and cost savings potential can be very significant based on what the impact fuel maybe. Venting of steam most often happens automatically as steam header pressure limits are reached. Sometimes steam venting is done by manually opening a "vent" or "sky" valve due to upset or trip conditions on the process side.

Combined Heat and Power (CHP) industrial plants that have steam turbines in operation may see steam venting more often than others, especially if there are only backpressure steam turbines driving process loads or operating under fixed power generation (or steam flow) conditions. Industrial plants having condensing turbines will almost never have steam venting unless the operating maximum capacity limits for the condensing turbine(s) has been reached. In several instances, an economic analysis based on marginal fuel and electric costs has to be done to determine the real value of vented steam. Most times it will be found that venting steam is not economical for CHP units, but there could be instances such as peak demand times, when power production is way more beneficial than the marginal cost of steam that is vented. More on this topic will be discussed in the section on "Combined Heat & Power Opportunities".

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Calculations for energy and cost benefits for minimizing (or eliminating) steam venting follow the same procedure as mentioned in the "Steam leaks" section and will not be repeated here.

6.2.3 Ensure that Steam Piping, Valves, Fittings and Vessels are well Insulated

Insulation is another area which comes under continuous maintenance and should be appraised periodically in all industrial plants. It has to be noted that although insulation is being discussed in the "steam distribution" area, it has impacts in all the steam areas. The main reason for discussing it in the "distribution area" is because it has the greatest impact here.

Insulation is extremely important on steam systems for the following reasons:

- Plant personnel safety
- Minimizing energy losses
- Maintaining steam conditions for process end-use requirement
- Protecting equipment, piping, etc. from ambient conditions
- Preserving overall system integrity

There are several reasons for damaged or missing insulation including:

- Missing insulation due to maintenance activities
- Missing / damaged insulation due to abuse
- Damaged insulation due to accidents
- Normal wear and tear of insulation due to ambient conditions
- Valves and other components not insulated because no insulation was specified at design

The most common areas of missing or damaged insulation include:

- Steam distribution headers
- Valves
- Inspection man-ways
- End-use equipment
- Storage tanks and vessels
- Condensate return lines

A first-order determination of the amount of energy lost and cost savings from uninsulated (or poorly insulated) areas in the steam system will provide the basis for determining the need for undertaking an insulation project. The main factors that affect the amount of energy lost from uninsulated or poorly insulated areas are:

- Process fluid temperature
- Ambient temperature
- Surface area exposed to ambient
- Wind speed
- Operating hours
- Thermal conductivity of pipe (or equipment) material
- Heat transfer resistance of insulation material (if any)

A first-order heat transfer model can be developed and used to determine the convective (natural and/or forced) and the radiant heat transfer energy losses that exist from all the areas that are

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either uninsulated or poorly insulated. Nevertheless, this can be cumbersome and will require heat transfer correlations which will vary based on geometry and the modes of convective heat transfer – natural or forced. Nevertheless, an analysis must be completed to determine the energy and cost savings as well as an economic insulation thickness. Many empirical and computerized tools are available to aid in the evaluation of insulation projects. One such tool is the 3EPlus® insulation evaluation software developed by the North American Insulation Manufacturers Association (NAIMA).

The 3EPlus® Insulation Thickness Computer Program is an industrial energy management tool used to simplify the task of determining energy and cost savings as well as an economic insulation thickness. Economic insulation thickness refers to determining the amount of insulation that provides the lowest life cycle cost for the system.

3EPlus® has been pre-populated with ~30 insulation materials including their thermal properties. Additionally, several different materials and jackets (with different emissivity) are also in-built in the software to allow the user to use drop-down menus to select specific materials for their applications. Lastly, different geometries and applications can be modeled in the software. The ability of this software tool is demonstrated in the example below.

<u>Example</u>

A 10m long section of 10 bar steam header is observed as uninsulated. The header has a nominal diameter of 10 inches (25.4 cm) with a steam temperature ~362°C. Estimate the economic impact of insulating this steam header.

Figure 18 shows the input screen for calculating the energy loss from this uninsulated header.

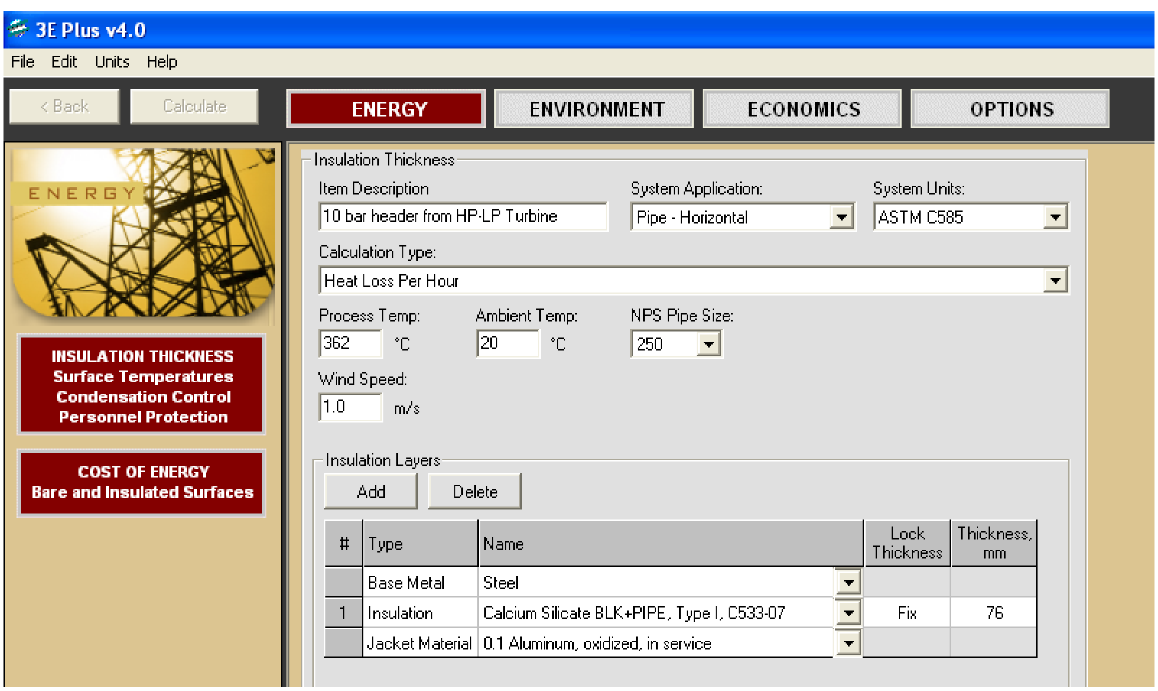

Figure 18: 3EPLus® Input Screen

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Figure 19 shows the "Heat Loss per Hour" results screen from the 3EPlus®.

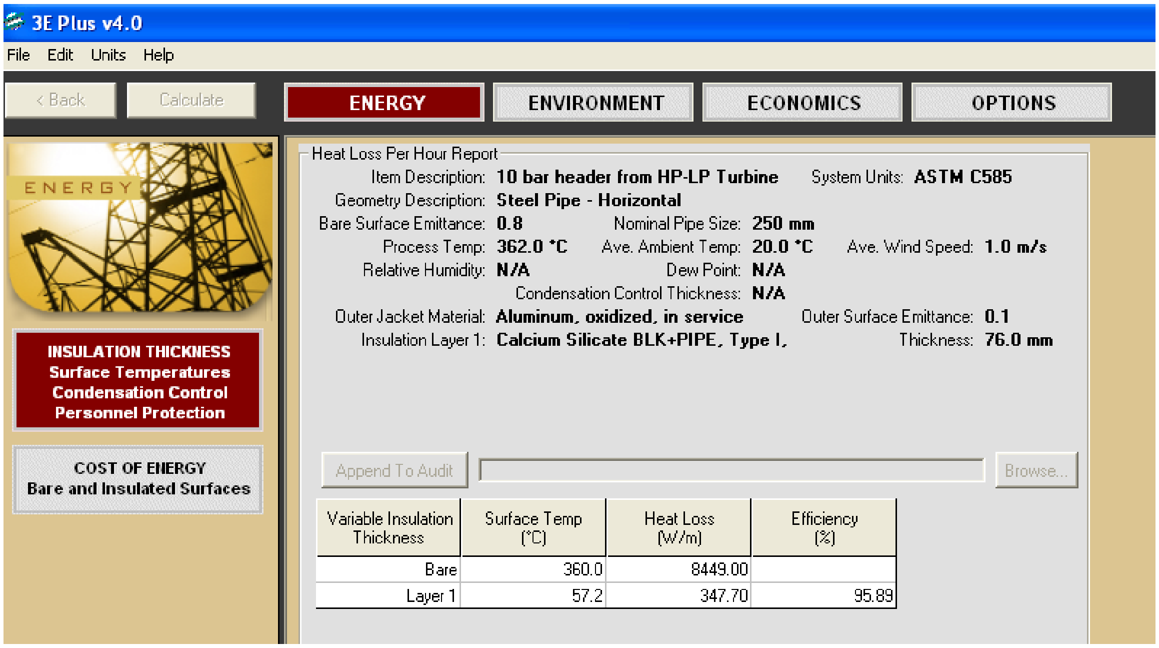

Figure 19: 3EPLus® Results Screen

The energy savings can be calculated as follows:

$$Q_{saved\_Insulation} = \left(HeatLoss_{bare} - HeatLoss_{insulated}\right) \times Length$$

$$Q_{saved\_Insulation} = (8{,}449 - 347.7) \times 10 = 81.0\,kW$$

where $HeatLoss_{bare}$ and $HeatLoss_{insulated}$ are values obtained from the 3EPlus® program. The cost savings can now be calculated based on cost of fuel (k_{fuel}), boiler efficiency (η_{boiler}), HHV of the fuel (HHV_{fuel}) and the operating period (T) as follows:

$$\sigma_{insulation} = \frac{Q_{saved\_Insulation} \times k_{fuel} \times T}{\eta_{boiler} \times HHV_{fuel}}$$

$$\sigma_{insulation} = \frac{81 \times 1.0 \times 3{,}600 \times 8{,}760}{0.80 \times 40{,}144}$$

$$\sigma_{insulation} \approx \$77{,}895 / yr$$

Insulation repair and maintenance in industrial plants maybe outsourced and most times it is cost effective to have several areas that need insulation repair by dealt at the same time. This implies that plant personnel should periodically undertake an insulation appraisal (audit) of their plant and identify the major areas that would benefit by upgrading or adding insulation. This should be a continuous activity done on a periodic basis and will ensure that the steam system is always well insulated and having minimal heat losses.

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6.2.4 Isolate Steam from Unused Lines

As industrial processes change, steam demand varies and sometimes steam is no longer required for a particular process, facility or air-handler. Nevertheless, the steam lines are still in place and contain live steam till the first block (isolation) valve of the process end-use. There are also times when certain equipment is decommissioned and will never be used again but the steam lines to that equipment are still connected to the live steam headers and are hot. This same situation can also happen during seasonal variations when the plant goes from a heating mode (in winter) to a cooling mode (in summer) where the steam lines are still running hot – adding more load to the cooling system. There are innumerable such circumstances that can exist in industrial plants and they all lead to significant energy and cost savings opportunities that a steam system optimization should capture via a systematic analysis of the distribution system in conjunction with the process end-uses.

From an energy and cost savings perspective, isolating steam from unused lines would:

- Eliminate heat transfer losses
- Eliminate steam leaks
- Eliminate any condensate formed in the headers which may lead to water hammer
- Reduce maintenance requirements of steam system components in that section.

In addition, there could be downstream processes which may get impacted by the quality of steam and there could be production impacts which may result in additional steam required thereby, increasing the costs of operations.

All the methodologies described earlier can be used to determine the energy and cost savings that would result from isolating steam from unused lines and they will not be repeated here.

6.2.5 Minimize Flows through Pressure Reducing Stations

Typically, steam is generated at a higher pressure and distributed on different lower pressure headers or via a single pressure header. Nevertheless, there are pressure reducing stations which drop the steam pressure appropriately. As steam flows through the pressure reducing valve, it expands (with pressure reduction) and temperature reduces. Hence, steam going through a pressure reducing valve doesn't loose its energy content (kJ/kg) because it is an "isenthalpic" process - the steam enthalpy does not change. Nevertheless, the entropy of steam does change and that implies that the steam's ability to do shaft work reduces. This is not a big issue when the industrial plant doesn't have steam turbines. Nevertheless, each industrial plant should evaluate the possible use of steam turbines if there exists a continuous and significant steam flow through pressure reducing valves. The exact handling of turbines and the economic benefit will be covered later in the section on "Combined Heat and Power".

This optimization opportunity has been listed in this area to ensure that steam is generated in industrial plants at the proper pressure required and there aren't any unnecessary inefficiencies due to steam expansion. A pressure reducing station will need periodic maintenance and most often it is not insulated. Additionally, the valve stem and packings become frequent places of steam leaks due to thermal cycling and movement of the stem due to variable steam demands on the process side.

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6.2.6 Reduce Pressure Drop in Headers

This optimization opportunity stems from the fact that over time, processes change and steam use varies. Additionally, the distribution system efficiency reduces due to wear and tear and there is an increase in the pressure drop in the steam header. In a saturated steam system, this implies a reduction in the steam supply temperature which may directly impact the process. Alternatively, it may mean more steam required due to a reduction in the steam enthalpy from heat losses.

There is no industry standard per se for pressure drop on headers but there are three main reasons for pressure drop increases on steam headers. They are:

- Increase in steam demand and so more steam flow on the same header
- Reduction in steam header pressure
- Condensation and two-phase flow in steam header
- A combination of the above

As steam flow increases, steam flow velocity increases and pressure drop is proportional to the square of the velocity. While doing a steam system optimization it is important to understand the design of the headers and the design steam loads on these headers. Typical, steam design flow velocities can be anywhere from 15-25 m/s. Excess of these velocities will result in a significant increase in noise and structural vibrations especially, near bends and supports.

As the steam header pressure is reduced, due to the lower density (higher specific volume) of steam, the steam velocity increases for the same mass flow rate. Hence, this will lead to excessive pressure drops as explained above. In several industrial plants, a common recommendation for energy savings is to drop the boiler operating pressure. This should be done with extreme caution and unless the steam header has been designed with excess capacity (which is very rare), this recommendation should not be implemented.

Condensation in saturated steam occurs as soon as a small amount of heat is lost from the header due to missing insulation, etc. This implies that the header now has two-phase flow conditions. If the condensate trap system is not working properly, this will imply that steam and water are traveling in the header with the same velocity. This compounded with the flow regime (based on amount of water) can lead to huge pressure drops and significant water hammer issues. More on this topic is provided in the section below.

The optimization opportunity for reducing pressure drop in steam headers would possibly include evaluation of one or more of the following strategies:

- Increasing header size by replacing the current header
- Adding another header for the same pressure level
- Reducing steam demand on the header by shifting steam demand to other pressure levels
- Upsizing valves and or re-trimming
- Eliminating any flow restrictions in the headers
- All of the optimization strategies in this section such as:
    - Eliminating steam leaks
    - Improving insulation
    - Ensuring proper operation of condensate drains, etc.

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6.2.7 Drain Condensate from Steam Headers

A steam distribution system can be extensive and there could be miles of steam piping in an industrial plant. Even when the steam lines are well insulated there is a certain amount of heat loss that exists which could lead to condensation in the steam headers especially for saturated steam systems. In certain systems where carryover is an issue from the boilers, this problem gets exacerbated and there is two-phase flow right from the generation area.

Most industrial plants will have condensate (steam) traps to remove any and all condensate that is formed in the steam header. Removal of condensate from the steam header ensures a highly reliable steam system operation and results in the following BestPractices:

- Steam header doesn't have excessive pressure drop
- No water hammer results in the steam header due to two-phase flow regime
- Process end-use receives dry steam
- Major equipment such as turbines receive dry steam
- No corrosion, pitting or erosion on pipe fittings, valves, etc.

Condensate that is drained from the steam headers can be flashed in a flash tank / separator vessel to a lower pressure steam header. The remainder of the condensate can either be sent back to the boiler plant directly or to a cascade condensate return system.

Some industrial plants have excellent condensate removal from the steam headers but may not be returning condensate and instead may dump it. There is both an energy and economic loss to dumping condensate removed from the steam headers. This evaluation will be done in the section on "Condensate Recovery". Nevertheless, it is very important to identify potential opportunities in the steam distribution area where condensate can and should be collected and returned back to the boiler plant.

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7. STEAM END-USE OPTIMIZATION OPPORTUNITIES

Industrial steam end-use is very varied and even the same basic process is different from one industry to another. As a result of that it is very difficult to cover steam end-uses in a simple training manual. Nevertheless, steam end-use is the main reason for having a steam system in an industrial plant and should not be neglected. Enough due diligence should be given to study and understand end-use because optimizing steam in end-use can provide significant benefits both from a perspective of fuel energy and cost savings as well as production and yield improvements. Plant personnel working in steam systems in industrial plants should be trained to understand how steam is used in their specific plants. This will allow them to really optimize their steam systems for their specific plant operations.

7.1 Steam Balance Overview

Steam demands take many different forms in industrial plants. In general, steam provides source of heat to the process. Most of the industrial processes will require a certain mass flow rate of steam which will correspond to a thermal heat load or duty (kW). But there are certain processes in industry which require both mass flow (heat duty) and volume flow of steam. These are typically devices which require certain steam velocity to perform the end-use functions in the industrial plant. Please note that steam turbines are not considered as end-users of steam and they are not covered in this section. They will be covered separately in the section on "Combined Heat and Power" later. Some of the steam end-use components are listed below. This is not a comprehensive list but provides a general guidance.

Steam end-uses which are specified and designed based on mass flow (heat duty) of steam are:
- Heat Exchangers
- Dryers
- Evaporators
- Reboilers
- Reformers
- Absorption chillers
- Humidifiers
- Preheat / Reheat Air Handling Coils

Steam end-uses which are specified and designed based on volume flow and mass flow (heat duty) of steam are:
- Steam jet ejectors / eductors
- Stripping columns
- Distillation towers
- Thermocompressors

For any steam system optimization analysis, it is very important to understand how much steam is used by each end-user in the industrial plant. This information can be gathered on an overall steam system level (as shown in Figure 20) or can be gathered for each individual pressure

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header level or by each individual area within an industrial plant. Most times it is difficult to create such a steam end-use distribution pie chart because sub-metering and flowmeters may not be available at each end-user. It is recommended that plant personnel understand operations and together with design information be able to assign steam demands (and heat duties) to the end-uses based on process load conditions. This methodology will help tremendously to develop an overview of the steam end-use and identify the major end-uses that one needs to focus attention on while undertaking an industrial steam system optimization. The examples in this section provide some idea of determining steam flows in processes using the fundamental principles of mass and energy balances.

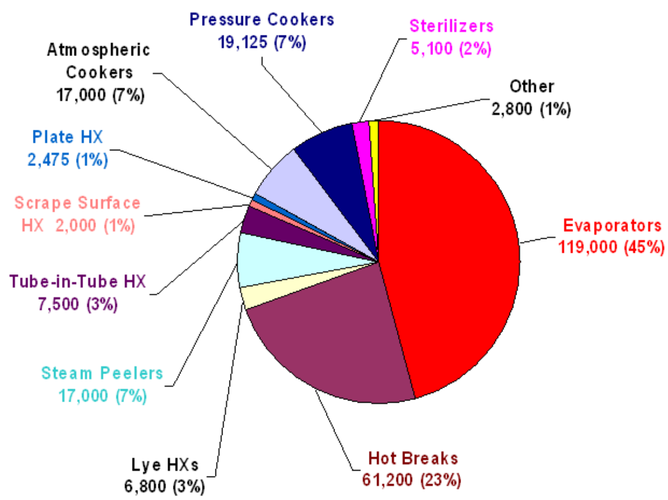

Figure 20: A Typical Steam End Use Pie Chart for a Food and Beverage Industry
(Note that numbers represent steam use in kg/hr)

<u>Example</u>
A shell-and-tube heat exchanger heats 600 liters/min of water from 25°C to 75°C. Saturated steam at atmospheric pressure is used for heating. Condensate exits the heat exchanger at 100°C. Calculate the heat duty and the amount of steam required for this indirect heat exchange process.

The heat transferred to the water is calculated as follows:

$$Q_{water} = m_{water} \times C_p \times \left(T_{out} - T_{in}\right)$$

$$Q_{water} = \frac{600}{60} \times 4.183 \times \left(75 - 25\right) = 2{,}091\,kW$$

From an energy balance this heat is supplied by the steam and so it can now be written as:

$$Q_{water} = Q_{steam} = m_{steam} \times \left(h_{steam} - h_{condensate}\right)$$

where h_{steam} (2,676 kJ/kg) is the enthalpy of saturated steam at atmospheric pressure and $h_{condensate}$ (419 kJ/kg) is the enthalpy of condensate at 100°C (from steam tables).

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$$Q_{water} = 2{,}091 = m_{steam} \times (2{,}676 - 419)$$

$$m_{steam} = \frac{2{,}091}{2{,}257} = 0.927\, kg/s = 3.34\, Tph$$

Figure 21 schematically shows the heat exchanger, heat duty and the different flows.

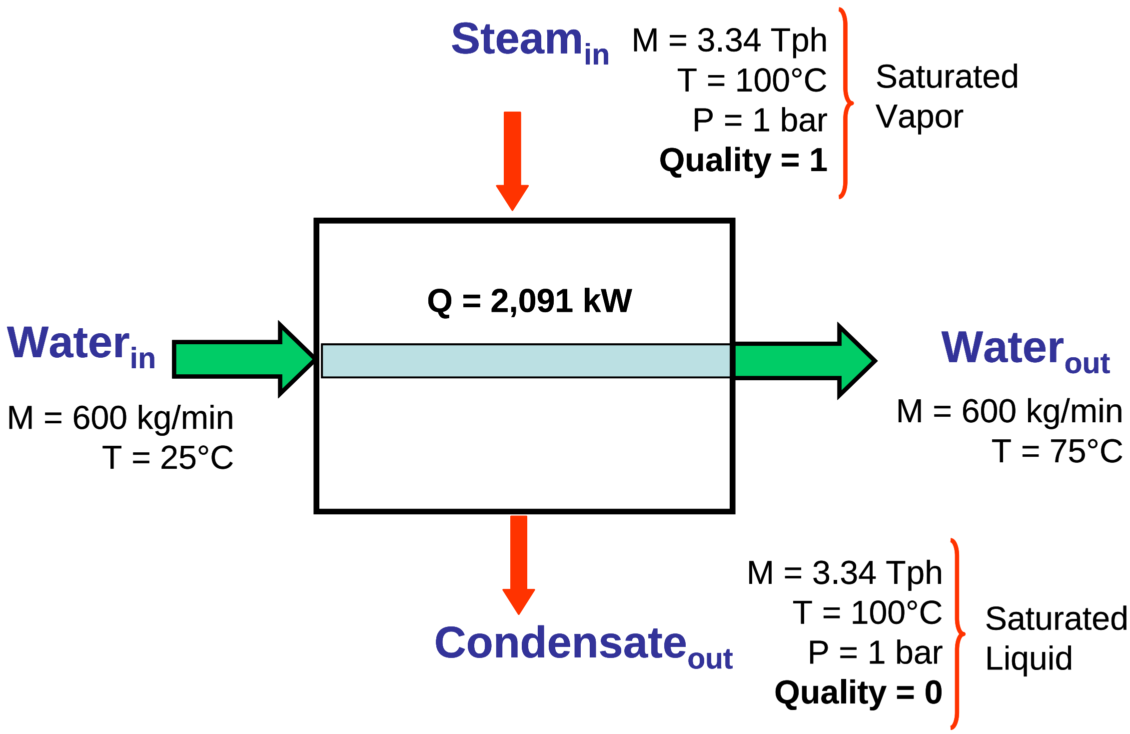

Figure 21: Steam / Water Indirect Heat Exchange

<u>Example</u>

Saturated steam at atmospheric pressure is directly injected in a vessel to heat water from 25°C to 75°C. The process requires 600 liters/min of heated water. Calculate the amount of steam required for this direct heat exchange process.

Water flow into the vessel (m_{water_in}) and steam flow (m_{steam}) are not known. The conservation of mass equation can be written as follows:

$$m_{water\_out} = m_{water\_in} + m_{steam}$$

Since, no shaft work is done in the vessel, the conservation of energy equation can be written as follows:

$$m_{water\_out} \times h_{water\_out} = m_{water\_in} \times h_{water\_in} + m_{steam} \times h_{steam}$$

where h_{steam} (2,676 kJ/kg) is the enthalpy of saturated steam at atmospheric pressure; h_{water_in} (104.8 kJ/kg) is the enthalpy of water entering the vessel at 25°C; and h_{water_out} (314 kJ/kg) is the enthalpy of water leaving the vessel at 75°C (from steam tables).

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Inputting the known values in these equations and solving them simultaneously provides the information about the unknowns.

$$m_{water\_out} = m_{water\_in} + m_{steam} = \frac{600}{60} \times \frac{974.9}{1{,}000} = 9.75\, kg/s$$

$$m_{water\_out} \times h_{water\_out} = m_{water\_in} \times h_{water\_in} + m_{steam} \times h_{steam}$$

$$9.75 \times (314) = m_{water\_in} \times (104.8) + m_{steam} \times (2{,}676)$$

$$m_{water\_in} \times (104.8) + m_{steam} \times (2{,}676) = 3{,}061.5$$

$$\therefore m_{water\_in} = 8.96\, kg/s = \frac{8.96}{997.1} \times 1{,}000 \times 60 = 539\, litres/\min$$

$$\therefore m_{steam} = 0.793\, kg/s = 2.85\, Tph$$

Figure 22 schematically shows the direct heat exchange process and the different flows.

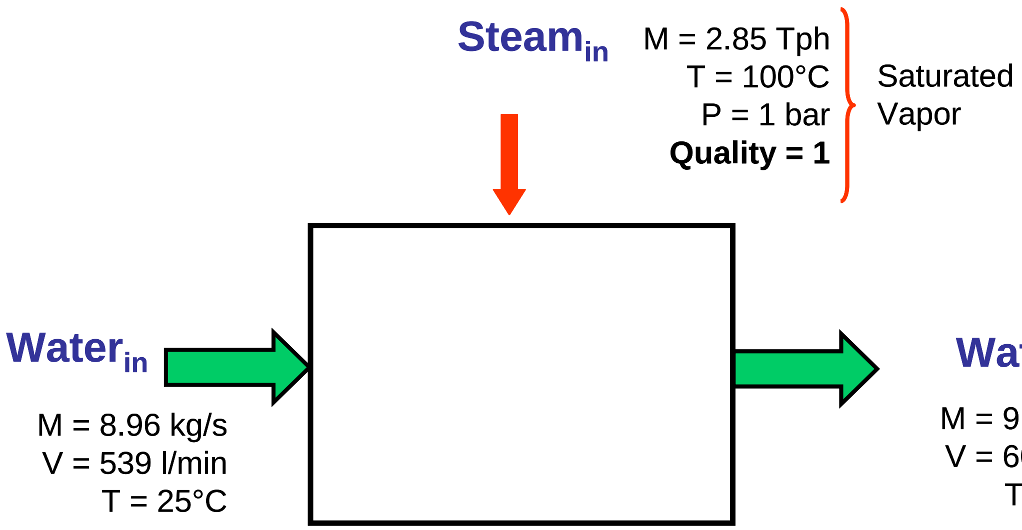

Figure 22: Steam / Water Direct Heat Exchange

7.2 Steam End-Use Optimization Opportunities & BestPractices

As mentioned earlier, it is extremely difficult to cover end-uses that are specific to industrial processes and plants. Hence, general methods are described here to understand steam end-use and identify optimization opportunities. Additionally, quantifying the benefits of optimizing steam end-use opportunities is presented here. There is no doubt about the fact that process integration will lead to overall energy system optimization of the plant and the benefits will be

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far-reaching. But extreme care has to be taken and significant due-diligence must be completed before implementing these opportunities because these opportunities could impact process parameters adversely if applied incorrectly. This unfortunately happens a lot in industrial plants and the technology gets a bad name though it maybe perfectly fine and proven but it was misapplied in the specific application.

In the classic configuration, the main strategy to optimize steam usage in end-use processes is to eliminate or reduce the amount of steam used by that process. This implies improving the process efficiency which thereby eliminates inappropriate steam usage. Then the optimization strategy looks to using steam at as low a pressure as possible which would possibly allow power generation while reducing pressure. Lastly, the optimization strategy would aim to shift all or part of the steam demand to a waste heat source. One other configuration of this last step would be to look for upgrading low pressure (or waste) steam to supply process demands that would have otherwise used much higher pressure steam.

Example

A process oven requires 2,000 m^3/min of ambient air at 20°C to be heated to 80°C. This is currently achieved using 2 bar saturated steam. Figure 23 provides information about the process schematically. Estimate the energy savings opportunity if waste heat from an adjoining process can be used to preheat the ambient air to 40°C.

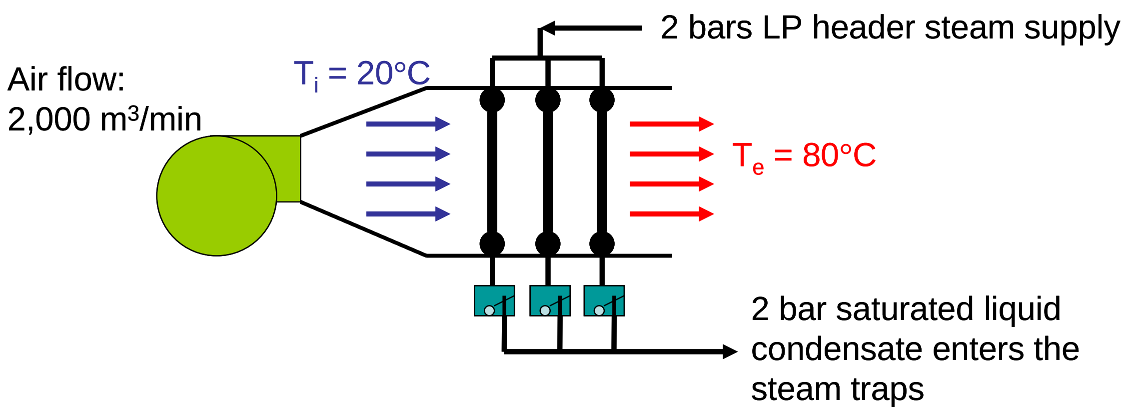

Figure 23: Steam Coil Air Heater (Current Operation)

The heat transferred to the air is calculated as follows:

$$Q_{air\_1} = m_{air} \times C_p \times (T_{out} - T_{in})$$
$$Q_{air\_1} = V_{air} \times \rho_{air} \times C_p \times (T_{out} - T_{in})$$
$$Q_{air\_1} = \frac{2,000}{60} \times 1.188 \times 1.006 \times (80 - 20) = 2,391\,kW$$

where Q_{air_1} is the heat transferred to the air by the steam in the current operation; V_{air} is the volume flow rate of air; ρ_{air} is the density of air; C_p is the specific heat of air and T_{out} and T_{in} are the outlet and inlet temperatures of air, respectively.

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In the optimized configuration, air is preheated to 40°C using a waste heat source from a nearby process. The heat transferred to air from steam in this optimized configuration is calculated as follows:

$$Q_{air\_2} = m_{air} \times C_p \times (T_{out} - T_{in})$$
$$Q_{air\_2} = V_{air} \times \rho_{air} \times C_p \times (T_{out} - T_{in})$$
$$Q_{air\_2} = \frac{2{,}000}{60} \times 1.188 \times 1.006 \times (80 - 40) = 1{,}594\, kW$$

where Q_{air_2} is the heat transferred to the air by the steam in the optimized configuration where air is preheated from a waste heat source; V_{air} is the volume flow rate of air; ρ_{air} is the density of air; C_p is the specific heat of air and T_{out} and T_{in} are the outlet and inlet temperatures of air in the optimized configuration, respectively.

Note that the savings in the amount of heat transferred by the steam is the difference between Q_{air_1} and Q_{air_2} which is equivalent to 796 kW. This amount of energy savings can be converted to amount of steam saved as follows:

$$m_{steam\_saved} = \frac{(Q_{air\_1} - Q_{air\_2})}{(h_{steam} - h_{condensate})}$$
$$m_{steam\_saved} = \frac{796}{(3{,}181 - 561.5)}$$

$$m_{steam\_saved} = 0.304\, kg/s = 1.094\, Tph$$

where h_{steam} is the enthalpy of steam entering the steam coil air heater and $h_{condensate}$ saturated condensate (at 2 bars) leaving the steam coil air heater.

The equivalent cost savings can be calculated as follows:

$$\sigma_{steam} = m_{steam\_saved} \times k_{steam} \times T$$
$$\sigma_{steam} = 1{,}094 \times \frac{91.67}{1{,}000} \times 8{,}760$$
$$\sigma_{steam} \approx \$878{,}000 / yr$$

This same analysis can be also done with a detailed steam system model such as the US DOE SSAT software. Nevertheless, it is important to undertake such first-order due-diligence studies for prioritizing optimization opportunities in the end-use area. Most often, significant additional due diligence will be needed before implementing optimization opportunities that involve process integration.

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8. STEAM CONDENSATE RECOVERY OPTIMIZATION OPPORTUNITIES

This section focuses on the condensate recovery area and the optimization opportunities and BestPractices in an industrial steam system.

8.1 Overview

Once steam has transferred its thermal energy it forms condensate. This condensate has to be continuously removed for the process to continue in the industrial plant. Condensate is not a waste stream but is the purest form of water (distilled) in the industrial plant. It has a significant amount of economic value because:

- Condensate is much hotter than make-up water and hence, has significant thermal energy
- Condensate doesn't need any chemical water treatment other than condensate polishing
- If collected, condensate doesn't need to be sewered and sewer stream doesn't need to be quenched for any thermal limitations on sewer discharge.

The main metric to determine how an industrial plant is performing in the area of condensate recovery is to determine how much of the available condensate is actually returned to the boiler plant. The amount of available condensate is the amount of steam that is used in indirect heat exchange processes and condensing turbines. This calculation is typically represented as a ratio of amount of condensate returned to the amount of steam produced. Depending on the industrial plant, sometimes due to multiple headers, this ratio is also calculated at each header level and then for the overall steam plant.

Condensate recovery is considered to be good when it exceeds 80%. Depending on the original industrial plant design and size of the plant, condensate recovery can be significantly lower and this becomes a major area of steam system optimization. Sometimes industrial process constraints such as possibility of condensate contamination in a process heat exchanger may dictate that condensate should not be returned to the boiler plant. This has to be evaluated on a case-by-case basis and will be discussed further later on in this section.

The main components of a condensate recovery system include:

- Steam Traps
- Condensate piping & fittings
- Flash tanks
- Receivers
- Pumps
- Lift stations
- Polishers & filters

Steam traps are an integral and cardinal part of a condensate recovery system. Hence, they will be discussed in detail here.

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8.2 Steam Traps

Steam traps are always a subject of major concern in reliable steam system operations. They are most often neglected due to lack of resources on the plant maintenance teams and their expertise and knowledge on steam traps and their operations. Steam traps serve several vital operating functions for a steam system but the most important of them all are:

- During start-up, they allow air and large quantities of condensate to escape
- During normal operation, they allow collected condensate to pass into the condensate return system, while minimizing (or eliminating) loss of steam

There are different kinds of steam traps and hence, functionality and principles of operation must be understood by specifying design engineers, plant operations and maintenance teams. All industrial steam plants should have an effective steam trap management program. Although steam trap failures may not always result in energy loss per se, but they almost always result in system operation problems and reliability issues. System debris, improper sizing, and improper application are most common causes of steam trap failures in industrial plants.

There are several types of steam traps along with variations and combinations of types. The most common traps (shown with a *) are classified on the principles of operation as follows:

- Thermostatic Traps
  - Bellows*
  - Bimetallic*
- Mechanical Traps
  - Ball Float
  - Float and Lever
  - Inverted Bucket*
  - Open Bucket
  - Float and Thermostatic*
- Thermodynamic Traps
  - Disc*
  - Piston
  - Lever
- Orifice Traps
  - Orifice Plate
  - Venturi Tube

8.2.1 Thermostatic Traps

A thermostatic steam trap operation is based on a certain temperature difference. Generally, the actuation results from an internal component expanding (or bending) when temperature increases — and contracting (or straightening out) when temperature decreases. When the trap internals are hot the thermostatic trap valve is closed.

Figure 24a shows steam entering the steam trap from the bottom left. An internal component such as a sealed bellows (or a bi-metallic strip) will expand (or bend) with temperature increase, thus closing the trap with a plug at the bottom of the mechanism. Then, as shown in Figure 24b,

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when sub-cooled condensate enters the steam trap the mechanism will contract, raising the plug at the bottom of the mechanism, allowing condensate or condensate and flash steam to flow out of the trap.

(a) Steam Trap Closed (b) Steam Trap Open

Figure 24: Functioning of Thermostatic Steam Trap
(Courtesy: US DOE Steam BestPractices End User Training)

An important operational point associated with a thermostatic steam trap is that the trap internals must cool to a temperature that is less than saturated steam temperature before the trap will open. Saturated steam and saturated condensate can exist in the trap at exactly the same temperature. At this point, the trap may not open. The trap will only open after the condensate has sub-cooled below a certain temperature. Typically, the traps will need a 5-20°C temperature difference for the traps to open.

8.2.2 Mechanical Traps

These traps work on the fundamental principle of buoyancy. The most common traps are:
- Float and Thermostatic (F&T)
- Inverted bucket

8.2.2.1 Float and Thermostatic (F&T) Traps

As the name suggests, the F&T trap is a combination of two types of traps – float and thermostatic. The Float is arranged such that condensate enters a reservoir in the trap. The outlet valve is actuated by a float mechanism and opens as the condensate level increases in the reservoir. This type of trap allows condensate to exit the system immediately after it forms making it an excellent selection for heat exchanger service and other applications where condensate back up has to be prevented at all costs. The valve closes as the condensate level drops in the reservoir. Figure 25a shows the trap in the closed configuration and Figure 25b shows the trap in the open configuration.

It has to be noted that only liquid can exit the float type trap and the mechanism will not allow air or non-condensable gases to exit. Hence, in industrial applications, a float type steam trap will always be coupled with thermostatic element trap. The thermostatic element is mainly there for start-up conditions and removal of air and non-condensables. This combined arrangement is known as an F&T trap.

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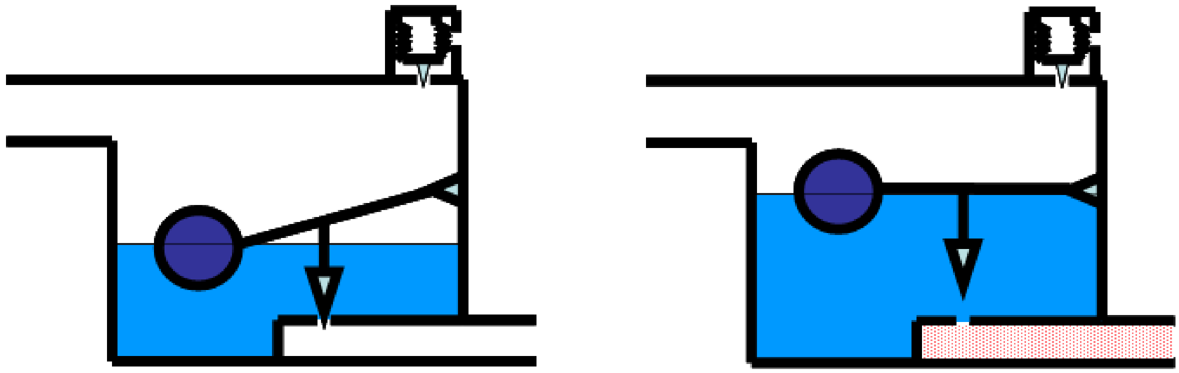
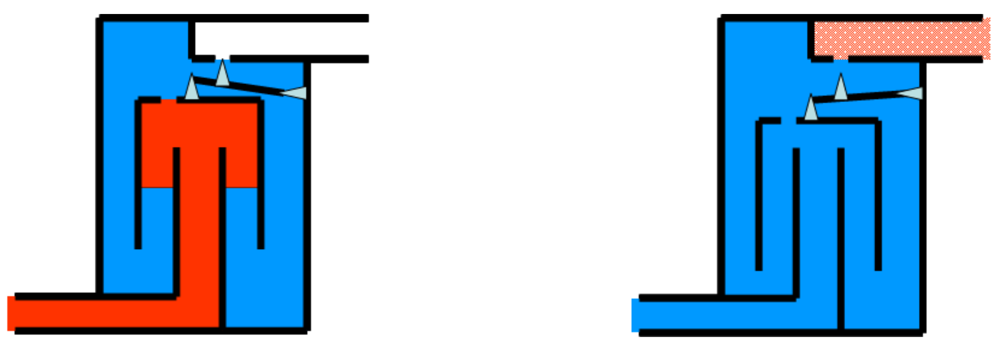


(a) Steam Trap Closed (b) Steam Trap Open

Figure 25: Functioning of F&T Mechanical Steam Trap
(Courtesy: US DOE Steam BestPractices End User Training)

8.2.2.2 Inverted Bucket Traps

An inverted bucket trap is another very commonly used mechanical trap that works on the principle of buoyancy. An upside-down bucket serves as the float. When the trap body and bucket are filled with condensate the bucket sinks. The outlet valve opens and condensate is removed. Both saturated and/or subcooled condensate can be removed by this trap. Once all the condensate is removed, steam enters the trap under the bucket. This pushes the bucket up closing the outlet valve. Figure 26a represents the inverted bucket trap in the closed configuration. Figure 26b represents the inverted bucket trap in the open configuration.



(a) Steam Trap Closed (b) Steam Trap Open

Figure 26: Functioning of Inverted Bucket Mechanical Steam Trap
(Courtesy: US DOE Steam BestPractices End User Training)

8.2.3 Thermodynamic Traps

Thermodynamic traps work on the Bernoulli principle and function identically to airfoils. The absolute pressure reduces as the velocity increases for a given substance in a control volume. This differential pressure can cause a disk to close an opening and function as a valve. One type of thermodynamic steam traps have a thin solid metal disk in a control chamber. Condensate

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enters the control chamber under the metal disk pushing the disk up. Condensate is then removed via an annular gap made between the disk seat and the trap body. As steam starts flowing, the velocity of steam across the annular gap is high compared to the static condensate. This results in an area of low-pressure locally while there is high-pressure area on the top of the metal disk. This forces the disk to seat and closes the trap. Figure 27a represents the thermodynamic trap in the closed configuration. Figure 27b represents the thermodynamic trap in the open configuration. This trap has very intermittent operation and they are also used for small condensate loads.

(a) Steam Trap Closed (b) Steam Trap Open

Figure 27: Functioning of Disk-type Thermodynamic Steam Trap
(Courtesy: US DOE Steam BestPractices End User Training)

8.2.4 Orifice Traps

Orifice steam traps work on the principle that steam and condensate have extremely different volumetric properties. Orifice traps do not have any moving parts but rely on a restricting orifice, small diameter short tube, or a Venturi-type nozzle as the primary working component. The density of condensate is significantly greater than the density of steam. This fact allows a significant amount of condensate to pass through a very small opening (such as an orifice) and a minimal amount of steam to pass through the same opening. As condensate passes through the orifice, the pressure drop causes condensate to generate flash steam. This flash steam serves as a form of a regulating valve for additional condensate / steam flow to pass through the trap.

The orifice traps have no moving parts and this is the biggest advantage of this trap over the other traps. This advantage implies minimal maintenance for the traps. In industrial steam systems that are not clean, this type of trap can become easily plugged by debris such corrosion particulate, dirt, etc. Hence, some care has to be taken to periodically clean them.

It is extremely critical to properly size orifice traps. If the trap is sized larger than necessary then significant amounts of live-steam will be lost to the condensate system. If the trap is sized smaller than necessary then condensate will backup into the system. These traps also work best when the steam load is continuous and steady. Intermittent and cyclical steam loading can create operational issues related to either steam venting or condensate back-up. Figure 28a represents the thermodynamic trap in a normal operating configuration. Figure 28b represents the thermodynamic trap in the open (steam leak) configuration.

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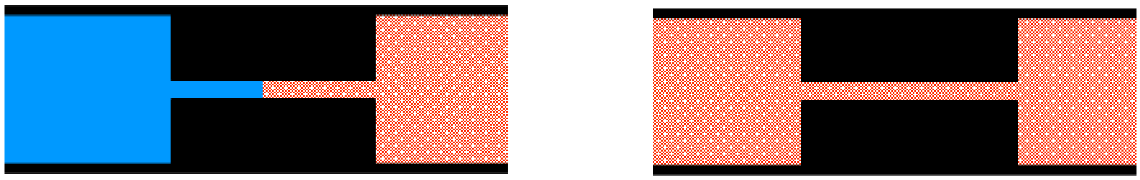

(a) Normal Operation (b) Steam flow (leak) Operation

Figure 28: Functioning of Orifice type Steam Traps
(Courtesy: US DOE Steam BestPractices End User Training)

8.3 Condensate Recovery Optimization Opportunities & BestPractices

Optimizing condensate recovery and its associated peripherals in an industrial plant can focus on many different areas. These areas are fundamental in the field of energy management and generally result in attractive economics when savings opportunities are identified. These areas are also essential to the continued efficient and reliable operation of any steam system.

There are several optimization opportunities in the steam distribution area including:
- Implement an effective steam-trap management and maintenance program
- Recover as much as possible of available condensate
- Recover condensate at the highest possible thermal energy
- Flash high pressure condensate to make low pressure steam

8.3.1 Implement an Effective Steam-Trap Management and Maintenance Program

It is vitally important to have an effective steam trap management and maintenance program in an industrial plant. There can be several hundreds of steam traps in large plants and this steam trap population should be checked periodically for proper operation. It is necessary to inspect every steam trap in the facility and determine how it is performing at least once a year. There are many different types of traps that function based on different principles. In order to investigate the steam traps it is important to understand how each type works. Hence, these inspections should be completed by trained personnel that understand the operation of steam traps and the steam system in general. Steam trap functionality should be assessed through the use of appropriate instruments like ultrasonic sensors and thermometers.

Steam traps fail in two major modes that have a significant economic and/or operational impact:
- Failed Open
- Failed Closed

A failed-open steam trap allows “live” steam to discharge from the system and so becomes a steam leak. A failed-closed trap does not remove condensate and it backs up in the upstream equipment. If this is a process heat exchanger, production processes will be heat duty limited. If this trap serves a steam distribution header, then it could result in water hammer and damage components. Even a well-maintained steam system will typically experience a 10% trap failure

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in a 1-year period. If unchecked, this can translate into significant economic losses and operational issues to the system.

The assessment results should be compiled in a database that includes results for the trap:
- Good and working properly
- Failed open and leaking steam
- Failed open and blowing to ambient
- Failed closed

A steam loss estimation for each failed leaking trap should be provided in the assessment. An excellent method to establish the maximum steam loss through a failed trap is to complete an orifice calculation (see Napier's equation). This will serve as the maximum steam loss for a particular trap. Uncertainty in this flow arises since it is not clear if there are internal obstructions to this flow. However, an order-of-magnitude steam loss estimate is generally sufficient to allow repair prioritization to occur.

There are several methodologies and techniques available in the industry for investigating steam trap performance such as:
- Visual
- Acoustic
- Thermal
- Online real time monitoring

Most of the times, using any one method may not provide a conclusive answer to the proper operation of the steam trap. Hence, a combination of the above methods is recommended. Additionally, since proper training and a good understanding of trap operations is a pre-requisite for inspecting steam traps, out-sourcing this activity on a periodic basis is a very good option. Most steam trap manufacturers and vendors will offer a steam trap audit service at minimal or no charge to the industrial plant.

Maintaining a steam trap database is absolutely essential for an effective steam trap management program. This database, at a minimum, should contain the following fields:
- Trap tag number
- Location
- Trap type
- Model number
- Manufacturer
- Date when the trap was last checked for performance
- Date when the trap was installed (or re-installed after failure)
- Cause of trap failure
- Name of person who installed or replaced the failed trap
- Potential economic loss if trap fails open
- Potential production issues if trap fails open
- Potential production issues if trap fails closed
- Tell-tale signs of trap failed open
- Tell-tale signs of trap failed closed

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Unless a detailed steam trap assessment is conducted at an industrial plant, it is difficult to potentially quantify the benefit of a steam trap management program. Nevertheless, historically and statistically it has been proven time and again that steam traps fail and if not replaced or repaired they can be a source of significant energy waste, a cause of production woes and affect system reliability adversely.

The US DOE SSAT tool offers a very high level gross estimate of potential energy and cost savings possible by implementing an effective steam trap management and maintenance program. This is based on historic failure rates of traps, number of traps in the plant and the last time a steam trap assessment followed by repair and/or replacement of traps was conducted in the plant.

8.3.2 Recover as much as possible of Available Condensate

Condensate is produced after steam has transferred all its thermal energy and condensed into water. There is significant amount of thermal energy still associated with the condensate. Every unit of condensate recovered implies one less unit of make up water required. Hence, returning additional condensate:

- Reduces the energy required in the deaerator
- Reduces make-up water
- Reduces chemicals for water treatment
- Reduces quenching water needed for sewers
- May reduce blowdown.

Optimizing condensate recovery begins by evaluating the current amount of condensate returned. Condensate returned should be evaluated based on different header levels. In large industrial plants which have an extensive distribution of steam system and a multitude of steam end-uses, condensate recovery depends on the following factors:

- Contamination levels
- Cost of recovery equipment
- Cost of condensate piping

Commercial technology is now available that can monitor contaminant levels in condensate real-time. These technologies have been very successfully implemented in industrial plants to aggressively collect condensate from all possible avenues including those areas which may have a probability of contaminated condensate. Their functionality is based on monitoring a certain contaminant level or conductivity of condensate and once those levels are exceeded, then a dump valve opens to sewer the condensate and simultaneously shuts off the return to the boiler plant. Every situation needs to be evaluated on its own merit and application. Sometimes it may not be cost effective to collect a small amount of condensate and take a high risk on contaminating the boiler feedwater system.

The cost of recovery equipment and piping will depend on the physical location of the end-use compared to the boiler plant and the distance that condensate will have to piped to get it to the boiler plant. Additionally, designs will have to consider electrically pumping condensate back versus using the steam pressure and a lift station.

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Condensate receivers can serve as a local collection point and help to reduce project costs of individually pumping condensate back from each end-user. Additionally, condensate receivers and flash tanks reduce the amount of steam entering the condensate return piping and this mitigates flow restrictions in the return piping. It will also help to eliminate water hammer in condensate return systems.

The amount of condensate to be recovered can be obtained in several different ways, including:

- Steam flow rate
- Steam trap size
- Energy and mass balance on the process end-use heat exchanger
- Design conditions
- Bucket and stopwatch (exercise extreme caution)

<u>Example</u>

An end-user in a process plant is using steam to heat the feed stream. Condensate is currently dumped into the sewer. A bucket and stopwatch methodology indicated that the condensate flow rate was 50 liters/min. Estimate the energy and cost savings associated with collecting and returning condensate to the boiler plant from this end-user. Current condensate collected elsewhere in the plant returns to the boiler at 70°C.

Incorporating a condensate recovery system would require a condensate receiver with an ambient vent collect all the condensate. It would then be pumped to the boiler plant as shown in Figure 29. Assume that this condensate return temperature at the boiler would also be 70°C which is similar to other condensate being returned.

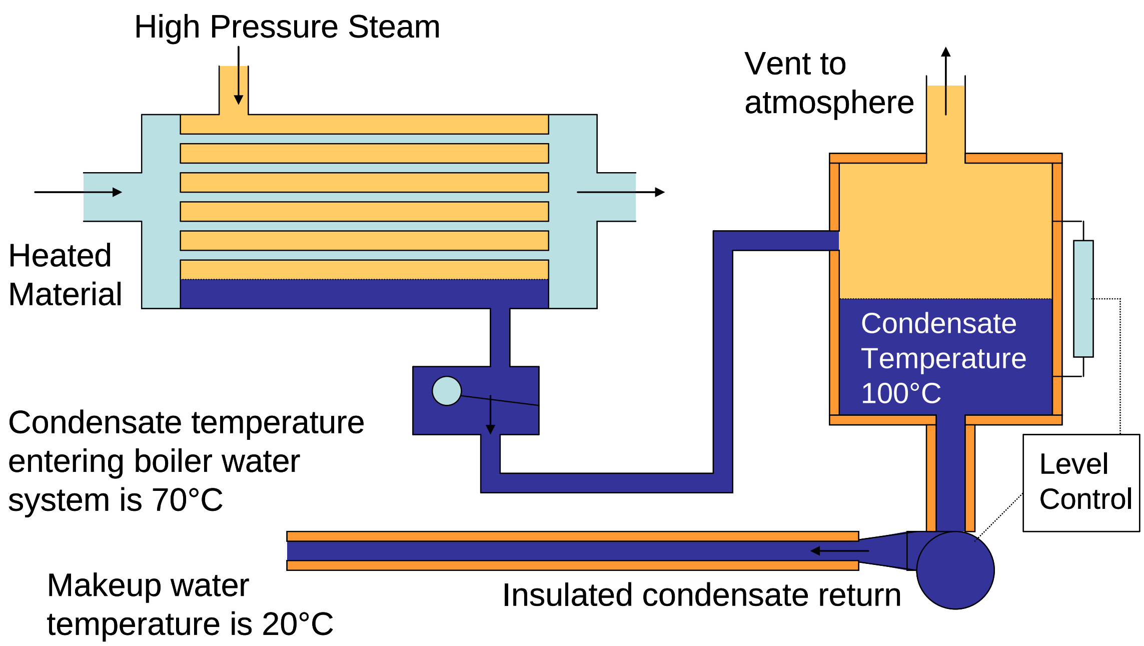

Figure 29: Condensate Return System

(Courtesy: US DOE BestPractices Steam EndUser Training)

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The mass flow of condensate to be returned is calculated as follows:

$$m_{condensate} = V_{condensate} \times \rho_{condensate}$$

where $V_{condensate}$ is the volume flow rate and $\rho_{condensate}$ is the density of condensate at the saturation temperature.

$$m_{condensate} = \frac{50}{60} \times \frac{977.8}{1{,}000} = 0.81\, kg/s$$

The amount of thermal energy in the condensate compared to equivalent make up water is calculated as follows:

$$Q_{condensate} = m_{condensate} \times \left(h_{condensate} - h_{makeup}\right)$$

where $h_{condensate}$ is the enthalpy of condensate (293.1 Btu/lb) at 70°C and h_{makeup} is the enthalpy of makeup water (83.9 Btu/lb) at 20°C. These were obtained from steam tables.

$$Q_{condensate} = m_{condensate} \times \left(h_{condensate} - h_{makeup}\right)$$

$$Q_{condensate} = 0.81 \times \left(293.1 - 83.9\right) = 169.5\, kW$$

In an industrial steam system, the makeup water would be heated by the steam in the deaerator. This implies that the actual fuel energy savings would need to incorporate the boiler inefficiencies. Hence, fuel energy and cost savings for condensate return from a system perspective are calculated as follows:

$$Q_{system} = \frac{Q_{condensate}}{\eta_{boiler}} = \frac{169.5}{0.80} \approx 212\, kW$$

$$\sigma_{condensate} = \frac{Q_{system} \times k_{fuel} \times T}{HHV_{fuel}} = \frac{212 \times 1.0 \times 3{,}600 \times 8{,}760}{40{,}144} \approx \$166{,}500 / yr$$

Condensate return calculations done above provide a very accurate measure of the optimization opportunity. Nevertheless, condensate return impacts the whole system and it is generally recommended to use a detailed steam system model to evaluate the true impacts of condensate return. Water costs (including chemical treatment) can account for a large fraction of the cost savings and should not be neglected.

8.3.3 Recover Condensate at the Highest Possible Thermal Energy

It is clear from the above discussions that higher condensate return temperatures imply lesser heating required in the deaerator. This directly translates to steam and energy cost savings. This optimization opportunity can be evaluated in a very similar manner as explained and demonstrated in the above opportunity. But collecting and returning high temperature condensate

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may need significant due-diligence which if not provided, could result in operational problems. The biggest concern is the issue of flashing that could happen in the condensate return lines. The problem can be magnified in a cascade system, where condensate from different locations is mixed and there are large temperature differences between the condensate returns.

The steam system optimization strategy weighs the additional cost of dedicated high temperature condensate return compared to having a condensate receiver / flash tank (with an ambient vent) to remove this extra thermal energy. Depending on the amount of condensate, this thermal energy can be significant and every effort should be made to capture condensate and return it back to the boiler plant with the highest thermal energy possible.

8.3.4 Flash High Pressure Condensate to make Low Pressure Steam

In industrial plants which have steam usage at different pressure levels, this optimization opportunity can significantly impact operating energy and costs. As mentioned earlier, condensate contains a lot of thermal energy and if it is at a higher pressure it can be collected and flashed to produce low pressure steam. Depending on the location and proximity to the headers or end-uses, this low pressure steam directly offsets "live" steam on the low pressure header that was produced by the boiler.

This optimization opportunity will clearly need a solid thermodynamic steam system model to evaluate the true economic impacts and using a US DOE SSAT tool would provide the means to determine the opportunity. Figure 30 provides a simple snap-shot of an industrial steam system balance in the SSAT tool to illustrate the impacts of flashing high pressure condensate to produce lower pressure steam.

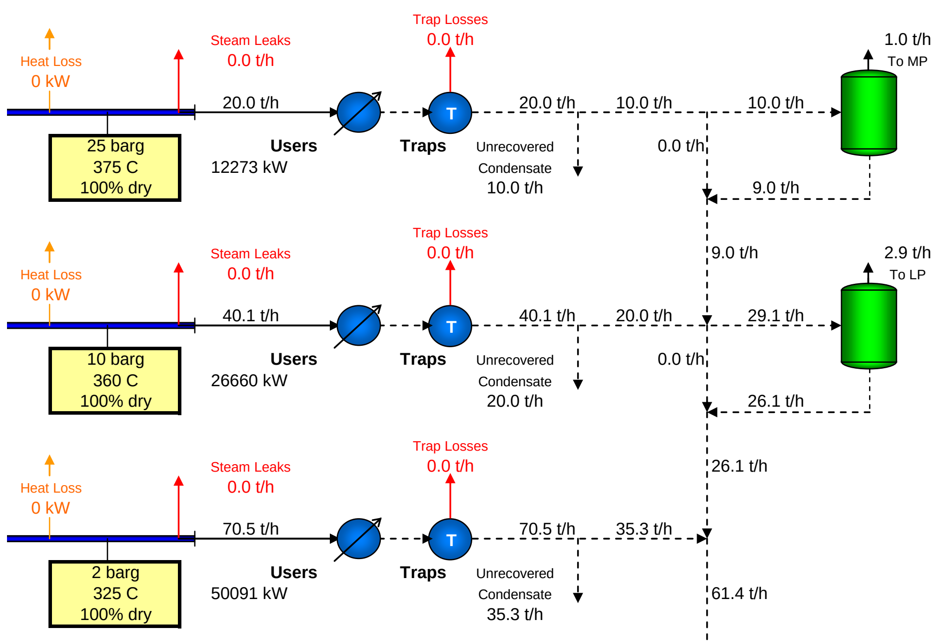

Figure 30: Flashing High Pressure Condensate to make Low Pressure Steam

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9. COMBINED HEAT & POWER (CHP) OPTIMIZATION OPPORTUNITIES

Steam is produced in an industrial plant primarily for providing heat to the processes. Nevertheless, steam can also be used to generate power or drive any rotating mechanical equipment such as a pump, compressor, fan, etc. Typically, this power is generated via steam turbines. Steam turbines do not consume steam and hence, are not treated as end-users of steam. This section details the different types of steam turbines that can be found in industrial plants and the optimization opportunities related to Combined Heat and Power (CHP) which is also known as Cogeneration.

9.1 Overview

An industrial plant operation needs both power and thermal energy (in the form of heat) simultaneously. Typically, the industrial plant has a power supply agreement with a utility company (and a generator) to supply a certain amount of electricity to the plant. There are different types of power agreements but in general an industrial plant pays a certain cost for the amount of power it purchases from the electric utility grid. Power supplied to the grid from central power stations which are based on typical Rankine-cycle are ~35-42% thermal efficiency. This implies that there is a large amount of thermal energy lost to the ambient (via cooling towers, river water, etc.) at the power generation site.

The industrial plant also buys fuel from a utility company to operate boilers or other direct-firing process heating equipment to supply its thermal demand. Alternately, an industrial plant with a steam system can operate a topping cycle, which can produce power via a steam turbine and then use the exhaust steam to satisfy the thermal demand of the processes. The overall thermal efficiency for such an industrial plant combined heat and power system can be 70% or higher. This is the main reason for implementing CHP optimization opportunities in industrial systems. There can be a significant amount of energy and cost savings including a highly reliable power supply configuration with CHP in industrial plants. Nevertheless, there could be a large capital cost as well as potentially some operating cost associated with the CHP optimization opportunity.

CHP will almost always be energy efficient compared to central utility plant power generation. But the CHP cost effectiveness and economics of operations need not be always beneficial to the industrial plant. Each industrial plant CHP analysis is unique and should be done independent of thumb rules. The overall economics of CHP operation depends on the following factors:

- Impact or marginal electric utility cost
- Impact or marginal fuel cost
- Boiler efficiency
- Steam turbine efficiency
- Thermal demand
- Timing of thermal and electric demand

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The main questions that are typically required to be answered while optimizing the operations of any CHP system are:

- What is the true economic impact of cogeneration?
- When is it viable?
  - To operate or shut down
  - To install
- What changes, if any, will be required on the steam system?
- What changes, if any, will be required for the electrical utility system and grid interconnects?

9.2 Steam Turbines

A thorough understanding of steam turbine operations will be required when optimizing boiler-steam turbine CHP systems. Steam turbines are devices which convert thermal energy from the steam into rotational shaft power. Steam turbines operate with high-pressure steam passing through a nozzle that increases the velocity of the steam and focuses the flow path into a jet of steam. This high-velocity jet of steam is directed to strike a blade. The blade is arranged such that the steam jet will transfer its energy into a force on the blade. The blade is mounted on a shaft that is free to rotate. As a result the force on the blade is converted into shaft torque and shaft rotation. Steam turbines are equipped with a stationary outer shell and a rotating inner shaft. The outer shell confines the steam and serves as the anchor for the nozzles and all of the stationary parts. The rotating shaft is equipped with the turbine blades and serves to collect and transfer the mechanical power from the turbine.

A steam turbine can be designed with a single wheel of blades or multiple wheels on the same shaft. A single nozzle directs steam to a wheel or several nozzles can direct steam to segments of a single wheel. If a turbine has multiple rows of blades it will also be equipped with multiple rows of nozzles. The nozzles serve to collect the steam from the upstream blades, increase the velocity of the steam, channel the steam into a focused jet, and direct the steam to the blades.

All steam turbines receive high-pressure steam and discharge low-pressure steam. Based on their operations and steam flow configurations, steam turbines are classified as follows:

- Backpressure
- Extraction
- Condensing
- A combination of the above

9.2.1 Backpressure Turbine

A backpressure turbine exhausts steam to a steam header with a pressure that is above atmospheric pressure. Backpressure turbines are also known as Topping turbines and non-condensing turbines. Backpressure turbines are the most common turbines in industrial plants. Backpressure turbines are always used in lieu of pressure reducing stations and are always located in parallel with pressure reducing stations between two steam headers. Backpressure turbines can be single stage (Figure 31a) or multi-stage (Figure 31b). Generally, multistage turbines are more efficient than single stage turbines.

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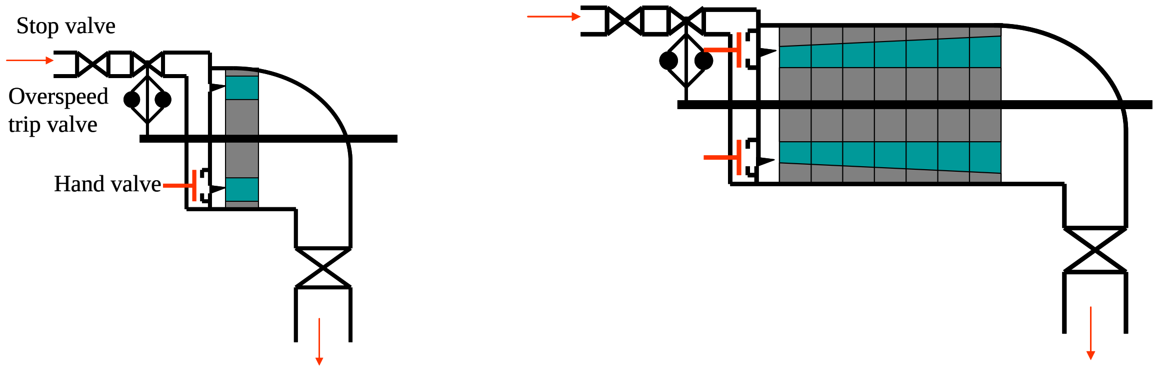

(a) Single Stage (b) Multi Stage

Figure 31: BackPressure Steam Turbines
(Courtesy: US DOE Steam BestPractices End User Training)

9.2.2 Extraction Turbine

A backpressure extraction turbine is a backpressure turbine with one or more additional ports for extracting steam at intermediate pressures between the inlet and the exhaust of steam. Backpressure extraction turbines can also be thought of as multiple turbines operating on the same shaft. They are very commonly found in industrial plants that have multiple steam pressure headers. They are an excellent candidate for balancing steam headers & eliminating steam venting on intermediate headers. Figure 32 shows a schematic of a backpressure extraction turbine.

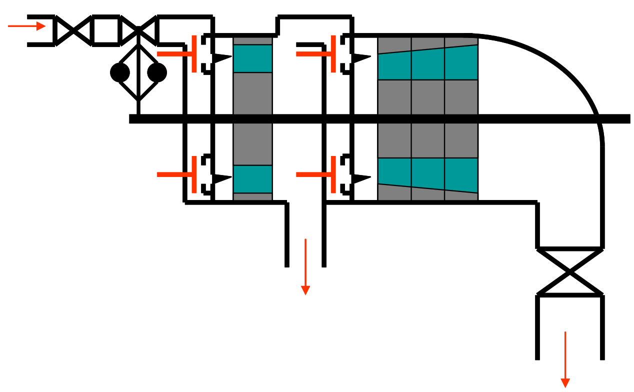

Figure 32: BackPressure Extraction Steam Turbine
(Courtesy: US DOE Steam BestPractices End User Training)

9.2.3 Condensing Turbine

A condensing turbine does not exhaust steam into a steam header but instead exhausts steam below atmospheric pressure to a surface condenser. The thermodynamic quality of the steam exiting a condensing steam turbine is typically greater than 90%. It contains a significant amount of thermal energy as it enters the surface condenser. The condenser uses cooling tower water (or river water) in the tubes to condense the steam on the shell side. Saturated water (condensate) is then removed from the condenser and pumped back to the boiler plant. Condensing turbines are

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large units and mainly used to generate power or drive large mechanical equipment such as centrifugal chillers, air compressors, etc. Figure 33 schematically represents a condensing turbine.

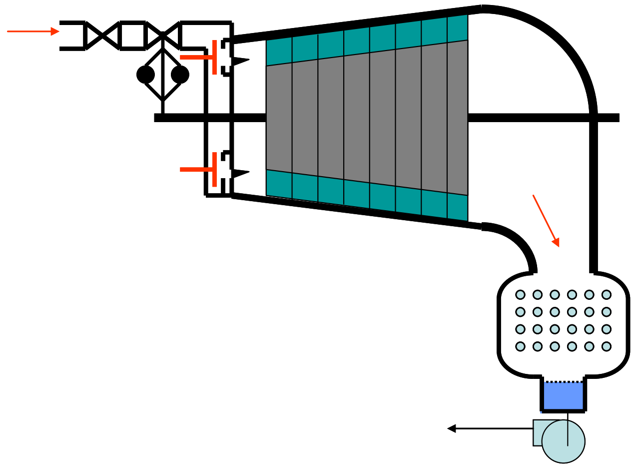

Figure 33: Condensing Turbine
(Courtesy: US DOE Steam BestPractices End User Training)

An extraction-condensing turbine is a combination of an extraction and condensing turbines. It is very commonly used to balance steam and power demands simultaneously.

9.3 Steam Turbine Efficiency

Steam turbine efficiency is not "like" boiler efficiency which follows the first law of thermodynamics. Steam turbine efficiency relates to the second law of thermodynamics and is a comparison of the actual turbine operation to that of a perfect turbine operating with the same inlet conditions and outlet pressure. Hence, it is also called isentropic turbine efficiency.

Isentropic turbine efficiency is a comparison of the shaft power from an actual turbine operation to that of a perfect (ideal) turbine operating with the same inlet conditions and outlet pressure (not outlet temperature!). Mathematically, it is expressed as follows:

$$\eta_{turbine} = \frac{Shaft\ Power\ of\ Actual\ Turbine}{Shaft\ Power\ of\ Ideal\ Turbine}$$

$$\eta_{turbine} = \frac{m_{steam}(h_{inlet} - h_{exit})_{actual}}{m_{steam}(h_{inlet} - h_{exit})_{ideal}} = \frac{(h_{inlet} - h_{exit})_{actual}}{(h_{inlet} - h_{exit})_{ideal}}$$

<u>Example</u>
Calculate the isentropic efficiency and shaft power produced by a backpressure steam turbine operating with steam inlet conditions of 25 bars and 375°C. The exhaust conditions are 2 bars and 271°C. The throttle steam flow of the turbine is 21 Tph.

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The thermodynamic properties of steam are obtained from the steam tables for the temperature and pressure conditions. They are as follows:

Actual Turbine:
H_{inlet} = 3,180.9 kJ/kg (based on 25 bars and 375°C)
H_{exit} = 3,009.8 kJ/kg (based on 2 bars and 271°C)

Ideal Turbine:
H_{inlet} = 3,180.9 kJ/kg (based on 25 bars and 375°C)
H_{exit} = 2,692 kJ/kg (based on 2 bars and entropy same as the inlet conditions)

Substituting the above information in the equation on steam turbine efficiency provides:

$$\eta_{turbine} = \frac{(h_{inlet} - h_{exit})_{actual}}{(h_{inlet} - h_{exit})_{ideal}}$$

$$\eta_{turbine} = \frac{(3{,}180.9 - 3{,}009.8)}{(3{,}180.9 - 2{,}692)} = 0.35$$

The isentropic turbine efficiency is calculated as 35%. The shaft power from this actual turbine is calculated as follows:

$$W_{actual} = m_{steam}(h_{inlet} - h_{exit})_{actual}$$

$$W_{actual} = \frac{21{,}000}{3{,}600} \times (3{,}180.9 - 3{,}009.8) = 1{,}000\, kW$$

The Ideal turbine shaft power can also be calculated from the above equations. The ideal turbine shaft power will be the maximum work that is theoretical possible given the steam inlet conditions and the exit pressure.

$$W_{ideal} = m_{steam}(h_{inlet} - h_{exit})_{ideal}$$

$$W_{ideal} = \frac{21{,}000}{3{,}600} \times (3{,}180.9 - 2{,}692) = 2{,}850\, kW$$

A steam turbine can have an efficiency ranging from 15-85%. A steam turbine with a low isentropic efficiency merely indicates that its ability to convert thermal energy into shaft power is not good. Hence, it preserves most of the thermal energy in the steam as it exhausts from the backpressure turbine and is used to supply the thermal demand of the industrial processes. This energy is not lost as would have been the case if this was the first law efficiency as the case is with boiler efficiency.

The exception to the above discussion is the condensing turbine which may be rejecting all its exhausted thermal energy to the ambient via the cooling water in the surface condenser.

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9.4 Steam Rate

Steam rate is an expression used to describe the amount of steam required to produce a specific amount of power. It is widely used in industry to specify the performance of an actual turbine. It can be related to turbine efficiency for given inlet conditions and exhaust pressures. Nevertheless, the steam rate is extremely dependent upon the inlet and outlet conditions. Throttling the inlet of turbine may not change the turbine isentropic efficiency but it can change the steam rate significantly. Hence, caution should be exercised when working with steam rates and comparing turbine performances using steam rates. Figure 34 shows a typical graph for correlating steam rates and turbine efficiency.

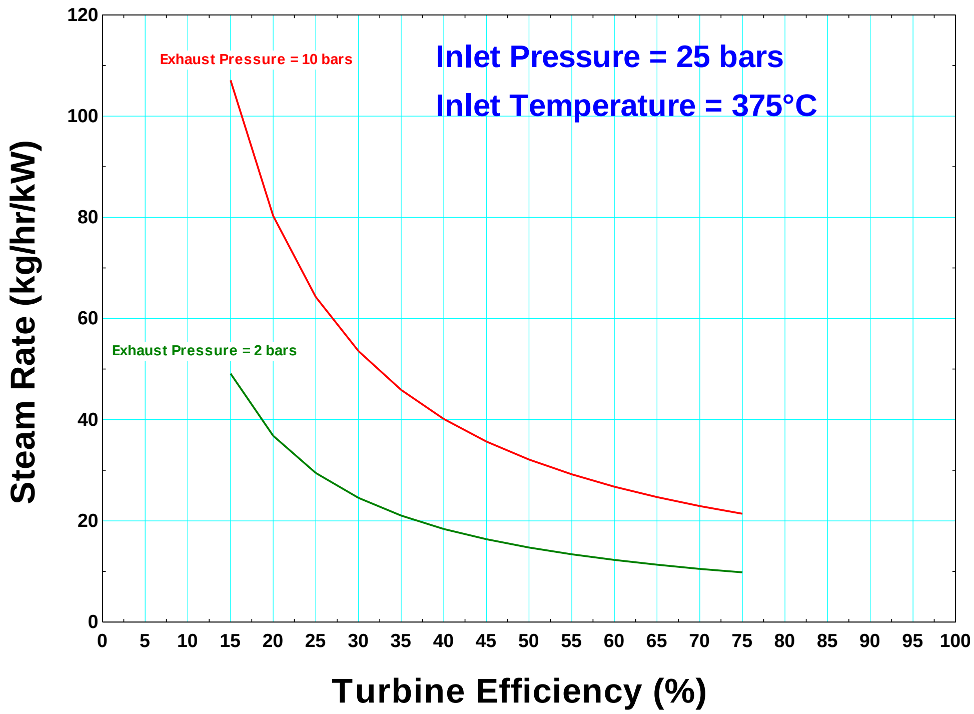

Figure 34: Steam Rate and Steam Turbine Efficiency

9.5 CHP Optimization Opportunities & BestPractices

The CHP optimization opportunity in industrial steam systems almost always relies on understanding the economic benefit of modifying operations of steam turbines. In industrial CHP applications, two major turbine configurations are encountered and they include:

- Backpressure
- Condensing

9.5.1 CHP Optimization Opportunity with Backpressure Turbine

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This opportunity specifically exists in industrial plants which have more than one steam pressure level where steam is required by the end-use processes. Additionally, having a continuous flow of steam through pressure reducing valves indicates that the plant may be a very good candidate to evaluate for a CHP optimization opportunity using a backpressure turbine. Evaluation of this optimization opportunity would require use of detailed steam system thermodynamic models. The evaluation methodology is best explained using an industrial plant example given below.

Example

A methane gas boiler with an efficiency of 80% produces superheated steam at 25 bars and 375°C. The thermal demand for a process end-use is 14,300 kW and requires steam at 2 bars. Currently, this steam flows through a Pressure Reducing Valve (PRV). Saturated condensate is discharged from the process load at 2 bars. Estimate the economic benefit of a CHP optimization opportunity by implementing a backpressure steam turbine that directly drives a pump requiring 1,000 kW of electric power. The steam isentropic turbine efficiency is expected to be 35%. The impact fuel cost is $1/Nm^3$ and the impact electric utility cost is $0.10/kWh.

Figure 35 depicts the current operation at the industrial plant. Based on the thermal end-use demand, steam flow through the PRV (Pressure Reducing Valve) can be calculated as follows:

$$Q_{enduse} = m_{PRV}\left(h_{PRV} - h_{condensate}\right)$$

$$m_{PRV} = \frac{Q_{enduse}}{\left(h_{PRV} - h_{condensate}\right)} = \frac{14{,}300}{\left(3{,}180.9 - 562.2\right)} = 5.45\,kg/s = 19.63\,Tph$$

where Q_{enduse} is the thermal demand; h_{PRV} is the enthalpy of steam exiting the PRV and entering the end-use; and $h_{condensate}$ is the enthalpy of condensate leaving the end-use.

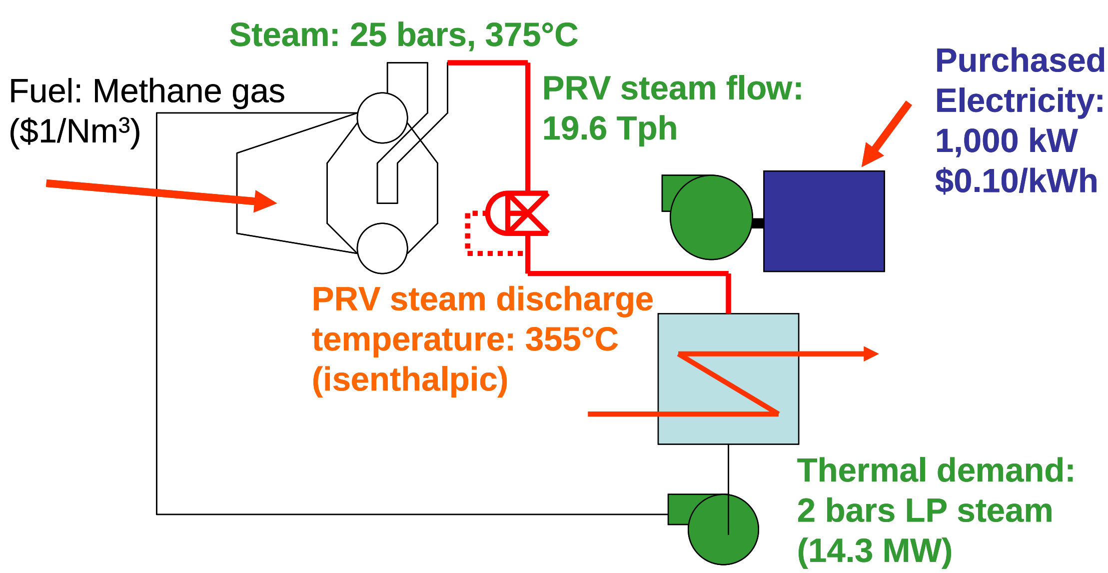

Figure 35: Current Operation at Industrial Plant using PRV

The CHP optimization opportunity will implement a backpressure steam turbine that will reduce the steam pressure from 25 bars to 2 bars. While doing so it will do shaft work which will drive

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the pump and offset the 1,000 kW of electric purchase from the grid. The steam turbine will extract energy from the steam and convert it into shaft energy thereby reducing the steam enthalpy exiting the turbine. This implies the steam will exit the turbine with a reduced temperature compared to the PRV. To satisfy the same thermal demand as in the current operation, there will be a net increase in the mass flow rate of steam. This additional steam will have to be produced by the boiler and the fuel energy cost for operations will increase. Figure 36 represents the new configuration of the industrial application with the steam turbine and CHP.

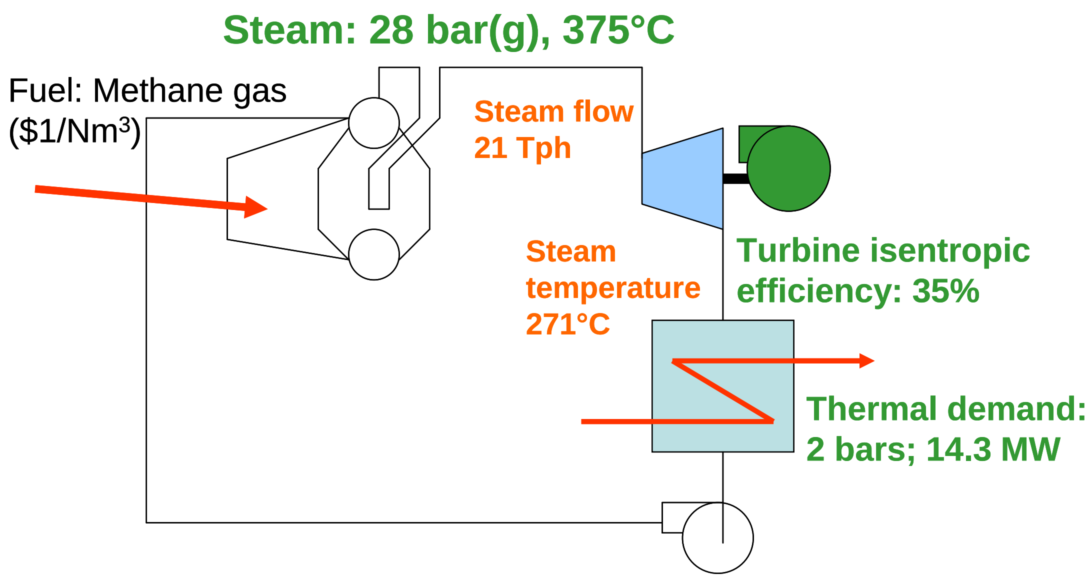

Figure 36: CHP Configuration at Industrial Plant using Steam Turbine

Comparing Figures 35 and 36 indicates that the steam entering the end-use has dropped in temperature from 355°C to 271°C. Based on the thermal end-use demand, steam flow through the steam turbine can be calculated as follows:

$$Q_{enduse} = m_{turbine}\left(h_{turbine} - h_{condensate}\right)$$

$$m_{turbine} = \frac{Q_{enduse}}{\left(h_{turbine} - h_{condensate}\right)} = \frac{14{,}300}{\left(3{,}009.8 - 562.2\right)} = 5.83\,kg/s = 21.0\,Tph$$

where Q_{enduse} is the thermal demand; $h_{turbine}$ is the enthalpy of steam exiting the steam turbine and entering the end-use; and $h_{condensate}$ is the enthalpy of condensate leaving the end-use.

The electrical energy cost savings associated with this CHP optimization opportunity are calculated as follows:

$$\sigma_{electric} = kW \times T \times k_{electric}$$

$$\sigma_{electric} = 1{,}000 \times 8{,}760 \times 0.10 = \$876{,}000 / yr$$

The fuel energy cost increase associated with this CHP optimization opportunity are calculated as follows:

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$$\sigma_{fuel} = (m_{turbine} - m_{PRV}) \times \frac{(h_{steam} - h_{feedwater})}{\eta_{boiler} \times HHV_{fuel}} \times k_{fuel} \times T$$

$$\sigma_{fuel} = (21.0 - 19.63) \times 1{,}000 \times \frac{(3{,}180.9 - 463.5)}{0.80 \times 40{,}144} \times 1.0 \times 8{,}760$$

$$\sigma_{fuel} = \$1{,}038{,}000 / yr$$

Hence, the net economic benefit of this CHP optimization opportunity is given as follows:

$$\sigma_{CHP} = \sigma_{electric} - \sigma_{fuel}$$

$$\sigma_{CHP} = 876{,}000 - 1{,}038{,}000 = -\$162{,}000 / yr$$

This example clearly shows that the CHP optimization opportunity is not a viable solution strategy in this industrial plant application.

Using the key parameters that influence the economic benefit of the CHP optimization opportunity, a parametric analysis was done. The results from this parametric analysis are provided in Table 6 below and clearly indicate when the CHP optimization opportunity can be economically justified in this industrial plant application.

Table 6: Parametric Analysis for a BackPressure Steam Turbine CHP Optimization Opportunity

Power Cost ($/kWh)	Fuel Cost ($/GJ)	Turbine Efficiency (%)	SSAT Boiler Efficiency (%)	Additional Power (kW)	Additional Steam (Tph)	Cost Savings ($K/yr)
0.100	25.0	35.0	81.7	998	1.5	(221)
0.125	25.0	35.0	81.7	998	1.5	(2)
0.100	12.5	35.0	81.7	998	1.5	325
0.100	5.4	35.0	86.7	998	1.5	650
0.100	25.0	65.0	81.7	1,853	2.8	(409)

Table 6 was developed using a US DOE SSAT model and doing a steam turbine implementation project. The impact power cost, impact fuel cost, steam turbine efficiency, impact boiler efficiency were varied individually to obtain the results presented in the Table. A detailed due diligence and parametric analysis will be required to be done for each CHP optimization opportunity to demonstrate and answer all questions related to the economic viability of the CHP optimization opportunity.

9.5.2 CHP Optimization Opportunity with Condensing Turbine

From the perspective of the definition of CHP in strictest sense, condensing turbine operations do not necessarily fall under CHP optimization opportunities. Nevertheless, they will still be covered here because the analysis principles are identical to those that have been discussed in the backpressure steam turbine cases. The main difference is that the steam passing through the condensing turbine does not exhaust to a steam header and neither does it satisfy any thermal

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demand. It is actually condensed in the surface condenser at the exit of the turbine. Hence, it loses all its thermal energy to the cooling water flowing in the tubes of the surface condenser. The condensing turbine aims to maximize power production from the steam to minimize thermal energy losses to the ambient.

The primary factors that influence condensing turbine operations are:

- Impact power cost
- Impact fuel cost
- Turbine efficiency
- Boiler efficiency
- Turbine discharge pressure

The power generated by the turbine is a function of the pressure ratio between the inlet and exhaust pressures. Typically, the inlet pressure is the steam generation pressure or a low pressure header in the steam system. But the exhaust pressure plays a very significant role in the amount of power produced. The exhaust pressure of the turbine is controlled by the surface condenser and this pressure should be maintained as close to design conditions as possible. There are several areas that should be targeted to ensure that the condenser pressure is at design conditions including:

- Removing non-condensable gases from condenser
- Cleaning the condenser periodically
- Supplying the condenser with reduced temperature water
- Supplying the condenser with additional cooling water

Evaluation of a condensing turbine related CHP optimization opportunity will require a detailed thermodynamic steam system model such as the US DOE SSAT tool. Table 7 presents a parametric analysis done on a condensing turbine industrial application that uses 25 bars, 375°C inlet steam and exhausts at 0.1 bar (absolute) pressure. The boiler efficiency is maintained at 80% and the fuel cost and turbine efficiency is varied.

Table 7: Parametric Analysis for a Condensing Turbine CHP Optimization Opportunity

Condensing Turbine Impact Power Cost			
Fuel Cost [$/GJ]	Impact Condensing Power Cost [$/MWh]		
	Turbine Isentropic Efficiency [%]		
	40	60	80
2.0	56	39	30
4.0	111	78	60
6.0	167	116	89
8.0	223	155	119
10.0	278	194	149
12.0	334	233	179
Steam inlet	25	bars	
Steam inlet	375	°C	
Steam exit	0.1	bar(a)	

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Table 7 provides the condensing turbine power generation costs based on different isentropic turbine efficiencies and impact fuel costs. As can be observed, for an industrial plant that purchases electric utility power at $100 per MWh, it will only be cost effective to run the condensing turbine if impact fuel costs are $2.0 per GJ or lower, irrespective of turbine efficiencies considered in the analysis. But as the impact fuel price increases to $4.0 per GJ, turbine efficiencies will need to be 60% or higher to be economically beneficial. Further increase in the impact fuel cost to $6.0 per GJ will require turbine operating efficiency of 80% or higher. When costs go to $8.0 per GJ and above, condensing turbine CHP operations will not be economical at all if electric power can be purchased from the grid at $100 per MWh.

It has to be noted that in condensing turbine CHP optimization opportunities are implemented, they result in major steam flow changes. Turning a condensing turbine ON can require another boiler to be turned ON and turning a condensing turbine OFF may lead to shutting down a boiler. These changes can change the impact boiler and the impact fuel cost. Care has to be taken to ensure that all the economic analysis properly accounts for these large changes in steam flows.

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10. CONCLUSIONS & NEXT STEPS

It is expected that this 2-Day Steam System Optimization Training Manual has provided an insight to the readers about the different avenues to investigate when working with an industrial steam system. There are several optimization opportunities and BestPractices that can be implemented to minimize operating costs, improve overall system operations and reduce GHG emissions. Each of these areas was discussed in detail in this Training Manual and is summarized in the section below.

10.1 Steam System Optimization Opportunities & BestPractices

This section summarizes all the steam system opportunities and BestPractices identified in an industrial plant. This section should also serve as a checklist for energy consultants and steam system users to ensure that their steam systems are operating at their optimized configurations. Although there could be many objectives for optimizing the steam system, the main objective for this Training Manual was to minimize operating costs.

10.1.1 Steam Generation Area Optimization Opportunities & BestPractices

There are several optimization opportunities and bestpractices in the steam generation area including:

- Minimize excess air
- Install heat recovery equipment
- Clean boiler heat transfer surfaces
- Improve water treatment
- Install an automatic boiler blowdown controller
- Recover energy from boiler blowdown
- Add/restore boiler refractory
- Minimize the number of operating boilers
- Investigate fuel switching
- Optimize deaerator operations

10.1.2 Steam Distribution Area Optimization Opportunities & BestPractices

There are several optimization opportunities and bestpractices in the steam distribution area including:

- Repair steam leaks
- Minimize vented steam
- Ensure that steam system piping, valves, fittings and vessels are well insulated
- Isolate steam from unused lines
- Minimize flows through pressure reducing stations
- Reduce pressure drop in headers
- Drain condensate from steam headers

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10.1.3 Steam End-Use Area Optimization Opportunities & BestPractices

It is extremely difficult to cover end-uses that are specific to industrial processes and plants. Process and utility integration leads to overall energy system optimization of the plant and the benefits are far-reaching. In the classic configuration, the main strategies to optimize steam in the end use area are:

- Eliminate or reduce the amount of steam used by a process
- Improve process efficiency and eliminate inappropriate steam usage
- Use steam at as low a pressure as possible which would possibly allow power generation
- Shift all or part of the steam demand to a waste heat source
- Upgrade low pressure (or waste) steam to supply process demands that would have otherwise used much higher pressure steam.

10.1.4 Condensate Recovery Area Optimization Opportunities & BestPractices

There are several optimization opportunities and bestpractices in the condensate recovery area including:

- Implement an effective steam-trap management and maintenance program
- Recover as much as possible of available condensate
- Recover condensate at the highest possible thermal energy
- Flash high pressure condensate to make low pressure steam

10.1.5 Combined Heat and Power Area Optimization Opportunities & BestPractices

The CHP optimization opportunity in industrial steam systems almost always relies on understanding the economic benefit of modifying operations of steam turbines. In industrial CHP applications, two major turbine configurations are encountered and they include:

- Backpressure
- Condensing

10.2 Next Steps

It is anticipated that after completing a 2-Day User Training on Steam System Optimization, attendees would be able to use the different tools and resources discussed in the class for evaluating industrial steam systems.

Energy consultants and industrial end-users should develop an action plan for assessing their steam systems. They should start with a simple scoping and information gathering tool that allows them to understand the industrial steam system to be evaluated at a high level. The first step should be to identify all the BestPractices currently implemented in the industrial steam system.

The second step should be to identify areas of optimization opportunities and develop an action plan including data collection, methodology of evaluating the economic benefits for the opportunity and presenting them to plant management in a manner that is easily understandable.

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The third step should be to conduct an energy assessment of the industrial steam system and use all the tools and resources identified in the 2-Day User Training.

The fourth step should be to compile a detailed steam system optimization opportunity assessment report identifying all the opportunities and savings potentials. This report should also specify next steps that the industrial plant should take to implement each of the optimization opportunities. A first level due-diligence should be done to determine cost of implementation of the optimization opportunities.

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APPENDIX A: STEAM TABLES (From REFPROP)

A.1 Saturated Liquid and Vapor Properties (by Pressure)

Temperature	Absolute Pressure	Liquid Density	Vapor Density	Liquid Enthalpy	Vapor Enthalpy	Liquid Entropy	Vapor Entropy
°C	bar	kg/m^3	kg/m^3	kJ/kg	kJ/kg	kJ/kg-K	kJ/kg-K
81.32	0.50	970.940	0.309	340.54	2645.20	1.0912	7.5930
99.61	1.00	958.630	0.590	417.50	2674.90	1.3028	7.3588
111.35	1.50	949.920	0.863	467.13	2693.10	1.4337	7.2230
120.21	2.00	942.940	1.129	504.70	2706.20	1.5302	7.1269
127.41	2.50	937.020	1.392	535.34	2716.50	1.6072	7.0524
133.52	3.00	931.820	1.651	561.43	2724.90	1.6717	6.9916
138.86	3.50	927.150	1.908	584.26	2732.00	1.7274	6.9401
143.61	4.00	922.890	2.163	604.65	2738.10	1.7765	6.8955
147.90	4.50	918.960	2.416	623.14	2743.40	1.8205	6.8560
151.83	5.00	915.290	2.668	640.09	2748.10	1.8604	6.8207
155.46	5.50	911.850	2.919	655.76	2752.30	1.8970	6.7886
158.83	6.00	908.590	3.169	670.38	2756.10	1.9308	6.7592
161.98	6.50	905.510	3.418	684.08	2759.60	1.9623	6.7322
164.95	7.00	902.560	3.666	697.00	2762.80	1.9918	6.7071
167.75	7.50	899.740	3.914	709.24	2765.60	2.0195	6.6836
170.41	8.00	897.040	4.161	720.86	2768.30	2.0457	6.6616
172.94	8.50	894.430	4.407	731.95	2770.80	2.0705	6.6409
175.35	9.00	891.920	4.654	742.56	2773.00	2.0940	6.6213
177.66	9.50	889.480	4.900	752.74	2775.10	2.1165	6.6027
179.88	10.00	887.130	5.145	762.52	2777.10	2.1381	6.5850
182.01	10.50	884.840	5.390	771.94	2778.90	2.1587	6.5681
184.06	11.00	882.620	5.635	781.03	2780.60	2.1785	6.5520
186.04	11.50	880.460	5.880	789.82	2782.20	2.1976	6.5365
187.96	12.00	878.350	6.125	798.33	2783.70	2.2159	6.5217
189.81	12.50	876.290	6.370	806.58	2785.10	2.2337	6.5074
191.60	13.00	874.280	6.614	814.60	2786.50	2.2508	6.4936
193.35	13.50	872.310	6.859	822.39	2787.70	2.2674	6.4803
195.04	14.00	870.390	7.103	829.97	2788.80	2.2835	6.4675
196.69	14.50	868.500	7.348	837.35	2789.90	2.2992	6.4550
198.29	15.00	866.650	7.592	844.56	2791.00	2.3143	6.4430
199.85	15.50	864.840	7.837	851.59	2791.90	2.3291	6.4313
201.37	16.00	863.050	8.082	858.46	2792.80	2.3435	6.4199
202.86	16.50	861.300	8.326	865.17	2793.70	2.3575	6.4089
204.31	17.00	859.580	8.571	871.74	2794.50	2.3711	6.3981
205.73	17.50	857.890	8.816	878.17	2795.20	2.3845	6.3877
207.11	18.00	856.220	9.061	884.47	2795.90	2.3975	6.3775
208.47	18.50	854.580	9.306	890.65	2796.60	2.4102	6.3675
209.80	19.00	852.960	9.551	896.71	2797.20	2.4227	6.3578
211.10	19.50	851.370	9.796	902.66	2797.80	2.4348	6.3483
212.38	20.00	849.800	10.042	908.50	2798.30	2.4468	6.3390

Temperature	Absolute Pressure	Liquid Density	Vapor Density	Liquid Enthalpy	Vapor Enthalpy	Liquid Entropy	Vapor Entropy
°C	bar	kg/m^3	kg/m^3	kJ/kg	kJ/kg	kJ/kg-K	kJ/kg-K
213.63	20.50	848.250	10.287	914.24	2798.80	2.4584	6.3299
214.86	21.00	846.720	10.533	919.87	2799.30	2.4699	6.3210
216.06	21.50	845.210	10.779	925.42	2799.70	2.4811	6.3123
217.25	22.00	843.720	11.026	930.87	2800.10	2.4921	6.3038
218.41	22.50	842.240	11.272	936.24	2800.50	2.5029	6.2954
219.56	23.00	840.790	11.519	941.53	2800.80	2.5136	6.2872
220.68	23.50	839.350	11.766	946.74	2801.10	2.5240	6.2791
221.79	24.00	837.920	12.013	951.87	2801.40	2.5343	6.2712
222.88	24.50	836.510	12.260	956.92	2801.70	2.5443	6.2634
223.95	25.00	835.120	12.508	961.91	2801.90	2.5543	6.2558
225.01	25.50	833.740	12.756	966.82	2802.10	2.5640	6.2483
226.05	26.00	832.370	13.004	971.67	2802.30	2.5736	6.2409
227.07	26.50	831.020	13.253	976.46	2802.50	2.5831	6.2336
228.08	27.00	829.680	13.501	981.18	2802.70	2.5924	6.2264
229.08	27.50	828.360	13.750	985.85	2802.80	2.6016	6.2194
230.06	28.00	827.040	14.000	990.46	2802.90	2.6106	6.2124
231.02	28.50	825.740	14.250	995.01	2803.00	2.6195	6.2056
231.98	29.00	824.450	14.500	999.51	2803.10	2.6283	6.1988
232.92	29.50	823.170	14.750	1004.00	2803.10	2.6370	6.1921
233.85	30.00	821.900	15.001	1008.30	2803.20	2.6455	6.1856
234.77	30.50	820.640	15.251	1012.70	2803.20	2.6540	6.1791
235.68	31.00	819.390	15.503	1017.00	2803.20	2.6623	6.1727
236.57	31.50	818.150	15.754	1021.20	2803.20	2.6706	6.1664
237.46	32.00	816.920	16.006	1025.40	2803.10	2.6787	6.1602
238.33	32.50	815.710	16.259	1029.60	2803.10	2.6867	6.1540
239.20	33.00	814.490	16.512	1033.70	2803.00	2.6946	6.1479
240.05	33.50	813.290	16.765	1037.80	2803.00	2.7025	6.1419
240.90	34.00	812.100	17.018	1041.80	2802.90	2.7102	6.1360
241.73	34.50	810.910	17.272	1045.80	2802.80	2.7178	6.1301
242.56	35.00	809.740	17.526	1049.80	2802.60	2.7254	6.1243
243.37	35.50	808.570	17.781	1053.70	2802.50	2.7329	6.1186
244.18	36.00	807.410	18.036	1057.60	2802.40	2.7403	6.1129
244.98	36.50	806.250	18.291	1061.50	2802.20	2.7476	6.1073
245.77	37.00	805.100	18.547	1065.30	2802.10	2.7549	6.1018
246.56	37.50	803.960	18.803	1069.10	2801.90	2.7620	6.0963
247.33	38.00	802.830	19.059	1072.80	2801.70	2.7691	6.0908
248.10	38.50	801.710	19.316	1076.50	2801.50	2.7761	6.0854
248.86	39.00	800.590	19.574	1080.20	2801.30	2.7831	6.0801
249.61	39.50	799.470	19.832	1083.90	2801.10	2.7900	6.0748
250.35	40.00	798.370	20.090	1087.50	2800.80	2.7968	6.0696
251.09	40.50	797.270	20.349	1091.10	2800.60	2.8035	6.0644
251.82	41.00	796.170	20.608	1094.70	2800.30	2.8102	6.0592
252.55	41.50	795.080	20.867	1098.20	2800.10	2.8168	6.0542
253.26	42.00	794.000	21.127	1101.70	2799.80	2.8234	6.0491
253.98	42.50	792.930	21.388	1105.20	2799.50	2.8299	6.0441
254.68	43.00	791.850	21.649	1108.70	2799.20	2.8363	6.0391
255.38	43.50	790.790	21.910	1112.10	2798.90	2.8427	6.0342
256.07	44.00	789.730	22.172	1115.50	2798.60	2.8490	6.0293
256.76	44.50	788.670	22.434	1118.90	2798.30	2.8553	6.0245
257.44	45.00	787.620	22.697	1122.20	2797.90	2.8615	6.0197

Temperature	Absolute Pressure	Liquid Density	Vapor Density	Liquid Enthalpy	Vapor Enthalpy	Liquid Entropy	Vapor Entropy
°C	bar	kg/m^3	kg/m^3	kJ/kg	kJ/kg	kJ/kg-K	kJ/kg-K
258.11	45.50	786.570	22.960	1125.60	2797.60	2.8677	6.0150
258.78	46.00	785.530	23.224	1128.90	2797.30	2.8738	6.0102
259.44	46.50	784.500	23.488	1132.20	2796.90	2.8799	6.0055
260.10	47.00	783.470	23.753	1135.50	2796.50	2.8859	6.0009
260.75	47.50	782.440	24.018	1138.70	2796.20	2.8918	5.9963
261.40	48.00	781.420	24.284	1141.90	2795.80	2.8978	5.9917
262.04	48.50	780.400	24.550	1145.10	2795.40	2.9036	5.9871
262.68	49.00	779.380	24.816	1148.30	2795.00	2.9095	5.9826
263.31	49.50	778.370	25.084	1151.50	2794.60	2.9153	5.9781
263.94	50.00	777.370	25.351	1154.60	2794.20	2.9210	5.9737
264.56	50.50	776.370	25.619	1157.80	2793.80	2.9267	5.9692
265.18	51.00	775.370	25.888	1160.90	2793.40	2.9323	5.9648
265.79	51.50	774.380	26.157	1164.00	2792.90	2.9380	5.9605
266.40	52.00	773.390	26.427	1167.00	2792.50	2.9435	5.9561
267.01	52.50	772.400	26.697	1170.10	2792.00	2.9491	5.9518
267.61	53.00	771.420	26.968	1173.10	2791.60	2.9546	5.9475
268.20	53.50	770.440	27.240	1176.10	2791.10	2.9600	5.9433
268.79	54.00	769.460	27.512	1179.10	2790.70	2.9654	5.9391
269.38	54.50	768.490	27.784	1182.10	2790.20	2.9708	5.9348
269.97	55.00	767.520	28.057	1185.10	2789.70	2.9762	5.9307
270.54	55.50	766.550	28.331	1188.00	2789.20	2.9815	5.9265
271.12	56.00	765.590	28.605	1191.00	2788.70	2.9868	5.9224
271.69	56.50	764.630	28.879	1193.90	2788.20	2.9920	5.9183
272.26	57.00	763.670	29.155	1196.80	2787.70	2.9972	5.9142
272.82	57.50	762.720	29.431	1199.70	2787.20	3.0024	5.9101
273.38	58.00	761.770	29.707	1202.60	2786.70	3.0075	5.9061
273.94	58.50	760.820	29.984	1205.40	2786.20	3.0126	5.9021
274.49	59.00	759.880	30.262	1208.30	2785.70	3.0177	5.8981
275.04	59.50	758.940	30.540	1211.10	2785.10	3.0228	5.8941
275.58	60.00	758.000	30.818	1213.90	2784.60	3.0278	5.8901
276.13	60.50	757.060	31.098	1216.70	2784.00	3.0328	5.8862
276.67	61.00	756.130	31.378	1219.50	2783.50	3.0377	5.8823
277.20	61.50	755.200	31.658	1222.30	2782.90	3.0427	5.8784
277.73	62.00	754.270	31.940	1225.10	2782.40	3.0476	5.8745
278.26	62.50	753.340	32.221	1227.80	2781.80	3.0524	5.8706
278.79	63.00	752.420	32.504	1230.50	2781.20	3.0573	5.8668
279.31	63.50	751.500	32.787	1233.30	2780.60	3.0621	5.8630
279.83	64.00	750.580	33.070	1236.00	2780.10	3.0669	5.8592
280.34	64.50	749.660	33.355	1238.70	2779.50	3.0716	5.8554
280.86	65.00	748.750	33.640	1241.40	2778.90	3.0764	5.8516
281.37	65.50	747.840	33.925	1244.10	2778.30	3.0811	5.8478
281.87	66.00	746.930	34.211	1246.70	2777.70	3.0858	5.8441
282.38	66.50	746.020	34.498	1249.40	2777.10	3.0904	5.8404
282.88	67.00	745.110	34.786	1252.00	2776.40	3.0951	5.8367
283.38	67.50	744.210	35.074	1254.70	2775.80	3.0997	5.8330
283.87	68.00	743.310	35.363	1257.30	2775.20	3.1043	5.8293
284.37	68.50	742.410	35.652	1259.90	2774.60	3.1088	5.8256
284.86	69.00	741.510	35.943	1262.50	2773.90	3.1134	5.8220
285.34	69.50	740.620	36.234	1265.10	2773.30	3.1179	5.8184
285.83	70.00	739.720	36.525	1267.70	2772.60	3.1224	5.8148

Temperature	Absolute Pressure	Liquid Density	Vapor Density	Liquid Enthalpy	Vapor Enthalpy	Liquid Entropy	Vapor Entropy
°C	bar	kg/m³	kg/m³	kJ/kg	kJ/kg	kJ/kg-K	kJ/kg-K
286.31	70.50	738.830	36.817	1270.20	2772.00	3.1269	5.8111
286.79	71.00	737.940	37.110	1272.80	2771.30	3.1313	5.8076
287.27	71.50	737.050	37.404	1275.30	2770.70	3.1358	5.8040
287.74	72.00	736.170	37.698	1277.90	2770.00	3.1402	5.8004
288.21	72.50	735.280	37.993	1280.40	2769.30	3.1446	5.7969
288.68	73.00	734.400	38.289	1282.90	2768.60	3.1489	5.7933
289.15	73.50	733.520	38.585	1285.40	2768.00	3.1533	5.7898
289.61	74.00	732.640	38.883	1287.90	2767.30	3.1576	5.7863
290.08	74.50	731.760	39.181	1290.40	2766.60	3.1619	5.7828
290.54	75.00	730.880	39.479	1292.90	2765.90	3.1662	5.7793
290.99	75.50	730.010	39.779	1295.40	2765.20	3.1705	5.7758
291.45	76.00	729.140	40.079	1297.90	2764.50	3.1747	5.7723
291.90	76.50	728.260	40.380	1300.30	2763.80	3.1789	5.7689
292.35	77.00	727.390	40.681	1302.80	2763.10	3.1832	5.7654
292.80	77.50	726.520	40.983	1305.20	2762.30	3.1874	5.7620
293.25	78.00	725.660	41.287	1307.70	2761.60	3.1915	5.7586
293.69	78.50	724.790	41.591	1310.10	2760.90	3.1957	5.7552
294.13	79.00	723.920	41.895	1312.50	2760.20	3.1998	5.7518
294.57	79.50	723.060	42.201	1314.90	2759.40	3.2040	5.7484
295.01	80.00	722.200	42.507	1317.30	2758.70	3.2081	5.7450
295.44	80.50	721.330	42.814	1319.70	2757.90	3.2122	5.7416
295.88	81.00	720.470	43.122	1322.10	2757.20	3.2162	5.7383
296.31	81.50	719.620	43.430	1324.50	2756.40	3.2203	5.7349
296.74	82.00	718.760	43.740	1326.80	2755.70	3.2243	5.7316
297.16	82.50	717.900	44.050	1329.20	2754.90	3.2284	5.7282
297.59	83.00	717.040	44.361	1331.60	2754.10	3.2324	5.7249
298.01	83.50	716.190	44.673	1333.90	2753.40	3.2364	5.7216
298.43	84.00	715.340	44.985	1336.30	2752.60	3.2403	5.7183
298.85	84.50	714.480	45.299	1338.60	2751.80	3.2443	5.7150
299.27	85.00	713.630	45.613	1340.90	2751.00	3.2483	5.7117
299.69	85.50	712.780	45.928	1343.30	2750.20	3.2522	5.7084
300.10	86.00	711.930	46.244	1345.60	2749.40	3.2561	5.7051
300.51	86.50	711.080	46.561	1347.90	2748.60	3.2600	5.7018
300.92	87.00	710.230	46.879	1350.20	2747.80	3.2639	5.6986
301.33	87.50	709.390	47.198	1352.50	2747.00	3.2678	5.6953
301.74	88.00	708.540	47.517	1354.80	2746.20	3.2717	5.6921
302.14	88.50	707.690	47.837	1357.10	2745.40	3.2755	5.6888
302.54	89.00	706.850	48.159	1359.30	2744.60	3.2793	5.6856
302.95	89.50	706.010	48.481	1361.60	2743.80	3.2832	5.6824
303.34	90.00	705.160	48.804	1363.90	2742.90	3.2870	5.6791
303.74	90.50	704.320	49.128	1366.10	2742.10	3.2908	5.6759
304.14	91.00	703.480	49.453	1368.40	2741.30	3.2946	5.6727
304.53	91.50	702.640	49.778	1370.60	2740.40	3.2983	5.6695
304.93	92.00	701.800	50.105	1372.90	2739.60	3.3021	5.6663
305.32	92.50	700.960	50.433	1375.10	2738.70	3.3058	5.6631
305.71	93.00	700.120	50.761	1377.40	2737.90	3.3096	5.6599
306.09	93.50	699.280	51.091	1379.60	2737.00	3.3133	5.6568
306.48	94.00	698.440	51.421	1381.80	2736.20	3.3170	5.6536
306.87	94.50	697.600	51.753	1384.00	2735.30	3.3207	5.6504
307.25	95.00	696.770	52.085	1386.20	2734.40	3.3244	5.6473
307.63	95.50	695.930	52.418	1388.40	2733.60	3.3281	5.6441
308.01	96.00	695.090	52.753	1390.60	2732.70	3.3317	5.6410
308.39	96.50	694.260	53.088	1392.80	2731.80	3.3354	5.6378
308.77	97.00	693.420	53.424	1395.00	2730.90	3.3390	5.6347
309.14	97.50	692.590	53.761	1397.20	2730.00	3.3427	5.6316
309.52	98.00	691.760	54.100	1399.40	2729.10	3.3463	5.6284
309.89	98.50	690.920	54.439	1401.60	2728.20	3.3499	5.6253
310.26	99.00	690.090	54.779	1403.70	2727.30	3.3535	5.6222
310.63	99.50	689.260	55.121	1405.90	2726.40	3.3571	5.6191
311.00	100.00	688.420	55.463	1408.10	2725.50	3.3606	5.6160

A.2 Saturated Liquid and Vapor Properties (by Temperature)

Temperature	Absolute Pressure	Liquid Density	Vapor Density	Liquid Enthalpy	Vapor Enthalpy	Liquid Entropy	Vapor Entropy
°C	bar	kg/m^3	kg/m^3	kJ/kg	kJ/kg	kJ/kg-K	kJ/kg-K
10	0.01	999.650	0.009	42.02	2519.20	0.1511	8.8998
20	0.02	998.160	0.017	83.91	2537.40	0.2965	8.6660
30	0.04	995.610	0.030	125.73	2555.50	0.4368	8.4520
40	0.07	992.180	0.051	167.53	2573.50	0.5724	8.2555
50	0.12	988.000	0.083	209.34	2591.30	0.7038	8.0748
60	0.20	983.160	0.130	251.18	2608.80	0.8313	7.9081
70	0.31	977.730	0.198	293.07	2626.10	0.9551	7.7540
80	0.47	971.770	0.294	335.01	2643.00	1.0756	7.6111
90	0.70	965.300	0.424	377.04	2659.50	1.1929	7.4781
99.61	1.00	958.630	0.590	417.50	2674.90	1.3028	7.3588
100	1.01	958.350	0.598	419.17	2675.60	1.3072	7.3541
110	1.43	950.950	0.827	461.42	2691.10	1.4188	7.2381
120	1.99	943.110	1.122	503.81	2705.90	1.5279	7.1291
130	2.70	934.830	1.497	546.38	2720.10	1.6346	7.0264
140	3.62	926.130	1.967	589.16	2733.40	1.7392	6.9293
150	4.76	917.010	2.548	632.18	2745.90	1.8418	6.8371
160	6.18	907.450	3.260	675.47	2757.40	1.9426	6.7491
170	7.92	897.450	4.122	719.08	2767.90	2.0417	6.6650
180	10.03	887.000	5.159	763.05	2777.20	2.1392	6.5840
190	12.55	876.080	6.395	807.43	2785.30	2.2355	6.5059
200	15.55	864.660	7.861	852.27	2792.00	2.3305	6.4302
210	19.08	852.720	9.589	897.63	2797.30	2.4245	6.3563
220	23.20	840.220	11.615	943.58	2800.90	2.5177	6.2840
230	27.97	827.120	13.985	990.19	2802.90	2.6101	6.2128
240	33.47	813.370	16.749	1037.60	2803.00	2.7020	6.1423
250	39.76	798.890	19.967	1085.80	2800.90	2.7935	6.0721
260	46.92	783.630	23.712	1135.00	2796.60	2.8849	6.0016
270	55.03	767.460	28.073	1185.30	2789.70	2.9765	5.9304
280	64.17	750.280	33.165	1236.90	2779.90	3.0685	5.8579
290	74.42	731.910	39.132	1290.00	2766.70	3.1612	5.7834
300	85.88	712.140	46.168	1345.00	2749.60	3.2552	5.7059
310	98.65	690.670	54.541	1402.20	2727.90	3.3510	5.6244
311	100.00	688.420	55.463	1408.10	2725.50	3.3606	5.6160

A.3 Superheated Vapor Properties (by Pressure)

Temperature	Absolute Pressure	Density	Enthalpy	Entropy
°C	bar	kg/m^3	kJ/kg	kJ/kg-K
120	1.0	0.558	2716.60	7.4678
140	1.0	0.529	2756.70	7.5672
160	1.0	0.504	2796.40	7.6610
180	1.0	0.481	2836.00	7.7503
200	1.0	0.460	2875.50	7.8356
140	3.0	1.621	2739.40	7.0269
160	3.0	1.537	2782.60	7.1291
180	3.0	1.462	2824.60	7.2239
200	3.0	1.396	2865.90	7.3131
220	3.0	1.336	2906.80	7.3978
180	7.0	3.512	2799.40	6.7893
200	7.0	3.333	2845.30	6.8884
220	7.0	3.177	2889.50	6.9799
240	7.0	3.037	2932.70	7.0658
260	7.0	2.912	2975.20	7.1472
200	10.0	4.854	2828.30	6.6955
220	10.0	4.609	2875.50	6.7934
240	10.0	4.394	2920.90	6.8836
260	10.0	4.204	2965.10	6.9681
280	10.0	4.032	3008.60	7.0482
220	15.0	7.110	2850.20	6.5659
240	15.0	6.743	2900.00	6.6649
260	15.0	6.425	2947.40	6.7555
280	15.0	6.144	2993.30	6.8400
300	15.0	5.893	3038.20	6.9198
220	20.0	9.787	2821.60	6.3867
240	20.0	9.217	2877.20	6.4973
260	20.0	8.740	2928.50	6.5952
280	20.0	8.330	2977.10	6.6849
300	20.0	7.968	3024.20	6.7684
250	25.0	11.487	2880.90	6.4107
275	25.0	10.732	2947.40	6.5350
300	25.0	10.107	3009.60	6.6459
325	25.0	9.574	3069.10	6.7476
350	25.0	9.109	3127.00	6.8424
375	25.0	8.696	3183.90	6.9319
400	25.0	8.325	3240.10	7.0170
275	40.0	18.313	2887.30	6.2312
300	40.0	16.987	2961.70	6.3639
325	40.0	15.928	3029.50	6.4797
350	40.0	15.044	3093.30	6.5843

Temperature	Absolute Pressure	Density	Enthalpy	Entropy
°C	bar	kg/m³	kJ/kg	kJ/kg-K
375	40.0	14.284	3154.70	6.6809
400	40.0	13.618	3214.50	6.7714
425	40.0	13.026	3273.20	6.8570
300	60.0	27.632	2885.50	6.0703
325	60.0	25.389	2969.50	6.2137
350	60.0	23.668	3043.90	6.3357
375	60.0	22.269	3112.80	6.4441
400	60.0	21.088	3178.20	6.5432
425	60.0	20.068	3241.40	6.6352
450	60.0	19.170	3302.90	6.7219
300	80.0	41.188	2786.50	5.7937
325	80.0	36.488	2898.40	5.9851
350	80.0	33.361	2988.10	6.1321
375	80.0	31.007	3066.90	6.2561
400	80.0	29.117	3139.40	6.3658
425	80.0	27.538	3207.70	6.4655
450	80.0	26.182	3273.30	6.5579
325	100.0	50.308	2810.30	5.7596
350	100.0	44.564	2924.00	5.9459
375	100.0	40.719	3016.30	6.0911
400	100.0	37.827	3097.40	6.2141
425	100.0	35.509	3172.00	6.3229
450	100.0	33.578	3242.30	6.4219
475	100.0	31.923	3309.70	6.5135

A.4 Subcooled Liquid Properties (by Pressure)

Temperature	Absolute Pressure	Density	Enthalpy	Entropy
°C	bar	kg/m^3	kJ/kg	kJ/kg-K
90	1.01	965.310	377.06	1.1928
65	1.01	980.550	272.18	0.8936
40	1.01	992.220	167.62	0.5724
10	1.01	999.700	42.119	0.1511
90	3.0	965.400	377.22	1.1927
65	3.0	980.640	272.34	0.8935
90	7.0	965.580	377.53	1.1924
65	7.0	980.810	272.68	0.8933
90	10.0	965.720	377.76	1.1922
65	10.0	980.950	272.92	0.8931
90	15.0	965.950	378.15	1.1918
65	15.0	981.160	273.34	0.8928
90	20.0	966.180	378.53	1.1915
65	20.0	981.380	273.75	0.8925
90	25.0	966.400	378.92	1.1911
65	25.0	981.600	274.17	0.8923
90	40.0	967.090	380.08	1.1900
65	40.0	982.260	275.41	0.8914
90	60.0	967.990	381.63	1.1886
65	60.0	983.120	277.07	0.8903
90	80.0	968.890	383.18	1.1872
65	80.0	983.990	278.72	0.8892
90	100.0	969.780	384.73	1.1858
65	100.0	984.850	280.38	0.8881

APPENDIX B: STACK LOSS TABLES

(Based on Combustion Model developed by Greg Harrell, Ph.D., P.E., EMSCAS)

B.1 Fuel Composition

Fuel Composition and Properties	Coal (Bituminous) Water - 4%; Ash - 7%		Coal (Bituminous) Water - 5%; Ash - 35%		Coal (Bituminous) Water - 10%; Ash - 15%		Green Wood		Natural Gas	
Component	Mole Fraction [$lbmol_i/lbmol_{fuel}$]	Mass Fraction [lbm_i/lbm_{fuel}]	Mole Fraction [$lbmol_i/lbmol_{fuel}$]	Mass Fraction [lbm_i/lbm_{fuel}]	Mole Fraction [$lbmol_i/lbmol_{fuel}$]	Mass Fraction [lbm_i/lbm_{fuel}]	Mole Fraction [$lbmol_i/lbmol_{fuel}$]	Mass Fraction [lbm_i/lbm_{fuel}]	Mole Fraction [$lbmol_i/lbmol_{fuel}$]	Mass Fraction [lbm_i/lbm_{fuel}]
C	0.6709	0.7500	0.4942	0.4400	0.6539	0.6300	0.1234	0.0500	0.0000	0.0000
H_2	0.2662	0.0500	0.3677	0.0550	0.2224	0.0360	0.0000	0.0000	0.0000	0.0000
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.9490	0.9053
N_2	0.0057	0.0150	0.0144	0.0300	0.0080	0.0180	0.0000	0.0000	0.0110	0.0183
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_2H_4 (Ethylene)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_2H_6 (Ethane)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0340	0.0607
C_3H_8 (Propane)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0060	0.0157
O_2	0.0225	0.0670	0.0295	0.0700	0.0210	0.0540	0.0000	0.0000	0.0000	0.0000
S	0.0033	0.0100	0.0021	0.0050	0.0035	0.0090	0.0004	0.0004	0.0000	0.0000
H_2O (intrinsic)	0.0226	0.0380	0.0374	0.0500	0.0691	0.1000	0.7889	0.4800	0.0000	0.0000
H_2O (extrinsic)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$C_6H_{10}O_5$ (Cellulose)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0839	0.4596	0.0000	0.0000
Ash (Total)	0.0087	0.0700	0.0546	0.3500	0.0221	0.1530	0.0034	0.0100	0.0000	0.0000
Ash Components										
Al_2O_3	0.0015	0.0147	0.0097	0.0735	0.0039	0.0321	0.0006	0.0021	0.0000	0.0000
SiO_2	0.0055	0.0308	0.0345	0.1540	0.0140	0.0673	0.0022	0.0044	0.0000	0.0000
Fe_2O_3	0.0016	0.0245	0.0103	0.1225	0.0042	0.0536	0.0006	0.0035	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Fuel Molecular Weight	$kgm_{fuel}/kgmol_{fuel}$	10.7340	13.4790		12.4549		29.6086		16.8182	
Fuel Higher Heating Value	kJ/kg	31,788	22,282		25,857		9,666		54,205	
Fuel Lower Heating Value	kJ/kg	30,603	20,958		24,826		7,869		48,906	

B.2 Stack Loss for Natural Gas

Stack Loss Table for			Natural Gas											
Flue Gas Oxygen Content Wet Basis [%]	Flue Gas Oxygen Content Dry Basis [%]	Comb Conc [ppm]	Stack Loss [% of fuel Higher Heating Value input] Net Stack Temperature [Δ°C] {Difference between flue gas exhaust temperature and ambient temperature}											
			100	120	140	160	180	200	220	240	260	280	300	320
1.0	1.2	0	13.6	14.4	15.2	15.9	16.7	17.5	18.3	19.1	19.9	20.7	21.5	22.3
2.0	2.4	0	13.8	14.6	15.4	16.2	17.1	17.9	18.7	19.6	20.4	21.3	22.1	23.0
3.0	3.6	0	14.0	14.8	15.7	16.6	17.4	18.3	19.2	20.1	21.0	21.9	22.7	23.6
4.0	4.7	0	14.2	15.1	16.0	16.9	17.9	18.8	19.7	20.6	21.6	22.5	23.5	24.4
5.0	5.8	0	14.5	15.4	16.4	17.4	18.3	19.3	20.3	21.3	22.3	23.3	24.3	25.3
6.0	6.9	0	14.8	15.8	16.8	17.8	18.9	19.9	21.0	22.0	23.1	24.1	25.2	26.2
7.0	8.0	0	15.1	16.2	17.3	18.4	19.5	20.6	21.7	22.8	24.0	25.1	26.2	27.3
8.0	9.1	0	15.5	16.7	17.8	19.0	20.2	21.4	22.6	23.8	25.0	26.2	27.4	28.6
9.0	10.1	0	15.9	17.2	18.5	19.7	21.0	22.3	23.6	24.9	26.2	27.5	28.8	30.1
10.0	11.1	0	16.5	17.9	19.2	20.6	22.0	23.4	24.8	26.2	27.6	29.0	30.5	31.9
Actual Exhaust T [°C]			120	140	160	180	200	220	240	260	280	300	320	340
Ambient T [°C]			20	20	20	20	20	20	20	20	20	20	20	20

B.3 Stack Loss for #2 Fuel Oil

Stack Loss Table for			Number 2 Fuel Oil											
Flue Gas Oxygen Content Wet Basis [%]	Flue Gas Oxygen Content Dry Basis [%]	Comb Conc [ppm]	Stack Loss [% of fuel Higher Heating Value input] Net Stack Temperature [Δ°C] {Difference between flue gas exhaust temperature and ambient temperature}											
			120	140	160	180	200	220	240	260	280	300	320	340
1.0	1.1	0	10.2	11.0	11.7	12.5	13.2	14.0	14.8	15.6	16.3	17.1	17.9	18.7
2.0	2.2	0	10.4	11.2	12.0	12.8	13.6	14.4	15.2	16.0	16.8	17.7	18.5	19.3
3.0	3.3	0	10.7	11.5	12.3	13.2	14.0	14.8	15.7	16.6	17.4	18.3	19.1	20.0
4.0	4.4	0	10.9	11.8	12.7	13.6	14.5	15.3	16.2	17.1	18.1	19.0	19.9	20.8
5.0	5.5	0	11.2	12.1	13.1	14.0	15.0	15.9	16.9	17.8	18.8	19.7	20.7	21.7
6.0	6.5	0	11.6	12.5	13.5	14.5	15.5	16.5	17.5	18.6	19.6	20.6	21.6	22.7
7.0	7.6	0	11.9	13.0	14.1	15.1	16.2	17.3	18.3	19.4	20.5	21.6	22.7	23.8
8.0	8.6	0	12.4	13.5	14.7	15.8	16.9	18.1	19.3	20.4	21.6	22.8	23.9	25.1
9.0	9.6	0	12.9	14.1	15.4	16.6	17.8	19.1	20.3	21.6	22.8	24.1	25.4	26.6
10.0	10.7	0	13.5	14.9	16.2	17.5	18.9	20.2	21.6	22.9	24.3	25.7	27.1	28.4
Actual Exhaust T [°C]			140	160	180	200	220	240	260	280	300	320	340	360
Ambient T [°C]			20	20	20	20	20	20	20	20	20	20	20	20

B.4 Stack Loss for #6 Fuel Oil

Stack Loss Table for			Number 6 Fuel Oil											
Flue Gas Oxygen Content Wet Basis [%]	Flue Gas Oxygen Content Dry Basis [%]	Comb Conc [ppm]	Stack Loss [% of fuel Higher Heating Value input] Net Stack Temperature [Δ°C] {Difference between flue gas exhaust temperature and ambient temperature}											
			120	140	160	180	200	220	240	260	280	300	320	340
1.0	1.1	0	9.5	10.3	11.1	11.8	12.6	13.4	14.2	14.9	15.7	16.5	17.3	18.1
2.0	2.2	0	9.8	10.6	11.4	12.2	13.0	13.8	14.6	15.4	16.3	17.1	17.9	18.7
3.0	3.3	0	10.0	10.8	11.7	12.5	13.4	14.2	15.1	16.0	16.8	17.7	18.6	19.4
4.0	4.4	0	10.3	11.2	12.0	12.9	13.8	14.7	15.6	16.6	17.5	18.4	19.3	20.2
5.0	5.4	0	10.6	11.5	12.4	13.4	14.3	15.3	16.3	17.2	18.2	19.2	20.1	21.1
6.0	6.5	0	10.9	11.9	12.9	13.9	14.9	15.9	17.0	18.0	19.0	20.0	21.1	22.1
7.0	7.5	0	11.3	12.4	13.4	14.5	15.6	16.7	17.8	18.9	20.0	21.1	22.2	23.3
8.0	8.5	0	11.8	12.9	14.0	15.2	16.4	17.5	18.7	19.9	21.0	22.2	23.4	24.6
9.0	9.6	0	12.3	13.5	14.8	16.0	17.2	18.5	19.8	21.0	22.3	23.6	24.8	26.1
10.0	10.6	0	12.9	14.2	15.6	16.9	18.3	19.7	21.0	22.4	23.8	25.2	26.6	28.0
Actual Exhaust T [°C]			140	160	180	200	220	240	260	280	300	320	340	360
Ambient T [°C]			20	20	20	20	20	20	20	20	20	20	20	20

B.5 Stack Loss for Bituminous Coal (Water – 4%; Ash – 7%)

Stack Loss Table for			Coal-Bituminous-Water 4%-Ash 7%											
Flue Gas Oxygen Content Wet Basis [%]	Flue Gas Oxygen Content Dry Basis [%]	Comb Conc [ppm]	Stack Loss [% of fuel Higher Heating Value input] Net Stack Temperature [Δ°C] {Difference between flue gas exhaust temperature and ambient temperature}											
			120	140	160	180	200	220	240	260	280	300	320	340
1.0	1.1	0	8.2	9.0	9.8	10.6	11.3	12.1	12.9	13.7	14.5	15.3	16.1	16.9
2.0	2.1	0	8.4	9.3	10.1	10.9	11.7	12.5	13.4	14.2	15.0	15.9	16.7	17.6
3.0	3.2	0	8.7	9.5	10.4	11.3	12.1	13.0	13.9	14.7	15.6	16.5	17.4	18.3
4.0	4.3	0	9.0	9.9	10.8	11.7	12.6	13.5	14.4	15.3	16.3	17.2	18.1	19.1
5.0	5.3	0	9.3	10.2	11.2	12.1	13.1	14.1	15.0	16.0	17.0	18.0	19.0	20.0
6.0	6.3	0	9.6	10.6	11.6	12.6	13.7	14.7	15.7	16.8	17.8	18.9	19.9	21.0
7.0	7.4	0	10.0	11.1	12.2	13.2	14.3	15.4	16.5	17.6	18.8	19.9	21.0	22.1
8.0	8.4	0	10.5	11.6	12.8	13.9	15.1	16.3	17.5	18.7	19.8	21.0	22.2	23.5
9.0	9.4	0	11.0	12.2	13.5	14.7	16.0	17.3	18.5	19.8	21.1	22.4	23.7	25.0
10.0	10.4	0	11.6	13.0	14.3	15.7	17.1	18.4	19.8	21.2	22.6	24.0	25.4	26.8
Actual Exhaust T [°C]			140	160	180	200	220	240	260	280	300	320	340	360
Ambient T [°C]			20	20	20	20	20	20	20	20	20	20	20	20

B.6 Stack Loss for Bituminous Coal (Water – 5%; Ash – 35%)

Stack Loss Table for			Coal-Bituminous-Water 5%-Ash 35%											
Flue Gas Oxygen Content Wet Basis	Flue Gas Oxygen Content Dry Basis	Comb Conc	Stack Loss [% of fuel Higher Heating Value input]											
			Net Stack Temperature [Δ°C] {Difference between flue gas exhaust temperature and ambient temperature}											
[%]	[%]	[ppm]	120	140	160	180	200	220	240	260	280	300	320	340
1.0	1.1	0	10.4	11.2	12.0	12.8	13.6	14.4	15.2	16.0	16.8	17.6	18.4	19.2
2.0	2.2	0	10.7	11.5	12.3	13.1	13.9	14.8	15.6	16.4	17.3	18.1	19.0	19.8
3.0	3.4	0	10.9	11.7	12.6	13.5	14.3	15.2	16.1	17.0	17.8	18.7	19.6	20.5
4.0	4.4	0	11.2	12.1	13.0	13.9	14.8	15.7	16.6	17.5	18.5	19.4	20.3	21.3
5.0	5.5	0	11.5	12.4	13.4	14.3	15.3	16.2	17.2	18.2	19.2	20.2	21.1	22.1
6.0	6.6	0	11.8	12.8	13.8	14.8	15.8	16.9	17.9	18.9	20.0	21.0	22.1	23.1
7.0	7.6	0	12.2	13.2	14.3	15.4	16.5	17.6	18.7	19.8	20.9	22.0	23.1	24.2
8.0	8.6	0	12.6	13.8	14.9	16.1	17.2	18.4	19.6	20.8	22.0	23.1	24.3	25.5
9.0	9.7	0	13.1	14.4	15.6	16.9	18.1	19.4	20.6	21.9	23.2	24.5	25.8	27.1
10.0	10.7	0	13.7	15.1	16.4	17.8	19.1	20.5	21.9	23.3	24.7	26.0	27.4	28.8
Actual Exhaust T [°C]			140	160	180	200	220	240	260	280	300	320	340	360
Ambient T [°C]			20	20	20	20	20	20	20	20	20	20	20	20

B.7 Stack Loss for Bituminous Coal (Water – 10%; Ash – 15%)

Stack Loss Table for			Coal-Bituminous-Water 10%-Ash 15%											
Flue Gas Oxygen Content Wet Basis	Flue Gas Oxygen Content Dry Basis	Comb Conc	Stack Loss [% of fuel Higher Heating Value input]											
			Net Stack Temperature [Δ°C] {Difference between flue gas exhaust temperature and ambient temperature}											
[%]	[%]	[ppm]	120	140	160	180	200	220	240	260	280	300	320	340
1.0	1.1	0	8.6	9.4	10.2	11.0	11.8	12.6	13.4	14.3	15.1	15.9	16.7	17.6
2.0	2.2	0	8.8	9.7	10.5	11.3	12.2	13.0	13.9	14.7	15.6	16.5	17.3	18.2
3.0	3.2	0	9.1	9.9	10.8	11.7	12.6	13.5	14.4	15.3	16.2	17.1	18.0	18.9
4.0	4.3	0	9.3	10.3	11.2	12.1	13.1	14.0	15.0	15.9	16.9	17.8	18.8	19.7
5.0	5.3	0	9.7	10.6	11.6	12.6	13.6	14.6	15.6	16.6	17.6	18.6	19.6	20.7
6.0	6.4	0	10.0	11.0	12.1	13.1	14.2	15.2	16.3	17.4	18.4	19.5	20.6	21.7
7.0	7.4	0	10.4	11.5	12.6	13.7	14.9	16.0	17.1	18.3	19.4	20.5	21.7	22.9
8.0	8.4	0	10.9	12.1	13.2	14.4	15.6	16.9	18.1	19.3	20.5	21.7	23.0	24.2
9.0	9.4	0	11.4	12.7	14.0	15.3	16.6	17.9	19.2	20.5	21.8	23.1	24.5	25.8
10.0	10.4	0	12.1	13.4	14.8	16.2	17.6	19.1	20.5	21.9	23.3	24.8	26.2	27.7
Actual Exhaust T [°C]			140	160	180	200	220	240	260	280	300	320	340	360
Ambient T [°C]			20	20	20	20	20	20	20	20	20	20	20	20

B.8 Stack Loss for Green Wood

Stack Loss Table for			Green-Wood Typical											
Flue Gas Oxygen Content Wet Basis [%]	Flue Gas Oxygen Content Dry Basis [%]	Comb Conc [ppm]	Stack Loss [% of fuel Higher Heating Value input] Net Stack Temperature [∆°C] {Difference between flue gas exhaust temperature and ambient temperature}											
			120	140	160	180	200	220	240	260	280	300	320	340
1.0	1.4	0	24.5	25.5	26.5	27.5	28.6	29.6	30.6	31.7	32.7	33.8	34.8	35.9
2.0	2.7	0	24.7	25.8	26.9	27.9	29.0	30.1	31.2	32.3	33.4	34.5	35.6	36.7
3.0	4.0	0	25.1	26.2	27.3	28.4	29.5	30.7	31.8	33.0	34.1	35.3	36.4	37.6
4.0	5.2	0	25.4	26.6	27.8	28.9	30.1	31.3	32.5	33.7	35.0	36.2	37.4	38.6
5.0	6.4	0	25.8	27.0	28.3	29.5	30.8	32.1	33.3	34.6	35.9	37.2	38.5	39.8
6.0	7.6	0	26.2	27.5	28.9	30.2	31.5	32.9	34.2	35.6	36.9	38.3	39.7	41.0
7.0	8.7	0	26.7	28.1	29.5	31.0	32.4	33.8	35.2	36.7	38.1	39.6	41.0	42.5
8.0	9.7	0	27.3	28.8	30.3	31.8	33.4	34.9	36.4	38.0	39.5	41.1	42.6	44.2
9.0	10.8	0	28.0	29.6	31.2	32.9	34.5	36.2	37.8	39.5	41.1	42.8	44.5	46.2
10.0	11.8	0	28.8	30.5	32.3	34.1	35.9	37.6	39.4	41.2	43.1	44.9	46.7	48.5
Actual Exhaust T [°C]			140	160	180	200	220	240	260	280	300	320	340	360
Ambient T [°C]			20	20	20	20	20	20	20	20	20	20	20	20