CHAPTER 2
GETTING THE MOST FOR YOUR FUEL BILL

Heat (Energy) Supplied = Heat (Energy) Required + Losses

This statement reflects the fact that of the many processes requiring heat, whether climate control of office buildings, steam for sterilizing food in a cannery, or hot gas to reheat steel ingots in a rolling mill, none are perfectly efficient. The losses are usually significant, and minimizing them is the objective of good energy management. Most of this chapter addresses a wide perspective, looking at energy issues other than combustion itself. There are many ways in which heat and energy losses can be reduced. It requires specific attention and effort but the payoff can be significant, from the viewpoints of both savings and emissions.

There are many ways in which heat and energy losses can be reduced. Some, like cogeneration, are more sophisticated and complex, but many can be easily implemented and pay back well. A major food processor saved $60,000 per year in fuel costs by testing and repairing steam traps[1]. A paper mill saved $92,000 per year through improved combustion from re-vamped boiler controls[1]. Lowering the system steam pressure or water temperature can also reduce energy consumption.

The Right Plant Configuration

<u>Heat Cascading</u>

Plants that have two or more requirements for heat: steam for a process, hot air for drying and hot water space heating; present the possibility of using the heat exhausted from one part of the process as the input for another. For example, air or gas exhausted from a high-temperature process could be passed through a waste heat boiler to generate steam or hot water for space heating and service water. Ideally, the heat supplied from fuel should be directed to the process having the highest temperature requirement and its exhaust heat utilized in lower temperature applications. The heat finally exhausted should be at the lowest temperature that can be economically achieved. In some cases selling steam or hot water to a neighboring facility may be feasible.

<u>Cogeneration</u>

Where there are both electrical and heating demands, or where electricity can be profitably sold, cogeneration may be economically viable. It is a specialized form of heat cascading in which the fuel is used to generate electricity, either by an engine or turbine-driven generator. The process heat demands are supplemented or met by recovering the waste heat from the hot gases exhausted by the turbine or engine. Cogeneration may require more fuel, and considerably more capital, than would be required to simply meet the heat requirement, but the bonus is the electric energy it provides at high thermal

[1] Enbridge Consumers Gas Steam Saver Program

efficiency. So the total electrical and thermal energy is supplied at lower cost. The overall system efficiency may be 70% or more, compared to 30% to 35% for generation of electricity alone.

The economic benefits depend on whether the value of the electricity sufficiently offsets the cost of the additional fuel and equipment. The environmental benefits depend on whether the emissions from the cogeneration system compare favourably to emissions associated with equivalent energy supplied from the electrical grid. This is often an easy case to make if the electric utility generates thermal power from fossil fuels, in which case the conversion of fuel energy to electricity is 35% or less.

Small cogeneration systems, up to 1 MWe capacity, typically use reciprocating engines to drive the generator. Heat from the engine exhaust and cooling systems is used to generate hot water or low-pressure steam. Larger cogeneration systems usually employ gas turbines to drive the electrical generators. The gas turbine exhaust, at about 540 °C (1000 °F) or more, is capable of generating high-pressure steam which may be used for process or heating purposes, or may power a steam turbine which drives an additional electrical generator. The Vineland Research Farm case study (see Chapter 7) is an example of a reciprocating engine cogeneration application.

Micro gas turbines, 1 MWe and smaller, are becoming available for applications where small generating capacity and high-pressure steam are required.

<u>Boiler Sizing</u>

Many boiler plants, particularly those serving mostly a space-heating load, experience substantial seasonal variations in demand. For reasons discussed in Chapter 3, the efficiency with which boilers convert fuel energy to steam or hot water drops sharply at low load, that is, as output drops below about 40% of maximum capacity rating (MCR). It therefore makes sense to select boiler sizes to match seasonal demand; perhaps a small boiler selected to operate at close to full load for periods of low demand, with one or two larger boilers sized to handle peak loads. The Saskatchewan Penitentiary case study (see Chapter 7) shows how this approach is saving one heating plant about 500,000 m^3 of natural gas per year, equivalent to approximately $75,000 annually. Reductions in emissions are also impressive.

Piping System Losses – Get the Heat Where It's Wanted

<u>Insulation</u>

Most systems that employ heat, whether for industrial processes or space heating, have to transport it from the source to the end user. Distances may vary from a few metres to a few kilometres. Steam is a popular transport medium because the change of state permits a high energy density. The source, a boiler, converts water to steam; the user extracts the energy, converting the steam back to water (condensate), which is returned to the boiler. Other systems simply employ a fluid medium, usually a liquid, without a change of state.

The source heats it, the user cools it. Those operating at relatively low temperatures may use water as the medium, while thermal fluids or water-and-glycol mixtures can meet higher temperature requirements.

Whatever the transport medium, a piping system is required, and heat is lost from it because the temperature of the fluid in the pipes is well above ambient. Insulating the piping system can substantially reduce the heat loss. Per unit of surface area, the heat loss is proportional to the temperature difference between the surface exposed to air and the air temperature. Thus, while an insulated pipe warm to the touch (and having a larger surface area than the same length of uninsulated pipe) still loses some heat, it loses much less than an uninsulated hot pipe.

The first step to reducing the energy lost from a piping system is to amply insulate all surfaces. Consider a system carrying steam at 125 psig through 4 inch diameter piping; if only ten flanges are left uninsulated the annual heat loss is equivalent to 2450 m^3 of natural gas, worth $367.50[2]. Uninsulated or poorly insulated lengths of pipe can quickly lose many times this much energy.

Temperature of Heat Transfer Fluid

Another way to reduce heat losses from piping systems is to reduce the temperature of the fluid in the pipes. This has the same effect as increasing the thickness of pipe insulation; it reduces the difference between ambient temperature and that of the fluid. The savings can be impressive. If, when the outside temperature is 0 °C (32 °F), a district heating system can maintain comfortable building temperatures with water supplied at 65 °C (150 °F) instead of 93 °C (200 °F) the energy loss from the piping system is reduced by 30%. In colder weather the supply temperature might have to be increased, but reducing supply temperature as the heat demand falls can offer substantial savings.

Steam heating systems can likewise reduce piping losses by operating at lower pressures. A piping system containing saturated steam at 125 psig has an internal temperature of 178 °C (353 °F). If the pressure were reduced to 100 psig the steam temperature would be 170 °C (338 °F). At an ambient temperature of 0 °C (32 °F) the piping losses would be reduced by about 4.7%. For a system with 5000 ft of insulated steam piping, this could result in savings of 400 m^3/h of natural gas, worth perhaps $600/h, and a corresponding reduction in combustion emissions.

Steam systems can be complicated and changing the system operating pressure may require verification that the boilers and end devices can operate at the lower pressure. However, the potential environmental and dollar savings are worth investigating.

Large energy savings can be realized by selecting, if possible, a low temperature system over a high temperature system, such as replacing a steam heating system with a water

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[2] with gas priced at $150/1000 m^3

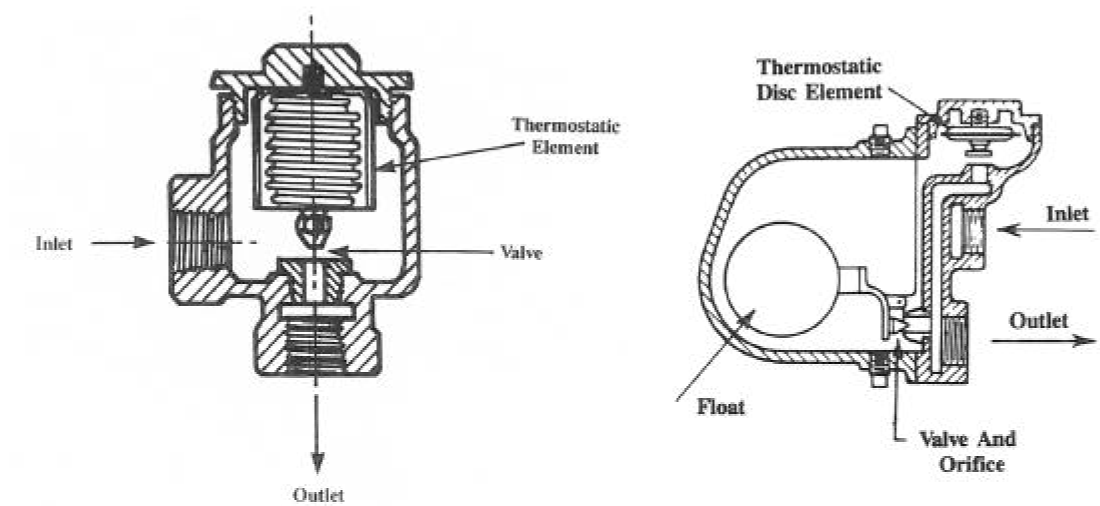
distribution system. Using the examples above, if the 125 psig system were converted to a 65 °C (150 °F) water system, the energy losses would be reduced by 63%. It is best to consider such an option at the initial design stage since converting an existing system requires a large capital investment.

Often building heating systems are operated through the summer, when little or no heating is required, because the system provides heat to a continuous process, such as domestic hot water. Installing a local water heater would permit shutdown of the heating system for the non-heating months, eliminating all the combustion and system losses for that period.

<u>Steam Traps – Keep the Steam In</u>

Steam systems offer high energy per unit of mass flow but have to deal with two fluids: steam and water. The heat users convert the steam to condensate as they absorb its energy; also, heat losses from the piping system, as already discussed, cause some steam to revert to liquid form. The condensate must be separated from the steam to prevent accumulations that can cause corrosion and water hammer, and should be returned to the boilerhouse to reduce the requirement for treated feedwater. Steam traps are the mechanical devices that remove the condensate from the steam lines, and it is important that they function efficiently. Any steam escaping through the traps is lost energy.

There are a variety of steam trap designs, each having specific applications. Two common types are shown in Figure 2-1. Recommended usage is given in Table 2-1. It is important that steam traps are sized correctly. A too large trap will allow steam to leak continuously and a trap that is too small will not release the condensate as fast as it gathers in the system.



Bellows Thermostatic Trap   Float And Thermostatic Trap

Figure 2-1   Common Steam Traps

In a steam distribution system, steam trap failures can average up to 25% per year. They can be caused by dirt or scale lodged inside the trap or a mechanical failure. Some trap types fail with their orifice closed and others fail open. In either case, the problems can be significant. If the trap fails closed, the condensate will back up into the steam system, posing the risk of water hammer. If the internal valve remains open, steam loss through the trap is continuous. A single 3.2 mm trap failure in a 100 psig steam system can lose the equivalent of 11,575 m^3/y of natural gas, an approximate value of $1700/y.

Table 2-1 Steam Trap Selection Guide[3]

Application	First Choice	Second Choice
Air Heating Coils	Float and Thermostatic	
Air Heating Steam Pipe Coils	Balanced Pressure Thermostatic Thermo-Matic Thermostatic	
Hot Water Heaters	Float and Thermostatic	
Shell and Tube Heat Exchangers		
Small or High Pressure	Thermo-Matic Thermostatic Balanced Pressure Thermostatic	Float and Thermostatic
Large or Low/Medium Pressure	Float and Thermostatic	
Steam Line Traps		
0-15 psig	Float and Thermostatic	
16-125 psig	Thermo-Dynamic	Float and Thermostatic
126-600 psig	Thermo-Dynamic	Inverted Bucket
High Pressure or Superheat	Bimetallic	Thermo-Dynamic
Steam Humidifiers	Float and Thermostatic	Inverted Bucket
Steam Radiators	Balanced Pressure Thermostatic	Thermo-Dynamic
Unit Heaters	Float and Thermostatic	Balanced Pressure Thermostatic
Submerged Heating Coils		
High Pressure	Thermo-Matic Thermostatic Thermo-Dynamic	Inverted Bucket Balanced Pressure Thermostatic
Low/Medium Pressure	Float and Thermostatic	Balanced Pressure Thermostatic
Steam Tracer Lines	Thermo-Dynamic Bimetallic	Liquid Expansion

Steam trap leaks can be detected in a number of ways. With condensate return systems that are not pressurized, the existence of major leaks can be determined by monitoring the condensate return tank temperature. If the temperature approaches the boiling point of water (100 °C or 212 °F) then a significant amount of steam is being returned to the tank, usually an indication of multiple steam trap leaks. The condensate return tank should be monitored continuously and, in general, if temperatures go above 80 °C (180 °F) the traps should be investigated.

[3] Natural Resources Canada, Energy Management Series, Steam and Condensate Systems

Searching for steam trap failures should be an ongoing maintenance program. Well designed condensate return systems, with a test valve at each steam trap, make verifying the steam trap a simple matter of opening the test valve and watching for steam or condensate as the trap operates. (Note that for pressurized condensate systems the condensate will flash as it exits the valve and troubleshooting the condensate system will be more difficult.) For systems without test valves, leaks can be found with a temperature measuring device or an acoustic leak detector or a stethoscope. Any of these devices can be purchased for less than $500. When checking steam traps it is important to understand the operation of the steam trap type being tested. Some types cycle between passing condensate (and a little steam) and no flow and others pass the condensate continuously. Cycling versus continuous flow can be detected with an acoustic device, taking care not to be confused by system noises carried by the piping system. An infrared temperature sensor can be used to check the function of an open-and-close type of trap as follows:

Proper functioning:	Slightly higher temperature on the inlet (steam) side of the trap than on the outlet (condensate) side.
Trap failed closed:	Low temperature on the steam side.
Trap failed open:	High temperature on the condensate side.

Caution: Leakage from another steam trap can raise the temperature of the entire condensate system.

In and Around the Boiler

Keep Your Boiler Clean

The flue gas leaving the boiler represent an important energy loss, the higher its temperature the greater the loss. In general, designers' predictions of flue gas temperature are based on a fouling factor, which assumes that for each fuel a certain amount of deposition on the fireside of the tubes is unavoidable. This deposition reduces heat transfer; tests have shown a 0.03 inch soot layer reduces heat transfer 9.5% and a 0.18 inch layer reduces heat transfer 69%[4]. The flue gas temperature rises as a result. (See Figure 2-2.) Boilers burning solid fuels such as coal and biomass have large fouling factors, whereas liquid fuels, particularly refined oils, are associated with low fouling factors. Natural gas can be expected to burn cleanly, leaving no deposits.

Maintaining the boiler at peak efficiency requires keeping the boiler surfaces as clean as possible. Large boilers and those burning fuels with high fouling factors have sootblower systems that clean the fireside surfaces while the boiler is operating. Small boilers and

[4] Diamond Power Specialty Company

natural-gas-fired boilers do not have sootblower systems and should be opened regularly for inspection and cleaning.

Figure 2-2 shows that heat transfer can also be impaired by deposits on the waterside of boiler tubes. Such deposits can reduce boiler efficiency substantially, and lead to serious mechanical and operating problems as well. Waterside deposits restrict the amount of heat transferred to the boiler water and, in watertube boilers, also restrict water circulation. The tube metal temperature rises as a result, which may increase both the rate of deposition and flue gas temperature. In extreme cases, the tubes fail from overheating.

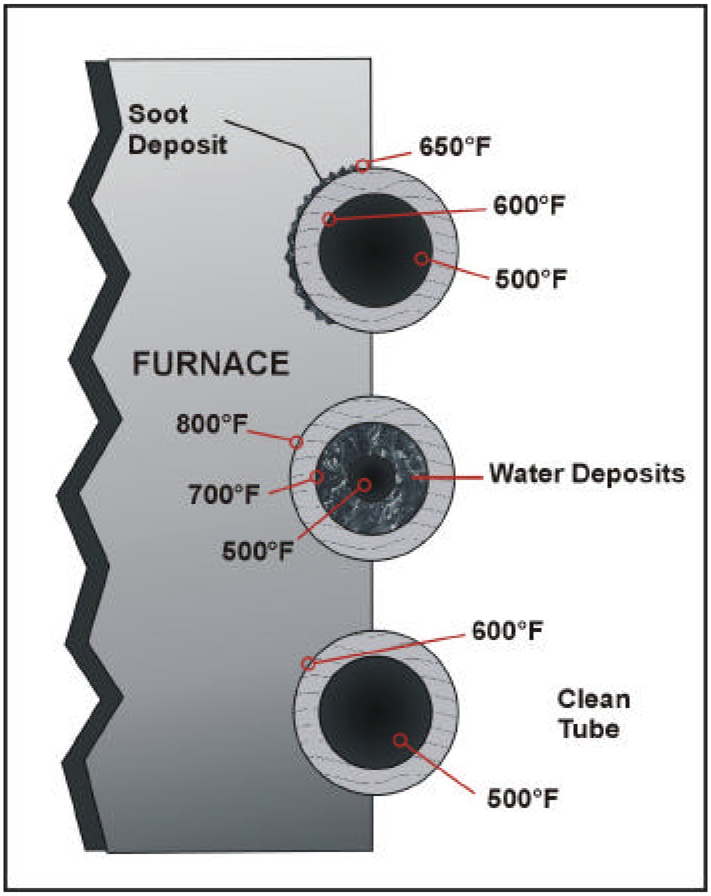


Figure 2-2 Effects of Deposits on Boiler Tube Heat Transfer

Visually checking the cleanliness of boiler waterside surfaces is difficult, since it involves shutting down and draining the boilers. Instead, waterside conditions are inferred by testing the boiler water while the boiler is operating. The results determine what water treatment chemicals are then injected. Smaller, lower pressure boiler plants test their boiler water daily while larger, higher pressure plants test every hour. The water treatment and testing program is critical to ensuring the maximum efficiency and reliable operation of any boiler plant.

An upward trend in flue gas temperature over weeks or months is usually an indication of deposit buildup on either the gas side or water side of boiler heat exchange surfaces. A boiler inspection should be done as soon as possible.

Boiler Blowdown – Heat Down the Drain

Boiler feedwater, even though treated, contains small quantities of dissolved solids, mostly compounds of iron, calcium, magnesium and sodium. As the water is evaporated into steam these impurities are concentrated in the remaining liquid, and readily lead to the undesirable waterside deposits already discussed. To prevent deposition, the concentration of impurities is controlled by periodic or continuous blowdown; some boiler water with a high concentration of impurities is drained, and replaced by feedwater containing a lower level of impurities. Unfortunately, the water containing the solids is also heated water. On simple blowdown systems, that energy literally goes down the drain. For a boiler operating at 125 psig, a pound of water contains 330 Btu. Continuous blowdown systems are normally set at 5% of the maximum boiler rating, so for a 50,000 lb/h boiler, the blowdown flow would be 2,500 lb/h or 825,000 Btu/h, the equivalent of 22 m^3/h of natural gas ($3.30/h or $28,200/y).

For steam boilers this loss cannot be eliminated completely, but there are ways to reduce it. The optimum blowdown rate can be established by testing the total dissolved solids (TDS) in the boiler water and/or blowdown water. As the blowdown flow is reduced, the TDS will increase. The blowdown flow can be decreased until the dissolved solids reach the maximum safe level, which will depend on the boiler type, water quality and typical boiler firing rate. Automatic blowdown control systems are available; they continuously measure the blowdown TDS and set the blowdown valve to maintain a specific value. Blowdown heat recovery systems are also available. A decision for these systems must weigh the economic and environmental benefits from the recovered heat against the installation costs and any additional system and operating complexity.

One advantage of water heating systems over steam heating systems is that water heating systems do not require blowdown.

Economizers and Air Heaters – The Misers of Heat Recovery

The boilerhouse, as the site of the primary heat generator, is the location of the highest-grade heat, and therefore has excellent potential for heat recovery. Blowdown heat recovery, already discussed, is by no means the only possibility. The best opportunities lie in supplementary heat recovery from the flue gas.

Even with the burners adjusted to provide the minimum flue gas temperatures commensurate with complete combustion, most boilers have exit flue gas temperatures that range from 175 °C (~350 °F) to 260 °C (500 °F). There is ample room to recover some of this heat that otherwise “goes up the stack,” provided it is properly designed. Figure 2-3 shows one arrangement, called an economizer, which takes heat from the flue gas to preheat boiler feedwater. It typically increases the overall boiler efficiency by 3%

to 4%. A similar device called an air heater transfers heat from the flue gas to the combustion air. Chapter 3 explains how to calculate the effect of supplementary heat recovery on boiler efficiency.

Design and operation of economizers and air heaters must be handled knowledgeably because of potential corrosion problems. As the flue gas temperature is reduced it approaches its dewpoint, the temperature at which vapour starts to condense. For two reasons, this is especially important with fuels that contain sulphur. First, the liquid, which condenses, contains sulphuric acid, and is very corrosive. Second, the presence of sulphur trioxide (SO_3) in the flue gas raises the dewpoint. It is also important to understand that the risk of condensation is not related to the average or even the lowest flue gas temperature, but to the lowest surface temperature in the heat exchanger. Thus, most susceptible are those parts where incoming air or feedwater may drop heat exchanger surface temperatures well below flue gas temperature.

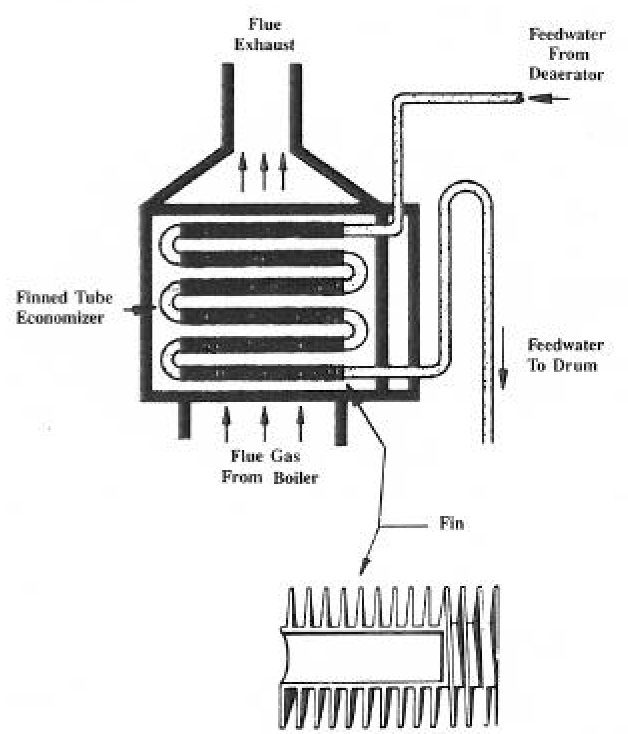


Figure 2-3   Flue Gas Economizer

Typical low temperature limits for different fuels are given in Table 2-2, although, dependent on fuel and the stack and ducting arrangement, each boiler has its specific limit, which should be determined individually when supplementary heat recovery is being considered. Since the flue gas temperatures are lower at lower loads, economizers usually are equipped with some form of bypass control that maintains the flue gas temperature above a preset minimum.

Table 2-2 Typical Low Flue Gas Temperature Limits for Different Fuels[5]

Natural Gas	120 °C (250 °F)
No. 2 Oil	135 °C (275 °F)
Low Sulphur No. 6 Oil	145 °C (~290 °F)
High Sulphur No. 6 Oil, Coal	150 °C (~300 °F)

Overall boiler efficiencies can be improved further with another type of economizer, called a condensing economizer. It cools the flue gas to well below the water vapour dewpoint, recovering both sensible heat from the flue gas and latent heat from moisture in the fuel and formed by the combustion of hydrogen. With these systems, condensation (and corrosion of metal surfaces) are a certainty, so the heat exchanger and downstream ducting are made of a corrosion-resistant material, usually fiberglass or ceramic. A variation of this concept is a direct contact economizer; water is sprayed directly into the flue gas and the resulting hot water is gathered for circulation, after treatment to neutralize its corrosion potential. With a condensing economizer, boiler efficiencies can readily exceed 90% and may approach 100%. The Sacré-Coeur Hospital heating plant retrofit case study (see Chapter 7) is an example where direct contact condensing economizers were used.

[5] Boiler Efficiency Institute, Boiler Efficiency Improvement Handbook